THIS FILING IS		
Item 1: [X] An Initial (Original) Submission	OR [ ]	Resubmission No. ____

Form 2 Approved
OMB No. 1902-0028
(Expires 05/31/2014)
Form 3-Q: Approved
OMB No.1902-0205
(Expires 05/31/2014)

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

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

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
Northern Natural Gas Company	**End of** 2011/Q3

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

GENERAL INFORMATION

I Purpose

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

II. Who Must Submit

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

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

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

III. What and Where to Submit

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

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

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

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

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

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

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

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

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

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

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

IV. When to Submit:

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

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

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

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

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the Form 2 collection of information is estimated to average 1,623 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the Form 2A collection of information is estimated to average 250 hours per response. The public reporting burden for the Form 3-Q collection of information is estimated to average 165 hours per response.

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

GENERAL INSTRUCTIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

General Penalties

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

QUARTERLY/ANNUAL REPORT OF MAJOR NATURAL GAS COMPANIES

IDENTIFICATION

01 Exact Legal Name of Respondent Northern Natural Gas Company	Year/Period of Report End of 2011/Q3
03 Previous Name and Date of Change (If name changed during year)	
04 Address of Principal Office at End of Year (Street, City, State, Zip Code) 1111 South 103rd Street, Omaha, NE 68124	
05 Name of Contact Person Thomas P. Tosoni	06 Title of Contact Person Director - Accounting and Reporting
07 Address of Contact Person (Street, City, State, Zip Code) 1111 South 103rd Street, Omaha, NE 68124	

08 Telephone of Contact Person, Including Area Code 402-398-7993	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)*

QUARTERLY CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

11 Name Joseph M. Lillo	12 Title Vice President - Finance
13 Signature /s/ Joseph M. Lillo	14 Date Signed 11/29/2011

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q3

List of Schedules (Natural Gas Company)

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

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Northern Natural Gas Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) / /	2011/Q3

Important Changes During the Quarter/Year

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

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

1. None.

2. None.

3. None.

4. None.

5. No important extensions or reductions of the Respondent's transmission system occurred pursuant to Section 7 of the Natural Gas Act and Part 157 of the regulations of the Federal Energy Regulatory Commission from July 1 through September 30, 2011.

BLANKET CERTIFICATE ACTIVITIES

No important extensions or reductions of the Respondent's transmission system occurred pursuant to its blanket certificate granted on September 1, 1982, in Docket No. CP82-401-000 from July 1 through September 30, 2011.

§311 FACILITIES

No important extensions or reductions of the Respondent's transmission system occurred pursuant to §311(a) of the Natural Gas Policy Act of 1978 from July 1 through September 30, 2011.

6. None.

7. None.

8. None.

9. See footnote 6 on page 122.

10. None.

11. None.

12. Mark A. Hewett, president, became a director August 9, 2011.

13. Not applicable.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q3

Comparative Balance Sheet (Assets and Other Debits)

Line No.	Title of Account (a)	Reference Page Number (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	3,368,555,566	3,332,876,290
3	Construction Work in Progress (107)	200-201	25,265,642	16,956,918
4	TOTAL Utility Plant (Total of lines 2 and 3)	200-201	3,393,821,208	3,349,833,208
5	(Less) Accum. Provision for Depr., Amort., Depl. (108, 111, 115)		1,256,612,777	1,231,104,888
6	Net Utility Plant (Total of line 4 less 5)		2,137,208,431	2,118,728,320
7	Nuclear Fuel (120.1 thru 120.4, and 120.6)		0	0
8	(Less) Accum. Provision for Amort., of Nuclear Fuel Assemblies (120.5)		0	0
9	Nuclear Fuel (Total of line 7 less 8)		0	0
10	Net Utility Plant (Total of lines 6 and 9)		2,137,208,431	2,118,728,320
11	Utility Plant Adjustments (116)	122	0	0
12	Gas Stored-Base Gas (117.1)	220	27,903,863	27,903,863
13	System Balancing Gas (117.2)	220	41,211,532	41,211,532
14	Gas Stored in Reservoirs and Pipelines-Noncurrent (117.3)	220	0	0
15	Gas Owed to System Gas (117.4)	220	(12,020,182)	(3,741,134)
16	**OTHER PROPERTY AND INVESTMENTS**			
17	Nonutility Property (121)		0	0
18	(Less) Accum. Provision for Depreciation and Amortization (122)		0	0
19	Investments in Associated Companies (123)	222-223	0	0
20	Investments in Subsidiary Companies (123.1)	224-225	0	0
21	(For Cost of Account 123.1 See Footnote Page 224, line 40)			
22	Noncurrent Portion of Allowances		0	0
23	Other Investments (124)	222-223	0	0
24	Sinking Funds (125)		0	0
25	Depreciation Fund (126)		0	0
26	Amortization Fund - Federal (127)		0	0
27	Other Special Funds (128)		27,128,046	22,161,688
28	Long-Term Portion of Derivative Assets (175)		0	0
29	Long-Term Portion of Derivative Assets - Hedges (176)		0	0
30	TOTAL Other Property and Investments (Total of lines 17-20, 22-29)		27,128,046	22,161,688
31	**CURRENT AND ACCRUED ASSETS**			
32	Cash (131)		33,101,778	(2,748,858)
33	Special Deposits (132-134)		1,845,637	2,433,653
34	Working Funds (135)		24,534	24,650
35	Temporary Cash Investments (136)	222-223	0	73,363,294
36	Notes Receivable (141)		0	0
37	Customer Accounts Receivable (142)		31,763,509	66,293,962
38	Other Accounts Receivable (143)		1,362,368	320,639
39	(Less) Accum. Provision for Uncollectible Accounts - Credit (144)		0	0
40	Notes Receivable from Associated Companies (145)		230,000,000	150,000,000
41	Accounts Receivable from Associated Companies (146)		3,558,152	7,472,725
42	Fuel Stock (151)		0	0
43	Fuel Stock Expenses Undistributed (152)		0	0

