



MONTANA-DAKOTA

UTILITIES CO.

A Division of MDU Resources Group, Inc.

400 North Fourth Street
Bismarck, ND 58501
(701) 222-7900

April 20, 2009

RECEIVED

APR 20 2009

PUBLIC SERVICE COMMISSION

Executive Secretary
North Dakota Public Service
Commission
State Capitol Building
Bismarck, ND 58505

Re: Annual Reports

Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc., herewith submits one copy of its FERC Form No. 1 for the year ended December 31, 2008, which will serve to complete Montana-Dakota's filing requirements for the North Dakota Annual Report.

Please acknowledge receipt by stamping or initialing the duplicate copy of this letter attached hereto and returning the same in the enclosed self-addressed, stamped envelope.

Sincerely,

Donald R. Ball
Vice President - Regulatory Affairs

Enclosure

THIS FILING IS

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

Form 1 Approved
OMB No. 1902-0021
(Expires 12/31/2011)
Form 1-F Approved
OMB No. 1902-0029
(Expires 12/31/2011)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 1/31/2012)



**FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of
Major Electric Utilities, Licensees
and Others and Supplemental
Form 3-Q: Quarterly Financial Report**

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. 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 confidential nature

Exact Legal Name of Respondent (Company)

MDU Resources Group, Inc.

Year/Period of Report

End of 2008/Q4



INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q) is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

- (1) one million megawatt hours of total annual sales,
- (2) 100 megawatt hours of annual sales for resale,
- (3) 500 megawatt hours of annual power exchanges delivered, or
- (4) 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

(a) Submit FERC Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: <http://www.ferc.gov/docs-filing/eforms/form-1/elec-subm-soft.asp>. The software is used to submit the electronic filing to the Commission via the Internet.

(b) The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

(c) Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:

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

(d) For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

- a) Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and
- b) 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. §§ 41.10-41.12 for specific qualifications.)

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

- e) The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of _____ for the year ended on which we have reported separately under date of _____, we have also reviewed schedules _____ of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases."

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

- (f) 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's website at <http://www.ferc.gov/help/how-to.asp>.

- (g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from <http://www.ferc.gov/docs-filing/eforms/form-1/form-1.pdf> and <http://www.ferc.gov/docs-filing/eforms.asp#3Q-gas>.

IV. When to Submit:

FERC Forms 1 and 3-Q must be filed by the following schedule:

- a) FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and
- b) FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,144 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 FERC Form 3-Q collection of information is estimated to average 150 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 this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.
- II. Enter in whole numbers (dollars or MWH) 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** (see VII. below).
- 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 software only. Please explain the reason for the resubmission in a footnote to the data field.
- VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.
- IX. 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.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the

termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

I. Commission Authorization (Comm. Auth.) -- 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.

II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

(3) 'Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

(4) 'Person' means an individual or a corporation;

(5) 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

(7) 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power;

(11) "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

(a) To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development -costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the -proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports salt be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, 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 FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be filed..."

General Penalties

The Commission may assess up to \$1 million per day per violation of its rules and regulations. *See* FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

**FERC FORM NO. 1/3-Q:
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER**

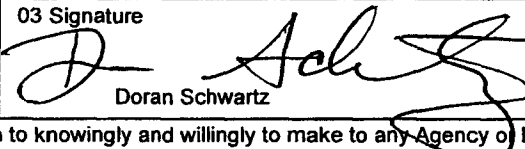
IDENTIFICATION

01 Exact Legal Name of Respondent MDU Resources Group, Inc.		02 Year/Period of Report End of <u>2008/Q4</u>
03 Previous Name and Date of Change (if name changed during year) / /		
04 Address of Principal Office at End of Period (Street, City, State, Zip Code) 400 North Fourth St, Bismarck, ND 58501-4092		
05 Name of Contact Person Doran Schwartz		06 Title of Contact Person VP and CAO
07 Address of Contact Person (Street, City, State, Zip Code) 1200 West Century Ave, Bismarck, ND, 58506-5650		
08 Telephone of Contact Person, Including Area Code (701) 530-1750	09 This Report Is (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	10 Date of Report (Mo, Da, Yr) 12/31/2008

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.

01 Name Doran Schwartz	03 Signature  Doran Schwartz	04 Date Signed (Mo, Da, Yr) 04/08/2009
02 Title VP and CAO		

Title 18, U.S.C. 1001 makes it a crime for any person to 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 MDU Resources Group, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of <u>2008/Q4</u>
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LIST OF SCHEDULES (Electric Utility)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	NA
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Important Changes During the Year	108-109	
7	Comparative Balance Sheet	110-113	
8	Statement of Income for the Year	114-117	
9	Statement of Retained Earnings for the Year	118-119	
10	Statement of Cash Flows	120-121	
11	Notes to Financial Statements	122-123	
12	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
13	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
14	Nuclear Fuel Materials	202-203	NA
15	Electric Plant in Service	204-207	
16	Electric Plant Leased to Others	213	NA
17	Electric Plant Held for Future Use	214	NA
18	Construction Work in Progress-Electric	216	
19	Accumulated Provision for Depreciation of Electric Utility Plant	219	
20	Investment of Subsidiary Companies	224-225	
21	Materials and Supplies	227	
22	Allowances	228-229	
23	Extraordinary Property Losses	230	NA
24	Unrecovered Plant and Regulatory Study Costs	230	NA
25	Transmission Service and Generation Interconnection Study Costs	231	NA
26	Other Regulatory Assets	232	
27	Miscellaneous Deferred Debits	233	
28	Accumulated Deferred Income Taxes	234	
29	Capital Stock	250-251	
30	Other Paid-in Capital	253	NA
31	Capital Stock Expense	254	
32	Long-Term Debt	256-257	
33	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
34	Taxes Accrued, Prepaid and Charged During the Year	262-263	
35	Accumulated Deferred Investment Tax Credits	266-267	
36	Other Deferred Credits	269	

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	NA
38	Accumulated Deferred Income Taxes-Other Property	274-275	
39	Accumulated Deferred Income Taxes-Other	276-277	
40	Other Regulatory Liabilities	278	
41	Electric Operating Revenues	300-301	
42	Sales of Electricity by Rate Schedules	304	
43	Sales for Resale	310-311	
44	Electric Operation and Maintenance Expenses	320-323	
45	Purchased Power	326-327	
46	Transmission of Electricity for Others	328-330	
47	Transmission of Electricity by ISO/RTOs	331	NA
48	Transmission of Electricity by Others	332	
49	Miscellaneous General Expenses-Electric	335	
50	Depreciation and Amortization of Electric Plant	336-337	
51	Regulatory Commission Expenses	350-351	
52	Research, Development and Demonstration Activities	352-353	NA
53	Distribution of Salaries and Wages	354-355	
54	Common Utility Plant and Expenses	356	
55	Amounts included in ISO/RTO Settlement Statements	397	NA
56	Purchase and Sale of Ancillary Services	398	NA
57	Monthly Transmission System Peak Load	400	
58	Monthly ISO/RTO Transmission System Peak Load	400a	NA
59	Electric Energy Account	401	
60	Monthly Peaks and Output	401	
61	Steam Electric Generating Plant Statistics	402-403	
62	Hydroelectric Generating Plant Statistics	406-407	NA
63	Pumped Storage Generating Plant Statistics	408-409	NA
64	Generating Plant Statistics Pages	410-411	
65	Transmission Line Statistics Pages	422-423	
66	Transmission Lines Added During the Year	424-425	

Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of <u>2008/Q4</u>
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LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Substations	426-427	
68	Footnote Data	450	
	<p>Stockholders' Reports Check appropriate box:</p> <p><input checked="" type="checkbox"/> Four copies will be submitted</p> <p><input type="checkbox"/> No annual report to stockholders is prepared</p>		

Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of <u>2008/Q4</u>
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GENERAL INFORMATION

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

Doran Schwartz - Vice President and Chief Accounting Officer
400 North Fourth Street
Bismarck, North Dakota 58501-4092

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.

Delaware - March 14, 1924

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.

None

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

Electric Service - Montana, North Dakota, South Dakota, and Wyoming
Natural Gas Service - Minnesota, Montana, North Dakota, South Dakota, and Wyoming
Propane Service - North Dakota
Nonutility Operations - Minnesota, Montana, North Dakota, South Dakota, Wyoming, Iowa, and Nebraska
Gas Transmission - Minnesota and North Dakota

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

- (1) Yes...Enter the date when such independent accountant was initially engaged:
(2) No

Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/Q4
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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.

Definitions

1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which 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)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Centennial Energy Holdings, Inc. (1)	Holding Company	100	
2	MDU Energy Capital, LLC (1)	Holding Company	100	
3	Prairie Cascade Energy Holdings, LLC - Z	Holding Company	100	
4	Cascade Natural Gas Corporation - AH	Gas Utility Company	100	
5	Cascade Land Leasing Co. - AD, Y	General Purposes	100	
6	CGC Energy, Inc. - AD, Y	Gas Management Services	100	
7	CGC Properties, Inc. - AD, Y	General Purposes	100	
8	CGC Resources, Inc. - AD	Gas Pipeline Capacity Segm.	100	
9	Prairie Intermountain Energy Holdings, LLC - Z	Holding Company	100	
10	Intermountain Gas Company - U	Gas Utility Company	100	
11	Knife River Corporation - A	Construction Materials&Mining	100	
12	KRC Holdings, Inc. - B	Holding Company	100	
13	Alaska Basic Industries, Inc. - C	Construction Materials	100	
14	Ames Sand & Gravel, Inc. - T	Construction Materials	100	
15	Anchorage Sand and Gravel Company, Inc. - H	Construction Materials	100	
16	Baldwin Contracting Company, Inc. - C	Construction Materials	100	
17	Central Oregon Redi-Mix, LLC - O	Construction Materials	78	
18	Concrete, Inc. - C	Construction Materials	100	
19	Connolly-Pacific Co. - C	Construction Materials	100	
20	D S S Company - C	Construction Materials	100	
21	Fairbanks Materials, Inc. - H	Construction Materials	100	
22	Granite City Ready Mix, Inc. - C	Construction Materials	100	
23	Hap Taylor & Sons, Inc. - C	Construction Materials	100	
24	Hawaiian Cement - I	Construction Materials	100	
25	JTL Group, Inc. - Montana - C	Construction Materials	100	
26	JTL Group, Inc. - Wyoming - C	Construction Materials	100	
27	Jebro Incorporated - C	Construction Materials	100	

Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/Q4
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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.

Definitions

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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)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Kent's Oil Service - C	Construction Materials	100	
2	KRC Aggregate, Inc. - C	Construction Materials	100	
3	Knife River Corporation - North Central	Construction Materials	100	
4	(f/k/a Bauerly Bros, Inc.) - C			
5	Knife River Corporation - South	Construction Materials	100	
6	(f/k/a Young Contractors, Inc.) - C			
7	Knife River Dakota, Inc. - C	Construction Materials	100	
8	Knife River Hawaii, Inc. - C	Construction Materials	100	
9	Knife River Marine, Inc. - C	Construction Materials	100	
10	Knife River Midwest, LLC	Construction Materials	100	
11	(f/k/a Fred Carlson Company, LLC) - C			
12	LTM, Incorporated - C	Construction Materials	100	
13	Morse Bros., Inc. - C	Construction Materials	100	
14	Northstar Materials, Inc. - C	Construction Materials	100	
15	Rogue Aggregates, Inc. - C	Construction Materials	100	
16	WHC, Ltd. - C	Construction Materials	100	
17	MDU Construction Services Group, Inc. - A	Holding Company	100	
18	BEH Electric Holdings, LLC - F	Holding Company	100	
19	Bell Electrical Contractors, Inc. - F	Construction Services	100	
20	BMH Mechanical Holdings, LLC - F	Holding Company	100	
21	Bombard Electric, LLC - AG	Construction Services	100	
22	Bombard Mechanical, LLC - AI	Construction Services	100	
23	Capital Electric Construction Company, Inc.-F	Construction Services	100	
24	Capital Electric Line Builders, Inc. - F	Construction Services	100	
25	Continental Line Builders, Inc. - F	Construction Services	100	
26	Coordinating and Planning Services, Inc. - F	Construction Services	100	
27	Desert Fire Holdings, Inc. - F	Holding Company	100	

Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/Q4
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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.

Definitions

1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which 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)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Desert Fire Protection, LLC - AN	Holding Company	100	
2	Desert Fire Protection, a Nevada	Construction Services	100	
3	Limited Partnership - AO			
4	Desert Fire Protection, Inc. - AN	Construction Services	100	
5	E.S.I., Inc. - P	Construction Services	100	
6	Frebco, Inc. - AM	Construction Services	100	
7	Hamlin Electric Company - Q	Construction Services	100	
8	Harp Engineering, Inc. - F	Engineering Services	100	
9	Independent Fire Fabricators, LLC - AN	Construction Services	100	
10	International Line Builders, Inc. - F	Construction Services	100	
11	ILB Hawaii, Inc. - G	Construction Services	100	
12	LME&U Holdings, LLC - F	Holding Company	100	
13	Lone Mountain Excavation & Utilities, LLC - AF	Construction Services	100	
14	Loy Clark Pipeline Co. - F	Construction Services	100	
15	MDU Industrial Services, Inc. - F	Holding Company	100	
16	Midland Technical Crafts, Inc. - AM	Construction Services	100	
17	Oregon Electric Construction, Inc. - F	Construction Services	100	
18	Pouk & Steidle, Inc. - F	Construction Services	100	
19	Rocky Mountain Contractors, Inc. - F	Construction Services	100	
20	USI Industrial Services, Inc. - AM	Construction Services	100	
21	Warner Enterprises, Inc. - F	Construction Services	100	
22	Wagner Group, Inc., The - F	Holding Company	100	
23	Wagner Industrial Electric, Inc. - AM	Holding Company	100	
24	Wagner-Smith Company, The - P	Construction Services	100	
25	Wagner-Smith Equipment Co. - F	Construction Services	100	
26	Wagner-Smith Pumps & Systems, Inc. - P	Construction Services	100	
27	WBI Holdings, Inc. - A	Holding Company	100	

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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	WBI Pipeline & Storage Group, Inc. - E	Holding Company	100	
2	Williston Basin Interstate Pipeline Company-L	Natural Gas Transmission	100	
3	WBI Canadian Pipeline, Ltd. - L	Natural Gas Trans & Storage	100	
4	Bitter Creek Pipelines, LLC - L	Natural Gas Gathering	100	
5	WBI Energy Services, Inc. - E	Holding Company	100	
6	Prairielands Magnetics Limited (f/k/a	Pipeline and Cable Mag/Locate	100	
7	Innovatum International Limited) - AE			
8	Prairielands Energy Marketing, Inc. - J	Energy Marketing	100	
9	Fidelity Exploration & Production Company - E	Oil & Natural Gas Production	100	
10	Fidelity Exploration & Production Company	Oil & Gas Production	100	
11	of Texas LLC - K, Y			
12	Fidelity Oil Co. - K	Oil & Natural Gas Production	100	
13	Seven Brothers Ranches, Inc. - K, Y	Oil & Natural Gas Production	100	
14	Clearflame, LLC - K	Energy Production	100	
15	Netricity LLC - V	Electric Generation	75	
16	Centennial Energy Resources LLC - A	Holding Company	100	
17	Centennial Energy Holdings Trinidad LLC - W, Y	Holding Company	100	
18	Centennial Energy Resources	Holding Company	100	
19	International, Inc. - D			
20	Centennial Holdings Capital LLC - A	Holding Company	100	
21	FutureSource Capital Corp. - R	Asset Management	100	
22	InterSource Insurance Company - R	Captive Insurance Company	100	
23	MDU Resources Luxembourg I LLC S.a.r.l. - W	Holding Company	100	
24	MDU Resources Luxembourg II LLC S.a.r.l. - AC	Holding Company	100	
25	MDU Brasil Ltda. - X	Holding Company	100	
26	MDU Norte Transmissao de Energia Ltda. - AQ	Holding Company	99	
27	MDU Sul Transmissao de Energia Ltda. - AQ	Holding Company	99	

Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/Q4
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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	MDU Resources International LLC - W	Holding Company	100	
2	MDU Chile Inversiones Ltda. - AB	Holding Company	100	
3	(1)-Direct subsidiary of MDU Resources			
4	Group, Inc.			
5	A-100% held by Centennial Energy Holdings, Inc			
6	B-100% held by Knife River Corporation			
7	C-100% held by KRC Holdings, Inc.			
8	D-100% held by Centennial Energy Resources LLC			
9	E-100% held by WBI Holdings, Inc.			
10	F-100% held by MDU Construction Services			
11	Group, Inc.			
12	G-100% held by International Line Builders,			
13	Inc.			
14	H-100% held by Alaska Basic Industries, Inc.			
15	I-Partners include Knife River Hawaii, Inc.			
16	(50%) and Knife River Dakota, Inc. (50%)			
17	J-100% held by WBI Energy Services, Inc.			
18	K-100% held by Fidelity Exploration &			
19	Production Company			
20	L-100% held by WBI Pipeline & Storage			
21	Group, Inc.			
22	M-Reserved for future use			
23	N-Reserved for future use			
24	O-78% held by Hap Taylor & Sons, Inc.			
25	P-100% held by The Wagner Group, Inc.			
26	Q-100% held by Rocky Mountain			
27	Contractors, Inc.			

Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/Q4
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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	R-100% held by Centennial Holdings			
2	Capital LLC			
3	S-Reserved for future use			
4	T-100% held by Knife River Corporation -			
5	North Central			
6	U-100% held by Prairie Intermountain			
7	Energy Holdings, LLC			
8	V-Interest held by Fidelity Exploration			
9	& Production Company			
10	W-100% held by Centennial Energy Resources			
11	International, Inc.			
12	X-99.9999% held by MDU Resources Luxembourg			
13	I LLC S.a.r.l. and .0001% held by			
14	Centennial Energy Resources International,			
15	Inc.			
16	Y-Entity was dissolved through merger with			
17	affiliate or dissolution			
18	Z-100% held by MDU Energy Capital, LLC			
19	AA-Equity interests sold to 3rd party			
20	AB-99.9% held by MDU Resources International			
21	LLC and 0.1% held by Centennial Energy			
22	Resources International, Inc.			
23	AC-100% held by MDU Resources Luxembourg I			
24	LLC S.a.r.l.			
25	AD-100% held by Cascade Natural			
26	Gas Corporation			
27	AE-100% held by Prairielands Energy Marketing,			

Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of <u>2008/Q4</u>
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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Inc.			
2	AF-100% held by LME&U Holdings, LLC			
3	AG-100% held by BEH Electric Holdings, LLC			
4	AH-100% held by Prairie Cascade			
5	Energy Holdings, LLC			
6	AI-100% held by BMH Mechanical Holdings, LLC			
7	AJ-Reserved for future use			
8	AK-Reserved for future use			
9	AL-Reserved for future use			
10	AM-100% held by MDU Industrial Services, Inc.			
11	AN-100% held by Desert Fire Holdings, Inc.			
12	AO-Partners include Desert Fire Protection,			
13	LLC (99%) and Desert Fire Holdings,			
14	Inc. (1%)			
15	AP-Reserved for future use			
16	AQ-99.99999% owned by MDU Brasil Ltda.			
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Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Month/Year) 12/31/2008	Year/Period of Report End of 2008/Q4
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OFFICERS

1. Report below the name, title and salary 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 principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
 2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1			
2	President and Chief Executive Officer	Terry D. Hildestad	
3			
4	President and Chief Executive Officer of Montana-	Bruce T. Imsdahl	
5	Dakota Utilities Co. and Great Plains Natural		
6	Gas Co.; Chief Executive Officer of Cascade Natural		
7	Gas Corp.		
8			
9	President and Chief Executive Officer of Montana-	David L. Goodin	
10	Dakota Utilities Co., Great Plains Natural Gas Co.,		
11	Cascade Natural Gas Corp. and Intermountain		
12	Gas Company		
13			
14	Vice President - Administration	Cynthia J Norland	
15			
16	Executive Vice President, Treasurer and Chief	Vernon A. Raile	
17	Financial Officer		
18			
19	Vice President - Human Resources	Mark Del Vecchio	
20			
21	General Counsel and Secretary	Paul K. Sandness	
22			
23	Controller	Nicole A. Kivisto	
24			
25	Vice President and Chief Accounting Officer	Doran N. Schwartz	
26			
27	Vice President - Strategic Planning	John P. Stumpf	
28			
29	Vice President - Renewable Resources	William E. Connors	
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Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report 2008/Q4
FOOTNOTE DATA			

Schedule Page: 104 Line No.: 4 Column: b

Bruce T. Imsdahl retired effective June 5, 2008.

Schedule Page: 104 Line No.: 9 Column: b

David L. Goodin was named president and chief executive officer of Montana-Dakota Utilities Co., Great Plains Natural Gas Co. and Cascade Natural Gas Corp. on June 6, 2008. He was named president and chief executive officer of Intermountain Gas Company when it was acquired on October 1, 2008.

Schedule Page: 104 Line No.: 29 Column: b

William E. Connors was named vice president of renewable resources effective September 1, 2008.

Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of <u>2008/Q4</u>
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DIRECTORS

- Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
- Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Harry J. Pearce, Chairman of the Board	Detroit, Michigan
2		
3	Terry D. Hildestad, President and Chief Executive Officer	Bismarck, North Dakota
4		
5	Thomas Everist	Sioux Falls, South Dakota
6		
7	Karen B. Fagg	Billings, Montana
8		
9	Dennis W. Johnson	Dickinson, North Dakota
10		
11	Richard H. Lewis	Denver, Colorado
12		
13	Patricia L. Moss	Bend, Oregon
14		
15	John L. Olson	Sidney, Montana
16		
17	Sister Thomas Welder, O.S.B.	Bismarck, North Dakota
18		
19	John K. Wilson	Omaha, Nebraska
20		
21	A. Bart Holaday	Placitas, New Mexico, and Grand Forks, North Dakota
22		
23	Thomas C. Knudson	Houston, Texas
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Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report 12/31/2008	Year/Period of Report End of 2008/Q4
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IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If 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: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the 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 condition. 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 give reference to 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 as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
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 reported on Page 106, 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. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. 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.

PAGE 108 INTENTIONALLY LEFT BLANK
SEE PAGE 109 FOR REQUIRED INFORMATION.

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
MDU Resources Group, Inc.	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 12/31/2008	2008/Q4
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

1. The Respondent renewed franchises in the fourth quarter in 2008 in New Leipzig, Burt, Bentley, Medina and Napoleon, North Dakota.

2. A subsidiary of the Respondent acquired all of the issued and outstanding capital stock of Yarbrough's Dirt Pit, Inc., doing business as Yarbrough's Material & Construction ("Yarbrough") in a cash-for-stock transaction. The Yarbrough operation supplies aggregate and produces ready-mix concrete near Sour Lake, Texas, approximately 25 miles west of Beaumont. The Yarbrough operation serves the southeast Texas market, primarily the Beaumont and Port Arthur areas, with an aggregate distribution yard and ready-mix plant.

In related transactions, (1) the Respondent, by and through a subsidiary, acquired all of the issued and outstanding capital stock of ATM Leasing and Management, Inc. and ownership of its operating subsidiary, Amador Transit Mix, Inc. in a stock-for-stock transaction and (2) a subsidiary of the Respondent acquired a related company in a cash-for-stock transaction (collectively referred to as "Amador"). The Amador operation produces ready-mix in Sutter Creek, California, located approximately 45 miles southwest of Sacramento.

A subsidiary of the Respondent acquired substantially all of the assets of Ideal Contractors, Inc. and certain assets of its affiliate ("Ideal") in a cash-for-assets transaction. Ideal produces construction aggregates and provides construction grading and pipe installation services. Ideal's operations are located in Idaho Falls, Idaho.

On October 1, 2008, the acquisition of Intermountain Gas Company ("IGC") was finalized. The Respondent acquired all of the issued and outstanding shares of IGC capital stock in a cash-for-stock transaction. The enterprise value of the transaction, including indebtedness, is approximately \$328 million. IGC, headquartered in Boise, Idaho, serves more than 300,000 customers in 74 communities in Idaho, including the Boise metropolitan area, Twin Falls, Sun Valley, Pocatello and Idaho Falls. IGC is an indirect wholly owned subsidiary of the Respondent, continuing to operate as Intermountain Gas Company. IGC joins Montana-Dakota Utilities Co., Great Plains Natural Gas Co. and Cascade Natural Gas Corp. as the Respondent's utility business units. Prior to the IGC acquisition, the Respondent's utility segment served approximately 510,000 natural gas customers in North Dakota, Minnesota, Montana, Oregon, South Dakota, Washington and Wyoming, as well as nearly 121,000 electric customers in North Dakota, Montana, South Dakota and Wyoming. With the addition of IGC, the utility customer base exceeds 930,000 customers.

A subsidiary of the Respondent acquired all of the issued and outstanding capital stock of Warner Enterprises, Inc., doing business as Sun Valley Electric Supply Company ("Sun Valley") in a cash-for-stock transaction. Sun Valley is a distributor of electrical supply products to the Las Vegas, NV construction market.

A subsidiary of the Respondent acquired substantially all of the assets of Arctic Circle Consulting Group, Inc., doing business as Fairbanks Block & Landscape Supply ("Fairbanks Block"), in a cash-for-assets transaction. The Fairbanks Block business manufactures and sells concrete block and landscape supplies and materials in the Fairbanks, AK area.

In 2008, the Respondent issued 207,392 original issue shares of the Respondent's Common Stock representing the stock consideration paid for all of the issued and outstanding capital stock with respect to businesses or business assets acquired during 2008 plus earn-out consideration issuances, a purchase price adjustment issuance, and a deferred consideration issuance with respect to prior years' acquisitions. See Note 2 to Financial Statements contained on page 123.12.

All of the original issue shares of the Respondent's common stock issued in connection with acquisitions were authorized by the following orders: (a) by the Federal Energy Regulatory Commission by an Order dated September 13, 2006 (effective October 27, 2006) in Docket No. ES06-60-000; (b) by the Montana Public Service Commission by an Order dated August 29, 2006 in Docket No. D2006.8.120, Default Order No. 6767; and (c) by the Public

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	12/31/2008	2008/Q4
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

Service Commission of Wyoming by an Order dated October 6, 2006 (effective October 2, 2006) in Docket No. 30013-178-GS-06 (Record No. 10739). These regulatory orders have now been superseded by the following regulatory orders.

The Respondent's common stock that may be issued in connection with acquisitions, if any, in the future are authorized by the following orders: (a) by the Federal Energy Regulatory Commission by an Order dated October 2, 2008 (effective October 27, 2008) in Docket No. ES08-56-000; (b) by the Montana Public Service Commission by an Order dated August 19, 2008 in Docket No. D2008.7.91, Default Order No. 6933; and (c) by the Public Service Commission of Wyoming by an Order Nunc Pro Tunc dated September 15, 2008 (effective October 2, 2008) in Docket No. 30013-206-GS-08 and Docket No. 20004-74-ES-08 (Record No. 11831).

3. None.

4. None, other than normal renewal of leaseholds in the normal course of business.

5. None.

6. The Respondent's commercial paper borrowings were \$22,500,000 at December 31, 2008. The issuance of commercial paper is authorized pursuant to the following orders:

On December 9, 2008, the Respondent received FERC authorization to incur short-term indebtedness in an amount not to exceed \$150 million. This authorization was granted in Docket No. ES09-8-000.

On November 26, 2008, the Respondent received the same authorization from the state of Montana. This order authorized the Respondent to issue up to \$150 million in short-term indebtedness. This authorization was granted in Docket No. D2008.11.125, Default Order No. 6959.

7. None.

8. Wage increases to nonunion employees averaged 4.49% in 2008. Wage increases to union employees averaged 4.09% effective May 1, 2008. The estimated annualized impact of the increases amounted to approximately \$2,813,000.

9. See Note 20 of the Notes to Financial Statements contained on pages 123.42 through 123.49.

10. None.

11. None.

12. None.

13. Bruce T. Imsdahl, president and chief executive officer of Montana-Dakota Utilities Co. and Great Plains Natural Gas Co. and chief executive officer of Cascade Natural Gas Corp., retired effective June 5, 2008.

David L. Goodin, on June 6, 2008, was named president and chief executive officer of Montana-Dakota Utilities Co., Great Plains Natural Gas Co. and Cascade Natural Gas Corp. He was named president and chief executive officer of Intermountain Gas Company when it was acquired October 1, 2008.

William E. Connors was named vice president renewable resources of MDU Resources Group, Inc. effective September 1, 2008.

14. Not applicable.

Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/Q4
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COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (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	1,106,816,262	1,015,157,478
3	Construction Work in Progress (107)	200-201	69,079,327	69,763,782
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		1,175,895,589	1,084,921,260
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	623,400,887	598,947,512
6	Net Utility Plant (Enter Total of line 4 less 5)		552,494,702	485,973,748
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		552,494,702	485,973,748
15	Utility Plant Adjustments (116)	122	0	0
16	Gas Stored Underground - Noncurrent (117)		3,166,622	2,757,982
17	OTHER PROPERTY AND INVESTMENTS			
18	Nonutility Property (121)		3,707,024	3,117,373
19	(Less) Accum. Prov. for Depr. and Amort. (122)		1,117,112	1,013,133
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	2,478,164,341	2,284,551,173
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		35,032,098	40,972,687
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		0	0
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	0
31	Long-Term Portion of Derivative Assets - Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		2,515,786,351	2,327,628,100
33	CURRENT AND ACCRUED ASSETS			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		181,115	2,633,013
36	Special Deposits (132-134)		1,200	1,200
37	Working Fund (135)		113,921	163,690
38	Temporary Cash Investments (136)		1,938,468	422,455
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		29,930,415	27,981,262
41	Other Accounts Receivable (143)		2,394,649	3,357,347
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		285,809	230,059
43	Notes Receivable from Associated Companies (145)		57,000,000	0
44	Accounts Receivable from Assoc. Companies (146)		26,427,125	30,629,676
45	Fuel Stock (151)	227	4,099,005	4,055,099
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	10,225,093	9,128,932
49	Merchandise (155)	227	1,742,091	1,470,096
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/Q4
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COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	0	0
55	Gas Stored Underground - Current (164.1)		8,529,714	18,158,827
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		4,865,549	4,425,641
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		46,729,484	39,762,227
62	Miscellaneous Current and Accrued Assets (174)		2,560	184,014
63	Derivative Instrument Assets (175)		0	0
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		193,894,580	142,143,420
68	DEFERRED DEBITS			
69	Unamortized Debt Expenses (181)		1,191,582	893,195
70	Extraordinary Property Losses (182.1)	230	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230	0	0
72	Other Regulatory Assets (182.3)	232	88,196,422	20,474,249
73	Prelim. Survey and Investigation Charges (Electric) (183)		579,901	766,627
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	17,318
75	Other Preliminary Survey and Investigation Charges (183.2)		2,084	0
76	Clearing Accounts (184)		-191,726	-49,436
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	26,229,986	30,878,709
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		9,990,648	10,604,809
82	Accumulated Deferred Income Taxes (190)	234	60,304,833	37,651,678
83	Unrecovered Purchased Gas Costs (191)		24,225,488	3,474,582
84	Total Deferred Debits (lines 69 through 83)		210,529,218	104,711,731
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		3,475,871,473	3,063,214,981

Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Rresubmission	Date of Report (mo, da, yr) 12/31/2008	Year/Period of Report end of 2008/Q4
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COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	184,208,283	182,946,528
3	Preferred Stock Issued (204)	250-251	15,000,000	15,000,000
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	941,909,202	916,218,614
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	3,610,416	3,412,569
11	Retained Earnings (215, 215.1, 216)	118-119	436,608,753	303,634,911
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	1,180,220,338	1,129,950,735
13	(Less) Reaquired Capital Stock (217)	250-251	3,625,813	3,625,813
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	10,365,311	-9,393,173
16	Total Proprietary Capital (lines 2 through 15)		2,761,075,658	2,531,319,233
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	235,500,000	150,500,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	80,708,867	61,800,000
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		1,837	2,417
24	Total Long-Term Debt (lines 18 through 23)		316,207,030	212,297,583
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)		1,582,142	1,821,121
29	Accumulated Provision for Pensions and Benefits (228.3)		59,371,415	45,052,837
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		0	0
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)		2,691,414	2,518,372
35	Total Other Noncurrent Liabilities (lines 26 through 34)		63,644,971	49,392,330
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		33,220,974	49,239,911
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		7,119,598	9,391,348
41	Customer Deposits (235)		2,408,988	2,340,670
42	Taxes Accrued (236)	262-263	-840,838	19,382,784
43	Interest Accrued (237)		4,206,271	2,664,504
44	Dividends Declared (238)		28,639,606	26,619,224
45	Matured Long-Term Debt (239)		0	0

Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (mo, da, yr) 12/31/2008	Year/Period of Report end of <u>2008/Q4</u>
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COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS) (Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		1,578,001	1,525,151
48	Miscellaneous Current and Accrued Liabilities (242)		25,765,992	25,405,080
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		0	0
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		102,098,592	136,568,672
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		5,289,755	3,342,874
57	Accumulated Deferred Investment Tax Credits (255)	266-267	361,334	609,529
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	101,962,554	46,514,581
60	Other Regulatory Liabilities (254)	278	9,003,884	10,023,560
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		77,224,425	61,172,778
64	Accum. Deferred Income Taxes-Other (283)		39,003,270	11,973,841
65	Total Deferred Credits (lines 56 through 64)		232,845,222	133,637,163
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		3,475,871,473	3,063,214,981

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	12/31/2008	2008/Q4
FOOTNOTE DATA			

Schedule Page: 110 Line No.: 62 Column: c

Variance from 2007 balance relates to imbalance gas: commencing 12/31/08 imbalance gas is reported in account 164.1, Gas Stored Underground - Current.