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

Line No.	Title of Account (a)	Reference Page Number (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
44	Residuals (Elec) and Extracted Products (Gas) (153)		0	0
45	Plant Materials and Operating Supplies (154)		23,251,169	22,357,868
46	Merchandise (155)		0	0
47	Other Materials and Supplies (156)		0	0
48	Nuclear Materials Held for Sale (157)		0	0
49	Allowances (158.1 and 158.2)		0	0
50	(Less) Noncurrent Portion of Allowances		0	0
51	Stores Expense Undistributed (163)		0	0
52	Gas Stored Underground-Current (164.1)	220	1,106,863	1,561,916
53	Liquefied Natural Gas Stored and Held for Processing (164.2 thru 164.3)	220	0	0
54	Prepayments (165)	230	20,998,606	14,239,619
55	Advances for Gas (166 thru 167)		0	0
56	Interest and Dividends Receivable (171)		0	100,274
57	Rents Receivable (172)		0	0
58	Accrued Utility Revenues (173)		0	0
59	Miscellaneous Current and Accrued Assets (174)		16,591,755	53,995,959
60	Derivative Instrument Assets (175)		3,677	48,409
61	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
62	Derivative Instrument Assets - Hedges (176)		2,660,690	0
63	(Less) Long-Term Portion of Derivative Instrument Assests - Hedges (176)		0	0
64	TOTAL Current and Accrued Assets (Total of lines 32 thru 63)		366,268,738	389,464,110
65	**DEFERRED DEBITS**			
66	Unamortized Debt Expense (181)		4,791,856	3,922,496
67	Extraordinary Property Losses (182.1)	230	0	0
68	Unrecovered Plant and Regulatory Study Costs (182.2)	230	0	0
69	Other Regulatory Assets (182.3)	232	127,326,228	146,576,050
70	Preliminary Survey and Investigation Charges (Electric)(183)		0	0
71	Preliminary Survey and Investigation Charges (Gas)(183.1 and 183.2)		0	0
72	Clearing Accounts (184)		0	0
73	Temporary Facilities (185)		0	0
74	Miscellaneous Deferred Debits (186)	233	5,350,193	6,538,465
75	Deferred Losses from Disposition of Utility Plant (187)		0	0
76	Research, Development, and Demonstration Expend. (188)		0	0
77	Unamortized Loss on Reacquired Debt (189)		0	0
78	Accumulated Deferred Income Taxes (190)	234-235	264,837,415	291,492,595
79	Unrecovered Purchased Gas Costs (191)		0	0
80	TOTAL Deferred Debits (Total of lines 66 thru 79)		402,305,692	448,529,606
81	TOTAL Assets and Other Debits (Total of lines 10-15,30,64,and 80)		2,990,006,120	3,044,257,985

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q3

Comparative Balance Sheet (Liabilities and Other Credits)

Line No.	Title of Account (a)	Reference Page Number (b)	Current Year End of Quarter/Year Balance	Prior Year End Balance 12/31 (d)
1	**PROPRIETARY CAPITAL**			
2	Common Stock Issued (201)	250-251	1,002	1,002
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)	252	0	0
5	Stock Liability for Conversion (203, 206)	252	0	0
6	Premium on Capital Stock (207)	252	0	0
7	Other Paid-In Capital (208-211)	253	981,867,972	981,867,972
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254	0	0
11	Retained Earnings (215, 215.1, 216)	118-119	244,538,912	232,978,353
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	0	0
13	(Less) Reacquired Capital Stock (217)	250-251	0	0
14	Accumulated Other Comprehensive Income (219)	117	(926,834)	(742,993)
15	TOTAL Proprietary Capital (Total of lines 2 thru 14)		1,225,481,052	1,214,104,334
16	**LONG TERM DEBT**			
17	Bonds (221)	256-257	150,000,000	150,000,000
18	(Less) Reacquired Bonds (222)	256-257	0	0
19	Advances from Associated Companies (223)	256-257	0	0
20	Other Long-Term Debt (224)	256-257	800,000,000	850,000,000
21	Unamortized Premium on Long-Term Debt (225)	258-259	0	0
22	(Less) Unamortized Discount on Long-Term Debt-Dr (226)	258-259	289,570	299,841
23	(Less) Current Portion of Long-Term Debt		0	250,000,000
24	TOTAL Long-Term Debt (Total of lines 17 thru 23)		949,710,430	749,700,159
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)		169,460	19,669
29	Accumulated Provision for Pensions and Benefits (228.3)		2,905,046	2,585,795
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		0	0

Comparative Balance Sheet (Liabilities and Other Credits)(continued)

Line No.	Title of Account (a)	Reference Page Number (b)	Current Year End of Quarter/Year Balance	Prior Year End Balance 12/31 (d)
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		49,160,660	60,966,274
35	TOTAL Other Noncurrent Liabilities (Total of lines 26 thru 34)		52,235,166	63,571,738
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Current Portion of Long-Term Debt		0	250,000,000
38	Notes Payable (231)		0	0
39	Accounts Payable (232)		13,648,940	18,112,978
40	Notes Payable to Associated Companies (233)		0	0
41	Accounts Payable to Associated Companies (234)		896,161	1,231,518
42	Customer Deposits (235)		13,429,833	9,494,971
43	Taxes Accrued (236)	262-263	44,106,970	44,960,823
44	Interest Accrued (237)		16,003,096	13,541,446
45	Dividends Declared (238)		0	0
46	Matured Long-Term Debt (239)		0	0
47	Matured Interest (240)		0	0
48	Tax Collections Payable (241)		644,715	796,468
49	Miscellaneous Current and Accrued Liabilities (242)	268	35,086,559	60,768,890
50	Obligations Under Capital Leases-Current (243)		0	0
51	Derivative Instrument Liabilities (244)		405,447	3,480,632
52	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
53	Derivative Instrument Liabilities - Hedges (245)		53,204,019	63,894,503
54	(Less) Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
55	TOTAL Current and Accrued Liabilities (Total of lines 37 thru 54)		177,425,740	466,282,229
56	**DEFERRED CREDITS**			
57	Customer Advances for Construction (252)		3,122,872	600,579
58	Accumulated Deferred Investment Tax Credits (255)		0	0
59	Deferred Gains from Disposition of Utility Plant (256)		0	0
60	Other Deferred Credits (253)	269	1,323,544	1,385,731
61	Other Regulatory Liabilities (254)	278	17,935,433	23,277,783
62	Unamortized Gain on Reacquired Debt (257)	260	0	0
63	Accumulated Deferred Income Taxes - Accelerated Amortization (281)		0	0
64	Accumulated Deferred Income Taxes - Other Property (282)		509,508,286	468,072,290
65	Accumulated Deferred Income Taxes - Other (283)		53,263,597	57,263,142
66	TOTAL Deferred Credits (Total of lines 57 thru 65)		585,153,732	550,599,525
67	TOTAL Liabilities and Other Credits (Total of lines 15,24,35,55,and 66)		2,990,006,120	3,044,257,985

Statement of Income

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

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

Line No.	Title of Account (a)	Reference Page Number (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current Three Months Ended Quarterly Only No Fourth Quarter (e)	Prior Three Months Ended Quarterly Only No Fourth Quarter (f)
1	**UTILITY OPERATING INCOME**					
2	Gas Operating Revenues (400)	300-301	431,176,746	426,138,166	111,849,788	117,630,779
3	Operating Expenses					
4	Operation Expenses (401)	317-325	134,469,282	115,850,995	42,101,595	34,188,362
5	Maintenance Expenses (402)	317-325	30,365,291	33,773,111	10,923,093	14,008,411
6	Depreciation Expense (403)	336-338	42,641,891	39,769,158	14,366,801	13,408,326
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-338	0	0	0	0
8	Amortization and Depletion of Utility Plant (404-405)	336-338	5,228,421	4,902,428	1,753,771	1,642,742
9	Amortization of Utility Plant Acu. Adjustment (406)	336-338	0	0	0	0
10	Amort. of Prop. Losses, Unrecovered Plant and Reg. Study Costs (407.1)		0	0	0	0
11	Amortization of Conversion Expenses (407.2)		0	0	0	0
12	Regulatory Debits (407.3)		7,077,274	7,045,362	2,359,091	2,348,454
13	(Less) Regulatory Credits (407.4)		0	0	0	0
14	Taxes Other than Income Taxes (408.1)	262-263	38,303,749	39,519,326	12,418,980	11,941,439
15	Income Taxes-Federal (409.1)	262-263	6,572,189	17,233,090	(8,600,136)	(15,987,362)
16	Income Taxes-Other (409.1)	262-263	3,171,236	7,277,369	(276,243)	204,181
17	Provision of Deferred Income Taxes (410.1)	234-235	62,261,392	44,895,308	27,468,887	29,587,086
18	(Less) Provision for Deferred Income Taxes-Credit (411.1)	234-235	20,104,169	13,294,874	12,517,425	3,842,737
19	Investment Tax Credit Adjustment-Net (411.4)		0	0	0	0
20	(Less) Gains from Disposition of Utility Plant (411.6)		0	0	0	0
21	Losses from Disposition of Utility Plant (411.7)		0	0	0	0
22	(Less) Gains from Disposition of Allowances (411.8)		0	0	0	0
23	Losses from Disposition of Allowances (411.9)		0	0	0	0
24	Accretion Expense (411.10)		0	0	0	0
25	TOTAL Utility Operating Expenses (Total of lines 4 thru 24)		309,986,556	296,971,273	89,998,414	87,498,902
26	Net Utility Operating Income (Total of lines 2 less 25) (Carry forward to page 116, line 27)		121,190,190	129,166,893	21,851,374	30,131,877