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(Next page is 114)

Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of <u>2008/Q4</u>
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STATEMENT OF INCOME

Quarterly

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

Annual or Quarterly if applicable

5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility column in a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
8. Report data for lines 8, 10 and 11 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1 and 407.2.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	584,829,693	479,711,278		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	470,670,904	376,331,906		
5	Maintenance Expenses (402)	320-323	19,311,970	18,240,027		
6	Depreciation Expense (403)	336-337	31,622,134	29,408,715		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	2,001,207	2,257,001		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	417,079	557,863		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)					
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	15,072,952	13,307,800		
15	Income Taxes - Federal (409.1)	262-263	-8,932,009	11,041,912		
16	- Other (409.1)	262-263	-1,066,422	1,334,554		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	78,259,688	43,796,440		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	59,075,796	47,575,113		
19	Investment Tax Credit Adj. - Net (411.4)	266				
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		548,281,707	448,701,105		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117, line 27		36,547,986	31,010,173		

STATEMENT OF INCOME FOR THE YEAR (Continued)

- 9. Use page 122 for important notes regarding the statement of income for any account thereof.
- 10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
- 11. Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts.
- 12. If any notes appearing in the report to stockholders are applicable to the Statement of Income, such notes may be included at page 122.
- 13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
- 14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
- 15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		Line No.
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	
						1
203,439,609	189,941,801	381,390,084	289,769,477			2
						3
120,267,566	113,443,902	350,403,338	262,888,004			4
15,685,232	15,057,765	3,626,738	3,182,262			5
22,263,977	20,509,629	9,358,157	8,899,086			6
						7
1,245,367	1,536,588	755,840	720,413			8
414,260	414,260	2,819	143,603			9
						10
						11
						12
						13
8,722,281	7,879,928	6,350,671	5,427,872			14
-1,344,590	7,999,500	-7,587,419	3,042,412			15
48,168	985,053	-1,114,590	349,501			16
40,010,477	26,475,998	38,249,211	17,320,442			17
30,938,171	27,243,957	28,137,625	20,331,156			18
						19
						20
						21
						22
						23
						24
176,374,567	167,058,666	371,907,140	281,642,439			25
27,065,042	22,883,135	9,482,944	8,127,038			26

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL		Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
			Current Year (c)	Previous Year (d)		
27	Net Utility Operating Income (Carried forward from page 114)		36,547,986	31,010,173		
28	Other Income and Deductions					
29	Other Income					
30	Nonutility Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		15,413,288	15,150,624		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		13,284,678	13,367,647		
33	Revenues From Nonutility Operations (417)		13,450,064	12,061,773		
34	(Less) Expenses of Nonutility Operations (417.1)		9,674,608	8,421,461		
35	Nonoperating Rental Income (418)					
36	Equity in Earnings of Subsidiary Companies (418.1)	119	264,879,580	405,457,963		
37	Interest and Dividend Income (419)		2,212,431	3,458,922		
38	Allowance for Other Funds Used During Construction (419.1)		119,056	1,230,086		
39	Miscellaneous Nonoperating Income (421)		35,554	-17,382		
40	Gain on Disposition of Property (421.1)		532	163,976		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		273,151,219	415,716,854		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)			1,178		
44	Miscellaneous Amortization (425)	340				
45	Donations (426.1)	340	318,212	265,260		
46	Life Insurance (426.2)					
47	Penalties (426.3)			2,219		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		28,745	57,205		
49	Other Deductions (426.5)		33,895	301,071		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		380,852	626,933		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	2,062	658		
53	Income Taxes-Federal (409.2)	262-263	2,573,441	-240,162		
54	Income Taxes-Other (409.2)	262-263	249,199	66,438		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	843,857	3,444,119		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	785,409	224,152		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)		248,195	355,732		
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		2,634,955	2,691,169		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		270,135,412	412,398,752		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		12,963,505	10,758,084		
63	Amort. of Debt Disc. and Expense (428)		64,625	63,191		
64	Amortization of Loss on Required Debt (428.1)		614,160	626,768		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Required Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)	340				
68	Other Interest Expense (431)	340	897,173	1,173,325		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		1,529,294	1,332,792		
70	Net Interest Charges (Total of lines 62 thru 69)		13,010,169	11,288,576		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		293,673,229	432,120,349		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		293,673,229	432,120,349		

Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report 2008/Q4
FOOTNOTE DATA			

Schedule Page: 114 Line No.: 4 Column: h

Per Docket No. RM04-12-000; Order No. 668: Operation Expenses reduced by Sales for Resale fuel and purchased power costs of \$2,413,319.

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. 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)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. 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.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		303,634,911	53,187,450
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	FIN 48 adjustment	236		69,222
5	Close-out KESOP dividend equivalents	242		55,725
6	Sale of IPP line of business	216		230,000,000
7	FAS 159 adoption	219	280,727	
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)		280,727	230,124,947
10	Dividends equivalents on stock based compensation	253	-149,784	(260,447)
11	Deferred taxes on FAS 159 adoption	190	-54,804	
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)		-204,588	(260,447)
16	Balance Transferred from Income (Account 433 less Account 418.1)		28,793,649	26,662,386
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24	4.5%	238	-450,004	(450,004)
25	4.7%	238	-235,000	(235,000)
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-685,004	(685,004)
30	Dividends Declared-Common Stock (Account 438)			
31			-109,925,942	(101,969,421)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-109,925,942	(101,969,421)
37	Transfers from Acct 216.1, Unappropri. Undistrib. Subsidiary Earnings		214,715,000	96,575,000
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		436,608,753	303,634,911
	APPROPRIATED RETAINED EARNINGS (Account 215)			

Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo Yr) 12/ J08	Year/Period of Report End of 2008/Q4
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STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. 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)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. 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.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
39				
40				
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		436,608,753	303,634,911
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		1,129,950,735	1,051,023,038
50	Equity in Earnings for Year (Credit) (Account 418.1)		264,879,580	405,457,963
51	(Less) Dividends Received (Debit)		214,715,000	96,575,000
52			105,023	(229,955,266)
53	Balance-End of Year (Total lines 49 thru 52)		1,180,220,338	1,129,950,735

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
MDU Resources Group, Inc.	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 12/31/2008	2008/Q4
FOOTNOTE DATA			

Schedule Page: 118 Line No.: 52 Column: c

Adoption of FAS 159	\$217,906
Dividend equivalents on stock based compensation - CEHI	(\$108,000)
Dividend equivalents on stock based compensation - MDU EC	(\$ 4,883)

Schedule Page: 118 Line No.: 52 Column: d

Sale of IPP line of buiness	(\$230,000,000)
Dividend equivalents on stock based compensation - CEHI	\$ 48,341
Dividend equivalents on stock based compensation - MDU EC	(\$ 3,607)

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(Next page is 120)

STATEMENT OF CASH FLOWS

(1) Codes to be used: (a) Net Proceeds or Payments; (b) Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) 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 Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	293,673,229	432,120,349
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	34,040,420	32,223,579
5	Amortization of		
6	Loss on Reacquired Debt, Bond Discount and Debt Exp	316,354	689,959
7			
8	Deferred Income Taxes (Net)	19,761,591	496,230
9	Investment Tax Credit Adjustment (Net)	-248,195	-355,732
10	Net (Increase) Decrease in Receivables	3,271,846	-1,449,017
11	Net (Increase) Decrease in Inventory	8,217,051	10,086,658
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	-34,470,080	17,597,389
14	Net (Increase) Decrease in Other Regulatory Assets	2,019,006	-4,000,748
15	Net Increase (Decrease) in Other Regulatory Liabilities	-781,318	-1,329,929
16	(Less) Allowance for Other Funds Used During Construction	119,056	1,230,086
17	(Less) Undistributed Earnings from Subsidiary Companies	171,164,580	308,882,963
18	Other (provide details in footnote):		
19	Unrecoverd Purchased Gas Costs	-20,750,906	-10,991,050
20	Net Change in Other Current & Accrued Assets	-7,225,711	-2,211,144
21	Other Noncurrent Changes	14,673,542	14,646,513
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	141,213,193	177,410,008
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-92,857,092	-110,629,425
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant	-11,781,411	-14,770,682
29	Gross Additions to Nonutility Plant	-592,637	-455,601
30	(Less) Allowance for Other Funds Used During Construction	-119,056	-1,230,086
31	Other (provide details in footnote):		
32	Gas in Underground Storage - Noncurrent	-408,640	1,135,536
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-105,520,724	-123,490,086
35			
36	Acquisition of Other Noncurrent Assets (d)		-3,097,384
37	Proceeds from Disposal of Noncurrent Assets (d)	5,940,589	
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	-172,005,700	-290,177,157
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies	121,000,000	281,230,210
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

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 31) 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 Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
54	Depreciation of Nonutility Plant	122,650	102,657
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-150,463,185	-135,431,760
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	100,508,867	35,250,000
62	Preferred Stock		
63	Common Stock	15,011,178	17,263,199
64	Other (provide details in footnote):	57,000,000	
65			
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	172,520,045	52,513,199
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-53,600,000	-6,600,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Adjustment to Retained Earnings	-44,761	-159,988
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock	-685,004	-685,004
81	Dividends on Common Stock	-109,925,942	-101,969,421
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	8,264,338	-56,901,214
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-985,654	-14,922,966
87			
88	Cash and Cash Equivalents at Beginning of Period	3,219,158	18,142,124
89			
90	Cash and Cash Equivalents at End of period	2,233,504	3,219,158

Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report 2008/Q4
FOOTNOTE DATA			

Schedule Page: 120 Line No.: 8 Column: b

Adjustment reflecting non-cash reclass for OCI (\$174,248)
Adjustment reflecting non-cash reclass for FAS 158 (\$492,082)

Schedule Page: 120 Line No.: 8 Column: c

Adjustment reflecting non-cash reclass for utility OCI (\$24,404)
Adjustment reflecting reclassification of GPNG acquisition adjustment (\$4,358,097)

Schedule Page: 120 Line No.: 13 Column: c

Adjustment reflecting non-cash reclass for FIN 48 \$40,675

Schedule Page: 120 Line No.: 14 Column: b

Adjustment reflecting non-cash reclass for OCI \$ 221,984
Adjustment reflecting non-cash reclass for FAS 158 \$69,519,195

Schedule Page: 120 Line No.: 14 Column: c

Adjustment reflecting non-cash reclass for manufactured gas
plant site ARO settlement (\$66,452)
Adjustment reflecting non-cash reclass for utility OCI \$9,139,874

Schedule Page: 120 Line No.: 15 Column: b

Adjustment reflecting non-cash reclass for FAS 158 \$65,316

Schedule Page: 120 Line No.: 15 Column: c

Adjustment reflecting non-cash reclass for utility OCI (\$401,898)

Schedule Page: 120 Line No.: 21 Column: b

Adjustment reflecting non-cash reclass for OCI (\$ 48,919)
Adjustment reflecting non-cash reclass for FAS 158 (\$69,092,429)
Adjustment reflecting non-cash reclass for common stock \$ 3,286,020

Schedule Page: 120 Line No.: 21 Column: c

Adjustment reflecting non-cash reclass for manufactured gas plant
site ARO settlement \$66,452
Adjustment reflecting reclassification of GPNG acquisition adjustment \$4,358,097
Adjustment reflecting non-cash reclass for utility OCI (\$8,344,416)
Adjustment reflecting non-cash reclass for FIN 48 (\$ 109,897)
Adjustment reflecting non-cash reclass for common stock \$3,748,845

Schedule Page: 120 Line No.: 36 Column: c

Adjustment reflecting non-cash reclass for utility OCI (\$369,156)

Schedule Page: 120 Line No.: 42 Column: b

Special dividends for subsidiary's acquisition of Intermountain Gas Company

Schedule Page: 120 Line No.: 42 Column: c

Proceeds from sale of IPP line of business

Schedule Page: 120 Line No.: 64 Column: b

Issuance of short-term note for subsidiary's acquisition of Intermountain Gas Company

Schedule Page: 120 Line No.: 77 Column: b

Adjustment reflecting non-cash reclass for OCI (\$225,923)
Dividend equivalents on stock based compensation \$181,162

Schedule Page: 120 Line No.: 77 Column: c

Dividend equivalents on stock based compensation (\$159,988)
FIN 48 Adjustment \$ 69,222
Adjustment reflecting non-cash reclass for FIN 48 (\$ 69,222)

Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report 12/31/2008	Year/Period of Report End of 2008/Q4
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NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Commission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 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 items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. 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.
8. 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.
9. 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.

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
MDU Resources Group, Inc.	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 12/31/2008	2008/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of presentation

The consolidated financial statements of the Company include the accounts of the following businesses: electric, natural gas distribution, construction services, pipeline and energy services, natural gas and oil production, construction materials and contracting, and other. The electric, natural gas distribution, and pipeline and energy services businesses are substantially all regulated. Construction services, natural gas and oil production, construction materials and contracting, and other are nonregulated. For further descriptions of the Company's businesses, see Note 16. The statements also include the ownership interests in the assets, liabilities and expenses of two jointly owned electric generating facilities.

The financial statements were prepared in accordance with the accounting requirements of the FERC as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America. These requirements differ from generally accepted accounting principles (GAAP) related to the presentation of certain items including, but not limited to, the current portion of long-term debt, deferred income taxes, cost of removal liabilities, and current unrecovered purchased gas costs.

The Respondent owns two wholly owned subsidiaries, Centennial Energy Holdings, Inc. and MDU Energy Capital, LLC. As required by the FERC for Form 1 report purposes, MDU Resources Group, Inc. reports its subsidiary investment using the equity method rather than consolidating the assets, liabilities, revenues and expenses of the subsidiary, as required by GAAP. If GAAP were followed, utility plant, other property and investments would increase by \$1,343,759,873; current and accrued assets would increase by \$1,078,397,064; deferred debits would increase by \$689,816,306; long-term debt would increase by \$1,252,428,624; other noncurrent liabilities and current and accrued liabilities would increase by \$801,731,078; deferred credits would increase by \$1,057,813,541 as of December 31, 2008. Furthermore, operating revenues would increase by \$4,418,448,695 and operating expenses, excluding income taxes, would increase by \$3,952,145,625 for the twelve months ended December 31, 2008. In addition, net cash provided by operating activities would increase by \$738,926,000; net cash used in investing activities would increase by \$1,050,810,000; net cash provided by financing activities would increase by \$259,399,000; the effect of exchange rate changes on cash would decrease by \$635,000; and the net change in cash and cash equivalents would be a decrease of \$53,121,000 for the twelve months ended December 31, 2008. Reporting its subsidiary investment using the equity method rather than GAAP has no effect on net income or retained earnings.

The Company's notes to the financial statements are presented consolidated with its subsidiary investments and prepared in conformity with GAAP. Accordingly, certain footnotes are not reflective of the Company's FERC basis financial statements contained herein.

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 SFAS No. 71. SFAS No. 71 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

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
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NOTES TO FINANCIAL STATEMENTS (Continued)			

being amortized consistently with the regulatory treatment established by the FERC and the applicable state public service commissions. See Note 6 for more information regarding the nature and amounts of these regulatory deferrals.

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

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.

Allowance for doubtful accounts

The Company's allowance for doubtful accounts as of December 31, 2008 and 2007, was \$13.7 million and \$14.6 million, respectively.

Natural gas in storage

Natural gas in storage for the Company's regulated operations is generally carried at cost using the last-in, first-out method. The portion of the cost of natural gas in storage expected to be used within one year was included in inventories and was \$27.6 million and \$28.8 million at December 31, 2008 and 2007, respectively. The remainder of natural gas in storage, which largely represents the cost of the gas required to maintain pressure levels for normal operating purposes, was included in other assets and was \$43.4 million and \$43.0 million at December 31, 2008 and 2007, respectively.

Inventories

Inventories, other than natural gas in storage for the Company's regulated operations, consisted primarily of aggregates held for resale of \$89.1 million and \$102.2 million, materials and supplies of \$92.4 million and \$56.0 million, and other inventories of \$52.4 million and \$42.3 million, as of December 31, 2008 and 2007, respectively. These inventories were stated at the lower of average cost or market value.

Investments

The Company's investments include its equity method investments as discussed in Note 4, the cash surrender value of life insurance policies, investments in fixed-income and equity securities and auction rate securities. Under the equity method, investments are initially recorded at cost and adjusted for dividends and undistributed earnings and losses. On January 1, 2008, upon the adoption of SFAS No. 159, the Company elected to measure its investments in certain fixed-income and equity securities at fair value with any unrealized gains and losses recorded on the Consolidated Statements of Income. Prior to the adoption of SFAS No. 159, the Company's fixed-income and equity securities were accounted for as available-for-sale investments in accordance with SFAS No. 115. In accordance with SFAS No. 115, these investments were recorded at fair value with any unrealized gains and losses, net of income taxes, recorded in accumulated other comprehensive income (loss) on the Consolidated Balance Sheets until realized. The Company accounts for auction rate securities as available-for-sale in accordance with SFAS No. 115. For more information, see Notes 8 and 17 and comprehensive income in this note.

Property, plant and equipment

Additions to property, plant and equipment are recorded at cost. When regulated assets are retired, or otherwise disposed of in the ordinary course of business, the original cost of the asset is charged to accumulated depreciation. With respect to the retirement or disposal of all other assets, except for natural gas and oil production properties as described in natural gas and oil properties in this note, the resulting gains or losses are recognized as a component of income. The Company is permitted to capitalize AFUDC on regulated construction projects and to include such amounts in rate base when the related facilities are placed in service. In addition, the Company capitalizes interest, when applicable, on certain construction projects associated with its other operations. The amount of AFUDC and interest capitalized was \$9.0 million, \$7.1 million and \$5.8 million

Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report 2008/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

in 2008, 2007 and 2006, respectively. Generally, property, plant and equipment are depreciated on a straight-line basis over the average useful lives of the assets, except for depletable aggregate reserves, which are depleted based on the units-of-production method, and natural gas and oil production properties, which are amortized on the units-of-production method based on total reserves.

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
MDU Resources Group, Inc.	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 12/31/2008	2008/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

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

	2008	2007	Weighted Average Depreciable Life in Years
<i>(Dollars in thousands, as applicable)</i>			
Regulated:			
Electric:			
Generation	\$ 408,851	\$ 371,557	63
Distribution	219,501	206,967	36
Transmission	142,081	133,973	44
Other	78,292	72,208	12
Natural gas distribution:			
Distribution	1,260,651	828,458	38
Other	168,836	119,988	17
Pipeline and energy services:			
Transmission	322,276	297,312	53
Gathering	41,825	41,233	19
Storage	32,592	32,082	52
Other	31,925	32,832	27
Nonregulated:			
Construction services:			
Land	4,526	4,513	---
Buildings and improvements	12,913	11,987	23
Machinery, vehicles and equipment	84,042	76,937	6
Other	9,820	8,498	4
Pipeline and energy services:			
Gathering	201,323	187,555	17
Other	10,980	9,698	10
Natural gas and oil production:			
Natural gas and oil properties	2,443,946	1,892,757	*
Other	33,456	31,142	9
Construction materials and contracting:			
Land	127,279	115,935	---
Buildings and improvements	68,356	94,598	20
Machinery, vehicles and equipment	932,545	921,199	12
Construction in progress	11,488	22,253	---
Aggregate reserves	384,361	384,731	**
Other:			
Land	2,942	3,022	---
Other	27,430	28,811	18
Less accumulated depreciation, depletion and amortization	2,761,319	2,270,691	
Net property, plant and equipment	\$ 4,300,918	\$ 3,659,555	

* *Amortized on the units-of-production method based on total proved reserves at an Mcf equivalent average rate of \$2.00, \$1.59 and \$1.38 for the years ended December 31, 2008, 2007 and 2006, respectively. Includes natural gas and oil production properties accounted for under the full-cost method, of which \$232.1 million and \$142.5 million were excluded from amortization at December 31, 2008 and 2007, respectively.*

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

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Impairment of long-lived assets

The Company reviews the carrying values of its long-lived assets, excluding goodwill and natural gas and oil properties, whenever events or changes in circumstances indicate that such carrying values may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the assets, compared to the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. No significant impairment losses were recorded in 2008, 2007 and 2006. Unforeseen events and changes in circumstances could require the recognition of other impairment losses at some future date.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of identifiable net tangible and intangible assets acquired in a business combination. Goodwill is required to be tested for impairment annually, which is completed in the fourth quarter, or more frequently if events or changes in circumstances indicate that goodwill may be impaired. For more information on goodwill impairments and goodwill, see Notes 3 and 5.

Natural gas and oil properties

The Company uses the full-cost method of accounting for its natural gas and oil production activities. Under this method, all costs incurred in the acquisition, exploration and development of natural gas and oil properties are capitalized and amortized on the units-of-production method based on total proved reserves. Any conveyances of properties, including gains or losses on abandonments of properties, are treated as adjustments to the cost of the properties with no gain or loss recognized. Capitalized costs are subject to a "ceiling test" that limits such costs to the aggregate of the present value of future net cash flows from proved reserves based on spot market prices that exist at the end of the period discounted at 10 percent, as mandated under the rules of the SEC, plus the cost of unproved properties less applicable income taxes. Future net revenue is estimated based on end-of-quarter spot market prices adjusted for contracted price changes. If capitalized costs exceed the full-cost ceiling at the end of any quarter, a permanent noncash write-down is required to be charged to earnings in that quarter unless subsequent price changes eliminate or reduce an indicated write-down.

Due to low natural gas and oil prices that existed on December 31, 2008, the Company's capitalized costs under the full-cost method of accounting exceeded the full-cost ceiling at December 31, 2008. Accordingly, the Company was required to write down its natural gas and oil producing properties. The noncash write-down amounted to \$135.8 million (\$84.2 million after tax) for the year ended December 31, 2008. Prices subsequent to December 31, 2008, remained low and therefore the noncash write-down was not reduced or eliminated. Sustained downward movements in natural gas and oil prices subsequent to December 31, 2008, could result in future write-downs of the Company's natural gas and oil properties.

The Company hedges a portion of its natural gas and oil production and the effects of the cash flow hedges were used in determining the full-cost ceiling. The Company would have recognized an additional write-down of its natural gas and oil properties of \$79.2 million (\$49.1 million after tax) if the effects of cash flow hedges had not been considered in calculating the full-cost ceiling. For more information on the Company's cash flow hedges, see Note 7.

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The following table summarizes the Company's natural gas and oil properties not subject to amortization at December 31, 2008, in total and by the year in which such costs were incurred:

	Year Costs Incurred				
	Total	2008	2007	2006	2005 and prior
	<i>(In thousands)</i>				
Acquisition	\$129,723	\$89,367	\$9,114	\$15,067	\$16,175
Development	56,559	45,973	8,519	1,584	483
Exploration	41,825	33,994	7,111	720	---
Capitalized interest	3,974	2,950	431	303	290
Total costs not subject to amortization	\$232,081	\$172,284	\$25,175	\$17,674	\$16,948

Costs not subject to amortization as of December 31, 2008, consisted primarily of unevaluated leaseholds, drilling costs, seismic costs and capitalized interest associated primarily with oil and gas development in the Paradox Basin in Utah; Bakken area in western North Dakota; Big Horn Basin in Wyoming; south Texas properties; CBNG in the Powder River Basin of Wyoming and Montana; and the newly acquired properties in eastern Texas. The Company expects that the majority of these costs will be evaluated within the next five years and included in the amortization base as the properties are evaluated and/or developed.

Revenue recognition

Revenue is recognized when the earnings process is complete, as evidenced by an agreement between the customer and the Company, when delivery has occurred or services have been rendered, when the fee is fixed or determinable and when collection is reasonably assured. The Company recognizes utility revenue each month based on the services provided to all utility customers during the month. Accrued unbilled revenue which is included in receivables, net, represents revenues recognized in excess of amounts billed. Accrued unbilled revenue at Montana-Dakota, Cascade and Intermountain was \$123.2 million at December 31, 2008. Accrued unbilled revenue at Montana-Dakota and Cascade was \$66.6 million at December 31, 2007. The Company recognizes construction contract revenue at its construction businesses using the percentage-of-completion method as discussed later. The Company recognizes revenue from natural gas and oil production properties only on that portion of production sold and allocable to the Company's ownership interest in the related well. The Company recognizes all other revenues when services are rendered or goods are delivered.

Percentage-of-completion method

The Company recognizes construction contract revenue from fixed-price and modified fixed-price construction contracts at its construction businesses using the percentage-of-completion method, measured by the percentage of costs incurred to date to estimated total costs for each contract. If a loss is anticipated on a contract, the loss is immediately recognized. Costs in excess of billings on uncompleted contracts of \$40.1 million and \$45.2 million at December 31, 2008 and 2007, respectively, represent revenues recognized in excess of amounts billed and were included in receivables, net. Billings in excess of costs on uncompleted contracts of \$106.9 million and \$81.4 million at December 31, 2008 and 2007, respectively, represent billings in excess of revenues recognized and were included in accounts payable. Amounts representing balances billed but not paid by customers under retainage provisions in contracts amounted to \$86.9 million and \$80.3 million at December 31, 2008 and 2007, respectively. The amounts expected to be paid within one year or less are included in receivables, net, and amounted to \$67.7 million and \$68.9 million at December 31, 2008 and 2007, respectively. The long-term retainage which was included in deferred charges and other assets - other was \$19.2 million and \$11.4 million at December 31, 2008 and 2007, respectively.

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Derivative instruments

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

The Company's policy generally allows the hedging of monthly forecasted natural gas and oil production at Fidelity for a period up to 24 months from the time the Company enters into the hedge. The Company's policy requires that interest rate derivative instruments not exceed a period of 24 months and foreign currency derivative instruments not exceed a 12-month period. The Company's policy allows the hedging of monthly forecasted purchases of natural gas at Cascade and Intermountain for a period up to three years.

The Company's policy requires that each month as physical natural gas and oil production at Fidelity occurs and the commodity is sold, the related portion of the derivative agreement for that month's production must settle with its counterparties. Settlements represent the exchange of cash between the Company and its counterparties based on the notional quantities and prices for each month's physical delivery as specified within the agreements. The fair value of the remaining notional amounts on the derivative agreements is recorded on the balance sheet as an asset or liability measured at fair value with the unrealized gains or losses recognized as a component of accumulated other comprehensive income (loss). The Company's policy also requires settlement of natural gas derivative instruments at Cascade and Intermountain monthly and all interest rate derivative transactions must be settled over a period that will not exceed 90 days, and any foreign currency derivative transaction settlement periods may not exceed a 12-month period. The Company has policies and procedures that management believes minimize credit-risk exposure. Accordingly, the Company does not anticipate any material effect on its financial position or results of operations as a result of nonperformance by counterparties. For more information on derivative instruments, see Note 7.

The estimated fair values of the Company's swap and collar agreements reflect the estimated amounts the Company would receive or pay to terminate the contracts at the reporting date. These values are based upon, among other things, futures prices, volatility and time to maturity.

Asset retirement obligations

The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the Company capitalizes a cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, the Company either settles the obligation for the recorded amount or incurs a gain or loss at its nonregulated operations or incurs a regulatory asset or liability at its regulated operations. For more information on asset retirement obligations, see Note 11.

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Natural gas costs recoverable or refundable through rate adjustments

Under the terms of certain orders of the applicable state public service commissions, the Company is deferring natural gas commodity, transportation and storage costs that are greater or less than amounts presently being recovered through its existing rate schedules. Such orders generally provide that these amounts are recoverable or refundable through rate adjustments within a period ranging from 12 to 28 months from the time such costs are paid. Natural gas costs refundable through rate adjustments were \$64,000 and \$11.6 million at December 31, 2008 and 2007, respectively, which is included in other accrued liabilities. Natural gas costs recoverable through rate adjustments were \$51.7 million and \$3.9 million at December 31, 2008 and 2007, respectively, which is included in prepayments and other current assets.

Insurance

Certain subsidiaries of the Company are insured for workers' compensation losses, subject to deductibles ranging up to \$750,000 per occurrence. Automobile liability and general liability losses are insured, subject to deductibles ranging up to \$500,000 per accident or occurrence. These subsidiaries have excess coverage above the primary automobile and general liability policies on a claims first-made basis beyond the deductible levels. The subsidiaries of the Company are retaining losses up to the deductible amounts accrued on the basis of estimates of liability for claims incurred and for claims incurred but not reported.

Income taxes

The Company provides deferred federal and state income taxes on all temporary differences between the book and tax basis of the Company's assets and liabilities. Excess deferred income tax balances associated with the Company's rate-regulated activities resulting from the Company's adoption of SFAS No. 109 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 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 accounts for uncertain tax positions in accordance with FIN 48. FIN 48 establishes standards for measurement and recognition in financial statements of tax positions taken or expected to be taken in an income tax return. Under FIN 48, tax positions are evaluated for recognition using a more-likely-than-not threshold, and those tax positions requiring recognition are measured as the largest amount of tax benefit that is greater than 50 percent likely of being realized upon ultimate settlement with a taxing authority. The Company recognizes interest and penalties accrued related to unrecognized tax benefits in income taxes.

Foreign currency translation adjustment

The functional currency of the Company's investment in the Brazilian Transmission Lines, as further discussed in Note 4, is the Brazilian Real. Translation from the Brazilian Real to the U.S. dollar for assets and liabilities is performed using the exchange rate in effect at the balance sheet date. Revenues and expenses are translated on a year-to-date basis using weighted average daily exchange rates. Adjustments resulting from such translations are reported as a separate component of other comprehensive income (loss) in common stockholders' equity.

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

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Common stock split

On May 11, 2006, the Company's Board of Directors approved a three-for-two common stock split. For more information on the common stock split, see Note 13.

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 outstanding stock options, restricted stock grants and performance share awards. In 2008, 2007 and 2006, there were no shares excluded from the calculation of diluted earnings per share. Common stock outstanding includes issued shares less shares held in treasury.

Stock-based compensation

On January 1, 2006, the Company adopted SFAS No. 123 (revised). This accounting standard requires entities to recognize compensation expense in an amount equal to the grant-date fair value of share-based payments granted to employees. SFAS No. 123 (revised) was adopted using the modified prospective method, recognizing compensation expense for all awards granted after the date of adoption of the standard and for the unvested portion of previously granted awards that remain outstanding at the date of adoption.

For more information on the Company's stock-based compensation, see Note 14.

Use of estimates

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

Cash flow information

Cash expenditures for interest and income taxes were as follows:

Years ended December 31,	2008	2007	2006
	<i>(In thousands)</i>		
Interest, net of amount capitalized	\$ 77,152	\$ 74,404	\$ 65,850
Income taxes	\$ 113,212	\$ 214,573	\$ 105,317

Income taxes paid for the year ended December 31, 2007, were higher than the amount paid for the years ended December 31, 2008 and 2006, primarily due to higher estimated quarterly tax payments paid in 2007 due in large part to the gain on the sale of the domestic independent power production assets as discussed in Note 3.

New accounting standards

SFAS No. 157 In September 2006, the FASB issued SFAS No. 157. SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. The standard applies under other accounting pronouncements that

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require or permit fair value measurements with certain exceptions. SFAS No. 157 was effective for the Company on January 1, 2008. FSP FAS No. 157-2 delays the effective date of SFAS No. 157 for certain nonfinancial assets and nonfinancial liabilities to January 1, 2009. The types of assets and liabilities that are recognized at fair value for which the Company has not applied the provisions of SFAS No. 157, due to the delayed effective date, include nonfinancial assets and nonfinancial liabilities initially measured at fair value in a business combination or new basis event, certain fair value measurements associated with goodwill impairment testing, indefinite-lived intangible assets and nonfinancial long-lived assets measured at fair value for impairment assessment, and asset retirement obligations initially measured at fair value. The adoption of SFAS No. 157, including the application to certain nonfinancial assets and nonfinancial liabilities with a delayed effective date of January 1, 2009, did not have a material effect on the Company's financial position or results of operations.

SFAS No. 159 In February 2007, the FASB issued SFAS No. 159. SFAS No. 159 permits entities to choose to measure many financial instruments and certain other items at fair value that are not currently required to be measured at fair value. The standard also establishes presentation and disclosure requirements designed to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. SFAS No. 159 was effective for the Company on January 1, 2008, and at adoption, the Company elected to measure its investments in certain fixed-income and equity securities at fair value in accordance with SFAS No. 159. These investments prior to January 1, 2008, were accounted for as available-for-sale investments and recorded at fair value with any unrealized gains or losses, net of income taxes, recorded in accumulated other comprehensive income (loss) on the Consolidated Balance Sheets until realized. Upon the adoption of SFAS No. 159, the unrealized gain on the available-for-sale investments of \$405,000 (after tax) was recorded as an increase to the January 1, 2008, balance of retained earnings. The adoption of SFAS No. 159 did not have a material effect on the Company's financial position or results of operations.

SFAS No. 141 (revised) In December 2007, the FASB issued SFAS No. 141 (revised). SFAS No. 141 (revised) requires an acquirer to recognize and measure the assets acquired, liabilities assumed and any noncontrolling interests in the acquiree at the acquisition date, measured at their fair values as of that date, with limited exception. In addition, SFAS No. 141 (revised) requires that acquisition-related costs will be generally expensed as incurred. SFAS No. 141 (revised) also expands the disclosure requirements for business combinations. SFAS No. 141 (revised) was effective for the Company on January 1, 2009. The adoption of SFAS No. 141 (revised) did not have a material effect on the Company's financial position or results of operations.

SFAS No. 160 In December 2007, the FASB issued SFAS No. 160. SFAS No. 160 establishes accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. SFAS No. 160 was effective for the Company on January 1, 2009. The adoption of SFAS No. 160 did not have a material effect on the Company's financial position or results of operations.

SFAS No. 161 In March 2008, the FASB issued SFAS No. 161. SFAS No. 161 requires enhanced disclosures about an entity's derivative and hedging activities including how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for, and how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. This Statement was effective for the Company on January 1, 2009. The adoption of SFAS No. 161 will require additional disclosures regarding the Company's derivative instruments; however, it will not impact the Company's financial position or results of operations.

FSP FAS No. 132(R)-1 In December 2008, the FASB issued FSP FAS No. 132(R)-1. FSP FAS No. 132(R)-1 provides guidance on an employer's disclosures about plan assets of a defined benefit pension or other postretirement plan to provide users of financial statements with an understanding of how investment allocation decisions are made, the major categories of

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plan assets, the inputs and valuation techniques used to measure the fair value of plan assets, the effect of fair value measurements using significant unobservable inputs on changes in plan assets for the period and significant concentrations of risk within plan assets. This statement was effective for the Company on January 1, 2009. The adoption of FSP FAS No. 132(R)-1 will require additional disclosures regarding the Company's defined benefit pension and other postretirement plans; however, it will not impact the Company's financial position or results of operations.

Modernization of Oil and Gas Reporting In January 2009, the SEC adopted final rules amending its oil and gas reporting requirements. The new rules include changes to the pricing used to estimate reserves, the ability to include nontraditional resources in reserves, the use of new technology for determining reserves and permitting disclosure of probable and possible reserves. The final rules are effective for the Company on December 31, 2009.

Comprehensive income

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

The components of other comprehensive income (loss), and their related tax effects for the years ended December 31, 2008, 2007 and 2006, were as follows:

	2008	2007	2006
	<i>(In thousands)</i>		
Other comprehensive income (loss):			
Net unrealized gain (loss) on derivative instruments qualifying as hedges:			
Net unrealized gain on derivative instruments arising during the period, net of tax of \$30,414, \$3,989 and \$12,359 in 2008, 2007 and 2006, respectively	\$49,623	\$6,508	\$19,743
Less: Reclassification adjustment for gain (loss) on derivative instruments included in net income, net of tax of \$3,795, \$12,504 and \$(16,194) in 2008, 2007 and 2006, respectively	6,175	20,013	(25,867)
Net unrealized gain (loss) on derivative instruments qualifying as hedges	43,448	(13,505)	45,610
Pension liability adjustment, net of tax of \$(8,750), \$1,835 and \$1,122 in 2008, 2007 and 2006, respectively	(13,751)	3,012	1,761
Foreign currency translation adjustment, net of tax of \$(6,108) and \$3,606 in 2008 and 2007, respectively	(9,534)	7,177	(1,585)
Net unrealized gain on available-for-sale investments, net of tax of \$270 in 2007	---	405	---
Total other comprehensive income (loss)	\$20,163	\$(2,911)	\$45,786

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The after-tax components of accumulated other comprehensive income (loss) as of December 31, 2008, 2007 and 2006, were as follows:

	Net Unrealized Gain on Derivative Instruments Qualifying as Hedges	Pension Liability Adjustment	Foreign Currency Translation Adjustment	Net Unrealized Gain on Available- for-sale Investment	Total Accumulated Other Comprehensive Income (Loss)
<i>(In thousands)</i>					
Balance at December 31, 2006	\$19,443	\$(24,342)	\$(1,583)	\$---	\$(6,482)
Balance at December 31, 2007	\$ 5,938	\$(21,330)	\$ 5,594	\$405	\$(9,393)
Balance at December 31, 2008	\$49,386	\$(35,081)	\$(3,940)	\$---	\$10,365

NOTE 2 - ACQUISITIONS

In 2008, the Company acquired a construction services business in Nevada; natural gas properties in Texas; construction materials and contracting businesses in Alaska, California, Idaho and Texas; and Intermountain, a natural gas distribution business, as discussed below. The total purchase consideration for these businesses and properties and purchase price adjustments with respect to certain other acquisitions made prior to 2008, consisting of the Company's common stock and cash and the outstanding indebtedness of Intermountain, was \$624.5 million.

On October 1, 2008, the acquisition of Intermountain was finalized and Intermountain became an indirect wholly owned subsidiary of the Company. Intermountain's service area is in Idaho.

In 2007, the Company acquired construction materials and contracting businesses in North Dakota, Texas and Wyoming; a construction services business in Nevada; and Cascade, a natural gas distribution business, as discussed below. The total purchase consideration for these businesses and properties and purchase price adjustments with respect to certain other acquisitions made prior to 2007, consisting of the Company's common stock and cash and the outstanding indebtedness of Cascade, was \$526.3 million.

On July 2, 2007, the acquisition of Cascade was finalized and Cascade became an indirect wholly owned subsidiary of the Company. Cascade's natural gas service areas are in Washington and Oregon.

In 2006, the Company acquired a construction services business in Nevada, natural gas and oil production properties in Wyoming, and construction materials and contracting businesses in California and Washington, none of which was material. The total purchase consideration for these businesses and properties and purchase price adjustments with respect to certain other acquisitions made prior to 2006, consisting of the Company's common stock and cash, was \$120.6 million.

The above acquisitions were accounted for under the purchase method of accounting and, accordingly, the acquired assets and liabilities assumed have been preliminarily recorded at their respective fair values as of the date of acquisition. On certain of the above acquisitions made in 2008, final fair market values are pending the completion of the review of the relevant assets and liabilities as of the acquisition date. The results of operations of the acquired businesses and properties are included in the financial statements since the date of each acquisition. Pro forma financial amounts reflecting the

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effects of the above acquisitions are not presented, as such acquisitions were not material to the Company's financial position or results of operations.

NOTE 3 - DISCONTINUED OPERATIONS

Innovatum, a component of the pipeline and energy services segment, specialized in cable and pipeline magnetization and location. During the third quarter of 2006, the Company initiated a plan to sell Innovatum because the Company determined that Innovatum is a non-strategic asset. During the fourth quarter of 2006, the stock and a portion of the assets of Innovatum were sold and the Company sold the remaining assets of Innovatum on January 23, 2008. The loss on disposal of Innovatum was not material.

During the fourth quarter of 2006, the Company initiated a plan to sell certain of the domestic assets of Centennial Resources. The plan to sell was based on the increased market demand for independent power production assets, combined with the Company's desire to efficiently fund future capital needs. The Company subsequently committed to a plan to sell CEM due to strong interest in the operations of CEM during the bidding process for the domestic independent power production assets in the first quarter of 2007.

On July 10, 2007, Centennial Resources sold its domestic independent power production business consisting of Centennial Power and CEM to Bicent Power LLC (formerly known as Montana Acquisition Company LLC). The transaction was valued at \$636 million, which included the assumption of approximately \$36 million of project-related debt. The gain on the sale of the assets, excluding the gain on the sale of Hartwell as discussed in Note 4, was approximately \$85.4 million (after tax).

In accordance with SFAS No. 144, the Company's consolidated financial statements and accompanying notes for prior periods present the results of operations of Innovatum and the domestic independent power production assets as discontinued operations. In addition, the assets and liabilities of these operations were treated as held for sale, and as a result, no depreciation, depletion and amortization expense was recorded from the time each of the assets was classified as held for sale.

In accordance with SFAS No. 142, at the time the Company committed to the plan to sell each of the assets, the Company was required to test the respective assets for goodwill impairment. The fair value of Innovatum, a reporting unit for goodwill impairment testing, was estimated using the expected proceeds from the sale, which was estimated to be the current book value of the assets of Innovatum other than its goodwill. As a result, a goodwill impairment of \$4.3 million (before tax) was recognized and recorded as part of discontinued operations, net of tax, in the Consolidated Statements of Income in the third quarter of 2006. There were no goodwill impairments associated with the other assets held for sale.

Operating results related to Innovatum for the years ended December 31, 2007 and 2006, were as follows:

	2007	2006
	<i>(In thousands)</i>	
Operating revenues	\$ 1,748	\$ 1,827
Loss from discontinued operations before income tax benefit	(210)	(5,994)
Income tax benefit	(316)	(3,834)
Income (loss) from discontinued operations, net of tax	\$ 106	\$ (2,160)

The income tax benefit for the year ended December 31, 2006, is larger than the customary relationship between the income tax benefit and the loss before tax due to a capital loss tax benefit (which reflects the effect of the \$4.3 million and \$4.0 million goodwill impairments in 2006 and 2004, respectively) resulting from the sale of the Innovatum stock.

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Operating results related to the domestic independent power production assets for the years ended December 31, 2007 and 2006, were as follows:

	2007	2006
	<i>(In thousands)</i>	
Operating revenues	\$ 125,867	\$ 66,145
Income from discontinued operations (including gain on disposal in 2007 of \$142.4 million) before income tax expense (benefit)	177,666	9,276
Income tax expense (benefit)	68,438	(863)
Income from discontinued operations, net of tax	\$ 109,228	\$ 10,139

The income tax benefit for the year ended December 31, 2006, reflects a renewable electricity production tax credit of \$4.4 million.

Revenues at the former independent power production operations were recognized based on electricity delivered and capacity provided, pursuant to contractual commitments and, where applicable, revenues were recognized under EITF No. 91-6 ratably over the terms of the related contract. Arrangements with multiple revenue-generating activities were recognized under EITF No. 00-21 with the multiple deliverables divided into separate units of accounting based on specific criteria and revenues of the arrangements allocated to the separate units based on their relative fair values.

The carrying amounts of the assets and liabilities related to discontinued operations at December 31, 2007, were not material.

NOTE 4 - EQUITY METHOD INVESTMENTS

Investments in companies in which the Company has the ability to exercise significant influence over operating and financial policies are accounted for using the equity method. The Company's equity method investments at December 31, 2008 and 2007, include the Brazilian Transmission Lines.

In August 2006, MDU Brasil acquired ownership interests in companies owning the Brazilian Transmission Lines. The interests involve the ENTE (13.3-percent ownership interest), ERTE (13.3-percent ownership interest) and ECTE (25-percent ownership interest) electric transmission lines, which are primarily in northeastern and southern Brazil. The transmission contracts provide for revenues denominated in the Brazilian Real, annual inflation adjustments and change in tax law adjustments and have between 22 and 24 years remaining under the contracts. Alusa, Brascan and CEMIG hold the remaining ownership interests, with CELESC also having an ownership interest in ECTE. The functional currency for the Brazilian Transmission Lines is the Brazilian Real.

In September 2004, Centennial Resources, through indirect wholly owned subsidiaries, acquired a 50-percent ownership interest in Hartwell, which owns a 310-MW natural gas-fired electric generating facility near Hartwell, Georgia. In July 2007, the Company sold its ownership interest in Hartwell, and realized a gain of \$10.1 million (\$6.1 million after tax) from the sale which is recorded in earnings from equity method investments on the Consolidated Statements of Income.

At December 31, 2008 and 2007, the Company's equity method investments had total assets of \$294.7 million and \$398.4 million, respectively, and long-term debt of \$158.0 million and \$211.2 million, respectively. The Company's investment in its equity method investments was approximately \$44.4 million and \$59.0 million, including undistributed earnings of \$6.8 million and \$6.9 million, at December 31, 2008 and 2007, respectively.

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NOTE 5 - GOODWILL AND OTHER INTANGIBLE ASSETS

The changes in the carrying amount of goodwill for the year ended December 31, 2008, were as follows:

	Balance as of January 1, 2008	Goodwill Acquired During the Year*	Balance as of December 31, 2008
<i>(In thousands)</i>			
Electric	\$ ---	\$ ---	\$ ---
Natural gas distribution	171,129	173,823	344,952
Construction services	91,385	4,234	95,619
Pipeline and energy services	1,159	---	1,159
Natural gas and oil production	---	---	---
Construction materials and contracting	162,025	11,980	174,005
Other	---	---	---
Total	\$425,698	\$ 190,037	\$ 615,735

* Includes purchase price adjustments that were not material related to acquisitions in a prior period.

The changes in the carrying amount of goodwill for the year ended December 31, 2007, were as follows:

	Balance as of January 1, 2007	Goodwill Acquired During the Year*	Balance as of December 31, 2007
<i>(In thousands)</i>			
Electric	\$ ---	\$ ---	\$ ---
Natural gas distribution	---	171,129	171,129
Construction services	86,942	4,443	91,385
Pipeline and energy services	1,159	---	1,159
Natural gas and oil production	---	---	---
Construction materials and contracting	136,197	25,828	162,025
Other	---	---	---
Total	\$ 224,298	\$ 201,400	\$ 425,698

* Includes purchase price adjustments that were not material related to acquisitions in a prior period.

Other amortizable intangible assets at December 31, 2008 and 2007, were as follows:

	2008	2007
<i>(In thousands)</i>		
Customer relationships	\$ 21,842	\$ 21,834
Accumulated amortization	(6,985)	(4,444)
	14,857	17,390
Noncompete agreements	10,080	10,655
Accumulated amortization	(5,126)	(3,654)
	4,954	7,001
Other	10,949	5,943
Accumulated amortization	(2,368)	(2,542)
	8,581	3,401
Total	\$ 28,392	\$ 27,792

Amortization expense for intangible assets for the years ended December 31, 2008, 2007 and 2006, was \$5.1 million, \$4.4 million and \$4.3 million, respectively. Estimated

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amortization expense for intangible assets is \$5.1 million in 2009, \$3.7 million in 2010, \$3.1 million in 2011, \$3.0 million in 2012, \$2.5 million in 2013 and \$11.0 million thereafter.

NOTE 6 - REGULATORY ASSETS AND LIABILITIES

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

	2008	2007
	<i>(In thousands)</i>	
Regulatory assets:		
Pension and postretirement benefits	\$ 119,868	\$ 21,613
Natural gas supply derivatives	89,813	16,324
Natural gas cost recoverable through rate adjustments	51,699	3,896
Deferred income taxes*	46,855	43,866
Long-term debt refinancing costs	9,991	10,605
Plant costs	8,534	4,930
Other	12,802	11,916
Total regulatory assets	339,562	113,150
Regulatory liabilities:		
Plant removal and decommissioning costs	94,737	89,991
Deferred income taxes*	65,909	17,630
Taxes refundable to customers	25,642	22,580
Natural gas supply derivatives	5,540	5,631
Natural gas costs refundable through rate adjustments	64	11,568
Other	7,460	8,250
Total regulatory liabilities	199,352	155,650
Net regulatory position	\$ 140,210	\$ (42,500)

* Represents deferred income taxes related to regulatory assets and liabilities.

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.

If, for any reason, the Company's regulated businesses cease to meet the criteria for application of SFAS No. 71 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 as an extraordinary item in the period in which the discontinuance of SFAS No. 71 occurs.

NOTE 7 - DERIVATIVE INSTRUMENTS

Derivative instruments, including certain derivative instruments embedded in other contracts, are required to be recorded on the balance sheet as either an asset or liability measured at fair value. Changes in the derivative instrument's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. Accounting for qualifying hedges allows derivative gains and losses to offset the related results on the hedged item in the income statement and requires that a company must formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment.

In the event a derivative instrument being accounted for as a cash flow hedge does not qualify for hedge accounting because it is no longer highly effective in offsetting changes in cash flows of a hedged item; if the derivative instrument expires or is sold, terminated or exercised; or if management determines that designation of the derivative instrument as a hedge instrument is no longer appropriate, hedge accounting would be discontinued and the derivative instrument would continue to be carried at fair value with

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changes in its fair value recognized in earnings. In these circumstances, the net gain or loss at the time of discontinuance of hedge accounting would remain in accumulated other comprehensive income (loss) until the period or periods during which the hedged forecasted transaction affects earnings, at which time the net gain or loss would be reclassified into earnings. In the event a cash flow hedge is discontinued because it is unlikely that a forecasted transaction will occur, the derivative instrument would continue to be carried on the balance sheet at its fair value, and gains and losses that had accumulated in other comprehensive income (loss) would be recognized immediately in earnings. In the event of a sale, termination or extinguishment of a foreign currency derivative, the resulting gain or loss would be recognized immediately in earnings. The Company's policy requires approval to terminate a derivative instrument prior to its original maturity. As of December 31, 2008, the Company had no outstanding foreign currency or interest rate hedges.

Cascade and Intermountain

At December 31, 2008, Cascade and Intermountain held natural gas swap agreements which were not designated as hedges. Cascade and Intermountain utilize natural gas swap agreements to manage a portion of the market risk associated with fluctuations in the price of natural gas on their forecasted purchases of natural gas for core customers in accordance with authority granted by the IPUC, WUTC and OPUC. Core customers consist of residential, commercial and smaller industrial customers. The fair value of the derivative instrument must be estimated as of the end of each reporting period and is recorded on the Consolidated Balance Sheets as an asset or a liability. Cascade and Intermountain apply SFAS No. 71 and record periodic changes in the fair market value of the derivative instruments on the Consolidated Balance Sheets as a regulatory asset or a regulatory liability, and settlements of these arrangements are expected to be recovered through the purchased gas cost adjustment mechanism. Under the terms of these arrangements, Cascade and Intermountain will either pay or receive settlement payments based on the difference between the fixed strike price and the monthly index price applicable to each contract. At December 31, 2008, the fair value of Cascade's natural gas swap agreements is presented net of the collateral provided to the counterparty of \$11.1 million.

Fidelity

At December 31, 2008, Fidelity held natural gas swaps, a basis swap and collar agreements designated as cash flow hedging instruments. Fidelity utilizes these derivative instruments to manage a portion of the market risk associated with fluctuations in the price of natural gas on its forecasted sales of natural gas production. These derivatives were designated as cash flow hedges of the forecasted sales of the related production.

The fair value of the hedging instruments must be estimated as of the end of each reporting period and is recorded on the Consolidated Balance Sheets as an asset or a liability. Changes in the fair value attributable to the effective portion of hedging instruments, net of tax, are recorded in stockholders' equity as a component of accumulated other comprehensive income (loss). At the date the natural gas quantities are settled, the amounts accumulated in other comprehensive income (loss) are reported in the Consolidated Statements of Income. To the extent that the hedges are not effective, the ineffective portion of the changes in fair market value is recorded directly in earnings. The proceeds received for natural gas production are generally based on market prices.

For the years ended December 31, 2008, 2007 and 2006, the amount of hedge ineffectiveness was immaterial, and there were no components of the derivative instruments' gain or loss excluded from the assessment of hedge effectiveness. Gains and losses must be reclassified into earnings as a result of the discontinuance of cash flow hedges if it is probable that the original forecasted transactions will not occur. There were no such reclassifications into earnings as a result of the discontinuance of hedges.

Gains and losses on derivative instruments that are reclassified from accumulated other comprehensive income (loss) to current-period earnings are included in the line item in which the hedged item is recorded. As of December 31, 2008, the maximum term of the swap

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and collar agreements, in which the exposure to the variability in future cash flows for forecasted transactions is being hedged, is 36 months. The Company estimates that over the next 12 months, net gains of approximately \$47.6 million (after tax) will be reclassified from accumulated other comprehensive income into earnings, subject to changes in natural gas market prices, as the hedged transactions affect earnings.

NOTE 8 - FAIR VALUE MEASUREMENTS

On January 1, 2008, the Company adopted SFAS No. 157 and SFAS No. 159, as discussed in Note 1.

Upon the adoption of SFAS No. 159, the Company elected to measure its investments in certain fixed-income and equity securities at fair value. These investments had previously been accounted for as available-for-sale investments in accordance with SFAS No. 115. The Company anticipates using these investments to satisfy its obligations under its unfunded, nonqualified benefit plans for executive officers and certain key management employees, and invests in these fixed-income and equity securities for the purpose of earning investment returns and capital appreciation. These investments, which totaled \$27.7 million as of December 31, 2008, are classified as Investments on the Consolidated Balance Sheets. The decrease in the fair value of these investments for the year ended December 31, 2008, was \$8.6 million (before tax), which is considered part of the cost of the plan, and is classified in operation and maintenance expense on the Consolidated Statements of Income. The Company did not elect the fair value option for its remaining available-for-sale securities, which are auction rate securities. The Company's auction rate securities, which totaled \$11.4 million at December 31, 2008, are accounted for as available-for-sale in accordance with SFAS No. 115 and are recorded at fair value. The fair value of the auction rate securities approximate cost and, as a result, there are no accumulated unrealized gains or losses recorded in accumulated other comprehensive income (loss) on the Consolidated Balance Sheets related to these investments.

SFAS No. 157 defines fair value 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 statement establishes a hierarchy for grouping assets and liabilities, based on the significance of inputs. The Company's assets and liabilities measured at fair value on a recurring basis are as follows:

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	Fair Value Measurements at December 31, 2008, Using			
	Balance at December 31, 2008	Quoted Prices in Active Markets for Identical Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
(In thousands)				
Assets:				
Available-for-sale securities	\$ 39,125	\$ 27,725	\$ 11,400	\$ ---
Commodity derivative instruments - current	78,164	---	78,164	---
Commodity derivative instruments - noncurrent	<u>3,222</u>	<u>---</u>	<u>3,222</u>	<u>---</u>
Total assets measured at fair value	\$ 120,511	\$ 27,725	\$ 92,786	\$ ---
Liabilities:				
Commodity derivative instruments - current	\$ 56,529	\$ ---	\$ 56,529	\$ ---
Commodity derivative instruments - noncurrent	23,534	---	23,534	---
Total liabilities measured at fair value	\$ 80,063	\$ ---	\$ 80,063	\$ ---

Note: The fair value of the commodity derivative agreements in a current liability position is presented net of collateral provided to the counterparty by Cascade of \$11.1 million.

The estimated fair value of the Company's Level 1 available-for-sale securities is based on quoted market prices in active markets for identical equity and fixed-income securities. The estimated fair value of the Company's Level 2 available-for-sale securities is based on comparable market transactions. The estimated fair values of the Company's commodity derivative instruments reflects the estimated amounts the Company would receive or pay to terminate the contracts at the reporting date. These values are based upon, among other things, futures prices, volatility and time to maturity.

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 estimated fair value of the Company's long-term debt was based on quoted market prices of the same or similar issues.

The estimated fair value of the Company's long-term debt at December 31 was as follows:

	2008		2007	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
(In thousands)				
Long-term debt	\$ 1,647,302	\$ 1,577,907	\$ 1,308,463	\$ 1,293,863

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The estimated fair value of the Company's commodity derivative instruments at December 31 was as follows:

	2007	
	Carrying Amount	Fair Value
	<i>(In thousands)</i>	
Commodity derivative instruments – current asset	\$ 12,740	\$ 12,740
Commodity derivative instruments – current liability	\$ (14,799)	\$ (14,799)
Commodity derivative instruments – noncurrent asset	\$ 3,419	\$ 3,419
Commodity derivative instruments – noncurrent liability	\$ (2,570)	\$ (2,570)

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

NOTE 9 - SHORT-TERM BORROWINGS

MDU Resources Group, Inc. In connection with the funding of the Intermountain acquisition, on September 26, 2008, the Company entered into a term loan agreement providing for a commitment amount of \$175 million. On October 1, 2008, the Company borrowed \$170 million under this agreement, which expired on March 24, 2009. There was \$57.0 million outstanding under the term loan agreement at December 31, 2008, which was repaid on March 2, 2009 with funds from an existing term loan borrowing agreement.

The agreement contains customary covenants and default provisions, including covenants of the Company not to permit, as of the end of any fiscal quarter, (A) the ratio of funded debt to total capitalization (on a consolidated basis) to be greater than 65 percent or (B) the ratio of funded debt to capitalization (determined with respect to the Company only, excluding subsidiaries) to be greater than 65 percent. The agreement also includes a covenant that does not permit the ratio of the Company's earnings before interest, taxes, depreciation and amortization to interest expense (determined with respect to the Company only, excluding subsidiaries), for the 12-month period ended each fiscal quarter, to be less than 2.5 to 1. The Company was in compliance with these covenants and met the required conditions at December 31, 2008.

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

Cascade Natural Gas Corporation Cascade has a revolving credit agreement with various banks totaling \$50 million with certain provisions allowing for increased borrowings, up to a maximum of \$75 million. The \$50 million credit agreement expires on December 28, 2012, with provisions allowing for an extension of up to two years upon consent of the banks. Under the terms of the \$50 million credit agreement, \$48.1 million and \$1.7 million were outstanding at December 31, 2008 and 2007, respectively. Cascade also had a revolving credit agreement totaling \$15 million, which expired on March 11, 2009. There was no amount outstanding under the \$15 million credit agreement at December 31, 2008. These borrowings are classified as short-term borrowings as Cascade intends to repay the borrowings within one year. The weighted average interest rate for borrowings outstanding at December 31, 2008, was less than one percent. As of December 31, 2008, there were outstanding letters of credit, as discussed in Note 20, of which \$1.9 million reduced amounts available under the \$50 million credit agreement.

In order to borrow under Cascade's credit agreements, Cascade must be in compliance with the applicable covenants and certain other conditions. This includes a covenant not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. Cascade was in compliance with these covenants and met the required conditions at December 31, 2008.

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

NOTE 10 - LONG-TERM DEBT AND INDENTURE PROVISIONS

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

	2008	2007
	<i>(In thousands)</i>	
First mortgage bonds and notes:		
Secured Medium-Term Notes, Series A, at a weighted average rate of 8.26%, due on dates ranging from October 1, 2009 to April 1, 2012	\$ 5,500	\$ 20,500
Senior Notes, 5.98%, due December 15, 2033	30,000	30,000
Total first mortgage bonds and notes	35,500	50,500
Senior Notes at a weighted average rate of 5.96%, due on dates ranging from February 2, 2009 to March 8, 2037	1,271,227	1,064,000
Commercial paper at a weighted average rate of 4.15%, supported by revolving credit agreements	172,500	61,000
Medium-Term Notes at a weighted average rate of 7.72%, due on dates ranging from September 4, 2012 to March 16, 2029	81,000	81,000
Credit agreements at a weighted average rate of 3.69%, due on dates ranging from May 1, 2009 to November 30, 2038	44,205	8,286
Other notes at a weighted average rate of 5.24%, due on dates ranging from September 1, 2020 to February 1, 2035	42,971	43,679
Discount	(101)	(2)
Total long-term debt	1,647,302	1,308,463
Less current maturities	78,666	161,682
Net long-term debt	\$1,568,636	\$1,146,781

The amounts of scheduled long-term debt maturities for the five years and thereafter following December 31, 2008, aggregate \$78.7 million in 2009; \$49.1 million in 2010; \$94.8 million in 2011; \$290.7 million in 2012; \$258.8 million in 2013 and \$875.2 million thereafter.

Certain debt instruments of the Company and its subsidiaries, including those discussed below, contain restrictive covenants, all of which the Company and its subsidiaries were in compliance with at December 31, 2008.

MDU Resources Group, Inc. The Company has a revolving credit agreement with various banks totaling \$125 million (with provision for an increase, at the option of the Company on stated conditions, up to a maximum of \$150 million). There were no amounts outstanding under the credit agreement at December 31, 2008 and 2007. The credit agreement supports the Company's \$125 million commercial paper program. Although volatility in the capital markets has recently increased significantly, the Company continues to issue commercial paper to meet its current needs. Under the Company's commercial paper program, \$22.5 million and \$61.0 million was outstanding at December 31, 2008 and 2007, respectively. The commercial paper borrowings are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings (supported by the credit agreement, which expires on June 21, 2011).

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In order to borrow under the Company's credit agreement, the Company must be in compliance with the applicable covenants and certain other conditions, including covenants not to permit, as of the end of any fiscal quarter, (A) the ratio of funded debt to total capitalization (determined on a consolidated basis) to be greater than 65 percent or (B) the ratio of funded debt to capitalization (determined with respect to the Company alone, excluding its subsidiaries) to be greater than 65 percent. Also included is a covenant that does not permit the ratio of the Company's earnings before interest, taxes, depreciation and amortization to interest expense (determined with respect to the Company alone, excluding its subsidiaries), for the 12-month period ended each fiscal quarter, to be less than 2.5 to 1. Other covenants include restrictions on the sale of certain assets and on the making of certain investments. The Company was in compliance with these covenants and met the required conditions at December 31, 2008. In the event the Company does not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued.

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

The Company's issuance of first mortgage debt is subject to certain restrictions imposed under the terms and conditions of its Mortgage. Generally, those restrictions require the Company to fund \$1.43 of unfunded property or use \$1.00 of refunded bonds for each dollar of indebtedness incurred under the Mortgage and, in some cases, to certify to the trustee that annual earnings (pretax and before interest charges), as defined in the Mortgage, equal at least two times its annualized first mortgage bond interest costs. Under the more restrictive of the tests, as of December 31, 2008, the Company could have issued approximately \$620 million of additional first mortgage bonds.

Approximately \$618.8 million in net book value of the Company's electric and natural gas distribution properties at December 31, 2008, with certain exceptions, are subject to the lien of the Mortgage and to the junior lien of the Indenture.

MDU Energy Capital, LLC On October 1, 2008, MDU Energy Capital entered into an amendment to its master shelf agreement which increased the facility amount from \$125 million to \$175 million. Under the terms of the master shelf agreement, \$165.0 million and \$85.0 million was outstanding at December 31, 2008 and 2007, respectively. MDU Energy Capital may incur additional indebtedness under the master shelf agreement until the earlier of August 14, 2010, or such time as the agreement is terminated by either of the parties thereto.

On October 1, 2008, MDU Energy Capital borrowed \$80.0 million under the agreement. The indebtedness consists of \$30 million of senior notes due October 1, 2013, and \$50 million of senior notes due October 1, 2015. MDU Energy Capital used the proceeds from the borrowing to pay a dividend to the Company which, in turn, used this dividend to partially fund the acquisition of Intermountain, as previously discussed.

The master shelf agreement contains customary covenants and provisions, including covenants of MDU Energy Capital not to permit (A) the ratio of its total debt (on a consolidated basis) to adjusted total capitalization to be greater than 70 percent, or (B) the ratio of subsidiary debt to subsidiary capitalization to be greater than 65 percent, or (C) the ratio of Intermountain's total debt (determined on a consolidated basis) to total capitalization to be greater than 65 percent. The agreement also includes a covenant requiring the ratio of MDU Energy Capital earnings before interest and taxes to interest expense (on a consolidated basis), for the 12-month period ended each fiscal quarter to be greater than 1.5 to 1. MDU Energy Capital was in compliance with these covenants and met the required conditions at December 31, 2008. In addition, payment obligations under the master shelf agreement may be accelerated upon the occurrence of an event of default (as described in the agreement).

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Intermountain Gas Company Intermountain has a revolving credit agreement with various banks totaling \$65 million with certain provisions allowing for increased borrowings, up to a maximum of \$70 million. The credit agreement expires on August 31, 2010. Under the terms of the credit agreement, \$36.5 million was outstanding at December 31, 2008.

In order to borrow under Intermountain's credit agreement, Intermountain must be in compliance with the applicable covenants and certain other conditions, including covenants not to permit, as of the end of any fiscal quarter, (A) the ratio of funded debt to total capitalization (determined on a consolidated basis) to be greater than 65 percent, or (B) the ratio of Intermountain's earnings before interest, taxes, depreciation and amortization to interest expense (determined on a consolidated basis), for the 12-month period ended each fiscal quarter, to be less than 2 to 1. Other covenants include limitations on the sale of certain assets and on the making of certain loans and investments. Intermountain was in compliance with these covenants and met the required conditions at December 31, 2008. In the event Intermountain does not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued.

Intermountain's credit agreement contains cross-default provisions. These provisions state that if (i) Intermountain fails to make any payment with respect to any indebtedness or guarantee in excess of \$5 million, (ii) any other event occurs that would permit the holders of indebtedness or the beneficiaries of guarantees to become payable, or (iii) certain conditions result in an early termination date under any swap contract, then Intermountain shall be in default under the revolving credit agreement.

Centennial Energy Holdings, Inc. Centennial has a revolving credit agreement with various banks and institutions totaling \$400 million with certain provisions allowing for increased borrowings. The credit agreement supports Centennial's \$400 million commercial paper program. Although volatility in the capital markets has recently increased significantly, the Company continues to issue commercial paper to meet its current needs. There were no outstanding borrowings under the Centennial credit agreement at December 31, 2008 and 2007. Under the Centennial commercial paper program, \$150.0 million was outstanding at December 31, 2008, and there was no amount outstanding at December 31, 2007. The Centennial commercial paper borrowings are classified as long-term debt as Centennial intends to refinance these borrowings on a long-term basis through continued Centennial commercial paper borrowings (supported by the Centennial credit agreement). The revolving credit agreement includes a provision for an increase, at the option of Centennial on stated conditions, up to a maximum of \$450 million and expires on December 13, 2012. As of December 31, 2008, Centennial had letters of credit outstanding, as discussed in Note 20, of which \$24.3 million reduced amounts available under the agreement.

Centennial has an uncommitted long-term master shelf agreement that allows for borrowings of up to \$550 million. Under the terms of the master shelf agreement, \$509.0 million and \$418.5 million was outstanding at December 31, 2008 and 2007, respectively. The ability to request additional borrowings under this master shelf agreement expires on May 8, 2009.

In order to borrow under Centennial's credit agreement and the Centennial uncommitted long-term master shelf agreement, Centennial and certain of its subsidiaries must be in compliance with the applicable covenants and certain other conditions, including covenants not to permit, as of the end of any fiscal quarter, the ratio of total debt to total capitalization to be greater than 65 percent (for the \$400 million credit agreement) and 60 percent (for the master shelf agreement). The master shelf agreement also includes a covenant that does not permit the ratio of Centennial's earnings before interest, taxes, depreciation and amortization to interest expense, for the 12-month period ended each fiscal quarter, to be less than 1.75 to 1. Other covenants include minimum consolidated net worth, limitation on priority debt and restrictions on the sale of certain assets and on the making of certain loans and investments. Centennial and such subsidiaries were in

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compliance with these covenants and met the required conditions at December 31, 2008. In the event Centennial or such subsidiaries do not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued.

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. Certain of Centennial's financing agreements and Centennial's practices limit the amount of subsidiary indebtedness.

Williston Basin Interstate Pipeline Company In December 2008, Williston Basin entered into an uncommitted long-term private shelf agreement that allows for borrowings up to \$125 million. Under the terms of the private shelf agreement, \$72.5 million was outstanding at December 31, 2008. The \$72.5 million outstanding consists of \$20.0 million of notes issued under the private shelf agreement and \$52.5 million of notes issued under a master shelf agreement that expired on December 20, 2008. At December 31, 2007, \$80.0 million was outstanding under the prior agreement. The ability to request additional borrowings under this private shelf agreement expires on December 23, 2010, with certain provisions allowing for an extension to December 23, 2011.

In order to borrow under its uncommitted long-term private shelf agreement, Williston Basin must be in compliance with the applicable covenants and certain other conditions, including covenants 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 limitation on priority debt and some restrictions on the sale of certain assets and the making of certain investments. Williston Basin was in compliance with these covenants and met the required conditions at December 31, 2008. In the event Williston Basin does not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued.

NOTE 11 - ASSET RETIREMENT OBLIGATIONS

The Company records obligations related to the plugging and abandonment of natural gas and oil wells, decommissioning of certain electric generating facilities and reclamation of certain aggregate properties.

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

	2008	2007
	<i>(In thousands)</i>	
Balance at beginning of year	\$64,453	\$56,179
Liabilities incurred	2,943	4,149
Liabilities acquired	2,369	652
Liabilities settled	(3,188)	(5,896)
Accretion expense	3,191	3,081
Revisions in estimates	207	6,100
Other	172	188
Balance at end of year	\$70,147	\$64,453

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

The fair value of assets that are legally restricted for purposes of settling asset retirement obligations at December 31, 2008 and 2007, was \$5.9 million and \$5.8 million, respectively.

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NOTE 12 - PREFERRED STOCKS

Preferred stocks at December 31 were as follows:

	2008	2007
	<i>(Dollars in thousands)</i>	
Authorized:		
Preferred –		
500,000 shares, cumulative, par value \$100, issuable in series		
Preferred stock A –		
1,000,000 shares, cumulative, without par value, issuable in series (none outstanding)		
Preference –		
500,000 shares, cumulative, without par value, issuable in series (none outstanding)		
Outstanding:		
4.50% Series – 100,000 shares	\$10,000	\$10,000
4.70% Series – 50,000 shares	5,000	5,000
Total preferred stocks	\$15,000	\$15,000

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

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

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

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

NOTE 13 - COMMON STOCK

On May 11, 2006, the Company's Board of Directors approved a three-for-two common stock split to be effected in the form of a 50 percent common stock dividend. The additional shares of common stock were distributed on July 26, 2006, to common stockholders of record on July 12, 2006. Certain common stock information appearing in the accompanying consolidated financial statements has been restated in accordance with accounting principles generally accepted in the United States of America to give retroactive effect to the stock split.

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In 1998, the Company's Board of Directors declared, pursuant to a stockholders' rights plan, a dividend of one preference share purchase right for each outstanding share of the Company's common stock. The rights expired on December 31, 2008.

The Stock Purchase Plan provides interested investors the opportunity to make optional cash investments and to reinvest all or a percentage of their cash dividends in shares of the Company's common stock. The K-Plan is partially funded with the Company's common stock. From July 2006 through March 2007 and October 1, 2008 through October 21, 2008, the Stock Purchase Plan and K-Plan, with respect to Company stock, were funded with shares of authorized but unissued common stock. From January 2006 through June 2006, April 2007 through September 30, 2008, and October 22, 2008 through December 2008, purchases of shares of common stock on the open market were used to fund the Stock Purchase Plan and K-Plan. At December 31, 2008, there were 20.2 million shares of common stock reserved for original issuance under the Stock Purchase Plan and K-Plan.

NOTE 14 - STOCK-BASED COMPENSATION

The Company has several stock-based compensation plans and is authorized to grant options, restricted stock and stock for up to 17.1 million shares of common stock and has granted options, restricted stock and stock of 7.3 million shares through December 31, 2008. The Company generally issues new shares of common stock to satisfy stock option exercises, restricted stock, stock and performance share awards.

Total stock-based compensation expense was \$3.7 million, net of income taxes of \$2.3 million in 2008; \$4.7 million, net of income taxes of \$3.1 million in 2007; and \$3.5 million, net of income taxes of \$2.2 million in 2006.

As of December 31, 2008, total remaining unrecognized compensation expense related to stock-based compensation was approximately \$5.0 million (before income taxes) which will be amortized over a weighted average period of 1.7 years.

Stock options

The Company has stock option plans for directors, key employees and employees. The Company has not granted stock options since 2003. Options granted to key employees automatically vest after nine years, but the plan provides for accelerated vesting based on the attainment of certain performance goals or upon a change in control of the Company, and expire 10 years after the date of grant. Options granted to directors and employees vest at the date of grant and three years after the date of grant, respectively, and expire 10 years after the date of grant.

The fair value of each option outstanding was estimated on the date of grant using the Black-Scholes option-pricing model.

A summary of the status of the stock option plans at December 31, 2008, and changes during the year then ended was as follows:

	Number of Shares	Weighted Average Exercise Price
Balance at beginning of year	1,495,908	\$13.09
Forfeited	(15,770)	12.30
Exercised	(476,314)	12.48
Balance at end of year	1,003,824	13.39
Exercisable at end of year	976,856	\$13.38

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Summarized information about stock options outstanding and exercisable as of December 31, 2008, was as follows:

Range of Exercisable Prices	Number Outstanding	Options Outstanding			Options Exercisable		
		Remaining Contractual Life in Years	Weighted Average Exercise Price	Aggregate Intrinsic Value (000's)	Number Exercisable	Weighted Average Exercise Price	Aggregate Intrinsic Value (000's)
\$ 8.88 – 11.00	15,186	1.1	\$ 9.86	\$ 178	15,186	\$ 9.86	\$ 178
11.01 – 14.00	915,659	2.2	13.20	7,673	894,124	13.21	7,487
14.01 – 17.13	<u>72,979</u>	2.2	16.46	<u>374</u>	<u>67,546</u>	16.48	<u>345</u>
Balance at end of year	1,003,824	2.2	\$13.39	\$8,225	976,856	\$13.38	\$ 8,010

The aggregate intrinsic value in the preceding table represents the total intrinsic value (before income taxes), based on the Company's stock price on December 31, 2008, which would have been received by the option holders had all option holders exercised their options as of that date.