Statement of Income(continued)

Line No.	Title of Account (a)	Reference Page Number (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current Three Months Ended Quarterly Only No Fourth Quarter (e)	Prior Three Months Ended Quarterly Only No Fourth Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		121,190,190	129,166,893	21,851,374	30,131,877
28	**OTHER INCOME AND DEDUCTIONS**					
29	Other Income					
30	Nonutility Operating Income					
31	Revenues form Merchandising, Jobbing and Contract Work (415)		0	0	0	0
32	(Less) Costs and Expense of Merchandising, Job & Contract Work (416)		0	37,592	0	37,592
33	Revenues from Nonutility Operations (417)		0	0	0	0
34	(Less) Expenses of Nonutility Operations (417.1)		497	0	1,972	0
35	Nonoperating Rental Income (418)		0	0	0	0
36	Equity in Earnings of Subsidiary Companies (418.1)	119	0	0	0	0
37	Interest and Dividend Income (419)		1,368,760	3,263,148	421,401	1,063,912
38	Allowance for Other Funds Used During Construction (419.1)		795,515	1,692,539	328,730	343,770
39	Miscellaneous Nonoperating Income (421)		1,127,948	5,786,370	590,148	1,350,389
40	Gain on Disposition of Property (421.1)		1,217,092	32,167	0	30,247
41	TOTAL Other Income (Total of lines 31 thru 40)		4,508,818	10,736,632	1,338,307	2,750,726
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		2,361	(158,537)	181	0
44	Miscellaneous Amortization (425)		0	0	0	0
45	Donations (426.1)	340	326,435	265,260	53,315	2,907
46	Life Insurance (426.2)		0	0	0	0
47	Penalties (426.3)		0	0	0	0
48	Expenditures for Certain Civic, Political and Related Activities (426.4)		132,064	251,591	25,993	80,129
49	Other Deductions (426.5)		846,765	7,422,886	333,646	3,680,267
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)	340	1,307,625	7,781,200	413,135	3,763,303
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other than Income Taxes (408.2)	262-263	0	0	0	0
53	Income Taxes-Federal (409.2)	262-263	(16,913,336)	(14,506,873)	(5,568,725)	(4,463,557)
54	Income Taxes-Other (409.2)	262-263	(3,855,033)	(3,306,530)	(1,269,272)	(1,017,372)
55	Provision for Deferred Income Taxes (410.2)	234-235	22,055,957	21,022,367	7,213,370	7,062,332
56	(Less) Provision for Deferred Income Taxes-Credit (411.2)	234-235	0	1,977,000	0	1,976,610
57	Investment Tax Credit Adjustments-Net (411.5)		0	0	0	0
58	(Less) Investment Tax Credits (420)		0	0	0	0
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		1,287,588	1,231,964	375,373	(395,207)
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		1,913,605	1,723,468	549,799	(617,370)
61	**INTEREST CHARGES**					
62	Interest on Long-Term Debt (427)		42,156,944	44,212,500	12,487,500	14,737,500
63	Amortization of Debt Disc. and Expense (428)	258-259	678,006	647,171	211,855	219,011
64	Amortization of Loss on Reacquired Debt (428.1)		0	0	0	0
65	(Less) Amortization of Premium on Debt-Credit (429)	258-259	0	0	0	0
66	(Less) Amortization of Gain on Reacquired Debt-Credit (429.1)		0	0	0	0
67	Interest on Debt to Associated Companies (430)	340	0	0	0	0
68	Other Interest Expense (431)	340	34,611	41,556	4,339	3,959
69	(Less) Allowance for Borrowed Funds Used During Construction-Credit (432)		326,325	785,857	135,484	159,663
70	Net Interest Charges (Total of lines 62 thru 69)		42,543,236	44,115,370	12,568,210	14,800,807
71	Income Before Extraordinary Items (Total of lines 27,60 and 70)		80,560,559	86,774,991	9,832,963	14,713,700
72	**EXTRAORDINARY ITEMS**					
73	Extraordinary Income (434)		0	0	0	0
74	(Less) Extraordinary Deductions (435)		0	0	0	0
75	Net Extraordinary Items (Total of line 73 less line 74)		0	0	0	0
76	Income Taxes-Federal and Other (409.3)	262-263	0	0	0	0
77	Extraordinary Items after Taxes (Total of line 75 less line 76)		0	0	0	0
78	Net Income (Total of lines 71 and 77)		80,560,559	86,774,991	9,832,963	14,713,700