The weighted average remaining contractual life of options exercisable was 2.2 years at December 31, 2008.

The Company received cash of \$5.9 million, \$10.2 million and \$4.5 million from the exercise of stock options for the years ended December 31, 2008, 2007 and 2006, respectively. The aggregate intrinsic value of options exercised during the years ended December 31, 2008, 2007 and 2006, was \$8.1 million, \$11.2 million and \$4.4 million, respectively.

Restricted stock awards

Prior to 2002, the Company granted restricted stock awards under a long-term incentive plan. The restricted stock awards granted vest at various times ranging from one year to nine years from the date of issuance, but certain grants may vest early based upon the attainment of certain performance goals or upon a change in control of the Company. The grant-date fair value is the market price of the Company's stock on the grant date.

A summary of the status of the restricted stock awards for the year ended December 31, 2008, was as follows:

	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested at beginning of period	26,733	\$13.22
Vested	---	---
Forfeited	<u>(6,127)</u>	13.22
Nonvested at end of period	20,606	\$13.22

The fair value of restricted stock awards that vested during the year ended December 31, 2006, was \$1.8 million.

Stock awards

Nonemployee directors may receive shares of common stock instead of cash in payment for directors' fees under the nonemployee director stock compensation plan. There were 45,675 shares with a fair value of \$1.2 million, 48,228 shares with a fair value of \$1.5 million and 50,627 shares with a fair value of \$1.3 million issued under this plan during the years ended December 31, 2008, 2007 and 2006, respectively.

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Performance share awards

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

Target grants of performance shares outstanding at December 31, 2008, were as follows:

Grant Date	Performance Period	Target Grant of Shares
February 2006	2006-2008	185,182
February 2007	2007-2009	175,596
February 2008	2008-2010	186,089

Participants may earn from zero to 200 percent of the target grant of shares based on the Company's total shareholder return relative to that of the selected peer group. Compensation expense is based on the grant-date fair value. The grant-date fair value of performance share awards granted during the years ended December 31, 2008, 2007 and 2006, was \$30.71, \$23.55 and \$25.22, per share, respectively. The grant-date fair value for the performance shares was determined by Monte Carlo simulation using a blended volatility term structure comprised of 50 percent historical volatility and 50 percent implied volatility and a risk-free interest rate term structure based on U.S. Treasury security rates in effect as of the grant date. In addition, the mean over all simulation paths of the discounted dividends expected to be earned in the performance period used in the valuation was \$1.64, \$1.25 and \$1.37 per target share for the 2008, 2007 and 2006 awards, respectively. The fair value of performance share awards that vested during the years ended December 31, 2008, 2007 and 2006, was \$8.5 million, \$6.0 million and \$2.2 million, respectively.

A summary of the status of the performance share awards for the year ended December 31, 2008, was as follows:

	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested at beginning of period	624,499	\$21.91
Granted	192,147	30.71
Additional performance shares earned	61,461	18.36
Vested	(317,542)	18.36
Forfeited	(13,698)	26.57
Nonvested at end of period	546,867	\$26.55

NOTE 15 - INCOME TAXES

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

	2008	2007	2006
	<i>(In thousands)</i>		
United States	\$436,029	\$508,210	\$469,741
Foreign	5,120	4,600	4,148
Income before income taxes	\$441,149	\$512,810	\$473,889

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

	2008	2007	2006
<i>(In thousands)</i>			
Current:			
Federal	\$ 82,279	\$ 106,399	\$ 108,843
State	(184)	15,135	18,487
Foreign	(104)	235	136
	<u>81,991</u>	<u>121,769</u>	<u>127,466</u>
Deferred:			
Income taxes –			
Federal	59,963	58,030	34,693
State	5,332	9,656	4,357
Investment tax credit	(405)	(414)	(405)
	<u>64,890</u>	<u>67,272</u>	<u>38,645</u>
Change in uncertain tax benefits	422	869	---
Change in accrued interest	173	114	---
Total income tax expense	<u>\$ 147,476</u>	<u>\$ 190,024</u>	<u>\$ 166,111</u>

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

	2008	2007
<i>(In thousands)</i>		
Deferred tax assets:		
Accrued pension costs	\$ 93,371	\$ 44,002
Regulatory matters	46,855	43,866
Asset retirement obligations	22,707	15,163
Deferred compensation	12,015	13,677
Other	62,456	45,335
Total deferred tax assets	<u>237,404</u>	<u>162,043</u>
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	562,326	498,933
Basis differences on natural gas and oil producing properties	284,231	260,417
Regulatory matters	65,909	17,630
Natural gas and oil price swap and collar agreements	30,414	3,989
Other	42,725	42,044
Total deferred tax liabilities	<u>985,605</u>	<u>823,013</u>
Net deferred income tax liability	<u>\$(748,201)</u>	<u>\$(660,970)</u>

As of December 31, 2008 and 2007, no valuation allowance has been recorded associated with the above deferred tax assets.

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The following table reconciles the change in the net deferred income tax liability from December 31, 2007, to December 31, 2008, to deferred income tax expense:

	2008
	<i>(In thousands)</i>
Change in net deferred income tax liability from the preceding table	\$ 87,231
Deferred taxes associated with other comprehensive income	(11,761)
Deferred taxes associated with acquisitions	(20,700)
Other	10,120
Deferred income tax expense for the period	\$ 64,890

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,	2008		2007		2006	
	Amount	%	Amount	%	Amount	%
<i>(Dollars in thousands)</i>						
Computed tax at federal statutory rate	\$ 154,402	35.0	\$ 179,484	35.0	\$ 165,861	35.0
Increases (reductions) resulting from:						
State income taxes, net of federal income tax benefit	10,709	2.4	17,121	3.3	17,786	3.8
Domestic production activities deduction	(3,031)	(.7)	(4,787)	(.9)	(2,324)	(.5)
Depletion allowance	(2,932)	(.7)	(4,073)	(.8)	(4,784)	(1.0)
Deductible K-Plan dividends	(2,144)	(.5)	(2,134)	(.4)	---	---
Federal renewable energy credit	(1,235)	(.3)	---	---	---	---
Resolution of tax matters and uncertain tax positions	595	.1	208	---	(3,660)	(.8)
Foreign operations	423	.1	9,603	1.8	136	---
Other	(9,311)	(2.0)	(5,398)	(.9)	(6,904)	(1.4)
Total income tax expense	\$ 147,476	33.4	\$ 190,024	37.1	\$ 166,111	35.1

Prior to the sale of the domestic independent power production assets on July 10, 2007, as discussed in Note 3, the Company considered earnings (including the gain from the sale of its foreign equity method investment in a natural gas-fired electric generating facility in Brazil in 2005) to be reinvested indefinitely outside of the United States and, accordingly, no U.S. deferred income taxes were recorded with respect to such earnings. Following the sale of these assets, the Company reconsidered its long-term plans for future development and expansion of its foreign investment and has determined that it has no immediate plans to explore or invest in additional foreign investments at this time. Therefore, in accordance with SFAS No. 109, in the third quarter of 2007, deferred income taxes were accrued with respect to the temporary differences which had not been previously recorded. The amount of cumulative undistributed earnings for which there are temporary differences is approximately \$34 million at December 31, 2008. The amount of deferred tax liability, net of allowable foreign tax credits, associated with the undistributed earnings at December 31, 2008, was approximately \$10.8 million, which was largely

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recognized in 2007. Future earnings will also be subject to additional U.S. taxes, net of allowable foreign tax credits.

On January 1, 2007, the Company adopted FIN 48. The Company and its subsidiaries file income tax returns in the U.S. federal jurisdiction, and various state, local and foreign jurisdictions. With few exceptions, the Company is no longer subject to U.S. federal, state and local, or non-U.S. income tax examinations by tax authorities for years ending prior to 2004.

Upon the adoption of FIN 48, the Company recognized a decrease in the liability for unrecognized tax benefits, which was not material and was accounted for as an increase to the January 1, 2007, balance of retained earnings. At the date of adoption, the amount of unrecognized tax benefits was \$4.5 million, including interest.

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

	2008	2007
	<i>(In thousands)</i>	
Balance at beginning of year	\$ 3,735	\$ 4,241
Additions based on tax positions related to the current year	1,102	373
Additions for tax positions of prior years	1,811	588
Reductions for tax positions of prior years	(1,062)	---
Lapse of statute of limitations	---	(1,467)
Balance at end of year	\$ 5,586	\$ 3,735

Included in the balance of unrecognized tax benefits at December 31, 2008, were \$540,000 of tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. Because of the impact of deferred tax accounting, other than interest and penalties, the disallowance of the shorter deductibility period would not affect the annual effective tax rate but would accelerate the payment of cash to the taxing authority to an earlier period. The amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate at December 31, 2008, was \$5.7 million, including approximately \$614,000 for the payment of interest and penalties.

The Company does not anticipate the amount of unrecognized tax benefits to significantly increase or decrease within the next 12 months.

For the years ended December 31, 2008, 2007 and 2006, the Company recognized approximately \$819,000, \$680,000 and \$7,100, respectively, in interest expense. Penalties were not material in 2008, 2007 and 2006. The Company recognized interest income of approximately \$223,000, \$480,000 and \$1.5 million for the years ended December 31, 2008, 2007 and 2006, respectively. The Company had accrued liabilities of approximately \$1.4 million, \$718,000 and \$436,000 at December 31, 2008, 2007 and 2006, respectively, for the payment of interest.

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 vast majority of the Company's operations are located within the United States. The Company also has investments in foreign countries, which largely consist of Centennial Resources' equity method investment in the Brazilian Transmission Lines.

The electric segment generates, transmits and distributes electricity in Montana, North Dakota, South Dakota and Wyoming. The natural gas distribution segment distributes natural

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gas in those states as well as in Idaho, Minnesota, Oregon and Washington. These operations also supply related value-added products and services.

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

The pipeline and energy services 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 energy-related management services.

The natural gas and oil production segment is engaged in natural gas and oil acquisition, exploration, development and production activities in the Rocky Mountain and Mid-Continent regions of the United States and in and around the Gulf of Mexico.

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

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

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

	2008	2007	2006
	<i>(In thousands)</i>		
External operating revenues:			
Electric	\$ 208,326	\$ 193,367	\$ 187,301
Natural gas distribution	1,036,109	532,997	351,988
Pipeline and energy services	440,764	369,345	349,997
	1,685,199	1,095,709	889,286
Construction services	1,256,759	1,102,566	987,079
Natural gas and oil production	420,637	288,148	251,153
Construction materials and contracting	1,640,683	1,761,473	1,877,021
Other	---	---	---
	3,318,079	3,152,187	3,115,253
Total external operating revenues	\$ 5,003,278	\$ 4,247,896	\$ 4,004,539
Intersegment operating revenues:			
Electric	\$ ---	\$ ---	\$ ---
Natural gas distribution	---	---	---
Construction services	560	649	503
Pipeline and energy services	91,389	77,718	93,723
Natural gas and oil production	291,642	226,706	232,799
Construction materials and contracting	---	---	---
Other	10,501	10,061	8,117
Intersegment eliminations	(394,092)	(315,134)	(335,142)
Total intersegment operating revenues	\$ ---	\$ ---	\$ ---
Depreciation, depletion and amortization:			
Electric	\$ 24,030	\$ 22,549	\$ 21,396
Natural gas distribution	32,566	19,054	9,776
Construction services	13,398	14,314	15,449
Pipeline and energy services	23,654	21,631	13,288
Natural gas and oil production	170,236	127,408	106,768
Construction materials and contracting	100,853	95,732	88,723
Other	1,283	1,244	1,131
Total depreciation, depletion and amortization	\$ 366,020	\$ 301,932	\$ 256,531
Interest expense:			
Electric	\$ 8,674	\$ 6,737	\$ 6,493
Natural gas distribution	24,004	13,566	3,885
Construction services	4,893	4,878	6,295
Pipeline and energy services	8,314	8,769	8,094
Natural gas and oil production	12,428	8,394	9,864
Construction materials and contracting	24,291	23,997	25,943
Other	374	10,717	11,775
Intersegment eliminations	(1,451)	(4,821)	(254)
Total interest expense	\$ 81,527	\$ 72,237	\$ 72,095

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	2008	2007	2006
	<i>(In thousands)</i>		
Income taxes:			
Electric	\$ 8,225	\$ 8,528	\$ 7,403
Natural gas distribution	18,827	6,477	2,108
Construction services	26,952	26,829	16,497
Pipeline and energy services	15,427	18,524	18,938
Natural gas and oil production	68,701	78,348	78,960
Construction materials and contracting	8,947	39,045	46,245
Other	397	12,273	(4,040)
Total income taxes	\$ 147,476	\$ 190,024	\$ 166,111
Earnings on common stock:			
Electric	\$ 18,755	\$ 17,700	\$ 14,401
Natural gas distribution	34,774	14,044	5,680
Construction services	49,782	43,843	27,851
Pipeline and energy services	26,367	31,408	32,126
Natural gas and oil production	122,326	142,485	145,657
Construction materials and contracting	30,172	77,001	85,702
Other	10,812	(4,380)	(4,324)
Earnings on common stock before income from discontinued operations	292,988	322,101	307,093
Income from discontinued operations, net of tax	---	109,334	7,979
Total earnings on common stock	\$ 292,988	\$ 431,435	\$ 315,072
Capital expenditures:			
Electric	\$ 72,989	\$ 91,548	\$ 39,055
Natural gas distribution	398,116	500,178	15,398
Construction services	24,506	18,241	31,354
Pipeline and energy services	42,960	39,162	42,749
Natural gas and oil production	710,742	283,589	328,979
Construction materials and contracting	127,578	189,727	141,088
Other	774	1,621	2,052
Net proceeds from sale or disposition of property	(86,927)	(24,983)	(30,501)
Net capital expenditures before discontinued operations	1,290,738	1,099,083	570,174
Discontinued operations	---	(548,216)	33,090
Total net capital expenditures	\$ 1,290,738	\$ 550,867	\$ 603,264
Assets:			
Electric*	\$ 479,639	\$ 428,200	\$ 353,593
Natural gas distribution*	1,548,005	942,454	264,102
Construction services	476,092	456,564	401,832
Pipeline and energy services	506,872	500,755	474,424
Natural gas and oil production	1,792,792	1,299,406	1,173,797
Construction materials and contracting	1,552,296	1,642,729	1,562,868
Other**	232,149	322,326	672,858
Total assets	\$ 6,587,845	\$ 5,592,434	\$ 4,903,474

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	2008	2007	2006
	<i>(In thousands)</i>		
Property, plant and equipment:			
Electric*	\$ 848,725	\$ 784,705	\$ 703,838
Natural gas distribution*	1,429,487	948,446	289,106
Construction services	111,301	101,935	94,754
Pipeline and energy services	640,921	600,712	562,596
Natural gas and oil production	2,477,402	1,923,899	1,636,245
Construction materials and contracting	1,524,029	1,538,716	1,410,657
Other	30,372	31,833	30,529
Less accumulated depreciation, depletion and amortization	2,761,319	2,270,691	1,735,302
Net property, plant and equipment	\$ 4,300,918	\$ 3,659,555	\$ 2,992,423

* Includes allocations of common utility property.

** Includes the domestic independent power production assets in 2006 that were sold in 2007, and 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: 2008 results reflect an \$84.2 million after-tax noncash write-down of natural gas and oil properties.

The pipeline and energy services segment recognized income from discontinued operations, net of tax, of \$106,000 for the year ended December 31, 2007, and a loss from discontinued operations, net of tax, of \$2.1 million for the year ended December 31, 2006. The Other category reflects income from discontinued operations, net of tax, of \$109.2 million and \$10.1 million for the years ended December 31, 2007 and 2006, respectively.

Excluding income (loss) from discontinued operations at pipeline and energy services, earnings from electric, natural gas distribution and pipeline and energy services are substantially all from regulated operations. Earnings from construction services, natural gas and oil production, construction materials and contracting, and other are all from nonregulated operations.

Capital expenditures for 2008, 2007 and 2006 include noncash transactions, including the issuance of the Company's equity securities, in connection with acquisitions and the outstanding indebtedness related to the 2008 Intermountain acquisition and the 2007 Cascade acquisition. The noncash transactions were \$97.6 million in 2008, \$217.3 million in 2007 and immaterial in 2006.

NOTE 17 - EMPLOYEE BENEFIT PLANS

The Company has noncontributory defined benefit pension plans and other postretirement benefit plans for certain eligible employees. Effective January 1, 2006, the Company discontinued defined pension plan benefits to all nonunion and certain union employees hired after December 31, 2005. These employees that would have been eligible for defined pension plan benefits are eligible to receive additional defined contribution plan benefits. The Company uses a measurement date of December 31 for all of its pension and postretirement benefit plans.

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Changes in benefit obligation and plan assets for the year ended December 31, 2008, and amounts recognized in the Consolidated Balance Sheets at December 31, 2008, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2008	2007	2008	2007
<i>(In thousands)</i>				
Change in benefit obligation:				
Benefit obligation at beginning of year	\$359,923	\$298,398	\$81,581	\$67,724
Service cost	8,812	9,098	1,977	1,865
Interest cost	21,264	18,591	5,079	4,212
Plan participants' contributions	---	---	2,120	1,790
Amendments	---	---	(382)	---
Actuarial (gain) loss	(8,336)	(8,079)	763	482
Acquisition	---	63,556	9,872	11,734
Benefits paid	(23,138)	(21,641)	(6,685)	(6,226)
Benefit obligation at end of year	358,525	359,923	94,325	81,581
Change in plan assets:				
Fair value of plan assets at beginning of year	330,966	259,275	73,684	58,747
Actual gain (loss) on plan assets	(83,960)	28,393	(20,058)	2,357
Employer contribution	2,346	4,236	3,212	3,888
Plan participants' contributions	---	---	2,120	1,790
Acquisition	---	60,703	7,812	13,128
Benefits paid	(23,138)	(21,641)	(6,685)	(6,226)
Fair value of plan assets at end of year	226,214	330,966	60,085	73,684
Funded status – under	\$(132,311)	\$(28,957)	\$(34,240)	\$(7,897)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Prepaid benefit cost (noncurrent)	\$ ---	\$ 10,253	\$ ---	\$ 664
Accrued benefit liability (current)	---	---	(407)	(408)
Accrued benefit liability (noncurrent)	(132,311)	(39,210)	(33,833)	(8,153)
Net amount recognized	\$(132,311)	\$(28,957)	\$(34,240)	\$(7,897)
Amounts recognized in accumulated other comprehensive (income) loss consist of:				
Actuarial (gain) loss	\$131,081	\$30,006	\$23,418	\$(2,466)
Prior service cost (credit)	2,685	3,350	(8,151)	(10,524)
Transition obligation	---	---	8,503	10,628
Total	\$133,766	\$33,356	\$23,770	\$(2,362)

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

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

The accumulated benefit obligation for the defined benefit pension plans reflected above was \$312.1 million and \$307.7 million at December 31, 2008 and 2007, respectively.

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The projected benefit obligation, accumulated benefit obligation and fair value of plan assets for the pension plans with accumulated benefit obligations in excess of plan assets at December 31, 2008 and 2007, were as follows:

	2008	2007
	<i>(In thousands)</i>	
Projected benefit obligation	\$358,525	\$106,236
Accumulated benefit obligation	\$312,110	\$95,435
Fair value of plan assets	\$226,214	\$94,845

Components of net periodic benefit cost for the Company's pension and other postretirement benefit plans for the years ended December 31, 2008, 2007 and 2006, were as follows:

	Pension Benefits		Other Postretirement Benefits			
	2008	2007	2006	2008	2007	2006
	<i>(In thousands)</i>					
Components of net periodic benefit cost:						
Service cost	\$8,812	\$9,098	\$8,901	\$1,977	\$1,865	\$2,015
Interest cost	21,264	18,591	16,056	5,079	4,212	3,633
Expected return on assets	(26,501)	(22,524)	(19,913)	(5,657)	(4,776)	(4,119)
Amortization of prior service cost (credit)	665	756	913	(2,755)	(1,300)	46
Recognized net actuarial (gain) loss	1,050	1,605	1,699	594	73	(243)
Amortization of net transition obligation (asset)	---	---	(3)	2,125	2,125	2,125
Net periodic benefit cost, including amount capitalized	5,290	7,526	7,653	1,363	2,199	3,457
Less amount capitalized	642	991	689	307	373	261
Net periodic benefit cost	4,648	6,535	6,964	1,056	1,826	3,196
Other changes in plan assets and benefit obligations recognized in accumulated other comprehensive (income) loss:						
Net (gain) loss	102,125	(11,095)	(22,983)	26,478	1,507	(6,340)
Acquisition-related actuarial loss	---	12,291	---	---	9,818	---
Prior service credit	---	---	---	(382)	---	---
Acquisition-related prior service credit	---	(1,842)	---	---	(12,472)	---
Amortization of actuarial gain (loss)	(1,050)	(1,605)	(1,699)	(594)	(73)	243
Amortization of prior service (cost) credit	(665)	(756)	(913)	2,755	1,300	(46)
Amortization of net transition (obligation) asset	---	---	3	(2,125)	(2,125)	(2,125)
Total recognized in accumulated other comprehensive (income) loss	100,410	(3,007)	(25,592)	26,132	(2,045)	(8,268)
Total recognized in net periodic benefit cost and accumulated other comprehensive (income) loss	\$105,058	\$3,528	\$(18,628)	\$27,188	\$(219)	(5,072)

The estimated net loss and prior service cost for the defined benefit pension plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost in 2009 are \$3.9 million and \$605,000, respectively. The estimated net loss, prior service credit and transition obligation for the other postretirement benefit plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2009 are \$1.1 million, \$2.8 million and \$2.1 million, respectively.

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

	Pension Benefits		Other Postretirement Benefits	
	2008	2007	2008	2007
Discount rate	6.25%	6.00%	6.25%	6.00%
Rate of compensation increase	4.00%	4.20%	4.00%	4.50%

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

	Pension Benefits		Other Postretirement Benefits	
	2008	2007	2008	2007
Discount rate	6.00%	5.75%	6.00%	5.75%
Expected return on plan assets	8.50%	8.40%	7.50%	7.50%
Rate of compensation increase	4.20%	4.20%	4.50%	4.50%

The expected rate of return on plan assets is based on the targeted asset allocation of 70 percent equity securities and 30 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:

	2008	2007
Health care trend rate assumed for next year	6.0%-9.0%	6.0%-10.0%
Health care cost trend rate – ultimate	5.0%-6.0%	5.0%-6.0%
Year in which ultimate trend rate achieved	1999-2017	1999-2017

The Company's other postretirement benefit plans include health care and life insurance benefits for certain employees. The plans underlying these benefits may require contributions by the employee depending on such employee's age and years of service at retirement or the date of retirement. The accounting for the health care plans anticipates future cost-sharing changes that are consistent with the Company's expressed intent to generally increase retiree contributions each year by the excess of the expected health care cost trend rate over 6 percent.

Assumed health care cost trend rates may have a significant effect on the amounts reported for the health care plans. A one percentage point change in the assumed health care cost trend rates would have had the following effects at December 31, 2008:

	1 Percentage Point Increase	1 Percentage Point Decrease
<i>(In thousands)</i>		
Effect on total of service and interest cost components	\$ 157	\$ (1,092)
Effect on postretirement benefit obligation	\$ 2,809	\$ (10,944)

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The Company's defined benefit pension plans' asset allocation at December 31, 2008 and 2007, and weighted average targeted asset allocations at December 31, 2008, were as follows:

Asset Category	Percentage of Plan Assets		Weighted Average Targeted Asset Allocation Percentage
	2008	2007	2008
Equity securities	46%	66%	70%
Fixed-income securities	25	29	30*
Other**	29	5	---
Total	100%	100%	100%

* Includes target for both fixed-income securities and other.

** Largely cash and cash equivalents.

The Company's pension assets are managed by 11 outside investment managers. The Company's other postretirement assets are managed by three outside investment managers. 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 future 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. Pension assets are largely valued based on quoted prices in active markets.

The Company's other postretirement benefit plans' asset allocation at December 31, 2008 and 2007, and weighted average targeted asset allocation at December 31, 2008, were as follows:

Asset Category	Percentage of Plan Assets		Weighted Average Targeted Asset Allocation Percentage
	2008	2007	2008
Equity securities	60%	70%	70%
Fixed-income securities	34	27	30*
Other	6	3	---
Total	100%	100%	100%

* Includes target for both fixed-income securities and other.

The Company expects to contribute approximately \$12.4 million to its defined benefit pension plans and approximately \$3.3 million to its postretirement benefit plans in 2009.

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The following benefit payments, which reflect future service, as appropriate, are expected to be paid:

Years	Pension Benefits	Other Postretirement Benefits
	<i>(In thousands)</i>	
2009	\$19,322	\$6,085
2010	20,018	6,278
2011	20,572	6,554
2012	21,543	6,738
2013	22,467	7,029
2014 - 2018	126,831	38,449

The following Medicare Part D subsidies are expected: \$700,000 in 2009; \$700,000 in 2010; \$800,000 in 2011; \$800,000 in 2012; \$800,000 in 2013; and \$5.1 million during the years 2014 through 2018.

In addition to company-sponsored plans, certain employees are covered under multi-employer pension plans administered by a union. Amounts contributed to the multi-employer plans were \$73.1 million, \$51.5 million and \$57.6 million in 2008, 2007 and 2006, respectively.

In addition to the qualified plan defined pension benefits reflected in the table at the beginning of this note, the Company also has unfunded, nonqualified benefit plans for executive officers and certain key management employees that generally provide for defined benefit payments at age 65 following the employee's retirement or to their beneficiaries upon death for a 15-year period. The Company had investments of \$56.3 million at December 31, 2008, consisting of equity securities of \$25.1 million, life insurance carried on plan participants (payable upon the employee's death) of \$28.5 million, fixed-income securities of \$2.6 million, and other investments of \$100,000, which the Company anticipates using to satisfy obligations under these plans. The Company's net periodic benefit cost for these plans was \$9.0 million, \$7.6 million and \$7.5 million in 2008, 2007 and 2006, respectively. The total projected benefit obligation for these plans was \$87.2 million and \$80.6 million at December 31, 2008 and 2007, respectively. The accumulated benefit obligation for these plans was \$77.3 million and \$69.3 million at December 31, 2008 and 2007, respectively. A discount rate of 6.25 percent and 6.00 percent at December 31, 2008 and 2007, respectively, and a rate of compensation increase of 4.00 percent and 4.25 percent at December 31, 2008 and 2007, respectively, were used to determine benefit obligations. A discount rate of 6.00 percent and 5.75 percent at December 31, 2008 and 2007, respectively, and a rate of compensation increase of 4.25 percent at December 31, 2008 and 2007, were used to determine net periodic benefit cost.

The amount of benefit payments for the unfunded, nonqualified benefit plans, as appropriate, are expected to aggregate \$3.9 million in 2009; \$4.4 million in 2010; \$4.8 million in 2011; \$5.2 million in 2012; \$5.7 million in 2013; and \$34.8 million for the years 2014 through 2018.

The Company sponsors various defined contribution plans for eligible employees. Costs incurred by the Company under these plans were \$23.8 million in 2008, \$21.1 million in 2007 and \$17.3 million in 2006. The costs incurred in each year reflect additional participants as a result of business acquisitions.

SFAS No. 158 became effective for the Company as of December 31, 2006. The adoption resulted in a negative transition effect on accumulated other comprehensive loss of \$18.5 million.

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NOTE 18 - JOINTLY OWNED FACILITIES

The consolidated financial statements include the Company's 22.7 percent and 25.0 percent ownership interests in the assets, liabilities and expenses of the Big Stone Station and the Coyote Station, respectively. Each owner of the Big Stone and Coyote stations is responsible for financing its investment in the jointly owned facilities.

The Company's share of the Big Stone Station and Coyote Station operating expenses was reflected in the appropriate categories of operating expenses in the Consolidated Statements of Income.

At December 31, the Company's share of the cost of utility plant in service and related accumulated depreciation for the stations was as follows:

	2008	2007
	<i>(In thousands)</i>	
Big Stone Station:		
Utility plant in service	\$61,030	\$61,568
Less accumulated depreciation	39,473	39,168
	\$21,557	\$22,400
Coyote Station:		
Utility plant in service	\$127,151	\$125,826
Less accumulated depreciation	82,018	79,783
	\$45,133	\$46,043

NOTE 19 - REGULATORY MATTERS AND REVENUES SUBJECT TO REFUND

On August 20, 2008, Montana-Dakota filed an application with the WYPSC for an electric rate increase. Montana-Dakota requested a total increase of \$757,000 annually or approximately 4 percent above current rates. A hearing before the WYPSC is scheduled for April 7, 2009. An order is anticipated in the second quarter of 2009.

In November 2006, Montana-Dakota filed an application with the NDPSC requesting an advance determination of prudence of Montana-Dakota's ownership interest in Big Stone Station II. Hearings on the application were held in June 2007. In September 2007, Montana-Dakota informed the NDPSC that certain of the other participants in the project had withdrawn and it was considering the impact of these withdrawals on the project and its options. Supplemental hearings before the NDPSC were held in late April 2008 regarding possible plant configuration changes as a result of the participant withdrawals and updated supporting modeling. On August 27, 2008, the NDPSC approved Montana-Dakota's request for advance determination of prudence for ownership in the proposed Big Stone Station II for a minimum of 121.8 MW up to a maximum of 133 MW and a proportionate ownership share of the associated transmission electric resources. On September 26, 2008, the intervenors in the proceeding appealed the NDPSC order to the North Dakota District Court. The appeal was assigned and a briefing schedule was established. The intervenors brief was filed January 16, 2009, and Montana-Dakota's brief is due in February 2009.

In December 1999, Williston Basin filed a general natural gas rate change application with the FERC. Williston Basin began collecting such rates effective June 1, 2000, subject to refund. Currently, the only remaining issue outstanding related to this rate change application is in regard to certain service restrictions. In May 2004, the FERC remanded this issue to an ALJ for resolution. In November 2005, the FERC issued an Order on Initial Decision affirming the ALJ's Initial Decision regarding certain service and annual demand quantity restrictions. In April 2006, the FERC issued an Order on Rehearing denying Williston Basin's Request for Rehearing of the FERC's Order on Initial Decision. In April 2006, Williston Basin appealed to the D.C. Appeals Court certain issues addressed by the FERC's Order on Initial Decision and its Order on Rehearing. On March 18, 2008, the D.C. Appeals Court issued its opinion in this matter concerning the service restrictions. The D.C. Appeals Court found that the FERC was correct to decide the case under the "just and

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reasonable" standard of section 5(a) of the Natural Gas Act; however, it remanded the case back to the FERC as flaws in the FERC's reasoning render its orders arbitrary and capricious. On December 18, 2008, the FERC issued its Order Requesting Data and Comment on this matter. Williston Basin and Northern States Power Company provided responses to FERC's requests in January 2009. In addition, initial comments addressing specific issues identified by the FERC are due to be filed by February 15, 2009, with reply comments due by March 7, 2009. The initial and reply comments should contain all the arguments and supporting evidence the parties determine they need to provide to update the record with regard to the issue under remand.

NOTE 20 - COMMITMENTS AND CONTINGENCIES

Litigation

Coalbed Natural Gas Operations Fidelity is a party to and/or certain of its operations are or have been the subject of more than a dozen lawsuits in Montana and Wyoming in connection with Fidelity's CBNG development in the Powder River Basin. The lawsuits generally involve either challenges to regulatory agency decisions under the NEPA or the MEPA or to Fidelity's management of water produced in association with its operations.

Challenges to State/Federal Regulatory Agency Decision Making Under NEPA/MEPA

In 1999 and 2000, the BLM, the Montana BOGC, and the Montana DEQ announced their respective decisions to prepare an EIS analyzing CBNG development in Montana. In 2003, the agencies each signed RODs approving a final EIS and allowing CBNG development throughout the State of Montana. The approval actions by the agencies resulted in numerous lawsuits initiated by environmental groups and the Northern Cheyenne Tribe related to the validity of the final EIS and associated environmental assessments. Fidelity has intervened in several of these lawsuits to protect its interests.

In lawsuits filed in Montana Federal District Court in May 2003, the NPRC and the Northern Cheyenne Tribe asserted that the BLM violated NEPA and other federal laws when approving the 2003 EIS. As a result of an order entered in those lawsuits, producers, including Fidelity, were allowed to engage in limited CBNG development of up to 500 CBNG wells to be drilled annually on private, state, and federal lands in the Montana Powder River Basin pending the BLM's preparation and adoption of a SEIS. As provided in the order, the injunction limiting development expired on January 14, 2009.

In December 2006, the BLM issued a draft SEIS that endorsed a phased-development approach to CBNG production in the Montana Powder River Basin, whereby future projects would be reviewed against four screens or filters (relating to water quality, wildlife, Native American concerns and air quality). Fidelity filed written comments on the draft SEIS asking the BLM to reconsider its proposed phased-development approach and to make numerous other changes to the draft SEIS. The final SEIS was released on October 31, 2008, and the related ROD was signed December 30, 2008. The final SEIS adopted a phased approach that is intended to reduce the overall cumulative impacts to any resource by managing the pace and place as well as the density and intensity of federal CBNG development. Among other limitations, the final SEIS includes a requirement to collect additional habitat data in order for the BLM to permit development in sage grouse crucial habitat areas. Fidelity believes that while permitting may be slower under the final SEIS, it should still be able to develop its CBNG resources at a pace sufficient to meet its investment objectives.

In a related action filed in Montana Federal District Court in December 2003, the NPRC asserted, among other things, that the actions of the BLM in approving Fidelity's applications for permits and the plan of development for the Badger Hills Project in Montana did not comply with applicable federal laws, including the NEPA. As a result of the litigation, Fidelity is operating under an Order, based on a stipulation between the parties, that allows production from existing wells in Fidelity's Badger Hills Project to continue pending preparation of a revised environmental analysis. Fidelity does not believe the revised environmental analysis will have a material impact on its operations. While Fidelity anticipates the revised environmental analysis will be tiered to the final SEIS, Fidelity does not anticipate the revised environmental analysis will impact existing

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development. With regard to future development, Fidelity's plans to drill in the Badger Hills Project are limited, and, as noted above, Fidelity believes it will be able to develop its CBNG resources at a pace sufficient to meet its investment objectives.

Cases Involving Fidelity's Management of Water Produced in Association with Its Operations

About half the CBNG cases Fidelity is involved in relate to administrative agency regulation of water produced in association with CBNG development in Montana and Wyoming. These cases involve legal challenges to the issuance of discharge permits, as well as challenges to the State of Wyoming's CBNG water permitting procedures.