Statement of Income

Line No.	Elec. Utility Current Year to Date (in dollars) (g)	Elec. Utility Previous Year to Date (in dollars) (h)	Gas Utility Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
1						
2	0	0	431,176,746	426,138,166	0	0
3						
4	0	0	134,469,282	115,850,995	0	0
5	0	0	30,365,291	33,773,111	0	0
6	0	0	42,641,891	39,769,158	0	0
7	0	0	0	0	0	0
8	0	0	5,228,421	4,902,428	0	0
9	0	0	0	0	0	0
10	0	0	0	0	0	0
11	0	0	0	0	0	0
12	0	0	7,077,274	7,045,362	0	0
13	0	0	0	0	0	0
14	0	0	38,303,749	39,519,326	0	0
15	0	0	6,572,189	17,233,090	0	0
16	0	0	3,171,236	7,277,369	0	0
17	0	0	62,261,392	44,895,308	0	0
18	0	0	20,104,169	13,294,874	0	0
19	0	0	0	0	0	0
20	0	0	0	0	0	0
21	0	0	0	0	0	0
22	0	0	0	0	0	0
23	0	0	0	0	0	0
24	0	0	0	0	0	0
25	0	0	309,986,556	296,971,273	0	0
26	0	0	121,190,190	129,166,893	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q3

Statement of Accumulated Comprehensive Income and Hedging Activities

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

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

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q3

Statement of Accumulated Comprehensive Income and Hedging Activities(continued)

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges (Insert Category) (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 116, Line 78) (i)	Total Comprehensive Income (j)
1		(8,013,921)	(8,013,921)	[redacted]	[redacted]
2		1,077,748	1,077,748	[redacted]	[redacted]
3		(24,223,059)	(24,223,059)	[redacted]	[redacted]
4		(23,145,311)	(23,145,311)	86,774,991	63,629,680
5		(31,159,232)	(31,159,232)	[redacted]	[redacted]
6		(742,993)	(742,993)	[redacted]	[redacted]
7		(78,246)	(78,246)	[redacted]	[redacted]
8		(105,595)	(105,595)	[redacted]	[redacted]
9		(183,841)	(183,841)	80,560,559	80,376,718
10		(926,834)	(926,834)	[redacted]	[redacted]

Schedule Page: 117 Line No.: 5 Column: g

The ($31,159,232) pertains to natural gas commodity swaps.

Fair Value Hedges

The Respondent has entered into natural gas commodity swaps accounted for as fair value hedges with the following objectives: 1) hedge the change in fair value of firm fixed-price gas sale and purchase contracts required for operational storage balancing purposes, and 2) hedge the change in fair value of firm fixed-price storage revenue contracts.

For the nine-month period ending September 30, 2010, the Respondent recognized a pre-tax gain of $675,739 in account 483 for gas sales contracts; a pre-tax loss of $419,219 in account 803 for gas purchase contracts and a pre-tax loss of $483,468 in account 489.4 for storage revenue contracts due to fair value hedge ineffectiveness.

As of September 30, 2010, the fair value of the hedged items was $12,656,060 reported in account 174 and ($3,665,584) reported in account 253. The fair value of the hedging instruments was ($9,738,420) reported in account 245. An unrealized loss of $196,951 was reported in account 182.3.

Schedule Page: 117 Line No.: 10 Column: g

The ($926,834) pertains to natural gas commodity swaps.

Fair Value Hedges

The Respondent has entered into natural gas commodity swaps accounted for as fair value hedges with the following objective: hedge the change in fair value of firm fixed-price gas sale and purchase contracts required for operational storage balancing purposes.