In April 2006, the Northern Cheyenne Tribe filed a complaint in Montana State District Court against the Montana DEQ seeking to set aside Fidelity's renewed direct discharge and treatment permits. The Northern Cheyenne Tribe claimed the Montana DEQ violated the Clean Water Act and the Montana Water Quality Act by failing to include in the permits conditions requiring application of the best practicable control technology currently available and by failing to impose a nondegradation policy like the one the BER adopted soon after the permit was issued. In addition, the Northern Cheyenne Tribe claimed that the actions of the Montana DEQ violated the Montana State Constitution's guarantee of a clean and healthful environment, that the Montana DEQ's related environmental assessment was invalid, that the Montana DEQ was required, but failed, to prepare an EIS and that the Montana DEQ failed to consider other alternatives to the issuance of the permits. Fidelity, the NPRC and the TRWUA were granted leave to intervene in this proceeding. On December 9, 2008, the Montana State District Court decided the case in favor of Fidelity and the Montana DEQ in all respects, denying the motions of the Northern Cheyenne Tribe, TRWUA, and NPRC, and granting the cross-motions of the Montana DEQ and Fidelity in their entirety. As a result, Fidelity may continue to utilize its direct discharge and treatment permits. Any appeal must be filed by March 23, 2009.

Fidelity's discharge of water pursuant to its two permits is its primary means for managing CBNG produced water. Fidelity believes that its discharge permits should, assuming normal operating conditions, allow Fidelity to continue its existing CBNG operations through the expiration of the permits in March 2011. If its permits are set aside, Fidelity's CBNG operations in Montana could be significantly and adversely affected.

The Powder River Basin Resource Council is funding litigation, filed in Wyoming State District Court in June 2007, on behalf of two surface owners against the Wyoming State Engineer and the Wyoming Board of Control. The plaintiffs seek a declaratory judgment that current ground water permitting practices are unlawful; that the state is required to adopt rules and procedures to ensure that coalbed groundwater is managed in accordance with the Wyoming Constitution and other laws; and that would prohibit the Wyoming State Engineer from issuing permits to produce coalbed groundwater and permits to store coalbed groundwater in reservoirs until the Wyoming State Engineer adopts such rules. The Wyoming State District Court granted the Petroleum Association of Wyoming's motion to intervene provided that the defendants motion to dismiss was denied. Fidelity is partly funding the intervention. On May 29, 2008, the Wyoming State District Court dismissed the case. The plaintiffs appealed to the Wyoming Supreme Court on June 27, 2008. Fidelity's CBNG operations in Wyoming could be materially adversely affected if the plaintiffs are successful in this lawsuit.

Fidelity will continue to vigorously defend its interests in all CBNG-related litigation in which it is involved, including the proceedings challenging its water permits. In those cases where damage claims have been asserted, Fidelity is unable to quantify the damages sought and will be unable to do so until after the completion of discovery. If the plaintiffs are successful in these lawsuits, the ultimate outcome of the actions could adversely impact Fidelity's existing CBNG operations and/or the future development of this resource in the affected regions.

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Electric Operations Montana-Dakota joined with two electric generators in appealing a September 2003 finding by the ND Health Department that it may unilaterally revise operating permits previously issued to electric generating plants. Although it is doubtful that any revision of Montana-Dakota's operating permits by the ND Health Department would reduce the amount of electricity its plants could generate, the finding, if allowed to stand, could increase costs for sulfur dioxide removal and/or limit Montana-Dakota's ability to modify or expand operations at its North Dakota generation sites. Montana-Dakota and the other electric generators filed their appeal of the order in October 2003 in the North Dakota District Court. Proceedings were stayed pending conclusion of the periodic review of sulfur dioxide emissions in the state.

In September 2005, the ND Health Department issued its final periodic review decision based on its August 2005 final air quality modeling report. The ND Health Department concluded there were no violations of the sulfur dioxide increment in North Dakota. In March 2006, the DRC filed a complaint in Colorado Federal District Court seeking to force the EPA to declare that the increment had been violated based on earlier modeling conducted by the EPA. The EPA defended against the DRC claim and filed a motion to dismiss the case. The Colorado Federal District Court has dismissed the case.

In June 2007, the EPA noticed for public comment a proposed rule that would, among other things, adopt PSD increment modeling refinements that, if adopted, would operate to formally ratify the modeling techniques and conclusions contained in the September 2005 ND Health Department decision and the August 2005 final report.

In December 2008, the EPA indicated that the increment modeling rule would not be finalized. Because the EPA's action does not alter the September 2005 final review decision of the ND Health Department, and because the DRC's 2006 complaint was dismissed, the Company has determined the September 2003 finding by the ND Health Department will not have a material adverse impact on the Company and it does not intend to pursue the appeal of that finding.

On June 10, 2008, the Sierra Club filed a complaint in the South Dakota Federal District Court against Montana-Dakota and the two other co-owners of the Big Stone Station. The complaint alleges certain violations of the PSD and NSPS provisions of the Clean Air Act and certain violation of the South Dakota SIP. The action further alleges that the Big Stone Station was modified and operated without obtaining the appropriate permits, without meeting certain emissions limits and NSPS requirements and without installing appropriate emission control technology, all allegedly in violation of the Clean Air Act and the South Dakota SIP. The Sierra Club alleges that these actions have contributed to air pollution and visibility impairment and have increased the risk of adverse health effects and environmental damage. The Sierra Club seeks both declaratory and injunctive relief to bring the co-owners of the Big Stone Station into compliance with the Clean Air Act and the South Dakota SIP and to require them to remedy the alleged violations. The Sierra Club also seeks unspecified civil penalties, including a beneficial mitigation project. The Company believes that these claims are without merit and that Big Stone Station has been and is being operated in compliance with the Clean Air Act and the South Dakota SIP. The ultimate outcome of these matters cannot be determined at this time.

Natural Gas Storage Based on reservoir and well pressure data and other information, Williston Basin believes that reservoir pressure (and therefore the amount of gas) in the EBSR, one of its natural gas storage reservoirs, has decreased as a result of Howell and Anadarko's drilling and production activities in areas within and near the boundaries of the EBSR. As of December 31, 2008, Williston Basin estimated that between 11.0 and 11.5 Bcf of storage gas had been diverted from the EBSR as a result of Howell and Anadarko's drilling and production.

Williston Basin filed suit in Montana Federal District Court in January 2006, seeking to recover unspecified damages from Howell and Anadarko, and to enjoin Howell and Anadarko's present and future production from specified wells in and near the EBSR. The Montana

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Federal District Court entered an Order in July 2006, dismissing the case for lack of subject matter jurisdiction. Williston Basin appealed and on May 9, 2008, the Ninth Circuit affirmed the Montana Federal District Court's decision.

In related litigation, Howell filed suit in Wyoming State District Court against Williston Basin in February 2006 asserting that it is entitled to produce any gas that might escape from the EBSR. In August 2006, Williston Basin moved for a preliminary injunction to halt Howell and Anadarko's production in and near the EBSR. The Wyoming State District Court denied Williston Basin's motion in July 2007. In December 2007, motions were argued to a court appointed special master concerning the application of certain legal principles to the production of Williston Basin's storage gas, including gas residing outside the certificated boundaries of the EBSR, by Howell and Anadarko. On March 17, 2008, the special master issued recommendations to the Wyoming State District Court. The special master recommended that the Wyoming State District Court adopt a ruling that gas injected into an underground reservoir belongs to the injector and the injector does not lose title to that gas unless the gas escapes or migrates from the reservoir because it was not well defined or well maintained or if the injector is unable to identify such injected gas because it has been commingled with native gas. The special master also recommended that the Wyoming State District Court adopt a ruling that generally would allow Howell and Anadarko to produce native gas residing inside or outside the certificated boundaries of the EBSR from its wells completed outside the certificated boundaries. The special master recognized that there are other issues yet to be developed that may be determinative of whether Howell and Anadarko may produce native or injected gas, or both. On July 1, 2008, the Wyoming State District Court adopted the special master's report. On July 16, 2008, Williston Basin filed a petition requesting the Wyoming Supreme Court to review a ruling by the Wyoming State District Court that the Natural Gas Act does not preempt the state law that permits an oil and gas producer to take gas that has been dedicated for use in a federally certificated gas storage reservoir. On August 5, 2008, the Wyoming Supreme Court denied the petition. The Wyoming State District Court has scheduled the case for trial beginning January 19, 2010.

In a related proceeding, the FERC issued an order on July 18, 2008, in response to a petition filed by Williston Basin on April 24, 2008, declaring that the certification of a storage facility under the Natural Gas Act conveys to the certificate holder the right to acquire native gas within the certificated boundaries of the storage facility. The FERC also concurred that state law precluding the certificate holder from acquiring the right to native gas would be preempted by federal law.

As previously noted, Williston Basin estimates that as of December 31, 2008, Howell and Anadarko had diverted between 11.0 and 11.5 Bcf from the EBSR. Although all of Howell's wells are shut in and no longer producing gas, Williston Basin believes that its gas losses from the EBSR will continue until pressures in the various interconnected geologic formations equalize. Williston Basin continues to monitor and analyze the situation. At trial, Williston Basin will seek recovery based on the amount of gas that has been and continues to be diverted as well as on the amount of gas that must be recovered as a result of the equalization of the pressures of various interconnected geological formations.

Expert reports were filed with the Wyoming State District Court in January 2008. Supplemental and rebuttal expert reports were filed September 15, 2008. Williston Basin's experts are of the opinion that all of the gas produced by Howell and Anadarko is Williston Basin's gas and will have to be replaced. Williston Basin's experts estimate that the replacement cost of the gas produced by Howell and Anadarko through July 2008 is approximately \$103 million if injection is completed by the end of the 2010 injection season. Williston Basin's experts also estimate that Williston Basin will expend \$6.3 million to mitigate the damages that Williston Basin suffered during the period of Howell and Anadarko's production if the replacement gas is injected by the end of the 2010 injection season. Williston Basin believes that its experts' opinions are based on sound law, economics, reservoir engineering, geology and geochemistry. The expert reports filed

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by Howell and Anadarko claim that storage gas owned by Williston Basin has migrated outside the EBSR into areas in which Howell and Anadarko have oil and gas rights. They theorize that Williston Basin is accountable to Howell and Anadarko for the migration of such gas. Although Howell and Anadarko have not specified the amount of damages they seek to recover, Williston Basin believes Howell and Anadarko's proposed methodology for valuing their alleged injury, if any, is flawed, inconsistent and lacking in factual and legal support.

Williston Basin intends to vigorously defend its rights and interests in these proceedings, to assess further avenues for recovery through the regulatory process at the FERC, and to pursue the recovery of any and all economic losses it may have suffered. Williston Basin cannot predict the ultimate outcome of these proceedings.

In light of the actions of Howell and Anadarko, Williston Basin installed temporary compression at the site in 2006 in order to maintain deliverability into the transmission system. Williston Basin leased working gas for the 2007 - 2008 and 2008 - 2009 heating seasons to supplement its cushion gas. While installation of the additional compression and leasing working gas provide temporary relief, Williston Basin believes that the adverse physical and operational effects occasioned by the past and potential future loss of storage gas could threaten the operation and viability of the EBSR, impair Williston Basin's ability to comply with the EBSR certificated operating requirements mandated by the FERC and adversely affect Williston Basin's ability to meet its contractual storage and transportation service commitments to customers. In another effort to protect the viability of the EBSR, Williston Basin, on April 18, 2008, filed an application with the FERC to expand the boundaries of the EBSR. The proposed expansion includes the areas from which Howell and Anadarko are producing.

The Company also is involved in other legal actions in the ordinary course of its business. Although the outcomes of any such legal actions cannot be predicted, management believes that the outcomes with respect to these other legal proceedings will not have a material adverse effect upon the Company's financial position or results of operations.

Environmental matters

Portland Harbor Site In December 2000, MBI was named by the EPA as a PRP in connection with the cleanup of a riverbed site adjacent to a commercial property site acquired by MBI from Georgia Pacific-West, Inc. in 1999. The riverbed site is part of the Portland, Oregon, Harbor Superfund Site. The EPA wants responsible parties to share in the cleanup of sediment contamination in the Willamette River. To date, costs of the overall remedial investigation and feasibility study of the harbor site are being recorded, and initially paid, through an administrative consent order by the LWG, a group of several entities, which does not include MBI or Georgia-Pacific West, Inc. Although the LWG originally estimated the overall remedial investigation and feasibility study would cost approximately \$10 million, it is now anticipated, on the basis of costs incurred to date and delays attributable to an additional round of sampling and potential further investigative work, that such cost could increase to a total in excess of \$60 million. It is not possible to estimate the cost of a corrective action plan until the remedial investigation and feasibility study have been completed, the EPA has decided on a strategy and a record of decision has been published. The development of a proposed plan and ROD on the harbor site is not anticipated to occur until 2010, after which corrective action will be undertaken. MBI also received notice in January 2008 that the Portland Harbor Natural Resource Trustee Council intends to perform an injury assessment to natural resources resulting from the release of hazardous substances at the Harbor Superfund Site. The Trustee Council indicates the injury determination is appropriate to facilitate early settlement of damages and restoration for natural resource injuries. It is not possible to estimate the costs of natural resource damages until an assessment is completed and allocations are undertaken.

Based upon a review of the Portland Harbor sediment contamination evaluation by the Oregon DEQ and other information available, MBI does not believe it is a Responsible Party. In

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addition, MBI has notified Georgia-Pacific West, Inc., that it intends to seek indemnity for any and all liabilities incurred in relation to the above matters, pursuant to the terms of their sale agreement. MBI has entered into an agreement tolling the statute of limitation in connection with the LWG's potential claim for contribution to the costs of the remedial investigation and feasibility study.

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

Manufactured Gas Plant Sites There are three claims against Cascade for cleanup of environmental contamination at manufactured gas plant sites operated by Cascade's predecessors.

The first claim is for soil and groundwater contamination at a site in Oregon and was received in 1995. There are PRPs in addition to Cascade that may be liable for cleanup of the contamination. Some of these PRPs have shared in the investigation costs. It is expected that these and other PRPs will share in the cleanup costs. Several alternatives for cleanup have been identified, with preliminary cost estimates ranging from approximately \$500,000 to \$11.0 million. It is not known at this time what share of the cleanup costs will actually be borne by Cascade. Additional ecological risk assessment conducted by Cascade and other PRPs is expected to be completed in 2009. The results of the assessment may affect the selection and implementation of a cleanup alternative.

The second claim is for contamination at a site in Washington and was received in 1997. A preliminary investigation has found soil and groundwater at the site contain contaminants that will require further investigation and cleanup. A supplemental investigation is currently being conducted to better characterize the extent of the contamination. The supplemental investigation is expected to be completed in 2009. The data from the preliminary investigation indicates other current and former owners of properties and businesses in the vicinity of the site may also be responsible for the contamination. There is currently not enough information to estimate the potential liability associated with this claim.

The third claim is also for contamination at a site in 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's predecessor from about 1946 to 1962. The notice indicates that current estimates to complete investigation and cleanup of the site exceed \$8.0 million. There is currently not enough information available to estimate the potential liability to Cascade associated with this claim.

To the extent these claims are not covered by insurance, Cascade will seek recovery through the OPUC and WUTC of remediation costs in its natural gas rates charged to customers.

Operating leases

The Company leases certain equipment, facilities and land under operating lease agreements. The amounts of annual minimum lease payments due under these leases as of December 31, 2008, were \$22.2 million in 2009, \$18.2 million in 2010, \$14.0 million in 2011, \$10.2 million in 2012, \$8.8 million in 2013 and \$42.2 million thereafter. Rent expense was \$35.3 million, \$35.6 million and \$23.1 million for the years ended December 31, 2008, 2007 and 2006, respectively.

Purchase commitments

The Company has entered into various commitments, largely natural gas and coal supply, purchased power, natural gas transportation and storage and construction materials supply contracts. These commitments range from one to 52 years. The commitments under these contracts as of December 31, 2008, were \$662.2 million in 2009, \$332.6 million in 2010, \$269.4 million in 2011, \$136.0 million in 2012, \$90.5 million in 2013 and \$268.1 million thereafter. Amounts purchased under various commitments for the years ended December 31,

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2008, 2007 and 2006, were approximately \$1.0 billion (including the acquisition of Intermountain as discussed in Note 2), \$857.0 million (including the acquisition of Cascade as discussed in Note 2) and \$265.8 million, respectively. These commitments were not reflected in the Company's consolidated financial statements.

Guarantees

In connection with the sale of MPX in June 2005 to Petrobras, an indirect wholly owned subsidiary of the Company has agreed to indemnify Petrobras for 49 percent of any losses that Petrobras may incur from certain contingent liabilities specified in the purchase agreement. Centennial has agreed to unconditionally guarantee payment of the indemnity obligations to Petrobras for periods ranging up to five and a half years from the date of sale. The guarantee was required by Petrobras as a condition to closing the sale of MPX.

Centennial continues to guarantee CEM's obligations under a construction contract with LPP for a 550-MW combined-cycle electric generating facility near Hobbs, New Mexico. As described in Note 3, Centennial Resources sold CEM in July 2007 to Bicent Power LLC, which has provided a \$10 million bank letter of credit to Centennial in support of that guarantee obligation. The guarantee, which has no fixed maximum, expires when CEM has completed its obligations under the construction contract. The warranty period associated with this project will expire one year after the date of substantial completion of construction. CEM declared substantial completion of the plant on February 16, 2009, and on February 27, 2009, Centennial received a Notice and Demand from LPP under the guaranty agreement alleging that CEM did not meet certain of its obligations under the construction contract and demanding that Centennial indemnify LPP against all losses, damages, claims, costs, charges and expenses arising from CEM's alleged failures. LPP did not quantify the amount of indemnification being sought, which could be material. The Company believes that the indemnification claims are without merit and intends to vigorously defend against such claims.

In addition, WBI Holdings has guaranteed certain of Fidelity's natural gas and oil price swap and collar agreement obligations. There is no fixed maximum amount guaranteed in relation to the natural gas and oil price swap and collar agreements as the amount of the obligation is dependent upon natural gas and oil commodity prices. The amount of hedging activity entered into by the subsidiary is limited by corporate policy. The guarantees of the natural gas and oil price swap and collar agreements at December 31, 2008, expire in the years ranging from 2009 to 2011; however, Fidelity continues to enter into additional hedging activities and, as a result, WBI Holdings from time to time may issue additional guarantees on these hedging obligations. There was no amount outstanding by Fidelity at December 31, 2008. In the event Fidelity defaults under its obligations, WBI Holdings would be required to make payments under its guarantees.

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, natural gas transportation and sales agreements, gathering contracts, a conditional purchase agreement and certain other guarantees. At December 31, 2008, the fixed maximum amounts guaranteed under these agreements aggregated \$221.7 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate \$185.6 million in 2009; \$1.8 million in 2010; \$25.0 million in 2011; \$2.3 million in 2012; \$800,000 in 2013; \$1.2 million in 2018; \$1.0 million, which is subject to expiration 30 days after the receipt of written notice; and \$4.0 million, which has no scheduled maturity date. The amount outstanding by subsidiaries of the Company under the above guarantees was \$1.5 million and was reflected on the Consolidated Balance Sheet at December 31, 2008. 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, materials obligations, natural gas transportation agreements and other agreements that guarantee the performance of other subsidiaries of the Company. At

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December 31, 2008, the fixed maximum amounts guaranteed under these letters of credit, which expire in 2009, aggregated \$36.8 million. There were no amounts outstanding under the above letters of credit at December 31, 2008.

Fidelity and WBI Holdings have outstanding guarantees to Williston Basin. These guarantees are related to natural gas transportation and storage agreements that guarantee the performance of Prairielands. At December 31, 2008, the fixed maximum amounts guaranteed under these agreements aggregated \$24.0 million. Scheduled expiration of the maximum amounts guaranteed under these agreements aggregate \$20.0 million in 2009 and \$4.0 million in 2011. In the event of Prairielands' default in its payment obligations, the subsidiary issuing the guarantee for that particular obligation would be required to make payments under its guarantee. The amount outstanding by Prairielands under the above guarantees was \$1.8 million, which was not reflected on the Consolidated Balance Sheet at December 31, 2008, because these intercompany transactions are eliminated in consolidation.

In addition, Centennial and Knife River have issued guarantees to third parties related to the Company's 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 its obligation in relation to the purchase of certain maintenance items, materials or lease obligations, Centennial or Knife River would be required to make payments under these guarantees. Any amounts outstanding by subsidiaries of the Company for these maintenance items and materials were reflected on the Consolidated Balance Sheet at December 31, 2008.

In the normal course of business, Centennial has purchased surety bonds related to construction contracts and reclamation obligations of its subsidiaries. In the event a subsidiary of Centennial does not fulfill a bonded obligation, Centennial would be responsible to the surety bond company for completion of the bonded contract or obligation. A large portion of the surety bonds is expected to expire within the next 12 months; however, Centennial will likely continue to enter into surety bonds for its subsidiaries in the future. As of December 31, 2008, approximately \$475 million of surety bonds were outstanding, which were not reflected on the Consolidated Balance Sheet.

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STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year		(24,342,134)		(1,582,999)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value	404,536	3,012,070		7,176,880
4	Total (lines 2 and 3)	404,536	3,012,070		7,176,880
5	Balance of Account 219 at End of Preceding Quarter/Year	404,536	(21,330,064)		5,593,881
6	Balance of Account 219 at Beginning of Current Year	404,536	(21,330,064)		5,593,881
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	(404,536)			
8	Current Quarter/Year to Date Changes in Fair Value		(13,750,459)		(9,534,050)
9	Total (lines 7 and 8)	(404,536)	(13,750,459)		(9,534,050)
10	Balance of Account 219 at End of Current Quarter/Year		(35,080,523)		(3,940,169)

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FOOTNOTE DATA			

Schedule Page: 122(a)(b) Line No.: 7 Column: b

Upon the adoption of SFAS No. 159, the unrealized gain on the available-for-sale investments of \$404,536 (after tax) was recorded as an increase to the January 1, 2008, balance of retained earnings.

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

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (f) common function.

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	1,096,305,581	736,893,792
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	1,096,305,581	736,893,792
9	Leased to Others	25,773	
10	Held for Future Use		
11	Construction Work in Progress	69,079,327	50,812,067
12	Acquisition Adjustments	10,484,908	10,387,642
13	Total Utility Plant (8 thru 12)	1,175,895,589	798,093,501
14	Accum Prov for Depr, Amort, & Depl	623,400,887	417,339,231
15	Net Utility Plant (13 less 14)	552,494,702	380,754,270
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	593,224,961	403,399,367
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	20,871,911	4,705,268
22	Total In Service (18 thru 21)	614,096,872	408,104,635
23	Leased to Others		
24	Depreciation	25,485	
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)	25,485	
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj	9,278,530	9,234,596
33	Total Accum Prov (equals 14) (22,26,30,31,32)	623,400,887	417,339,231

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
288,109,383				71,302,406	3
					4
					5
					6
					7
288,109,383				71,302,406	8
25,773					9
					10
4,548,121				13,719,139	11
97,266					12
292,780,543				85,021,545	13
168,655,157				37,406,499	14
124,125,386				47,615,046	15
					16
					17
167,617,954				22,207,640	18
					19
					20
967,784				15,198,859	21
168,585,738				37,406,499	22
					23
25,485					24
					25
25,485					26
					27
					28
					29
					30
					31
43,934					32
168,655,157				37,406,499	33

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. 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)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents		
4	(303) Miscellaneous Intangible Plant	5,513,658	457,650
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	5,513,658	457,650
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,018,687	
9	(311) Structures and Improvements	48,350,568	1,006,003
10	(312) Boiler Plant Equipment	159,267,197	2,880,622
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	44,836,647	500,151
13	(315) Accessory Electric Equipment	13,617,338	1,197,789
14	(316) Misc. Power Plant Equipment	15,258,982	510,400
15	(317) Asset Retirement Costs for Steam Production	282,876	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	282,632,295	6,094,965
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights		
28	(331) Structures and Improvements		
29	(332) Reservoirs, Dams, and Waterways		
30	(333) Water Wheels, Turbines, and Generators		
31	(334) Accessory Electric Equipment		
32	(335) Misc. Power PLant Equipment		
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)		
36	D. Other Production Plant		
37	(340) Land and Land Rights	66,533	
38	(341) Structures and Improvements	452,964	333,831
39	(342) Fuel Holders, Products, and Accessories	610,045	4,798
40	(343) Prime Movers		
41	(344) Generators	31,519,204	34,292,015
42	(345) Accessory Electric Equipment	885,151	42,939
43	(346) Misc. Power Plant Equipment	49,414	6,042
44	(347) Asset Retirement Costs for Other Production		28,495
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	33,583,311	34,708,120
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	316,215,606	40,803,085

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

distributions of these tentative classifications in columns (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 end of year.

7. 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, 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.

8. 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 requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, 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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)	Line No.
				1
				2
				3
			5,971,308	4
			5,971,308	5
				6
				7
			1,018,687	8
140,118		331,991	49,548,444	9
744,181		-1,222,771	160,180,867	10
				11
1,198,799		890,780	45,028,779	12
3,328			14,811,799	13
73,504		-11,152	15,684,726	14
			282,876	15
2,159,930		-11,152	286,556,178	16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
				35
				36
			66,533	37
522			786,273	38
			614,843	39
				40
			65,811,219	41
1,200			926,890	42
			55,456	43
			28,495	44
1,722			68,289,709	45
2,161,652		-11,152	354,845,887	46

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	3,133,040	22,448
49	(352) Structures and Improvements	1,789	
50	(353) Station Equipment	66,198,385	1,319,519
51	(354) Towers and Fixtures	4,448,232	612,745
52	(355) Poles and Fixtures	30,194,574	1,786,422
53	(356) Overhead Conductors and Devices	25,825,926	1,106,818
54	(357) Underground Conduit		2,039,996
55	(358) Underground Conductors and Devices		3,434,449
56	(359) Roads and Trails		
57	(359.1) Asset Retirement Costs for Transmission Plant	797	
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	129,802,743	10,322,397
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	1,907,630	38,368
61	(361) Structures and Improvements		
62	(362) Station Equipment	32,792,992	1,963,258
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	26,697,457	777,709
65	(365) Overhead Conductors and Devices	18,742,659	449,450
66	(366) Underground Conduit	218,143	11
67	(367) Underground Conductors and Devices	43,257,953	4,409,922
68	(368) Line Transformers	39,195,144	4,171,364
69	(369) Services	19,556,503	1,103,886
70	(370) Meters	12,925,099	2,278,800
71	(371) Installations on Customer Premises	2,086,202	151,343
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	5,915,742	305,014
74	(374) Asset Retirement Costs for Distribution Plant	39,748	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	203,335,272	15,649,125
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	8,137	
87	(390) Structures and Improvements	518,602	
88	(391) Office Furniture and Equipment	976,295	73,050
89	(392) Transportation Equipment	4,862,825	494,517
90	(393) Stores Equipment	108,109	
91	(394) Tools, Shop and Garage Equipment	1,944,471	231,139
92	(395) Laboratory Equipment	1,141,859	10,955
93	(396) Power Operated Equipment	7,880,138	926,672
94	(397) Communication Equipment	1,875,014	99,792
95	(398) Miscellaneous Equipment	64,929	
96	SUBTOTAL (Enter Total of lines 86 thru 95)	19,380,379	1,836,125
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant		
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	19,380,379	1,836,125
100	TOTAL (Accounts 101 and 106)	674,247,658	69,068,382
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	674,247,658	69,068,382

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)	Line No.
				47
2,218		7,966	3,161,236	48
			1,789	49
409,866		-7,966	67,100,072	50
516			5,060,461	51
85,336			31,895,660	52
90,071			26,842,673	53
			2,039,996	54
			3,434,449	55
				56
			797	57
588,007			139,537,133	58
				59
			1,945,998	60
				61
65,171		-49,078	34,642,001	62
				63
272,478		15,414	27,218,102	64
270,643		33,664	18,955,130	65
			218,154	66
638,234			47,029,641	67
197,559			43,168,949	68
239,101			20,421,288	69
829,577			14,374,322	70
79,849		64	2,157,760	71
				72
80,588		-64	6,140,104	73
			39,748	74
2,673,200			216,311,197	75
				76
				77
				78
				79
				80
				81
				82
				83
				84
				85
			8,137	86
			518,602	87
62,408		-5,886	981,051	88
274,420		-38,808	5,044,114	89
943			107,166	90
362,075		2,408	1,815,943	91
			1,152,814	92
232,749		11,899	8,585,960	93
25,255			1,949,551	94
			64,929	95
957,850		-30,387	20,228,267	96
				97
				98
957,850		-30,387	20,228,267	99
6,380,709		-41,539	736,893,792	100
				101
				102
				103
6,380,709		-41,539	736,893,792	104

CONSTRUCTION WORK IN PROGRESS -- ELECTRIC (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 Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or \$100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Construct Big Stone II power plant near Milbank, SD	13,690,418
2	Construct 20MW Cedar Hills wind farm in southwest ND	9,681,781
3	Construct waste heat energy converter near Glen Ullin, ND	7,615,586
4	Construct additional 10MW at Diamond Willow wind farm near Baker, MT	5,227,480
5	Install mercury control system at Lewis & Clark Station near Sidney, MT	1,499,947
6	Replace turbine components at Coyote Station near Beulah, ND	1,370,991
7	Replace boiler reheat tubes at Coyote Station near Beulah, ND	821,595
8	Install gas compression equipment at gas turbine near Glendive, MT	771,165
9	Replace auto transformer at transmission substation near Tioga, ND	701,031
10	Construct and upgrade trans. substations for waste heat energy converter near Glen Ullin, N	629,974
11	Replace sootblowers at Heskett Station in Mandan, ND	394,487
12	Construct underground distribution line to coal bed methane project outside Sheridan, WY	364,656
13	Install bed ash and limestone handling equipment at Heskett Station in Mandan, ND	355,381
14	Upgrade Honeywell control system at Heskett Station in Mandan, ND	346,567
15	Construct transmission substation for Cedar Hills wind farm in southwest ND	324,005
16	Construct distribution line and transformer to oil pipeline station outside Stanley, ND	294,227
17	Replace control board at Heskett Station in Mandan, ND	239,362
18	Purchase digger derrick in Williston, ND	230,722
19	Purchase digger derrick in Dickinson, ND	230,414
20	Purchase digger derrick in Kenmare, ND	230,405
21	Replace station elevator at Lewis & Clark Station near Sidney, MT	174,495
22	Replace retract sootblowers at Lewis & Clark Station near Sidney, MT	162,853
23	Purchase 25MW of the WYGEN III power plant near Gillette, WY	162,426
24	Upgrade transmission substation at Diamond Willow wind farm near Baker, MT	158,939
25	Purchase manlift truck in Bismarck, ND	153,903
26	Construct underground distribution line to industrial customer in Bismarck, ND	151,342
27	Purchase bucket truck in Kenmare, ND	135,837
28	Install lightning arrestors on transmission lines near Bismarck, ND	129,409
29	Construct underground distribution line to residential development outside Sheridan, WY	124,765
30	Replace 480V circuit breakers at Heskett Station in Mandan, ND	121,257
31	Modify transmission substations for oil activity near Tioga, ND	103,548
32		
33	Minor projects less than \$100,000:	
34	Steam Production	1,037,440
35	Other Production	-56,076
36	Transmission	497,335
37	Distribution	2,254,952
38	General	480,448
39	Intangible	-1,000
40		
41		
42		
43	TOTAL	50,812,067

Name of Respondent
MDU Resources Group, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo., Yr)
12/3 ,8

Year/Period of Report
End of 2008/Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC 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 electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional 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 Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	388,933,401	388,933,401		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	22,263,977	22,263,977		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	987,565	987,565		
7	Other Clearing Accounts	-168,451	-168,451		
8	Other Accounts (Specify, details in footnote):	-1,099,212	-1,099,212		
9		7,821	7,821		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	21,991,700	21,991,700		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	6,378,491	6,378,491		
13	Cost of Removal	1,389,649	1,389,649		
14	Salvage (Credit)	318,200	318,200		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	7,449,940	7,449,940		
16	Other Debit or Cr. Items (Describe, details in footnote):	-75,794	-75,794		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	403,399,367	403,399,367		

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

20	Steam Production	193,932,003	193,932,003		
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	12,903,690	12,903,690		
25	Transmission	78,504,432	78,504,432		
26	Distribution	108,519,648	108,519,648		
27	Regional Transmission and Market Operation				
28	General	9,539,594	9,539,594		
29	TOTAL (Enter Total of lines 20 thru 28)	403,399,367	403,399,367		

Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report 2008/Q4
FOOTNOTE DATA			

Schedule Page: 219 Line No.: 7 Column: c

Amortization of deferred depreciation, AFUDC and interest on portion of Coyote Station previously excluded from Montana rate base after in service date.

Schedule Page: 219 Line No.: 8 Column: c

Common plant depreciation expense charged to electric operations.

Schedule Page: 219 Line No.: 9 Column: c

SFAS 143 ARO depreciation expense reclassified to a regulatory asset.

Schedule Page: 219 Line No.: 16 Column: c

Reserve reclassifications between utility segments and net gains and losses on depreciable plant.

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INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
 - (a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
 - (b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1				
2	CENTENNIAL ENERGY HOLDINGS, INC. (100% OWNED)	12/88		
3	Capital investment in subsidiaries			924,133,478
4				
5	Equity in undistributed subsidiary earnings since acquisition			1,130,915,920
6				
7				
8	MDU ENERGY CAPITAL, LLC (100% OWNED)	07/07		
9	Capital investment in subsidiaries			230,466,960
10				
11	Equity in undistributed subsidiary earnings since acquisition			-965,185
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 \$	2,478,164,341	TOTAL	2,284,551,173

Name of Respondent
MDU Resources Group, Inc.

This Report is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Yr)
12/3 08

Year/Period of Report
End of 2008/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, 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 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 difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
				2
		953,826,225		3
				4
239,458,896	199,856,000	1,170,628,722		5
				6
				7
				8
		344,117,778		9
				10
25,420,684	14,859,000	9,591,616		11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
				35
				36
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				39
				40
				41
264,879,580	214,715,000	2,478,164,341		42

Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report 2008/Q4
FOOTNOTE DATA			

Schedule Page: 224 Line No.: 9 Column: g

Acquisition of Intermountain Gas Company on October 2, 2008.

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Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo Yr) 12/31 2008	Year/Period of Report End of 2008/Q4
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MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	4,055,099	4,099,005	Electric & Gas
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	6,396,615	7,163,270	Electric & Gas
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	2,052,680	2,174,671	Electric
8	Transmission Plant (Estimated)	54,957	129,296	Electric
9	Distribution Plant (Estimated)	703,665	875,151	Electric & Gas
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	-78,985	-117,295	Electric & Gas
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	9,128,932	10,225,093	
13	Merchandise (Account 155)	1,470,096	1,742,091	
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)			
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	14,654,127	16,066,189	

Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report 2008/Q4
FOOTNOTE DATA			

Schedule Page: 227 Line No.: 11 Column: b

Allowance for inventory shrinkage - materials and supplies.

Schedule Page: 227 Line No.: 11 Column: c

Allowance for inventory shrinkage - materials and supplies.