As of September 30, 2011, the fair value of the hedged items was ($3,683,244) reported in account 242. The fair value of the hedging instruments was ($716,762) reported in account 245 and $4,753,957 was reported in account 176. Ineffectiveness gains of $353,951 were reported in account 182.3.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q3

Statement of Retained Earnings

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter Year to Date Balance (c)	Previous Quarter Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS			
1	Balance-Beginning of Period		232,978,353	103,682,734
2	Changes (Identify by prescribed retained earnings accounts)			
3	Adjustments to Retained Earnings (Account 439)			
4	TOTAL Credits to Retained Earnings (Account 439) (footnote details)			
5	TOTAL Debits to Retained Earnings (Account 439) (footnote details)			
6	Balance Transferred from Income (Acct 433 less Acct 418.1)		80,560,559	86,774,991
7	Appropriations of Retained Earnings (Account 436)			
8	TOTAL Appropriations of Retained Earnings (Account 436) (footnote details)			
9	Dividends Declared-Preferred Stock (Account 437)			
10	TOTAL Dividends Declared-Preferred Stock (Account 437) (footnote details)			
11	Dividends Declared-Common Stock (Account 438)			
12	TOTAL Dividends Declared-Common Stock (Account 438) (footnote details)	131	69,000,000	
13	Transfers from Account 216.1, Unappropriated Undistributed Subsidiary Earnings			
14	Balance-End of Period (Total of lines 1, 4, 5, 6, 8, 10, 12, and 13)		244,538,912	190,457,725
15	APPROPRIATED RETAINED EARNINGS (Account 215)			
16	TOTAL Appropriated Retained Earnings (Account 215) (footnote details)			
17	APPROPRIATED RETAINED EARNINGS-AMORTIZATION RESERVE, FEDERAL (Account			
18	TOTAL Appropriated Retained Earnings-Amortization Reserve, Federal (Account			
19	TOTAL Appropriated Retained Earnings (Accounts 215, 215.1) (Total of lines			
20	TOTAL Retained Earnings (Accounts 215, 215.1, 216) (Total of lines 14 and 1		244,538,912	190,457,725
21	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account 216.1)			
	Report only on an Annual Basis no Quarterly			
22	Balance-Beginning of Year (Debit or Credit)			
23	Equity in Earnings for Year (Credit) (Account 418.1)			
24	(Less) Dividends Received (Debit)			
25	Other Changes (Explain)			
26	Balance-End of Year			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q3

Statement of Cash Flows

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

Line No.	Description (See Instructions for explanation of codes) (a)	Current Year to Date Quarter/Year	Previous Year to Date Quarter/Year
1	Net Cash Flow from Operating Activities		
2	Net Income (Line 78(c) on page 116)	80,560,559	86,774,991
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	47,870,312	44,671,586
5	Amortization of (Specify) (footnote details)	17,253,452	15,707,884
6	Deferred Income Taxes (Net)	64,213,180	50,645,801
7	Investment Tax Credit Adjustments (Net)		
8	Net (Increase) Decrease in Receivables	35,026,875	57,247,251
9	Net (Increase) Decrease in Inventory	(438,248)	(384,058)
10	Net (Increase) Decrease in Allowances Inventory		
11	Net Increase (Decrease) in Payables and Accrued Expenses	(8,677,256)	(14,022,424)
12	Net (Increase) Decrease in Other Regulatory Assets	(11,890,214)	(31,278,984)
13	Net Increase (Decrease) in Other Regulatory Liabilities	(1,003,578)	3,072,788
14	(Less) Allowance for Other Funds Used During Construction	795,515	1,692,539
15	(Less) Undistributed Earnings from Subsidiary Companies		
16	Other (footnote details):	2,730,608	24,278,093
17	Net Cash Provided by (Used in) Operating Activities		
18	(Total of Lines 2 thru 16)	224,850,175	235,020,389
19			
20	Cash Flows from Investment Activities:		
21	Construction and Acquisition of Plant (including land):		
22	Gross Additions to Utility Plant (less nuclear fuel)	(58,988,867)	(89,401,967)
23	Gross Additions to Nuclear Fuel		
24	Gross Additions to Common Utility Plant		
25	Gross Additions to Nonutility Plant		
26	(Less) Allowance for Other Funds Used During Construction	(795,515)	(1,692,539)
27	Other (footnote details):	(7,573,848)	(4,876,468)
28	Cash Outflows for Plant (Total of lines 22 thru 27)	(65,767,200)	(92,585,896)
29			
30	Acquisition of Other Noncurrent Assets (d)		
31	Proceeds from Disposal of Noncurrent Assets (d)	4,500,000	
32			
33	Investments in and Advances to Assoc. and Subsidiary Companies		
34	Contributions and Advances from Assoc. and Subsidiary Companies		
35	Disposition of Investments in (and Advances to)		
36	Associated and Subsidiary Companies		
37			
38	Purchase of Investment Securities (a)		
39	Proceeds from Sales of Investment Securities (a)		

Statement of Cash Flows (continued)

Line No.	Description (See Instructions for explanation of codes) (a)	Current Year to Date Quarter/Year	Previous Year to Date Quarter/Year
40	Loans Made or Purchased		
41	Collections on Loans		
42			
43	Net (Increase) Decrease in Receivables		
44	Net (Increase) Decrease in Inventory		
45	Net (Increase) Decrease in Allowances Held for Speculation		
46	Net Increase (Decrease) in Payables and Accrued Expenses		
47	Other (footnote details):		
48	Net Cash Provided by (Used in) Investing Activities		
49	(Total of lines 28 thru 47)	(61,267,200)	(92,585,896)
50			
51	Cash Flows from Financing Activities:		
52	Proceeds from Issuance of:		
53	Long-Term Debt (b)	199,956,000	
54	Preferred Stock		
55	Common Stock		
56	Other (footnote details):		
57	Net Increase in Short-term Debt (c)		
58	Other: Note (payment to) proceeds from MEHC	(80,000,000)	(95,000,000)
59	Cash Provided by Outside Sources (Total of lines 53 thru 58)	119,956,000	(95,000,000)
60			
61	Payments for Retirement of:		
62	Long-Term Debt (b)	(250,000,000)	
63	Preferred Stock		
64	Common Stock		
65	Other (footnote details): Debt issuance costs	(2,051,749)	
66	Net Decrease in Short-Term Debt (c)		
67			
68	Dividends on Preferred Stock		
69	Dividends on Common Stock	(69,000,000)	
70	Net Cash Provided by (Used in) Financing Activities		
71	(Total of lines 59 thru 69)	(201,095,749)	(95,000,000)
72			
73	Net Increase (Decrease) in Cash and Cash Equivalents		
74	(Total of line 18, 49 and 71)	(37,512,774)	47,434,493
75			
76	Cash and Cash Equivalents at Beginning of Period	70,639,086	9,127,574
77			
78	Cash and Cash Equivalents at End of Period	33,126,312	56,562,067

FOOTNOTE DATA

Schedule Page: 120 Line No.: 5 Column: b

	2011	2010
Regulatory assets	$ 16,575,446	$ 15,060,713
Debt discount and expense	678,006	647,171
Total	$ 17,253,452	$ 15,707,884

Schedule Page: 120 Line No.: 16 Column: b

	2011	2010
Gas balancing activities	$ 2,301,610	$ 28,969,662
Price risk management activities	(74,890)	8,430,113
Gain on the sale of assets	(1,214,731)	(1,149,376)
Post retirement benefits other than pension obligation payments	(33,725)	(751,196)
Prepayments and other assets	1,752,342	(2,010,984)
Customer security deposits and other deferred credits	-	(9,210,126)
Total	$ 2,730,606	$ 24,278,093

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	2011	2010
Removal costs, net	$ (1,683,613)	$ (5,738,836)
Net increase(decrease) in payables and accrued expenses	(5,890,235)	862,368
Total	$ (7,573,848)	$ (4,876,468)

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	2011	2010
Proceeds from MidAmerican Energy Holdings Company for redemption of promissory notes	$ -	$ 65,000,000
Loans to MidAmerican Energy Holdings Company in exchange for promissory notes	(80,000,000)	(160,000,000)
Total	$ (80,000,000)	$ (95,000,000)

Notes to Financial Statements

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

(1) General

Northern Natural Gas Company (the “Respondent”) is an indirect wholly-owned subsidiary of MidAmerican Energy Holdings Company (“MEHC”). MEHC is a consolidated subsidiary of Berkshire Hathaway Inc. (“Berkshire Hathaway”). The Respondent owns the largest interstate natural gas pipeline system in the United States, which reaches from southern Texas to Michigan’s Upper Peninsula (the “System”). The System, which is interconnected with many interstate and intrastate pipelines in the national grid system, consists of two distinct, but operationally integrated, markets. Its traditional end-use and distribution market area, referred to as the Market Area, includes points in Iowa, Nebraska, Minnesota, Wisconsin, South Dakota, Michigan and Illinois. Its natural gas supply and delivery service area, referred to as the Field Area, includes Kansas, Texas, Oklahoma and New Mexico. The Respondent primarily transports and stores natural gas for utilities, municipalities, other pipeline companies, gas marketing companies, industrial and commercial users and other end-users. The System consists of 15,000 miles of natural gas pipelines, including 6,400 miles of mainline transmission pipelines and 8,600 miles of branch and lateral pipelines, with a Market Area design capacity of 5.5 billion cubic feet (“bcf”) per day and a Field Area delivery capacity of 2.0 bcf per day to the Market Area. Additionally, the Respondent has three underground natural gas storage facilities and two liquefied natural gas storage peaking units that have a total firm service and operational storage cycle capacity of 73 bcf and over 2.0 bcf of peak day delivery capability. Based on a review of relevant 2010 industry data, the System is the largest single pipeline in the United States as measured by pipeline miles.