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	Allowances Inventory (Account 158.1) (a)	Current Year		2009	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year		27,869.00		11,804.00
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509		9,962.00		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year		17,907.00		11,804.00
30					
31	Sales:				
32	Net Sales Proceeds (Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year		169.00		168.00
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales		47.00		
40	Balance-End of Year		122.00		168.00
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)		47.00		88,511
45	Gains		47.00		88,511
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transfersors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2010		2011		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
11,607.00		11,607.00		313,389.00		376,276.00		1
								2
								3
								4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
						9,962.00		17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
11,607.00		11,607.00		313,389.00		366,314.00		28
								29
								30
								31
								32
								33
								34
								35
168.00		167.00		7,537.00		8,209.00		36
								37
								38
				46.00		93.00		39
168.00		167.00		7,491.00		8,116.00		40
								41
								42
				46.00	4,747	93.00	93,258	43
				46.00	4,747	93.00	93,258	44
								45
								46

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than \$50,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Deferred SFAS No. 106 Costs; Montana gas	343,545		G-926	54,531	289,014
2	amortization over 240 months beginning					
3	11/94 and South Dakota gas amortization					
4	over 216 months beginning 1/95					
5						
6	Unamortized AFUDC on portion of Coyote I Station	1,168,254		E-403	132,255	1,035,999
7	that had been disallowed in rate base by Montana;					
8	amortization of 12/83 balance over 388 months end-					
9	ing 10/16 and amortization of 6/84 balance over					
10	356 months					
11						
12	Deferred depreciation on portion of Coyote I	271,964		E-403	30,789	241,175
13	Station that had been disallowed in rate base by					
14	Montana; amortization of 12/83 balance over 388					
15	months ending 10/16 and amortization of 6/84					
16	balance over 356 months					
17						
18	Interest deferred on portion of Coyote I Station	47,772		E-403	5,408	42,364
19	AFUDC which had been disallowed in rate base by					
20	Montana; amortization of interest on 6/84 AFUDC					
21	balance over 356 months					
22						
23	Unamortized Regulatory Commission Expense:	737,558	535,358		426,528	846,388
24	North Dakota gas amortization					
25	over 48 months beginning 12/02;					
26	Minnesota gas amortization over					
27	36 months beginning 1/07; South Dakota					
28	gas amortization over 60 months beginning					
29	12/04; South Dakota gas amortization over 36					
30	months beginning 9/05; Montana electric					
31	amortization over 36 months beginning					
32	5/08					
33						
34	Accumulated costs associated with Electric rate	462,054	96,095	1823	535,279	22,870
35	cases in Montana and Wyoming					
36						
37						
38	Asset Retirement Obligation at Coyote I	2,013,192	169,739	230	65	2,182,866
39	Station, Big Stone Station, Heskett Station,					
40	Lewis and Clark Station, electric transmission,					
41	electric and gas distribution, common general					
42	plant and Diamond Willow					
43						
44	TOTAL	20,474,249	75,107,683		7,385,510	88,196,422

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than \$50,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Margin Sharing Adjustment - North Dakota	3,019,633	2,880,156	142	2,399,771	3,500,018
2	Electric					
3						
4	Deferred fuel and purchased power costs -					
5	North Dakota - Electric	1,545,425	7,178		3,017,442	-1,464,839
6	Wyoming - Electric	(502,303)	1,102,009	4310	9,401	590,305
7	Montana - Electric		379,484			379,484
8						
9	FAS 158- Pension	9,537,076	56,465,320			66,002,396
10						
11	Manufactured Gas Plant Site - Bismarck, ND	1,050,221	7,334	1832	149,782	907,773
12						
13	Regulatory Matters - FAS 109	779,858	188,420		623,529	344,749
14						
15	FAS 158 - Post Retirement		13,276,590	219	730	13,275,860
16						
17						
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43						
44	TOTAL	20,474,249	75,107,683		7,385,510	88,196,422

Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report 2008/Q4
FOOTNOTE DATA			

Schedule Page: 232 Line No.: 23 Column: d

E-928 \$ 85,708
G-928 \$ 340,820

Schedule Page: 232 Line No.: 34 Column: d

Montana Electric rate case accumulated costs of \$535,279 transferred to Unamortized Regulatory Commission Expense, line 23. Amortization began May 2008.

Schedule Page: 232.1 Line No.: 5 Column: d

E-555 (deferral) \$2,131,826
E-555 (amortization) 885,616

Schedule Page: 232.1 Line No.: 6 Column: c

E-555 Deferral \$ 722,367
E-555 Amortization 379,642

Schedule Page: 232.1 Line No.: 13 Column: d

2820 \$ 381,600
2830 241,929

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than \$50,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1	Natural gas minimum bill obligation	5,342,863				5,342,863
2						
3						
4	Deferred pension expense	10,199,515	329,513		10,529,028	
5						
6	Deferred capital stock expense	378,029	656,150		707,138	327,041
7						
8	Unamortized lease improvements, amortized beginning 12/90 and ending 11/10	7,775		G-931	2,666	5,109
9						
10						
11						
12	Conservation Programs	-5,806	1,811,423		2,145,970	-340,353
13						
14	Future Source Capital Corporation	262,404	165,808			428,212
15						
16						
17	Goodwill - Great Plains Natural Gas Co.	4,812,244				4,812,244
18						
19						
20	Subsidiary Postretirement Trust Assets	9,881,685	6,429,142		655,957	15,654,870
21						
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45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	30,878,709				26,229,986

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report 2008/Q4
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MDU Resources Group, Inc.

FOOTNOTE DATA

Schedule Page: 233 Line No.: 4 Column: d

182 \$10,264,028 (moved to regulatory assets)
184 265,000

Schedule Page: 233 Line No.: 6 Column: d

146 \$ 88,472
181 362,432
207 66,742
214 189,492

Schedule Page: 233 Line No.: 12 Column: d

142 \$ 2,092,817
143 3,612
419 5,559
E-908 43,982

Schedule Page: 233 Line No.: 20 Column: d

123 \$ 577,341
2283 78,616

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.

Line No.	Description and Location (a)	Balance of Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	Pension Expense	2,251,753	12,915,881
3	Management Incentive	912,670	1,013,620
4	Customer Advances	591,740	1,104,654
5	Restricted Stock Bonus Plan	852,283	687,958
6			
7	Other	20,300	24,932
8	TOTAL Electric (Enter Total of lines 2 thru 7)	4,628,746	15,747,045
9	Gas		
10	Pension Expense	2,956,626	15,338,300
11	Customer Advances	656,822	853,856
12	Restricted Stock Bonus Plan	709,039	582,525
13	Capitalized Overheads	836,120	407,188
14	Prepaid Demand Charge	-1,062,919	-1,038,091
15	Other	2,462,202	2,524,450
16	TOTAL Gas (Enter Total of lines 10 thru 15)	6,557,890	18,668,228
17	Other (Specify) *	26,465,042	25,889,560
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	37,651,678	60,304,833

Notes

	Balance at Beginning of Year	Balance at End of Year
*Utility		
Vacation Pay Accrual	\$ 2,533,349	\$ 2,559,309
Property Insurance	706,597	613,874
Sundry Reserves	91,613	83,763
Supplemental Income Security Plan	14,911,081	15,264,107
FAS 106 - Medical Life	914,494	5,581,118
BOD Compensation & Benefits	2,562,351	2,057,664
FAS 158 - Post Retirement	22,516	(4,576,947)
Regulatory Matters	4,158,356	3,736,027
Total Utility	\$25,900,357	\$25,318,915
*Non-Utility		
Capitalized Overheads	\$ 105,621	\$ 79,887
C.I.A.C.'s	227,690	253,638
Management Incentive	112,920	112,920
FAS 106 - Medical Life	106,124	691,877
FAS 158 - Post Retirement	2,825	(574,373)
Bad Debts	9,505	6,696
Total Non-Utility	\$ 564,685	\$ 570,645
*Total Other	\$26,465,042	\$25,889,560

Name of Respondent
 MDU Resources Group, Inc.

This report is:
 (1) An Original
 (2) A Resubmission

Date of Report
 (Mo, Yr)
 12/3 08

Year/Period of Report
 End of 2008/Q4

CAPITAL STOCKS (Account 201 and 204)

- Report below the particulars (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. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
- Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (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	500,000,000	1.00	
3	Total Account 201	500,000,000		
4				
5	Account 204			
6	Preferred Stock	500,000	100.00	
7	4.50% Cumulative			105.00
8	4.70% Cumulative			102.00
9				
10	Total Account 204	500,000		
11				
12	Preferred Stock A - Cumulative	1,000,000		
13				
14	Preference Stock - Cumulative	500,000		
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CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
 4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
 5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
- 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 purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
Shares (e)	Amount (f)	AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
		Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
184,208,283	184,208,283					2
184,208,283	184,208,283					3
						4
						5
						6
100,000	10,000,000					7
50,000	5,000,000					8
						9
150,000	15,000,000					10
						11
						12
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						14
						15
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Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report 2008/Q4
FOOTNOTE DATA			

Schedule Page: 250 Line No.: 2 Column: a
See footnote number 13 on pages 123.25

Schedule Page: 250 Line No.: 7 Column: d
Plus accrued dividends

Schedule Page: 250 Line No.: 8 Column: d
Plus accrued dividends

Name of Respondent
MDU Resources Group, Inc.

This Report is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
12/31/2008

Year/Period of Report
End of 2008/Q4

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (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)
1		
2	Common Stock, \$1.00 par value	3,610,416
3	(Primarily stock expense related to the issuance of common stock through public offering	
4	during February 2004.)	
5		
6		
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21		
22	TOTAL	3,610,416

Name of Respondent
MDU Resources Group, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
12/31/2008

Year/Period of Report
End of 2008/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. 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.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (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.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Account 221 - First Mortgage Bonds:		
2			
3	Secured Medium-Term Notes, Series A:		
4	8.60%	35,000,000	573,418
5			88,900 D
6	6.71%	15,000,000	155,914
7	5.83%	15,000,000	186,086
8			
9	Unsecured Senior Note		
10	6.33%	100,000,000	344,061
11	6.04%	100,000,000	362,431
12			
13	Senior Notes		
14	5.98%	30,000,000	543,168
15			
16	SUBTOTAL	295,000,000	2,253,978
17			
18	Account 222 (None)		
19	Account 223 (None)		
20	Account 224		
21	5.1% Preferred Stock, Cumulative, subject to mandatory redemption	5,000,000	
22	Commercial Paper - 1.55% @ 12-31-08, 3.182% average for 2008		
23			
24	Wells Fargo Term Loan related to IGC acquisition	132,000,000	
25			
26	Minot Air Force Base Note Payable	509,197	
27	SUBTOTAL	137,509,197	
28			
29			
30			
31			
32			
33	TOTAL	432,509,197	2,253,978

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, 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) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD		Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
		Date From (f)	Date To (g)			
						1
						2
						3
040192	040112	040192	040112	4,500,000	387,000	4
						5
093097	100109	100197	100109	1,000,000	67,100	6
091898	100108	100198	100108		655,875	7
						8
						9
082406	082426	082406	082426	100,000,000	6,330,000	10
091608	091618	091608	091618	100,000,000	1,761,667	11
						12
						13
121503	121533	121503	121533	30,000,000	1,794,000	14
						15
				235,500,000	10,995,642	16
						17
						18
						19
						20
052361				700,000	40,800	21
				22,500,000	1,921,288	22
						23
100208				57,000,000		24
						25
092308	113038			508,867	5,775	26
				80,708,867	1,967,863	27
						28
						29
						30
						31
						32
				316,208,867	12,963,505	33

Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report 2008/Q4
FOOTNOTE DATA			

Schedule Page: 256 Line No.: 21 Column: e

The Respondent is obligated to make annual sinking fund contributions to retire 1,000 shares of the 5.1% Series preferred stock at par ending 12/31/2014. The redemption price is \$102 plus accrued dividends.

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(Next page is 261)

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.

2. If the utility is a member of a group which files a 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 member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.

3. A substitute page, designed to meet a particular need of a company, may be used as long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	293,673,229
2		
3		
4	Taxable Income Not Reported on Books	
5	Dividends Received from Subsidiary Companies	214,715,000
6	Customer Advances	1,946,879
7	Contributions in Aid of Construction	299,005
8	Miscellaneous	21,347
9	Deductions Recorded on Books Not Deducted for Return	
10	Book Depreciation and Amortization	34,002,939
11	Federal Income Tax Provision	10,930,164
12	Supplemental Income Security Plan	7,275,663
13	See Footnote	13,595,807
14	Income Recorded on Books Not Included in Return	
15	Equity in Earnings of Subsidiaries	264,879,580
16	Medicare Part D Subsidy	374,064
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	Dividends Received from Subsidiaries	214,715,000
21	Tax Depreciation and Amortization	79,695,969
22	Unrecovered Purchased Gas Cost	20,393,628
23	401(k) Dividend Deduction	3,648,347
24	Deferred Compensation - Directors	1,235,053
25	Restricted Stock Bonus Plan	749,587
26	See Footnote	2,197,711
27	Federal Tax Net Income	-11,428,906
28	Show Computation of Tax:	
29		
30	Federal Tax @ 35% of Line 27	-4,000,116
31	Nonhighway Fuel Credit	-23,000
32	Wind Production Credit	-1,234,941
33	Plus: Rounding and Out-of-Period Adjustments	-1,100,511
34		
35	TOTAL 2008 FEDERAL INCOME TAX	-6,358,568
36		
37		
38	Response to instruction #2 - see footnote	
39		
40		
41		
42		
43		
44		

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
MDU Resources Group, Inc.	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 12/31/2008	2008/Q4
FOOTNOTE DATA			

Schedule Page: 261 Line No.: 13 Column: b

Deductions Recorded on Books Not Deducted for Return:

Depreciation Expensed through Clearing Accounts	\$3,571,343
Pension Expense	2,825,775
State Income Tax Provision	1,288,848
Capitalized Interest	934,512
Amortization of Loss on Bond Retirements	614,160
Capitalized Depreciation	584,861
Fuel and Purchased Power Deferral	575,637
Vacation Accrual	462,588
State Income Tax Benefit	443,472
Management Incentive	386,139
Rate Case	330,355
Post Retirement Benefits Accrued	252,272
Disallowed Meals and Entertainment Expense - 50%	234,207
Prepaid Demand Charges	58,442
Bad Debts	55,750
Preferred Stock Expense	40,800
Miscellaneous	936,646
Total carried to page 261, line 13	\$13,595,807

Schedule Page: 261 Line No.: 26 Column: b

Deductions on Return Not Charged Against Book Income:

Margin Sharing Adjustment	\$480,385
Qualified Production Activity Deduction	424,000
Decrease in Capitalized Overheads	390,273
Property Insurance Adjustment	238,979
Dividend Paid Deduction	180,000
AFUDC Equity	119,056
Board of Directors - Retirement Benefits	65,687
Miscellaneous	299,331
Total Carried to Page 261, Line 26	\$2,197,711

Schedule Page: 261 Line No.: 38 Column: a

The Respondent files a consolidated return; however, the information above has been prepared on a separate return basis. The consolidated group elected to allocate tax liabilities in accordance with method #2 under Internal Revenue Code Section 1552 (Earnings and Profits). The 2008 federal tax provision was:

Centennial Energy Holdings, Inc.	\$88,832,183
----------------------------------	--------------

Name of Respondent
MDU Resources Group, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo. Yr)
12/31 2008

Year/Period of Report
End of 2008/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (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 proportions of prepaid taxes chargeable 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 BEGINNING OF YEAR		Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1	CORPORATE INCOME					
2	Federal	11,196,827		-6,358,568	11,042,034	-819,062
3	State	1,370,597		-817,223	2,270,223	329,318
4	SUBTOTAL	12,567,424		-7,175,791	13,312,257	-489,744
5						
6	UNEMPLOYMENT					
7	Federal	19,277		37,998	69,501	
8	Minnesota	856		89,505	19,056	
9	Montana	162		7,356	5,793	
10	Nevada	1,393		19,155	7,760	
11	North Dakota	13,217		29,054	38,568	
12	South Dakota	41		-41		
13	Wyoming	1,123		5,317	5,032	
14	SUBTOTAL	36,069		188,344	145,710	
15						
16	GROSS REVENUE					
17	Montana	103,423		569,702	570,426	
18	South Dakota			100,997	100,997	
19	Wyoming	46,172		104,108	98,226	
20	SUBTOTAL	149,595		774,807	769,649	
21						
22	USE					
23	Minnesota	2,373		17,204	19,073	
24	North Dakota	48,790		411,014	434,248	
25	South Dakota	2,696		56,544	46,247	
26	Wyoming	2,870		60,238	61,551	
27	Iowa	922		93,274	66,423	
28	Nebraska	524		7,075	7,599	
29	SUBTOTAL	58,175		645,349	635,141	
30						
31	PROPERTY					
32	Minnesota	305,000		366,022	311,022	
33	Montana	2,027,868		5,033,936	4,546,615	
34	North Dakota	2,183,706		2,479,653	2,182,912	
35	North Dakota - Wahpeton	16,724		17,292	14,627	
36	South Dakota	945,874		958,619	946,535	
37	Wyoming	45,075		108,828	99,489	
38	SUBTOTAL	5,524,247		8,964,350	8,101,200	
39						
40						
41	TOTAL	19,382,784		10,865,268	30,599,145	-489,744

Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/Q4
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TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (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 foot- note. 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. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
-7,022,837		-1,344,590			-5,013,978	2
-1,387,531		48,168			-865,391	3
-8,410,368		-1,296,422			-5,879,369	4
						5
						6
-12,226		19,255			18,743	7
71,305					89,505	8
1,725		1,762			5,594	9
12,788					19,155	10
3,703		10,203			18,851	11
					-41	12
1,408		1,488			3,829	13
78,703		32,708			155,636	14
						15
						16
102,699		183,822			385,880	17
		18,163			82,834	18
52,054		55,545			48,563	19
154,753		257,530			517,277	20
						21
						22
504					17,204	23
25,556					411,014	24
12,993					56,544	25
1,557					60,238	26
27,773					93,274	27
					7,075	28
68,383					645,349	29
						30
						31
360,000					366,022	32
2,515,189		2,865,661			2,168,275	33
2,480,447		1,709,694			769,959	34
19,389					17,292	35
957,958		544,218			414,401	36
54,414		75,596			33,232	37
6,387,397		5,195,169			3,769,181	38
						39
						40
-840,838		7,425,859			3,439,409	41

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (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 know, 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 proportions of prepaid taxes chargeable 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 BEGINNING OF YEAR		Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1	FRANCHISE					
2	Delaware	33,025		165,025	165,025	
3	Wyoming	99,997		239,415	216,559	
4	Hettinger ND	3,383		26,059	26,206	
5	SUBTOTAL	136,405		430,499	407,790	
6						
7						
8						
9	MISCELLANEOUS					
10	Federal-FICA	642,377		5,861,321	6,056,803	
11	Federal-Highway Use			3,136	3,136	
12	Montana WET Tax	25,057		105,319	104,405	
13	Montana-Electric License	18,361		80,017	76,623	
14	ND-Coal Conversion	38,240		977,606	976,302	
15	Secretaries of State			2,054	2,054	
16	(annual filing fees)					
17	Hettinger inspection fee					
18	Fort Peck Tribal	184,000				
19	Crow Agency Tribal	2,368		5,357	5,046	
20	Federal CNG Tax	43		49	67	
21	Montana CNG Tax	451		891	974	
22	North Dakota CNG Tax	-28		1,960	1,988	
23	South Dakota CNG Tax					
24	SUBTOTAL	910,869		7,037,710	7,227,398	
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	19,382,784		10,865,268	30,599,145	-489,744

Name of Respondent
MDU Resources Group, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
12/31/2008

Year/Period of Report
End of 2008/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then 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 foot- note. 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. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
33,025		93,239			71,786	2
122,852		122,434			116,981	3
3,236					26,059	4
159,113		215,673			214,826	5
						6
						7
						8
						9
446,895		1,854,742			4,006,579	10
		2,357			779	11
25,971		105,319				12
21,755		80,017				13
39,544		977,606				14
		1,160			894	15
						16
						17
184,000						18
2,679					5,357	19
25					49	20
368					891	21
-56					1,960	22
						23
721,181		3,021,201			4,016,509	24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
-840,838		7,425,859			3,439,409	41

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
MDU Resources Group, Inc.	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 12/31/2008	2008/Q4
FOOTNOTE DATA			

Schedule Page: 262 Line No.: 3 Column: a

Minnesota, Montana and North Dakota state income taxes.

Schedule Page: 262 Line No.: 6 Column: a

Allocated between electric and gas operations on the basis of payroll charges. The amounts charged to other include allocation of payroll taxes to various electric and gas construction, clearing or expense accounts based on a company-wide derived payroll loading factor.

Schedule Page: 262 Line No.: 16 Column: a

Allocated on a gross revenue ratio by state.

Schedule Page: 262 Line No.: 22 Column: a

Charged directly to various inventory and construction accounts.

Schedule Page: 262 Line No.: 31 Column: a

Allocated based on specific identification.

Schedule Page: 262.1 Line No.: 2 Column: a

Allocated on a corporate overhead ratio basis.

Schedule Page: 262.1 Line No.: 3 Column: a

Allocated based on specific identification.

Schedule Page: 262.1 Line No.: 4 Column: a

Allocated based on specific identification.

Schedule Page: 262.1 Line No.: 10 Column: a

Allocated between electric and gas operations on the basis of payroll charges. The amounts charged to other include allocation of payroll taxes to various electric and gas construction, clearing or expense accounts based on a company-wide derived payroll loading factor.

Schedule Page: 262.1 Line No.: 11 Column: a

Allocated on a corporate overhead ratio basis.

Schedule Page: 262.1 Line No.: 15 Column: a

Allocated on a corporate overhead ratio basis.

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(Next page is 266)

Name of Respondent
MDU Resources Group, Inc.

This Report is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
12/31/2008

Year/Period of Report
End of 2008/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g). Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%	318,756			420	125,435	
6	8%	142,154			420	68,402	
7							
8	TOTAL	460,910				193,837	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	GAS UTILITY						
11	4%						
12	10%	66,663			420	21,967	
13	8%	81,477			420	31,912	
14	SUBTOTAL	148,140				53,879	
15							
16	COMMON UTILITY						
17	4%						
18	10%	479			420	479	
19	8%						
20	SUBTOTAL	479				479	
21							
22							
23							
24	TOTAL OTHER UTILITY	148,619				54,358	
25							
26							
27							
28							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
193,321	20 YEARS		5
73,752			6
			7
267,073			8
			9
			10
			11
44,696	20 YEARS		12
49,565			13
94,261			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
94,261			24
			25
			26
			27
			28
			30
			31
			32
			33
			34
			35
			36
			37
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			47
			48

Name of Respondent
MDU Resources Group, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
12/31/2008

Year/Period of Report
End of 2008/Q4

OTHER DEFERRED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than \$10,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	Accrued pension expense	24,546,427	184	168,190	54,516,130	78,894,367
2						
3	Accrued and deferred benefit					
4	compensation plans	10,910,825		1,605,738	695,113	10,000,200
5						
6	Reserve for natural gas					
7	minimum bill obligation	5,342,863				5,342,863
8						
9	Intercompany portion of					
10	Supplemental income					
11	Security Program trust assets	5,714,466			2,003,750	7,718,216
12						
13	Gas affordability tracker		131	7,725	14,633	6,908
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	46,514,581		1,781,653	57,229,626	101,962,554

Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report 2008/Q4
FOOTNOTE DATA			

Schedule Page: 269 Line No.: 4 Column: c

242	\$883,993
131	703,993
216	17,752

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. For other (Specify), include deferrals relating to other income and deductions.

Line No.	Account (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	Account 282			
2	Electric	49,816,138	22,082,486	10,160,417
3	Gas	8,595,586	9,502,904	5,324,666
4	Utility	2,389,805	1,750,039	1,948,402
5	TOTAL (Enter Total of lines 2 thru 4)	60,801,529	33,335,429	17,433,485
6	Non-Utility	371,249		
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	61,172,778	33,335,429	17,433,485
10	Classification of TOTAL			
11	Federal Income Tax	54,793,983	29,795,354	15,794,846
12	State Income Tax	6,378,795	3,540,075	1,638,639
13	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
						61,738,207	2
						12,773,824	3
			621,885		709,153	2,278,710	4
			621,885		709,153	76,790,741	5
83,632	21,197					433,684	6
							7
							8
83,632	21,197		621,885		709,153	77,224,425	9
							10
75,441	19,121		281,877		704,629	69,273,563	11
8,191	2,076		340,008		4,524	7,950,862	12
							13

NOTES (Continued)

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
MDU Resources Group, Inc.	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 12/31/2008	2008/Q4
FOOTNOTE DATA			

Schedule Page: 274 Line No.: 4 Column: a
Utility definition includes Common Plant and Regulatory Matters.

Schedule Page: 274 Line No.: 4 Column: b

Common Plant	\$7,649,772
Regulatory Matters - 254	(5,737,240)
Regulatory Matters - 182	477,273
Total Utility	\$2,389,805

Schedule Page: 274 Line No.: 4 Column: c

Common Plant	\$1,750,039
--------------	-------------

Schedule Page: 274 Line No.: 4 Column: d

Common Plant	\$1,948,402
--------------	-------------

Schedule Page: 274 Line No.: 4 Column: h

Regulatory Matters - 254	\$309,404
Regulatory Matters - 182	312,481
	\$621,885

Schedule Page: 274 Line No.: 4 Column: j

Regulatory Matters - 254	\$662,959
Regulatory Matters - 182	46,194
	\$709,153

Schedule Page: 274 Line No.: 4 Column: k

Common Plant	\$7,451,409
Regulatory Matters - 254	(5,383,685)
Regulatory Matters - 182	210,986
Total Utility	\$2,278,710

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(Next page is 276)

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. For other (Specify), include deferrals relating to other income and deductions.

Line No.	Account (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	Account 283			
2	Electric			
3	Fuel & Purch. Power Deferral	609,109	356,122	609,109
4	Margin Sharing Adjustment	1,186,047	187,011	
5	Rate Case	182,078	36,887	33,799
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	1,977,234	580,020	642,908
10	Gas			
11	Unrecovered Purch. Gas Costs	1,533,698	8,268,430	499,163
12	Rate Case	294,248		137,637
13	Def. Postretirement Benefit	131,870		20,787
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	1,959,816	8,268,430	657,587
18	Other	8,036,791	22,005,272	2,678,658
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	11,973,841	30,853,722	3,979,153
20	Classification of TOTAL			
21	Federal Income Tax	10,807,700	27,866,826	3,463,306
22	State Income Tax	1,166,141	2,986,896	515,847
23	Local Income Tax			

NOTES

Name of Respondent
MDU Resources Group, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Day, Year)
12/31/2008

Year/Period of Report
End of 2008/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
							2
						356,122	3
						1,373,058	4
						185,166	5
							6
							7
							8
						1,914,346	9
							10
						9,302,965	11
						156,611	12
						111,083	13
							14
							15
							16
						9,570,659	17
1,973			202,012		354,899	27,518,265	18
1,973			202,012		354,899	39,003,270	19
							20
1,780			178,707		155,623	35,189,916	21
193			23,305		199,276	3,813,354	22
							23

NOTES (Continued)

Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report 2008/Q4
FOOTNOTE DATA			

Schedule Page: 276 Line No.: 18 Column: b

UTILITY	
Bond Redemption Costs	\$4,114,667
FAS 158 Pension	3,700,386
Unrealized Gain/(Loss) on Supplemental Income Security Plan	0
Regulatory Matters-182	302,585
Regulatory Matters-254	(62,648)
Total Utility	<u>\$8,054,990</u>

NON-UTILITY	
Partnership Ordinary Gain/(Loss)	\$ 18,199)
TOTAL OTHER	\$8,036,791

Schedule Page: 276 Line No.: 18 Column: c

UTILITY	
FAS 158 Pension	\$22,005,272

Schedule Page: 276 Line No.: 18 Column: d

UTILITY	
Unrealized Gain/(Loss) on Supplemental Income Security Plan	\$2,343,636
Bond Redemption Costs	238,294
FAS 158 Pension	96,728

Schedule Page: 276 Line No.: 18 Column: e

NON-UTILITY	
Partnership Ordinary Gain	\$1,973

Schedule Page: 276 Line No.: 18 Column: h

UTILITY	
Regulatory Matters - 182	\$198,108
Regulatory Matters - 254	3,904

Schedule Page: 276 Line No.: 18 Column: j

UTILITY	
Unrealized Gain/(Loss) on Supplemental Income Security Plan - 190	\$143,233
Regulatory Matters - 182	29,286
Regulatory Matters - 254	182,380

Schedule Page: 276 Line No.: 18 Column: k

UTILITY	
Bond Redemption Costs	\$ 3,876,373
FAS 158 Pension	25,608,930
Unrealized Gain/(Loss) on Supplemental Income Security Plan	(2,200,403)
Regulatory Matters - 182	133,763
Regulatory Matters - 254	115,828
Total Utility	<u>\$27,534,491</u>

NON-UTILITY	
Partnership Ordinary Gain/(Loss)	(\$ 16,226)
TOTAL OTHER	\$27,518,265

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(Next page is 278)

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than \$50,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	Regulatory matters - FAS 109	10,023,560		1,022,833	3,157	9,003,884
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
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27						
28						
29						
30						
31						
32						
33						
34						
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36						
37						
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39						
40						
41	TOTAL	10,023,560		1,022,833	3,157	9,003,884

Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report 2008/Q4
FOOTNOTE DATA			

Schedule Page: 278 Line No.: 1 Column: c

190	\$421,436
282	353,702
228	65,316
283	182,379

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	75,758,155	73,019,435
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	81,628,333	77,427,146
5	Large (or Ind.) (See Instr. 4)	25,152,009	21,919,172
6	(444) Public Street and Highway Lighting	2,244,047	2,172,884
7	(445) Other Sales to Public Authorities	2,770,625	2,700,999
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales	649,860	645,102
10	TOTAL Sales to Ultimate Consumers	188,203,029	177,884,738
11	(447) Sales for Resale	4,593,278	3,286,769
12	TOTAL Sales of Electricity	192,796,307	181,171,507
13	(Less) (449.1) Provision for Rate Refunds	-2,954,760	-2,978,337
14	TOTAL Revenues Net of Prov. for Refunds	195,751,067	184,149,844
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	197,852	120,799
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	3,313,420	3,433,361
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	2,356,557	908,851
22	(456.1) Revenues from Transmission of Electricity of Others	1,820,713	1,328,946
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	7,688,542	5,791,957
27	TOTAL Electric Operating Revenues	203,439,609	189,941,801

Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of <u>2008/Q4</u>
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ELECTRIC OPERATING REVENUES (Account 400)

5. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
6. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
7. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
8. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
945,501	930,418	99,596	98,647	2
				3
1,149,921	1,130,859	19,485	19,212	4
482,412	453,426	329	334	5
32,004	32,325	634	602	6
44,907	45,627	873	879	7
				8
8,707	8,994	207	208	9
2,663,452	2,601,649	121,124	119,882	10
223,778	165,639			11
2,887,230	2,767,288	121,124	119,882	12
				13
2,887,230	2,767,288	121,124	119,882	14

Line 12, column (b) includes \$ -260,782 of unbilled revenues.
Line 12, column (d) includes -3,686 MWH relating to unbilled revenues

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Residential-440					
2	Montana					
3	10-Residential Service	158,637	13,281,378	18,852	8,415	0.0837
4	11-Dual Fuel Space Heating Serv	107	5,027	4	26,750	0.0470
5	20-Small General Service	2,772	207,117	259	10,703	0.0747
6	52-Outdoor Lighting Service	666	71,525	867	768	0.1074
7	North Dakota					
8	10-Residential Service	576,629	45,232,873	62,955	9,159	0.0784
9	16-Optional Time-of-Day Service	198	12,786	12	16,500	0.0646
10	20-Small General Service	4,695	475,075	618	7,597	0.1012
11	25-Irrigation Power Service					
12	30-Large General Service	2,254	191,550	43	52,419	0.0850
13	32-General Space Heating Service	834	45,328	9	92,667	0.0544
14	52-Outdoor Lighting Service	999	85,327	1,141	876	0.0854
15	South Dakota					
16	10-Residential Service	63,256	6,215,221	6,713	9,423	0.0983
17	20-Small General Service	295	28,481	22	13,409	0.0965
18	24-Private Lighting Service	191	15,470	276	692	0.0810
19	53-Dual Fuel Space Heating Serv	3,341	182,426	191	17,492	0.0546
20	54-General Dual Fuel Space Heati	21	1,149	2	10,500	0.0547
21	Wyoming					
22	10-Residential Service	101,351	7,805,009	11,068	9,157	0.0770
23	11-Controlled Service	9,273	397,628	701	13,228	0.0429
24	18-Residential Service	19,710	1,550,569	1,440	13,688	0.0787
25	20-Small General Service	1,246	101,694	221	5,638	0.0816
26	22-Special Controlled Service	8	371	1	8,000	0.0464
27	24-Private Lighting Service	506	35,110	700	723	0.0694
28	Unbilled-net	-1,487	-182,959			0.1230
29	Adjust for Duplicate Customers			-6,499		
30	Subtotal Residential	945,502	75,758,155	99,596	9,493	0.0801
31						
32	Small Commercial-442					
33	Montana					
34	20-Small General Service	98,583	7,251,499	4,864	20,268	0.0736
35	22-Dual Fuel Space Heating Serv	259	11,065	2	129,500	0.0427
36	25-Irrigation Power Service	2,523	145,443	56	45,054	0.0576
37	26-Time-of-Day General Service	100	6,470	1	100,000	0.0647
38	52-Outdoor Lighting Service	1,653	178,309	920	1,797	0.1079
39	North Dakota					
40	20-Small General Service	83,497	7,416,837	7,849	10,638	0.0888
41	TOTAL Billed	0	0	0	0	0.0000
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	0	0	0	0	0.0000

Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/Q4
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SALES OF ELECTRICITY BY RATE SCHEDULES

- Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
- Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
- Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
- The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
- For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
- Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	25-Irrigation Power Service	915	53,771	35	26,143	0.0588
2	26-Time-of-Day Small General Ser	88	5,155	4	22,000	0.0586
3	30-Large General Service	207,232	16,785,779	2,193	94,497	0.0810
4	31-Time-of-Day General Service	116	10,873	5	23,200	0.0937
5	32-General Space Heating Service	20,434	1,126,384	235	86,953	0.0551
6	52-Outdoor Lighting Service	4,133	353,071	1,391	2,971	0.0854
7	South Dakota					
8	20-Small General Service	32,745	3,082,515	1,887	17,353	0.0941
9	24-Private Lighting Service	478	38,761	328	1,457	0.0811
10	25-Irrigation Power Service	200	14,543	4	50,000	0.0727
11	26-Time-of-Day Small General Ser	24	2,611	1	24,000	0.1088
12	50-General Water Heating Service	26	2,771	11	2,364	0.1066
13	54-Dual Fuel Space Heating Serv	2,092	103,738	61	34,295	0.0496
14	56-Space Heating Service	804	62,381	47	17,106	0.0776
15	Wyoming					
16	20-Small General Service	51,500	3,426,301	2,253	22,858	0.0665
17	22-Special Controlled Service	268	11,506	18	14,889	0.0429
18	24-Private Lighting Service	665	46,013	394	1,688	0.0692
19	25-Irrigation Power Service	2,233	134,040	63	35,444	0.0600
20	Unbilled-net	-919	-51,020			0.0555
21	Adjust for Duplicate Customers			-4,213		
22	Subtotal Small Commercial	509,649	40,218,816	18,409	27,685	0.0789
23						
24	Large Commercial-442					
25	Montana					
26	25-Irrigation Power Service	365	21,124	3	121,667	0.0579
27	30-Large General Service	107,209	6,462,427	220	487,314	0.0603
28	52-Outdoor Lighting Service	482	52,152	142	3,394	0.1082
29	North Dakota					
30	25-Irrigation Power Service	48	2,860	2	24,000	0.0596
31	30-Large General Service	398,684	27,384,469	691	576,967	0.0687
32	31-Time-of-Day Large General Ser	3,207	246,492	23	139,435	0.0769
33	32-General Space Heating Service	4,811	247,896	10	481,100	0.0515
34	39-Large Interruptible Power Ser	18,029	855,549	2	9,014,500	0.0475
35	52-Outdoor Lighting Service	539	46,035	182	2,962	0.0854
36	South Dakota					
37	24-Private Lighting Service	87	7,096	42	2,071	0.0816
38	25-Irrigation Power Service	6	404	1	6,000	0.0673
39	30-Large General Service	22,377	1,653,754	68	329,074	0.0739
40	Wyoming					
41	TOTAL Billed	0	0	0	0	0.0000
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	0	0	0	0	0.0000

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
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5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	24-Private Lighting Service	77	5,310	33	2,333	0.0690
2	39-Large General Service	84,309	4,409,726	126	669,119	0.0523
3	Unbilled-net	41	14,224			0.3469
4	Adjust for Duplicate Customers			-469		
5	Subtotal Large Commercial	640,271	41,409,518	1,076	595,047	0.0647
6						
7	Small Industrial-442					
8	Montana					
9	20-Small General Service	4,658	312,429	89	52,337	0.0671
10	27-Feed Grinding Service		195	1		
11	31-Optional Time-of-Day Service	107	10,381	4	26,750	0.0970
12	32-Mandatory Time-of-Day Service	73	6,088	2	36,500	0.0834
13	35-Contract Rate Service	632	39,175	4	158,000	0.0620
14	52-Outdoor Lighting Service	5	566	5	1,000	0.1132
15	North Dakota					
16	20-Small General Service	840	72,591	71	11,831	0.0864
17	30-Large General Service	1,958	193,054	35	55,943	0.0986
18	32-General Space Heating Service	825	42,227	2	412,500	0.0512
19	52-Outdoor Lighting Service	55	4,681	22	2,500	0.0851
20	South Dakota					
21	20-Small General Service	566	55,746	18	31,444	0.0985
22	24-Private Lighting Service	20	1,634	9	2,222	0.0817
23	27-Feed Grinding Service	2	826	2	1,000	0.4130
24	54-Dual Fuel Space Heating Servi	9	500	1	9,000	0.0556
25	Wyoming					
26	20-Small General Service	325	22,701	14	23,214	0.0698
27	24-Private Lighting Service	2	115	2	1,000	0.0575
28	Unbilled-net	-53	-2,497			0.0471
29	Adjust for Duplicate Customers			-48		
30	Subtotal Small Industrial	10,024	760,412	233	43,021	0.0759
31						
32	Large Industrial-442					
33	Montana					
34	30-Large General Service	93,763	5,077,382	31	3,024,613	0.0542
35	31-Optional Time-of-Day Service	6,304	331,180	2	3,152,000	0.0525
36	32-Mandatory Time-of-Day Service	3,433	162,301	1	3,433,000	0.0473
37	35-Contract Rate Service	197,128	8,881,816	13	15,163,692	0.0451
38	52-Outdoor Lighting Service	2	160	3	667	0.0800
39	North Dakota					
40	30-Large General Service	146,846	8,444,758	56	2,622,250	0.0575
41	TOTAL Billed	0	0	0	0	0.0000
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	0	0	0	0	0.0000

SALES OF ELECTRICITY BY RATE SCHEDULES

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5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	31-Optional Time-of-Day Service	4,649	304,956	3	1,549,667	0.0656
2	32-General Electric Space Heatin	41	2,873	1	41,000	0.0701
3	39-Large Interruptible Power Ser	6,638	298,299	1	6,638,000	0.0449
4	52-Outdoor Lighting Service	11	895	5	2,200	0.0814
5	South Dakota					
6	24-Private Lighting Service	11	885	2	5,500	0.0805
7	30-Large General Service	8,409	550,718	5	1,681,800	0.0655
8	Wyoming					
9	39-Large General Service	5,785	345,758	7	826,429	0.0598
10	Unbilled-net	-632	-10,385			0.0164
11	Adjust for Duplicate Customers			-34		
12	Subtotal Large Industrial	472,388	24,391,596	96	4,920,708	0.0516
13						
14	Public Street & Hwy Lighting-444					
15	Montana					
16	20-Small General Service	153	10,049	7	21,857	0.0657
17	41-Municipal Lighting Service	7,062	478,866	259	27,266	0.0678
18	52-Outdoor Lighting Service	29	3,133	13	2,231	0.1080
19	North Dakota					
20	20-Small General Service	359	36,204	46	7,804	0.1008
21	41-Municipal Lighting Service	20,756	1,409,650	855	24,276	0.0679
22	52-Outdoor Lighting Service	86	6,483	24	3,583	0.0754
23	South Dakota					
24	20-Small General Service		292	2		
25	24-Private Lighting Service	6	491	5	1,200	0.0818
26	41-Municipal Lighting Service	2,630	229,349	140	18,786	0.0872
27	Wyoming					
28	20-Small General Service	17	1,559	4	4,250	0.0917
29	24-Private Lighting Service	5	368	2	2,500	0.0736
30	41-Municipal Lighting Service	1,203	85,796	15	80,200	0.0713
31	Unbilled-net	-302	-18,193			0.0602
32	Adjust for Duplicate Customers			-738		
33	Subtotal Pub Str & Hwy Lighting	32,004	2,244,047	634	50,479	0.0701
34						
35	Other Sales to Public Auth-446					
36	Montana					
37	48-Municipal Pumping Service	7,034	387,237	111	63,369	0.0551
38	North Dakota					
39	20-Small General Service	395	42,952	63	6,270	0.1087
40	30-Large General Service	1,828	133,347	7	261,143	0.0729
41	TOTAL Billed	0	0	0	0	0.0000
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	0	0	0	0	0.0000

Name of Respondent
MDU Resources Group, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
12/31/2008

Year/Period of Report
End of 2008/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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- For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
- Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	40-Municipal Service	4,300	328,983	374	11,497	0.0765
2	48-Municipal Pumping Service	29,186	1,725,261	322	90,640	0.0591
3	52-Outdoor Lighting Service	1	70	1	1,000	0.0700
4	South Dakota					
5	48-Municipal Pumping Service	2,432	160,104	60	40,533	0.0658
6	Unbilled-net	-269	-7,329			0.0272
7	Adjust for Duplicate Customers			-65		
8	Subtotal Other Sales	44,907	2,770,625	873	51,440	0.0617
9						
10	Interdepartmental-448					
11	Montana					
12	Billed	602	52,065	100	6,020	0.0865
13	North Dakota					
14	Billed	7,599	551,708	184	41,299	0.0726
15	South Dakota					
16	Billed	329	30,378	16	20,563	0.0923
17	Wyoming					
18	Billed	244	18,333	30	8,133	0.0751
19	Unbilled-net	-67	-2,624			0.0392
20	Adjust for Duplicate Customers			-123		
21	Subtotal Interdepartmental	8,707	649,860	207	42,063	0.0746
22						
23	Total	2,663,452	188,203,029	121,124	21,989	0.0707
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	0	0	0	0	0.0000
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	0	0	0	0	0.0000

Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report 2008/Q4
FOOTNOTE DATA			

Schedule Page: 300 Line No.: 4 Column: b

Basis of classification - Commercial Customers

Schedule Page: 300 Line No.: 4 Column: c

Basis of classification - Commercial Customers

Schedule Page: 300 Line No.: 5 Column: b

Basis of classification - Industrial Customers

Schedule Page: 300 Line No.: 5 Column: c

Basis of Classification - Industrial Customers

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
MDU Resources Group, Inc.	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 12/31/2008	2008/Q4
FOOTNOTE DATA			

Schedule Page: 304.4 Line No.: 27 Column: a

Revenue Billed Pursuant to Fuel Clause Adjustment (FCA) (Included in revenue amounts on pages 304-304.4)

Residential-440

Montana

10-Residential Service	\$321,181
20-Small General Service	5,344
52-Outdoor Lighting Service	1,421

North Dakota

10-Residential Service	6,451,044
16-Optional Time of Day Service	2,245
20-Small General Service	53,182
25-Irrigation Power Service	0
30-Large General Service	25,573
32-General Space Heating Service	9,927
52-Outdoor Lighting Service	11,300

South Dakota

10-Residential Service	494,558
20-Small General Service	2,281
24-Private Lighting Service	1,485
53-Dual Fuel Space Heating Service	25,915
54-General Dual Fuel Space Heating Service	165

Wyoming

10-Residential Service	(460,465)
11-Controlled Service	(41,893)
18-Residential Service	(89,413)
20-Small General Service	(5,643)
22-Special Controlled Service	(35)
24-Private Lighting Service	(2,297)
Unbilled-net	32,658
Subtotal Residential	6,838,533

Small Commercial-442

Montana

20-Small General Service	204,913
25-Irrigation Power Service	5,723
26-Optional Time of Day Small General Service	183
52-Outdoor Lighting Service	3,590

North Dakota

20-Small General Service	939,146
25-Irrigation Power	9,684
26-Time of Day Small General Service	999
30-Large General Service	2,333,146
31-Time of Day General Service	1,293
32-General Space Heating Service	230,995
52-Outdoor Lighting Service	46,842

South Dakota

20-Small General Service	256,284
24-Private Lighting Service	3,751
25-Irrigation Power Service	1,763
26-Time of Day General Service	192
50-General Water Heating Service	197
54-Dual Fuel Space Heating Service	16,467

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
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FOOTNOTE DATA			

56-Space Heating Service	6,403
Wyoming	
20-Small General Service	(234,475)
22-Special Controlled Service	(1,202)
24-Private Lighting Service	(3,031)
25-Irrigation Power Service	(10,293)
Unbilled-net	29,921
Subtotal Small Commercial	3,842,491

Large Commercial-442	
Montana	
25-Irrigation Power Service	807
30- Large General Service	227,051
52-Outdoor Lighting Service	1,232
North Dakota	
25-Irrigation Power	470
30-Large General Service	4,487,639
31-Time of Day General Service	36,119
32-General Space Heating Service	55,892
38-Interruptible Large Power Demand Response	208,398
52-Outdoor Lighting Service	6,115
South Dakota	
24-Private Lighting Service	690
25-Irrigation Power Service	80
30-Large General Service	178,911
Wyoming	
24-Private Lighting Service	(349)
39-Large General Service	(384,217)
Unbilled-net	26,811
Subtotal Large Commercial	4,845,649

Small Industrial-442	
Montana	
20-Small General Service	9,768
31-Optional Time of Day Service	101
35-Contract Service	0
52-Outdoor Lighting Service	10
North Dakota	
20-Small General Service	9,440
30-Large General Service	21,960
32-General Space Heating Service	9,146
52-Outdoor Lighting Service	620
South Dakota	
20-Small General Service	4,404
24-Private Lighting Service	161
27-Feed Grinding Service	0
54-Dual Fuel Space Heating Service	77
Wyoming	
20-Small General Service	(1,480)
24-Private Lighting Service	(8)
Unbilled-net	16
Subtotal Small Industrial	54,215

Large Industrial-442
Montana

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	12/31/2008	2008/Q4
FOOTNOTE DATA			

30-Large General Service	122,675
31-Optional Time of Day Service	7,726
35-Contract Service	0
52-Outdoor Lighting Service	3
North Dakota	
30-Large General Service	1,655,667
31-Optional Time of Day General Service	52,663
32-General Electric Space Heating Service	449
39-Interruptible Large Power Service	73,673
52-Outdoor Lighting Service	119
South Dakota	
24-Private Lighting Service	87
30-Large General Service	66,618
Wyoming	
39-Large General Service	(26,378)
Unbilled-net	14,538
Subtotal Large Industrial	1,967,840

Public Street and Highway Lighting-444

Montana	
20-Small General Service	232
41-Municipal Lighting Service	15,021
52-Outdoor Lighting Service	61
North Dakota	
20-Small General Service	4,050
41-Municipal Lighting Service	234,306
52-Outdoor Lighting Service	906
South Dakota	
20-Small General Service	0
24-Private Lighting Service	46
41-Municipal Lighting Service	20,357
Wyoming	
20-Small General Service	(78)
24-Private Lighting Service	(24)
41-Municipal Lighting Service	(5,484)
Unbilled-net	(185)
Subtotal Public Street and Highway Lighting	269,208

Other Sales to Public Authorities-446

Montana	
48-Municipal Pumping Service	14,367
North Dakota	
20-Small General Service	4,345
30-Large General Service	20,633
40-Municipal Service	48,153
48-Municipal Pumping Service	324,552
52-Outdoor Lighting Service	9
South Dakota	
48-Municipal Pumping Service	18,959
Unbilled-net	139
Subtotal Other Sales	431,157

Interdepartmental Sales-448

Montana	1,168
North Dakota	84,850

Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report 2008/Q4
FOOTNOTE DATA			

South Dakota	2,583
Wyoming	(1,116)
Unbilled-Net	(126)
Subtotal Interdepartmental	87,359
Total Fuel Clause Adjustment	\$18,336,452

Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo Yr) 12/31/2008	Year/Period of Report End of 2008/Q4
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SALES FOR RESALE (Account 447)

- Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
- Enter the name of the purchaser in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
- In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
 RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
 LF - for long-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
 IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
 SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
 LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
 IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Midwest Independent Transmission					
2	System Operator (MISO)	OS	MISO	NA	NA	NA
3	Sales for Resale Fuel Cost					
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

SALES FOR RESALE (Account 447) (Continued)

- OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
- AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401, line 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
					1
223,778		8,043,463		8,043,463	2
		-3,450,185		-3,450,185	3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
0	0	0	0	0	
223,778	0	4,593,278	0	4,593,278	
223,778	0	4,593,278	0	4,593,278	

Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report 2008/Q4
FOOTNOTE DATA			

Schedule Page: 310 Line No.: 2 Column: b

Respondent began participation in the Midwest Independent System Operator (MISO) RTO in April 2005.

Schedule Page: 310 Line No.: 3 Column: i

Per Docket No. RM04-12-000; Order No. 668: Sales for Resale Revenue offset by Sales for Resale fuel and purchased power costs of \$3,450,185.

Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/Q4
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ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	2,113,061	1,976,075
5	(501) Fuel	40,721,107	35,636,289
6	(502) Steam Expenses	3,873,570	3,741,740
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,255,520	1,186,459
10	(506) Miscellaneous Steam Power Expenses	2,956,434	2,748,454
11	(507) Rents	312	361
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	50,920,004	45,289,378
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	826,672	778,991
16	(511) Maintenance of Structures	565,954	570,586
17	(512) Maintenance of Boiler Plant	5,699,794	4,466,297
18	(513) Maintenance of Electric Plant	1,027,150	793,491
19	(514) Maintenance of Miscellaneous Steam Plant	1,095,577	976,723
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	9,215,147	7,586,088
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	60,135,151	52,875,466
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)		
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)		

Name of Respondent		This Report Is:		Date of Report	Year/Period of Report
MDU Resources Group, Inc.		(1) <input checked="" type="checkbox"/> An Original	(2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 12/31/2008	End of 2008/Q4
ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)					
If the amount for previous year is not derived from previously reported figures, explain in footnote.					
Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)		
60	D. Other Power Generation				
61	Operation				
62	(546) Operation Supervision and Engineering	148,517	107,829		
63	(547) Fuel	765,886	2,028,736		
64	(548) Generation Expenses	191,363	1,531		
65	(549) Miscellaneous Other Power Generation Expenses	270,080	431,089		
66	(550) Rents	3,750			
67	TOTAL Operation (Enter Total of lines 62 thru 66)	1,379,596	2,569,185		
68	Maintenance				
69	(551) Maintenance Supervision and Engineering	84,339	83,519		
70	(552) Maintenance of Structures	5,049	5,199		
71	(553) Maintenance of Generating and Electric Plant	177,887	1,150,326		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	51	-104		
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	267,326	1,238,940		
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	1,646,922	3,808,125		
75	E. Other Power Supply Expenses				
76	(555) Purchased Power	30,395,977	31,951,329		
77	(556) System Control and Load Dispatching	1,163,875	1,209,750		
78	(557) Other Expenses				
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	31,559,852	33,161,079		
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	93,341,925	89,844,670		
81	2. TRANSMISSION EXPENSES				
82	Operation				
83	(560) Operation Supervision and Engineering	1,544,761	1,454,706		
84	(561) Load Dispatching				
85	(561.1) Load Dispatch-Reliability	346,979	288,478		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	695,077	560,412		
87	(561.3) Load Dispatch-Transmission Service and Scheduling	72			
88	(561.4) Scheduling, System Control and Dispatch Services	383,341	466,357		
89	(561.5) Reliability, Planning and Standards Development				
90	(561.6) Transmission Service Studies				
91	(561.7) Generation Interconnection Studies				
92	(561.8) Reliability, Planning and Standards Development Services	27,925	33,972		
93	(562) Station Expenses	659,510	592,849		
94	(563) Overhead Lines Expenses	144,884	120,659		
95	(564) Underground Lines Expenses				
96	(565) Transmission of Electricity by Others	513,456	494,297		
97	(566) Miscellaneous Transmission Expenses	143,577	138,527		
98	(567) Rents	1,490,537	1,489,759		
99	TOTAL Operation (Enter Total of lines 83 thru 98)	5,950,119	5,640,016		
100	Maintenance				
101	(568) Maintenance Supervision and Engineering	62,482	84,137		
102	(569) Maintenance of Structures				
103	(569.1) Maintenance of Computer Hardware				
104	(569.2) Maintenance of Computer Software				
105	(569.3) Maintenance of Communication Equipment				
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant				
107	(570) Maintenance of Station Equipment	474,504	443,665		
108	(571) Maintenance of Overhead Lines	871,362	933,748		
109	(572) Maintenance of Underground Lines	1,169	1,364		
110	(573) Maintenance of Miscellaneous Transmission Plant				
111	TOTAL Maintenance (Total of lines 101 thru 110)	1,409,517	1,462,914		
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	7,359,636	7,102,930		

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services	427,605	391,143
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	427,605	391,143
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)	427,605	391,143
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	1,230,857	1,340,521
135	(581) Load Dispatching		
136	(582) Station Expenses	573,586	515,434
137	(583) Overhead Line Expenses	591,833	587,172
138	(584) Underground Line Expenses	806,814	764,330
139	(585) Street Lighting and Signal System Expenses	63,133	55,552
140	(586) Meter Expenses	868,231	934,986
141	(587) Customer Installations Expenses	389,423	362,875
142	(588) Miscellaneous Expenses	2,363,136	2,469,781
143	(589) Rents	112,606	112,685
144	TOTAL Operation (Enter Total of lines 134 thru 143)	6,999,619	7,143,336
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	422,437	481,174
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	186,329	129,262
149	(593) Maintenance of Overhead Lines	2,314,748	2,128,552
150	(594) Maintenance of Underground Lines	599,502	684,194
151	(595) Maintenance of Line Transformers	158,964	168,535
152	(596) Maintenance of Street Lighting and Signal Systems	159,536	152,330
153	(597) Maintenance of Meters	25,812	15,759
154	(598) Maintenance of Miscellaneous Distribution Plant	425,626	412,564
155	TOTAL Maintenance (Total of lines 146 thru 154)	4,292,954	4,172,370
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	11,292,573	11,315,706
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	341,496	318,590
160	(902) Meter Reading Expenses	913,016	1,129,909
161	(903) Customer Records and Collection Expenses	2,057,010	2,064,515
162	(904) Uncollectible Accounts	203,537	198,094
163	(905) Miscellaneous Customer Accounts Expenses	325,253	326,993
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	3,840,312	4,038,101

Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/Q4
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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	51,006	18,435
168	(908) Customer Assistance Expenses	136,849	83,623
169	(909) Informational and Instructional Expenses	35,395	56,724
170	(910) Miscellaneous Customer Service and Informational Expenses	3,207	1,308
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	226,457	160,090
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision	65,084	81,593
175	(912) Demonstrating and Selling Expenses	188,065	145,196
176	(913) Advertising Expenses	17,777	28,395
177	(916) Miscellaneous Sales Expenses	43,323	43,904
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	314,249	299,088
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	5,031,408	5,671,167
182	(921) Office Supplies and Expenses	2,700,993	2,233,345
183	(Less) (922) Administrative Expenses Transferred-Credit		
184	(923) Outside Services Employed	423,044	589,800
185	(924) Property Insurance	468,058	564,459
186	(925) Injuries and Damages	652,174	918,344
187	(926) Employee Pensions and Benefits	8,389,119	6,180,176
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	243,573	70,492
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	125,769	174,825
192	(930.2) Miscellaneous General Expenses	296,017	550,474
193	(931) Rents	319,598	212,723
194	TOTAL Operation (Enter Total of lines 181 thru 193)	18,649,753	17,165,805
195	Maintenance		
196	(935) Maintenance of General Plant	500,288	597,453
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	19,150,041	17,763,258
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	135,952,798	130,914,986

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(Next page is 326)

Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo Yr) 12/31, 2008	Year/Period of Report End of 2008/Q4
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**PURCHASED POWER (Account 555)
(Including power exchanges)**

- Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
- Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
- In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Black Hills Power & Light Co.	RQ	BHPL #42	50	50	50
2	Xcel Energy	OS	MAPP #5	106.67	106.67	106.67
3	Western Area Power Administration	OS	19			
4	Western Area Power Admin - Ft. Peck	LF	19			
5	Western Area Power Administration	EX	19			
6	Midwest Independent Transmission	EX	MISO			
7	System Operator (MISO)					
8	Deferral per tariff					
9						
10						
11						
12						
13						
14						
	Total					

Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, /r) 12/31/2008	Year/Period of Report End of 2008/Q4
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PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
287,946			6,466,241	7,170,846		13,637,087	1
640			1,970,000	196,914		2,166,914	2
							3
14,347				351,358		351,358	4
	29,318	27,500			43,641	43,641	5
211,902				12,547,829		12,547,829	6
							7
					1,649,148	1,649,148	8
							9
							10
							11
							12
							13
							14
514,835	29,318	27,500	8,436,241	20,266,947	1,692,789	30,395,977	

Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report 2008/Q4
FOOTNOTE DATA			

Schedule Page: 326 Line No.: 2 Column: b

Other Service classification includes purchases for scheduled outages, operational control, general purpose, emergencies, interruptible load replacement and economical reasons.

Schedule Page: 326 Line No.: 2 Column: d

Contract period May - October

Schedule Page: 326 Line No.: 5 Column: l

Amounts recorded to reflect power exchanges and do not constitute monetary settlements.

Schedule Page: 326 Line No.: 8 Column: l

Reflects amount of fuel and purchased power deferred in accordance with respective state tariffs.

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(Next page is 328)

Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Yr) 12/31/2008	Year/Period of Report End of 2008/Q4
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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.

2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).

3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)

4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Western Area Power Administration (WAPA)	WAPA	WAPA	OLF
2	Basin Electric Power Cooperative	Basin Electric Power Cooperative	Basin Electric Power Cooperative	OLF
3	Powder River Energy Corp.	Powder River Energy Corp.	Powder River Energy Corp.	OLF
4	Midwest Independent Transmission			
5	System Operator (MISO)	MISO participants	MISO participants	OS
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions referred to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
19	Various	Various		463,421	440,606	1
#30	Various	Various		1,058,873	989,601	2
5	Sheridan	Various		98,209	91,784	3
						4
MISO	Various	Various				5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
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						23
						24
						25
						26
						27
						28
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						31
						32
						33
						34
			0	1,620,503	1,521,991	

Name of Respondent
MDU Resources Group, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo Yr)
12/5 J8

Year/Period of Report
End of 2008/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions referred to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.

10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.

11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges (\$) (k)	Energy Charges (\$) (l)	(Other Charges) (\$) (m)	Total Revenues (\$) (k+l+m) (n)	Line No.
	314,246		314,246	1
		105,678	105,678	2
	73,656		73,656	3
				4
	1,327,133		1,327,133	5
				6
				7
				8
				9
				10
				11
				12
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				26
				27
				28
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				31
				32
				33
				34
0	1,715,035	105,678	1,820,713	

Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report 2008/Q4
FOOTNOTE DATA			

Schedule Page: 328 Line No.: 1 Column: d

WAPA contract termination 12/31/2015

Schedule Page: 328 Line No.: 2 Column: m

Fixed monthly wheeling fee

Schedule Page: 328 Line No.: 3 Column: d

Sheridan-Johnson REA contract is perpetual.

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to-Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Megawatt-hours Received (c)	Megawatt-hours Delivered (d)	Demand Charges (\$) (e)	Energy Charges (\$) (f)	Other Charges (\$) (g)	Total Cost of Transmission (\$) (h)
1	DELIVERED POWER TO AND							
2	RECEIVED POWER FROM							
3	WHEELER							
4	Western Area Power Admn	FNS	504,692	540,020		494,545		494,545
5	Mor Gran Sou Elec Coop	LFP	1,295	1,411				
6	Southeast Elec Coop	LFP	187	206		1,993		1,993
7	Midwest Independent							
8	Transmission System							
9	Operator (MISO)	OS					16,918	16,918
10								
11								
12								
13								
14								
15								
16								
	TOTAL		506,174	541,637		496,538	16,918	513,456

Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of <u>2008/Q4</u>
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MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	243,992
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < \$5,000	
6	Director's Fees and Expenses	52,025
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
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41		
42		
43		
44		
45		
46	TOTAL	296,017

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of acquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403); (c) Depreciation Expense for Asset Retirement Costs (Account 403.1); (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).

2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.

3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.

Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.

In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.

For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.

4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			368,623		368,623
2	Steam Production Plant	8,760,154				8,760,154
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	2,229,463				2,229,463
7	Transmission Plant	2,649,719				2,649,719
8	Distribution Plant	7,015,280				7,015,280
9	Regional Transmission and Market Operation					
10	General Plant	510,149				510,149
11	Common Plant-Electric	1,099,212		876,744		1,975,956
12	TOTAL	22,263,977		1,245,367		23,509,344

B. Basis for Amortization Charges

Range from five year, 20% to ten year, 10% Straight Line Amortization for computer software.

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Steam Production Plant					0	
13	311	49,548				0	
14	312	160,181				0	
15	314	45,029				0	
16	315	14,812				0	
17	316	15,684				0	
18	317	283				0	
19	Subtotal	285,537				0	
20						0	
21	Other Production Plant					0	
22	341	786				0	
23	342	615				0	
24	344	65,811				0	
25	345	927				0	
26	346	56				0	
27	347	28					
28	Subtotal	68,223				0	
29						0	
30	Transmission Plant						
31	350.2	2,500				0	
32	352	2				0	
33	353	67,100				0	
34	354	5,060				0	
35	355	31,896				0	
36	356	26,843					
37	357	2,040					
38	358	3,434					
39	359.1	1				0	
40	Subtotal	138,876				00	
41						0	
42	Distribution Plant					0	
43	360.2	837				0	
44	362	34,642				0	
45	364	27,218				0	
46	365	18,955				0	
47	366	218				0	
48	367	47,030				0	
49	368	43,169				0	
50	369	20,421				0	

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	370	14,374				0	
13	371	2,158				0	
14	373	6,140				0	
15	374	40					
16	Subtotal	215,202				0	
17						0	
18						0	
19						0	
20	General Plant					0	
21	303	5,971				0	
22	390	519				0	
23	391.1	156					
24	391.2	24				0	
25	391.3	125				0	
26	391.4	669				0	
27	391.5	8				0	
28	392.1	442				0	
29	392.2	4,602				0	
30	393	107				0	
31	394.1	1,816				0	
32	395	1,153				0	
33	396.1	218				0	
34	396.2	8,368				0	
35	397.1	69				0	
36	397.2	71				0	
37	397.3	8				0	
38	397.4	81				0	
39	397.5	98				0	
40	397.6	1,298				0	
41	397.8	150					
42	397.9	173				0	
43	398	65				0	
44	Subtotal	26,191					
45							
46	Total	734,029					
47							
48	Footnote						
49							
50							

Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report 2008/Q4
FOOTNOTE DATA			

Schedule Page: 336 Line No.: 18 Column: a

SFAS 143 Asset Retirement Obligation (ARO) depreciated over the estimated remaining life until removal of the asset, with legal obligations.

Schedule Page: 336 Line No.: 27 Column: a

SFAS 143 Asset Retirement Obligation (ARO) depreciated over the estimated remaining life until removal of the asset, with legal obligations.

Schedule Page: 336 Line No.: 39 Column: a

SFAS 143 Asset Retirement Obligation (ARO) depreciated over the estimated remaining life until removal of the asset, with legal obligations.

Schedule Page: 336.1 Line No.: 15 Column: a

SFAS 143 Asset Retirement Obligation (ARO) depreciated over the estimated remaining life until removal of the asset, with legal obligations.

Schedule Page: 336.1 Line No.: 48 Column: a

Column (b) - 12/31/08 depreciable sub-plant account balances.

Other depreciation provisions include:

Provision for deferred AFUDC, interest and depreciation of Coyote I Station which had been disallowed in Montana rate base: \$168,452 in 2008.

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	State Commission Regulatory Expense Amortized				
2	Over Various 12 Month Periods				
3					
4	MONTANA				
5	Electric				462,054
6					
7	Gas				
8					
9					
10	NORTH DAKOTA				
11	Electric				
12					
13	Gas				40,250
14					
15					
16	SOUTH DAKOTA				
17	Electric				
18					
19	Gas				127,488
20					
21					
22	SOUTH DAKOTA - EAST RIVER				
23	Gas				33,908
24					
25					
26	WYOMING				
27	Electric				
28					
29	Gas				
30					
31					
32	MINNESOTA				
33	Gas				535,912
34					
35					
36	NORTH DAKOTA - WAHPETON				
37	Gas				
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				1,199,612

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than \$25,000) may be grouped.

EXPENSES INCURRED DURING YEAR			AMORTIZED DURING YEAR				
CURRENTLY CHARGED TO			Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
Department (f)	Account No. (g)	Amount (h)					
							1
							2
							3
							4
Electric	928	40,424	73,304	928	85,709	449,649	5
							6
Gas	928	25,690					7
							8
							9
							10
Electric	928	80,062					11
							12
Gas	928	1,967		928	40,250		13
							14
							15
							16
Electric	928	9,776					17
							18
Gas	928	13,213		928	39,899	87,589	19
							20
							21
							22
Gas	928	10,644		928	3,470	30,438	23
							24
							25
							26
Electric	928	27,602	22,870			22,870	27
							28
Gas	928	32,452					29
							30
							31
							32
Gas	928	87,827		928	257,200	278,712	33
							34
							35
							36
Gas	928	900					37
							38
							39
							40
							41
							42
							43
							44
							45
		330,557	96,174		426,528	869,258	46

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution	2,024,856		
49	Administrative and General	137,799		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	2,173,183		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)	222,513		
55	Storage, LNG Terminating and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)	13,817		
57	Distribution (Lines 36 and 48)	12,828,782		
58	Customer Accounts (Line 37)	4,474,520		
59	Customer Service and Informational (Line 38)	262,743		
60	Sales (Line 39)	628,087		
61	Administrative and General (Lines 40 and 49)	2,882,595		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	21,313,057	80,058	21,393,115
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	43,981,841	150,527	44,132,368
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	2,889,574	977,957	3,867,531
69	Gas Plant	2,810,886	507,005	3,317,891
70	Other (provide details in footnote):	1,046,797	1,680,015	2,726,812
71	TOTAL Construction (Total of lines 68 thru 70)	6,747,257	3,164,977	9,912,234
72	Plant Removal (By Utility Departments)			
73	Electric Plant	239,839	3,348	243,187
74	Gas Plant	221,226	2,499	223,725
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	461,065	5,847	466,912
77	Other Accounts (Specify, provide details in footnote):			
78	146 Accounts Receivable from Associated Companies	10,314,158	128	10,314,286
79	183 Preliminary Survey and Investigation	14,633	103	14,736
80	184 Clearing Accounts	786,517	25,057	811,574
81	416 Cost & Expense of Merchandising, Jobbing & Contract Work	5,292,528		5,292,528
82	417 Expenses for Nonutility Operations	975,185		975,185
83	426 Miscellaneous Income Deductions	6,739	7,566	14,305
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	17,389,760	32,854	17,422,614
96	TOTAL SALARIES AND WAGES	68,579,923	3,354,205	71,934,128

Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report 2008/Q4
FOOTNOTE DATA			

Schedule Page: 354 Line No.: 70 Column: b
CWIP

Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of <u>2008/Q4</u>
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COMMON UTILITY PLANT AND EXPENSES

- Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
- Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
- Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
- Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Account No.	Utility Plant	Accumulated Depreciation	Depreciation Expense
PLANT IN SERVICE			
303 Misc. Intangible Plant	\$22,784,037	\$15,198,859	\$1,551,758
389 Land and Land Rights	2,778,248	---	---
390 Structures and Improvements	26,865,572	11,607,449	756,856
391 Office Furniture & Equipment	6,297,811	4,044,148	886,166
392 Transportation Equipment	8,378,167	4,014,321	756,420
393 Stores Equipment	45,012	16,460	1,284
394 Miscellaneous Tools	1,204,719	817,116	41,121
396 Power Operated Equipment	53,433	7,670	1,437
397 Communication Equipment	1,954,936	1,240,493	139,530
398 Miscellaneous Equipment	932,732	449,366	30,186
3991 Asset Retirement Obligations	7,739	4,410	
	\$71,302,406	\$37,400,292	\$4,164,758
WORK IN PROGRESS			
	\$13,719,139	\$ 6,207	
	\$85,021,545	\$37,406,499	\$4,164,758
Allocation of Common Utility Plant			
Electric Department	\$47,873,553	\$22,861,462	\$1,975,956
Natural Gas Department	37,147,992	14,545,037	1,531,222
Clearing Accounts			657,580
	\$85,021,545	\$37,406,499	\$4,164,758

Basis of Allocation

- General Office common plant and depreciation are allocated based on net plant and employee ratios.
- Other common plant and depreciation are directly assigned or allocated based on the ratio of electric transmission and distribution and gas distribution gross plant investment by state or employee ratios.
- Expenses other than depreciation are not shown above but are allocated on net plant in service and number of employee ratios.

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

- (1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
- (2) Report on Column (b) by month the transmission system's peak load.
- (3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
- (4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM: INTERGRATED SYSTEM

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	668	29	1900	407	261				
2	February	656	10	2000	401	255				
3	March	588	7	1000	369	219				
4	Total for Quarter 1	1,912			1,177	735				
5	April	512	1	1000	327	185				
6	May	455	16	1300	305	150				
7	June	609	30	1800	418	191				
8	Total for Quarter 2	1,576			1,050	526				
9	July	661	30	1700	473	188				
10	August	690	20	1700	477	213				
11	September	540	18	1700	364	176				
12	Total for Quarter 3	1,891			1,314	577				
13	October	527	28	900	351	176				
14	November	601	20	2000	378	223				
15	December	744	15	1900	455	289				
16	Total for Quarter 4	1,872			1,184	688				
17	Total Year to Date/Year	7,251			4,725	2,526				

Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report 2008/Q4
FOOTNOTE DATA			

Schedule Page: 400 Line No.: 1 Column: b

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

Name of System: Sheridan System

Line #	Month (a)	Monthly Peak (b)	Day (c)	Hour (d)	FN-Self (e)	FN-Others (f)
1	January	65	21	1900	53	12
2	February	59	04	1900	48	11
3	March	55	04	1900	43	12
4	Total Q 1	179			144	35
5	April	53	01	0800	42	11
6	May	50	02	0900	39	11
7	June	58	30	1800	47	11
8	Total Q 2	161			128	33
9	July	66	22	1800	54	12
10	August	66	25	1700	54	12
11	September	50	17	1700	38	12
12	Total Q 3	182			146	36
13	October	53	27	0700	40	13
14	November	56	20	1800	43	13
15	December	72	15	1900	59	13
16	Total Q 4	181			142	39
17	Total for Year	703			560	143

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	2,663,452
3	Steam	2,469,936	23	Requirements Sales for Resale (See instruction 4, page 311.)	
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	223,778
5	Hydro-Conventional		25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
7	Other	68,503	27	Total Energy Losses	230,911
8	Less Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	3,118,141
9	Net Generation (Enter Total of lines 3 through 8)	2,538,439			
10	Purchases	514,835			
11	Power Exchanges:				
12	Received	29,318			
13	Delivered	27,500			
14	Net Exchanges (Line 12 minus line 13)	1,818			
15	Transmission For Other (Wheeling)				
16	Received	1,620,503			
17	Delivered	1,521,991			
18	Net Transmission for Other (Line 16 minus line 17)	98,512			
19	Transmission By Others Losses	-35,463			
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	3,118,141			

Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo Yr) 12/31 2008	Year/Period of Report End of 2008/Q4
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MONTHLY PEAKS AND OUTPUT

- (1) Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
- (2) Report on line 2 by month the system's output in Megawatt hours for each month.
- (3) Report on line 3 by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
- (4) Report on line 4 by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
- (5) Report on lines 5 and 6 the specified information for each monthly peak load reported on line 4.

NAME OF SYSTEM: INTEGRATED SYSTEM

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirements Sales for Resale & Associated Losses (c)	MONTHLY PEAK		
				Megawatts (See Instr. 4) (d)	Day of Month (e)	Hour (f)
29	January	262,437	6,054	407	29	1900
30	February	234,557	15,850	401	10	2000
31	March	243,201	26,472	369	7	1000
32	April	240,517	43,053	327	1	1000
33	May	202,723	6,278	305	16	1300
34	June	188,774	2,205	418	30	1800
35	July	243,562	14,717	472	30	1700
36	August	257,618	23,951	477	20	1700
37	September	204,123	20,117	364	18	1700
38	October	239,629	42,594	352	28	0900
39	November	235,519	18,922	378	20	2000
40	December	271,110	3,565	455	15	1900
41	TOTAL	2,823,770	223,778			

Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report 2008/Q4
FOOTNOTE DATA			

Schedule Page: 401 Line No.: 29 Column: b

MONTHLY PEAKS AND OUTPUT

Name of System: SHERIDAN SYSTEM

Line No.	Month (a)	Total Mo. Energy (b)	Megawatts (d)	Day (e)	Hour (f)
29	January	29,377	65	21	1900
30	February	25,645	59	04	1900
31	March	24,572	55	04	1900
32	April	22,176	53	01	0800
33	May	21,310	50	02	0900
34	June	21,067	58	30	1800
35	July	26,380	66	22	1800
36	August	25,883	66	25	1700
37	September	20,349	50	17	1700
38	October	22,502	53	27	0700
39	November	23,613	56	20	1800
40	December	31,497	72	15	1900
		294,371			

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(Next page is 402)

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: <i>R.M. Heskett</i> (b)	Plant Name: <i>Lewis & Clark</i> (c)				
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Steam	Steam				
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor Boiler	Outdoor Boiler				
3	Year Originally Constructed	1954	1958				
4	Year Last Unit was Installed	1963	1958				
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	86.00	44.00				
6	Net Peak Demand on Plant - MW (60 minutes)	103	54				
7	Plant Hours Connected to Load	7845	8156				
8	Net Continuous Plant Capability (Megawatts)	0	0				
9	When Not Limited by Condenser Water	96	48				
10	When Limited by Condenser Water	103	52				
11	Average Number of Employees	51	25				
12	Net Generation, Exclusive of Plant Use - KWh	566695300	331504151				
13	Cost of Plant: Land and Land Rights	242583	80862				
14	Structures and Improvements	10418664	4001373				
15	Equipment Costs	66247441	28427407				
16	Asset Retirement Costs	124396	34548				
17	Total Cost	77033084	32544190				
18	Cost per KW of Installed Capacity (line 17/5) Including	895.7335	739.6407				
19	Production Expenses: Oper, Supv, & Engr	959003	340003				
20	Fuel	12360969	5972247				
21	Coolants and Water (Nuclear Plants Only)	0	0				
22	Steam Expenses	1586998	754571				
23	Steam From Other Sources	0	0				
24	Steam Transferred (Cr)	0	0				
25	Electric Expenses	283195	191533				
26	Misc Steam (or Nuclear) Power Expenses	1434530	474094				
27	Rents	0	0				
28	Allowances	0	0				
29	Maintenance Supervision and Engineering	370902	166917				
30	Maintenance of Structures	302522	34310				
31	Maintenance of Boiler (or reactor) Plant	2793314	668742				
32	Maintenance of Electric Plant	524088	70624				
33	Maintenance of Misc Steam (or Nuclear) Plant	385312	403865				
34	Total Production Expenses	21000833	9076906				
35	Expenses per Net KWh	0.0371	0.0274				
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal-Lignite	Coal-SubB	Gas	Coal-Lignite	Coal-SubB	Gas
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Tons	Mcf	Tons	Tons	Mcf
38	Quantity (Units) of Fuel Burned	532641	10214	373	316315	1442	9883
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	6940	8735	1094	6556	8537	1180
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	21.693	28.825	12.851	17.429	0.000	10.333
41	Average Cost of Fuel per Unit Burned	22.639	28.508	12.851	18.447	24.307	10.333
42	Average Cost of Fuel Burned per Million BTU	1.631	1.632	11.746	1.407	1.424	8.755
43	Average Cost of Fuel Burned per KWh Net Gen	0.022	0.900	0.000	0.018	0.000	0.000
44	Average BTU per KWh Net Generation	13375.378	0.000	0.000	12620.677	0.000	0.000

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)(Continued)

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: <i>Miles City</i> (d)	Plant Name: <i>Big Stone</i> (e)	Plant Name: <i>Big Stone Continued</i> (f)	Line No.						
Gas Turbine	Steam		1						
Conventional	Conventional		2						
1972	1975		3						
1972	1975		4						
23.15	94.11	0.00	5						
22	109	0	6						
42	8380	0	7						
0	0	0	8						
29	108	0	9						
23	108	0	10						
0	17	0	11						
368680	826737419	0	12						
609	150559	0	13						
147190	9459201	0	14						
3023074	48749706	0	15						
0	4060	0	16						
3170873	58363526	0	17						
136.9708	620.1629	0.0000	18						
36964	388824	0	19						
99737	15340349	0	20						
0	0	0	21						
19550	243220	0	22						
0	0	0	23						
0	0	0	24						
36369	383391	0	25						
505	525862	0	26						
0	0	0	27						
0	0	0	28						
26533	124109	0	29						
743	102203	0	30						
39007	811950	0	31						
0	266252	0	32						
0	116218	0	33						
259408	18302378	0	34						
0.7036	0.0221	0.0000	35						
Gas	Fuel Oil	Coal-SubB	Fuel Oil	Tires	RRM				36
Mcf	Bbl	Tons	Bbl	Tons	Tons				37
2268	897	0	506803	945	2466	281	0	0	38
1030	140000	0	8425	140000	15000	7187	0	0	39
12.255	80.899	0.000	30.069	126.034	23.859	8.494	0.000	0.000	40
12.255	80.206	0.000	29.922	121.393	23.859	8.494	0.000	0.000	41
11.898	13.647	0.000	1.776	20.649	0.795	0.591	0.000	0.000	42
0.271	0.000	0.000	0.019	0.000	0.000	0.000	0.000	0.000	43
20634.797	0.000	0.000	10430.514	0.000	0.000	0.000	0.000	0.000	44

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a term basis report the Btu content of the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: <i>Glendive</i> (b)	Plant Name: <i>Coyote</i> (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Gas Turbine	Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional	Conventional
3	Year Originally Constructed	1979	1981
4	Year Last Unit was Installed	2003	1981
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	75.50	103.65
6	Net Peak Demand on Plant - MW (60 minutes)	76	109
7	Plant Hours Connected to Load	210	7975
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	88	107
10	When Limited by Condenser Water	77	107
11	Average Number of Employees	3	20
12	Net Generation, Exclusive of Plant Use - KWh	3217680	744998977
13	Cost of Plant: Land and Land Rights	37924	522773
14	Structures and Improvements	278832	25669207
15	Equipment Costs	25582584	92281615
16	Asset Retirement Costs	0	119872
17	Total Cost	25899340	118593467
18	Cost per KW of Installed Capacity (line 17/5) Including	343.0376	1144.1724
19	Production Expenses: Oper, Supv, & Engr	40490	425231
20	Fuel	655618	10497727
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	69265	1288781
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	102256	397401
26	Misc Steam (or Nuclear) Power Expenses	1420	521948
27	Rents	0	312
28	Allowances	0	0
29	Maintenance Supervision and Engineering	27513	164744
30	Maintenance of Structures	3991	126919
31	Maintenance of Boiler (or reactor) Plant	105015	1425788
32	Maintenance of Electric Plant	14	166186
33	Maintenance of Misc Steam (or Nuclear) Plant	0	190182
34	Total Production Expenses	1005582	15205219
35	Expenses per Net KWh	0.3125	0.0204
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas	Fuel Oil
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Mcf	Bbl
38	Quantity (Units) of Fuel Burned	41440	2378
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	960	140000
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	9.921	116.773
41	Average Cost of Fuel per Unit Burned	9.921	102.812
42	Average Cost of Fuel Burned per Million BTU	10.335	17.484
43	Average Cost of Fuel Burned per KWh Net Gen	0.204	0.000
44	Average BTU per KWh Net Generation	16709.515	0.000

Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report 2008/Q4
FOOTNOTE DATA			

Schedule Page: 402 Line No.: -1 Column: d
Plant is designed for peak load service

Schedule Page: 402 Line No.: -1 Column: e
Plant is 22.7% owned by Respondent. Statistics represent Respondent's share of plant costs, production expenses and other data.

Schedule Page: 402 Line No.: 5 Column: b
Maximum Turbine Name Plate Rating

Schedule Page: 402 Line No.: 5 Column: c
Maximum Turbine Name Plate Rating

Schedule Page: 402 Line No.: 5 Column: d
Maximum Turbine Name Plate Rating

Schedule Page: 402 Line No.: 5 Column: e
Statistics reflect 22.7% of Maximum Turbine Name Plate Rating of 414.6

Schedule Page: 402 Line No.: 10 Column: d
Limited by ambient air temperature

Schedule Page: 402 Line No.: 20 Column: b
Total fuel costs for all generating plants include sales for resale fuel costs of \$3,450,185.

Schedule Page: 402.1 Line No.: -1 Column: b
Plant is designed for peak load service.

Schedule Page: 402.1 Line No.: -1 Column: c
Plant is 25% owned by Respondent. Statistics represent Respondent's share of plant costs, production expenses and other data.

Schedule Page: 402.1 Line No.: 5 Column: b
Maximum Turbine Name Plate Rating

Schedule Page: 402.1 Line No.: 5 Column: c
Statistics reflect 25% of Maximum Turbine Name Plate Rating of 414.6

Schedule Page: 402.1 Line No.: 10 Column: b
Limited by ambient air temperature

Schedule Page: 402 Line No.: 43 Column: b1
Average cost of all fuels burned per net kWh generated.

Schedule Page: 402 Line No.: 43 Column: b2
Average cost of all fuels burned per net kWh generated.

Schedule Page: 402 Line No.: 43 Column: b3
Average cost of all fuels burned per net kWh generated.

Schedule Page: 402 Line No.: 43 Column: c1
Average cost of all fuels burned per net kWh generated.

Schedule Page: 402 Line No.: 43 Column: c2
Average cost of all fuels burned per net kWh generated.

Schedule Page: 402 Line No.: 43 Column: c3
Average cost of all fuels burned per net kWh generated.

Schedule Page: 402 Line No.: 43 Column: d1
Average cost of all fuels burned per net kWh generated.

Schedule Page: 402 Line No.: 43 Column: d2
Average cost of all fuels burned per net kWh generated.

Schedule Page: 402 Line No.: 43 Column: e1
Average cost of all fuels burned per net kWh generated.

Schedule Page: 402 Line No.: 43 Column: e2
Average cost of all fuels burned per net kWh generated.

Schedule Page: 402 Line No.: 43 Column: e3
Average cost of all fuels burned per net kWh generated.

Schedule Page: 402 Line No.: 43 Column: f1
Average cost of all fuels burned per net kWh generated.

Schedule Page: 402 Line No.: 44 Column: b1

Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report 2008/Q4
FOOTNOTE DATA			

Average Btu per net kWh generated for all fuels.

Schedule Page: 402 Line No.: 44 Column: b2

Average Btu per net kWh generated for all fuels.

Schedule Page: 402 Line No.: 44 Column: b3

Average Btu per net kWh generated for all fuels.

Schedule Page: 402 Line No.: 44 Column: c1

Average Btu per net kWh generated for all fuels.

Schedule Page: 402 Line No.: 44 Column: c2

Average Btu per net kWh generated for all fuels.

Schedule Page: 402 Line No.: 44 Column: c3

Average Btu per net kWh generated for all fuels.

Schedule Page: 402 Line No.: 44 Column: d1

Average Btu per net kWh generated for all fuels.

Schedule Page: 402 Line No.: 44 Column: d2

Average Btu per net kWh generated for all fuels.

Schedule Page: 402 Line No.: 44 Column: e1

Average Btu per net kWh generated for all fuels.

Schedule Page: 402 Line No.: 44 Column: e2

Average Btu per net kWh generated for all fuels.

Schedule Page: 402 Line No.: 44 Column: e3

Average Btu per net kWh generated for all fuels.

Schedule Page: 402 Line No.: 44 Column: f1

Average Btu per net kWh generated for all fuels.

Schedule Page: 402.1 Line No.: 43 Column: b1

Average cost of all fuels burned per net kWh generated.

Schedule Page: 402.1 Line No.: 43 Column: b2

Average cost of all fuels burned per net kWh generated.

Schedule Page: 402.1 Line No.: 43 Column: c1

Average cost of all fuels burned per net kWh generated.

Schedule Page: 402.1 Line No.: 43 Column: c2

Average cost of all fuels burned per net kWh generated.

Schedule Page: 402.1 Line No.: 44 Column: b1

Average Btu per net kWh generated for all fuels.

Schedule Page: 402.1 Line No.: 44 Column: b2

Average Btu per net kWh generated for all fuels.

Schedule Page: 402.1 Line No.: 44 Column: c1

Average Btu per net kWh generated for all fuels.

Schedule Page: 402.1 Line No.: 44 Column: c2

Average Btu per net kWh generated for all fuels.

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(Next page is 410)

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	GAS TURBINE					
2	Williston	1953	7.80	10.9	-79,724	1,967,382
3						
4	WIND					
5	Diamond Willow	2007	19.50	19.6	64,996,896	36,970,402
6						
7						
8						
9						
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13						
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GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents per Million Btu) (l)	Line No.
		Fuel (i)	Maintenance (j)			
						1
252,228	33,810	10,531	25,427	Nat Gas		2
						3
						4
1,895,918	273,081		39,083	Wind		5
						6
						7
						8
						9
						10
						11
						12
						13
						14
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						45
						46

Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report 2008/Q4
FOOTNOTE DATA			

Schedule Page: 410 Line No.: 2 Column: c

Maximum Turbine Name Plate Rating

Schedule Page: 410 Line No.: 5 Column: a

1 wind turbine placed in service in 2007 (1.5 MW)

12 wind turbines placed in service in 2008 (1.5 MW each)

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(Next page is 422)

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	AVS	Charlie Creek	345.00	345.00	3	26.57		1
2	Coyote	Center	345.00	345.00	2	11.41		1
3	Coyote Switch Yard		345.00	345.00	2	1.04		1
4	Center	Jamestown	345.00	345.00	2	10.69		1
5	Big Stone Plant	Sisseton	230.00	230.00	2	47.55		1
6	Heskett Station	East Bismarck	230.00	230.00	2	10.49		1
7	Bismarck	Wishek	230.00	230.00	2	67.41		1
8	Wishek	Ellendale	230.00	230.00	2	54.83		1
9	Heskett Station	WAPA Tie	230.00	230.00	2	2.08		1
10	Montana Border	South Dakota Border	230.00	230.00	2	85.60		1
11								
12	Lines Below 132 Kilovolts		115.00	115.00	2	572.81	2.96	
13			69.00	69.00	Various	85.16	1.33	1
14			41.60	69.00	2	103.62		1
15			57.00	69.00	2	3.34		1
16			57.00	60.00	Various	863.19	0.89	1
17			41.60		Various	1,044.14	17.86	
18			33.00	35.00	1	28.99		1
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	3,018.92	23.04	15

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
2306.2 KcMIL								1
2-954 MCM								2
2-954 MCM								3
2-1272 MCM								4
954 MCM								5
795 MCM								6
795 MCM								7
795 MCM								8
954 MCM								9
954 MCM								10
								11
Various								12
Various								13
4/0 ACSR								14
4/0 ACSR								15
Various								16
Various								17
Various								18
								19
	2,563,696	69,275,028	71,838,724	3,286,616	1,409,517	1,490,537	6,186,670	20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	2,563,696	69,275,028	71,838,724	3,286,616	1,409,517	1,490,537	6,186,670	36

Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report 2008/Q4
FOOTNOTE DATA			

Schedule Page: 422 Line No.: 4 Column: b

Respondent, Otter Tail Power Company, Northern Municipal Power Agency and Northwestern Public Service (NMPA) share ownership of 10.69 miles of transmission line. Respondent's ownership share is 6.25%. NMPA pays all operating and maintenance expenses and they are shared based on mileage percentage. Respondent's expenses are reflected in accounts 562 and 570.

Schedule Page: 422 Line No.: 12 Column: h

Various

Schedule Page: 422 Line No.: 17 Column: d

Various

Schedule Page: 422 Line No.: 17 Column: h

Various

Schedule Page: 422 Line No.: 20 Column: j

Cost by transmission line not available. Total costs for all transmission lines.

Schedule Page: 422 Line No.: 20 Column: k

Cost by transmission line not available. Total costs for all transmission lines.

Schedule Page: 422 Line No.: 20 Column: l

Cost by transmission line not available. Total costs for all transmission lines.

Schedule Page: 422 Line No.: 20 Column: m

Cost by transmission line not available. Total costs for all transmission lines.

Schedule Page: 422 Line No.: 20 Column: n

Cost by transmission line not available. Total costs for all transmission lines.

Schedule Page: 422 Line No.: 20 Column: o

Cost by transmission line not available. Total costs for all transmission lines.

Schedule Page: 422 Line No.: 20 Column: p

Cost by transmission line not available. Total costs for all transmission lines.

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(Next page is 424)

Name of Respondent
MDU Resources Group, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
12/31/2008

Year/Period of Report
End of 2008/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.

2. Provide separate subheadings for overhead and under-ground construction and show each transmission line separately. If actual costs of completed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION		Line Length in Miles (c)	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)		Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1	Baker, MT	Glendive, MT	0.11	SP	13.00	1	1
2			-0.11	Retired			
3	Bowdle, SD	Mobridge, SD	0.18	SP	21.00	1	1
4			-0.17	Retired			
5	Tioga, ND	Kenmare, ND	2.55	H-Frame	17.00	1	1
6			-2.55	Retired			
7	Bismarck, ND	Loop Line	0.11	U.B. on SP	17.00	1	1
8			-0.18	U.B. Retired			
9	Northwest Bismarck, ND	East Bismarck, ND	0.12	SP	17.00	1	1
10			-0.13	Retired			
11	Beulah, ND	Bismarck, ND	0.15	SP	26.00	1	1
12			0.44	UG Added		1	1
13			-0.49	Retired			
14	South Mandan, ND	Bismarck, ND: Sweet Ave	0.45	SP	35.00	1	1
15			0.40	UG Added		1	1
16			-0.80	Retired			
17	Bismarck, ND: Sweet Ave	TL403 & 405	0.34	SP	32.00	1	1
18			0.20	U.B. on SP	17.00	1	1
19			0.46	UG Added		1	1
20			-0.26	Retired			
21			-0.43	U.B. Retired			
22							
23							
24							
25							
26							
27							
28							
29							
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36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		0.39		195.00	12	12

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
 3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage KV (Operating) (k)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
4/0	ACSR	T-60-A	57		103,463			103,463	1
					-545			-545	2
2/0	ACSR	T-46-AS1	42		6,091	1,523		7,614	3
					-667		795	128	4
477		T-115-A	115		42,023	279,608		321,631	5
					-532	-8,938	-3,932	-13,402	6
4/0	ACSR	T-46-HUB	42		6,079	21,274		27,353	7
						-2,306	500	-1,806	8
954	MCMACSR	T-115-PA	115		71,331	45,511		116,842	9
					-3,163	-6,351	3,328	-6,186	10
954	MCMACSR	T-115-PD	115		275,884	22,990		298,874	11
1500	MCMXLPE	N/A	115		689,709	1,310,448		2,000,157	12
					-2,165	-12,297	2,283	-12,179	13
954	MCMACSR	T-115-PA	115	18,805	551,152	225,472		795,429	14
1500	MCMXLPE	N/A	115		526,100	1,202,514		1,728,614	15
					-47,615	-46,889	9,643	-84,861	16
336	MCMACSR	T-46-HA1	42	8,724	366,412	115,158		490,294	17
336	MCMACSR	T-46-HUB	42						18
750	MCMXLPE	N/A	42		774,699	837,513		1,612,212	19
					-2,996	-2,981	12,516	6,539	20
									21
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									43
				27,529	3,355,260	3,982,249	25,133	7,390,171	44

Name of Respondent MDU Resources Group, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report 2008/Q4
FOOTNOTE DATA			

Schedule Page: 424	Line No.: 1	Column: j	86" X 86" X 86" Triangular
Schedule Page: 424	Line No.: 1	Column: k	60 KV Design
Schedule Page: 424	Line No.: 3	Column: j	59" X 59" X 110" Triangular
Schedule Page: 424	Line No.: 3	Column: k	46 KV Design
Schedule Page: 424	Line No.: 5	Column: i	MCM ACSS-HS 285
Schedule Page: 424	Line No.: 5	Column: j	14'6" x 14'6" Horizontal
Schedule Page: 424	Line No.: 7	Column: j	6' X 6' X 9' Vertical
Schedule Page: 424	Line No.: 7	Column: k	46 KV Design
Schedule Page: 424	Line No.: 9	Column: j	11' X 11' X 10' Vertical
Schedule Page: 424	Line No.: 11	Column: j	7' X 7' X 7' Vertical
Schedule Page: 424	Line No.: 12	Column: e	N/A
Schedule Page: 424	Line No.: 14	Column: j	11' X 11' X 10' Vertical
Schedule Page: 424	Line No.: 15	Column: e	N/A
Schedule Page: 424	Line No.: 17	Column: j	6' X 6' X 9' Vertical
Schedule Page: 424	Line No.: 17	Column: k	46 KV Design
Schedule Page: 424	Line No.: 18	Column: j	6' X 6' X 9' Vertical
Schedule Page: 424	Line No.: 18	Column: k	46 KV Design
Schedule Page: 424	Line No.: 19	Column: e	N/A
Schedule Page: 424	Line No.: 19	Column: k	69 KV Design

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Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Month Year) 12/31/08	Year/Period of Report End of 2008/Q4
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SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	Big Stone, SD (22.7% Interest)	Trans at Plant	230.00	22.90	
2	Big Stone, SD (22.7% Interest)	Trans at Plant	230.00	118.00	13.80
3	Coyote Station, ND (25% Interest)	Trans at Plant	345.00	22.90	
4	Coyote Station, ND (25% Interest)	Trans at Plant	115.00	13.80	
5	Coyote Station, ND	Trans at Plant	345.00	115.00	13.80
6	Diamond Willow, MT	Trans at Plant	57.20	34.50	
7	Glendive, MT (Turbine)	Trans at Plant	115.00	60.00	
8	Glendive, MT (Turbine)	Trans at Plant	115.00	13.20	
9	Glendive, MT (Turbine)	Trans at Plant	115.00	60.00	
10	Heskett Station, ND	Trans at Plant	230.00	115.00	13.80
11	Heskett Station, ND	Trans at Plant	116.00	13.20	
12	Heskett Station, ND	Trans at Plant	115.00	13.20	
13	Heskett Station, ND	Trans at Plant	115.00	41.60	
14	Heskett Station, ND	Trans at Plant	115.00	69.00	
15	Lewis & Clark Station, MT	Trans at Plant	115.00	13.80	
16	Lewis & Clark Station, MT	Trans at Plant	57.00	13.80	
17	Lewis & Clark Station, MT	Trans at Plant	115.00	60.00	
18	Miles City, MT (Turbine)	Trans at Plant	57.00	13.80	
19	Substations under 10,000 KVA (1)				
20	SUBTOTAL		2702.20	813.70	41.40
21					
22	Baker, MT	Trans Unattended	115.00	57.00	
23	Baker, MT	Trans Unattended	230.00	115.00	14.10
24	Baker, MT Cabin Creek Jct	Trans Unattended	115.00	57.20	
25	Beulah Jct., ND	Trans Unattended	115.00	41.60	
26	Bismarck Jct., ND (E. Bismarck)	Trans Unattended	115.00	41.60	
27	Bismarck, ND NW	Trans Unattended	115.00	41.60	
28	Bismarck, ND Sweet Ave.	Trans Unattended	115.00	41.60	
29	Bowdle Jct., SD	Trans Unattended	115.00	41.60	
30	Dickinson, ND	Trans Unattended	115.00	41.60	
31	Dunning, ND	Trans Unattended	115.00	57.00	
32	Ellendale Jct., ND	Trans Unattended	230.00	115.00	13.80
33	Ellendale Jct., ND	Trans Unattended	115.00	41.60	
34	Elgin, ND	Trans Unattended	69.00	41.60	
35	Gascoyne Jct., ND	Trans Unattended	115.00	41.60	
36	Glenham Jct., SD	Trans Unattended	230.00	115.00	41.60
37	Glenham Jct., SD	Trans Unattended	230.00	115.00	41.60
38	Halliday, ND	Trans Unattended	115.00	41.60	
39	Hettinger Jct., ND	Trans Unattended	115.00	41.60	
40	Hettinger Jct., ND	Trans Unattended	230.00	115.00	14.10

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
105	1					1
52	1					2
121	1					3
21	1					4
168	1					5
28	2					6
50	1					7
40	1					8
37	1					9
112	1					10
94	1	1				11
28	1					12
34	1					13
45	1			1		4 14
53	1					15
20	1					16
47	1					17
31	1					18
7	1					19
1093	20	1		1		4 20
						21
40	1			1		4 22
112	1					23
83	1					24
45	1					25
80	2			2		8 26
47	1			1		4 27
56	1					28
20	1			1		2 29
75	1					30
20	1			1		2 31
100	1					32
37	1					33
15	1					34
11	1			1		1 35
30	1			1		3 36
50	1					37
20	1			1		2 38
25	1			1		3 39
112	1					40

Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Yr) 12/31/2008	Year/Period of Report End of 2008/Q4
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SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	Kenmare Jct., ND	Trans Unattended	115.00	57.00	
2	Linton Jct., ND	Trans Unattended	115.00	41.60	
3	McIntosh Jct., SD	Trans Unattended	115.00	41.60	
4	Miles City, MT	Trans Unattended	230.00	115.00	13.80
5	Miles City, MT	Trans Unattended	115.00	57.00	13.80
6	New England, ND	Trans Unattended	115.00	41.60	
7	Plentywood Jct., MT	Trans Unattended	115.00	57.00	
8	Poplar Jct., MT	Trans Unattended	115.00	57.00	
9	Rosebud Creek, MT	Trans Unattended	230.00	60.00	13.80
10	Sheridan, WY (PP&L)	Trans Unattended	230.00	41.60	
11	Sheridan, WY (PP&L)	Trans Unattended	230.00	41.60	
12	Sheridan, WY	Trans Unattended	230.00	41.60	
13	Stanley Jct., ND	Trans Unattended	115.00	69.00	12.47
14	Tioga, ND	Trans Unattended	230.00	115.00	
15	Tioga Jct., ND	Trans Unattended	115.00	57.00	
16	Wishek Jct., ND	Trans Unattended	115.00	41.60	
17	Wishek Jct., ND	Trans Unattended	230.00	115.00	
18	Substations under 10,000 KVA (5)				
19	SUBTOTAL		5474.00	2254.00	179.07
20					
21	Substations under 10,000 KVA Distrib at Plant (2)				
22	SUBTOTAL				
23					
24	Beulah, ND Dragline	Distrib Unattended	115.00	6.90	
25	KRCM Beulah, ND Dragline KRCM Site II	Distrib Unattended	115.00	6.90	
26	Baker, MT Lookout Butte	Distrib Unattended	57.20	12.47	
27	Bismarck, ND 6th St	Distrib Unattended	41.60	12.47	
28	Bismarck, ND Kirkwood	Distrib Unattended	115.00	12.47	
29	Bismarck, ND-West Loop	Distrib Unattended	41.60	12.47	
30	Bismarck, ND SE Expressway	Distrib Unattended	115.00	12.47	
31	Bismarck, ND NW (Century)	Distrib Unattended	115.00	12.47	
32	Bismarck, ND NE	Distrib Unattended	115.00	12.47	
33	Bismarck, ND Front Ave	Distrib Unattended	115.00	12.47	
34	Bismarck, ND Front Ave	Distrib Unattended	115.00	12.50	
35	Bismarck, ND Turnpike	Distrib Unattended	115.00	12.47	
36	Bismarck, ND South 9th St.	Distrib Unattended	41.60	12.50	
37	Bismarck, ND East Loop Sub	Distrib Unattended	41.60	12.47	
38	Dickinson, ND NW	Distrib Unattended	41.60	12.47	
39	Dickinson, ND East Broadway	Distrib Unattended	41.60	12.47	
40	Dickinson, ND NE	Distrib Unattended	41.60	12.47	

Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2008	Year/Period of Report End of 2008/Q4
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SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
30	1			1	3	1
15	1			1	2	2
13	1			2	1	3
100	1					4
56	1					5
22	1			1	2	6
47	1					7
37	1					8
40	1					9
37	1					10
20	1					11
75	1					12
20	1			1	2	13
112	1					14
30	1			1	3	15
30	1			1	3	16
112	1					17
12	8	1				18
1786	45	1		18	45	19
						20
	1			1	1	21
	1			1	1	22
						23
11	1					24
11	1					25
11	1					26
14	1			3	2	27
28	1			6	2	28
14	1			3	1	29
53	2			9	4	30
22	1			3	2	31
28	1			6	2	32
47	1			15	3	33
47	1			12	4	34
28	1			6	2	35
11	1			3	1	36
14	1			3	1	37
14	1			3	1	38
14	1			3	1	39
14	1			3	1	40

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	Dickinson, ND	Distrib Unattended	41.60	12.47	
2	Glendive, MT	Distrib Unattended	57.00	12.47	
3	Glendive, MT West	Distrib Unattended	57.00	12.47	
4	Glendive, MT	Distrib Unattended	57.00	12.47	
5	Mandan, ND Collins Ave	Distrib Unattended	41.60	12.47	
6	Mandan, ND Midway	Distrib Unattended	41.60	12.50	
7	Mandan, ND Amoco Refinery	Distrib Unattended	41.60	4.16	
8	Mandan, ND	Distrib Unattended	115.00	12.47	
9	Miles City, MT-East	Distrib Unattended	57.00	12.47	
10	Miles City, MT	Distrib Unattended	57.00	12.47	
11	Mobridge, SD	Distrib Unattended	115.00	12.47	
12	Sheridan, WY Broadway	Distrib Unattended	41.60	12.47	
13	Sheridan, WY Broadway	Distrib Unattended	41.60	12.47	
14	Sheridan, WY Highview	Distrib Unattended	41.60	12.47	
15	Sheridan, WY Sugarland	Distrib Unattended	41.60	12.47	
16	Sheridan, WY	Distrib Unattended	41.60	12.47	
17	Sidney, MT	Distrib Unattended	57.00	12.47	
18	Sidney, MT	Distrib Unattended	57.00	12.47	
19	Williston, ND East Broadway	Distrib Unattended	57.00	12.47	
20	Williston, ND NE	Distrib Unattended	57.00	12.47	
21	Williston, ND NW	Distrib Unattended	57.00	12.47	
22	Williston, ND NW	Distrib Unattended	57.00	13.80	
23	Substations Under 10,000 KVA (230)				
24	SUBTOTAL		2614.80	468.30	
25					
26	GRAND TOTAL		10791.00	3536.00	220.47
27					
28					
29	FOOTNOTES				
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
11	1			3	1	1
14	1			3	1	2
11	1			3	1	3
11	1			3	1	4
14	1			3	1	5
11	1			3	1	6
11	1					7
50	2			9	3	8
10	1			6	2	9
11	1			3	1	10
22	1			9	1	11
11	1			3	2	12
13	1			3	1	13
11	1			3	1	14
11	1			3	2	15
11	1			3	2	16
11	1			3	1	17
11	1			3	1	18
10	1			3	1	19
10	1			3	1	20
10	1			3	1	21
14	1					22
455	390			429	42	23
1135	431			582	95	24
						25
4014	497	2		602	145	26
						27
						28
						29
						30
						31
						32
						33
						34
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Name of Respondent	This Report is:	Date of Report	Year/Period of Report
MDU Resources Group, Inc.	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 12/31/2008	2008/Q4
FOOTNOTE DATA			

Schedule Page: 426 Line No.: 26 Column: a
See (A) and (B) of footnotes
Schedule Page: 426 Line No.: 27 Column: a
See (B) and (C) of footnotes
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See (J) and (K) of footnotes
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See (N) and (O) of footnotes
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See (H) and (I) of footnotes
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See (P) of footnotes
Schedule Page: 426.1 Line No.: 5 Column: a
See (L) and (M) of footnotes
Schedule Page: 426.1 Line No.: 9 Column: a
See (D) and (E) of footnotes
Schedule Page: 426.1 Line No.: 17 Column: a
See (F) and (G) of footnotes
Schedule Page: 426.2 Line No.: 29 Column: a

FOOTNOTES:

- (A) Capital Electric Cooperative, Inc. has a 25 MVA capacity interest.
- (B) Capital Electric Cooperative, Inc. pays for all expenses relating to equipment owned by them and is not an associated company.
- (C) Capital Electric Cooperative, Inc. has a 10 MVA capacity interest.
- (D) Mid-Yellowstone Electric Cooperative, Inc. has a 14,911 KVA capacity interest.
- (E) Respondent and Mid-Yellowstone Electric Cooperative, Inc. shared the facilities construction cost and available capacity in the respective percentages of 63% and 37%. All maintenance and operating expenses are shared in the same percentage. The Respondent's expenses are reflected in accounts 570 and 562. Mid-Yellowstone Electric Cooperative, Inc. is not an associated company.
- (F) KEM Electric Cooperative, Inc. has a 59,136 KVA capacity interest.
- (G) KEM Electric Cooperative, Inc. pays for all expenses relating to equipment owned by them and is not an associated company.
- (H) Upper Missouri G&T Electric Cooperative, Inc. has a 15,300 KVA capacity interest.
- (I) Upper Missouri G&T Electric Cooperative, Inc. pays for all expenses relating to equipment owned by them and is not an associated company.
- (J) Central Power and Upper Missouri G&T Electric Cooperative, Inc. have a 9,420 KVA capacity interest.
- (K) Central Power pays for all expenses relating to equipment owned by them and is not an associated company. Respondent pays for all expenses relating to transformer and regulator equipment owned by Respondent.
- (L) Western Area Power Administration (WAPA) has a 9,500 KVA capacity interest.
- (M) WAPA does routine maintenance at their expense and major repairs are allocated 19% WAPA and 81% Respondent.
- (N) Mor-Gran-Sou Electric Cooperative has a 4,560 KVA capacity interest.
- (O) Mor-Gran-Sou Electric Cooperative pays for all expenses relating to equipment owned by them and is not an associated company.
- (P) WAPA has a 25,000 KVA capacity interest.

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