The financial statements and supporting schedules were prepared in accordance with the Uniform System of Accounts as prescribed by the Federal Energy Regulatory Commission (“FERC”). The FERC-approved tariff establishes rates, terms and conditions under which the Respondent provides services to its customers. The Uniform System of Accounts is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America (“GAAP”). Financial accounting and reporting differences between FERC and GAAP for the Respondent are principally related to account classifications such as but not limited to: revenues collected for future plant retirement costs are classified as a regulatory liability for GAAP and as accumulated provision for depreciation for FERC; and deferred tax assets and liabilities are presented as gross assets and liabilities for FERC purposes, but are netted for GAAP.

The unaudited Financial Statements do not include all of the information and disclosures required for the Respondent’s annual financial statements in its 2010 FERC Form No. 2. Management believes the unaudited Financial Statements contain all adjustments (consisting only of normal recurring adjustments) considered necessary for the fair presentation of the Financial Statements as of September 30, 2011 and for the nine-month periods ended September 30, 2011 and 2010. The results of operations for the nine-month period ended September 30, 2011 are not necessarily indicative of the results to be expected for the full year. The Respondent has evaluated subsequent events through November 29, 2011, which is the date the unaudited Financial Statements were available to be issued.

The preparation of the unaudited Financial Statements in conformity with FERC guidelines requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the Financial Statements and the reported amounts of revenues and expenses during the period. Actual results may differ from the estimates used in preparing the unaudited Financial Statements. Note 2 of Notes to Financial Statements included in the Respondent’s FERC Form No. 2 for the year ended December 31, 2010 describes the most significant accounting policies used in the preparation of the Financial Statements. There have been no significant changes in the Respondent’s assumptions regarding significant accounting estimates and policies during the nine-month period ended September 30, 2011.

(2) New Accounting Pronouncements

In June 2011, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) No. 2011 05, which amends FASB Accounting Standards Codification (“ASC”) Topic 220, “Comprehensive Income.” ASU No. 2011-05 provides an entity with the option to present the total of comprehensive income, the components of net income and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. Regardless of the option chosen, this guidance also requires presentation of items on the face of the financial statements that are reclassified from other comprehensive income to net income. This guidance does not change the items that must be reported in other comprehensive income, when an item of other comprehensive income must be reclassified to net income or how tax effects of each item of other comprehensive income are presented. This guidance is effective for reporting periods ending after December 15, 2012. The Respondent is currently evaluating which presentation option will be implemented.

In May 2011, the FASB issued ASU No. 2011-04, which amends FASB ASC Topic 820, “Fair Value Measurements and Disclosures.” The amendments in this guidance are not intended to result in a change in current accounting. ASU No. 2011 04 requires additional disclosures relating to fair value measurements categorized within Level 3 of the fair value hierarchy, including quantitative information about unobservable inputs, the valuation process used by the entity and the sensitivity of unobservable input measurements. Additionally, entities are required to disclose the level of the fair value hierarchy for assets and liabilities that are not measured at fair value in the balance sheet, but for which disclosure of the fair value is required. This guidance is effective for reporting periods beginning after December 15, 2011. The Respondent is currently evaluating the impact of adopting this guidance on its disclosures included within Notes to Financial Statements.

In January 2010, the FASB issued ASU No. 2010-06, which amends FASB ASC Topic 820, “Fair Value Measurements and Disclosures.” ASU No. 2010-06 requires disclosure of (a) the amount of significant transfers into and out of Levels 1 and 2 of the fair value hierarchy and the reasons for those transfers and (b) gross presentation of purchases, sales, issuances and settlements in the Level 3 fair value measurement rollforward. This guidance clarifies that existing fair value measurement disclosures should be presented for each class of assets and liabilities. The existing disclosures about the valuation techniques and inputs used to measure fair value for both recurring and nonrecurring fair value measurements have also been clarified to ensure such disclosures are presented for the Levels 2 and 3 fair value measurements. The Respondent adopted this guidance as of January 1, 2010 with the exception of the disclosure requirement to present purchases, sales, issuances and settlements gross in the Level 3 fair value measurement rollforward, which the Respondent adopted as of January 1, 2011. The adoption of this guidance did not have a material impact on the Respondent’s disclosures included within Notes to Financial Statements.

(3) Fair Value Measurements

The Respondent has various financial assets and liabilities that are measured at fair value on the Financial Statements using inputs from the three levels of the fair value hierarchy. A financial asset or liability classification within the hierarchy is determined based on the lowest level input that is significant to the fair value measurement. The three levels are as follows:

- Level 1 – Inputs are unadjusted quoted prices in active markets for identical assets or liabilities that the Respondent has the ability to access at the measurement date.
- Level 2 – Inputs include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means (market corroborated inputs).
- Level 3 – Unobservable inputs reflect the Respondent’s judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. The Respondent develops these inputs based on the best information available, including its own data.

The following table presents the Respondent’s assets and liabilities recognized on the Balance Sheets and measured at fair value on a recurring basis (in thousands):

	Input Levels for Fair Value Measurements				
	Level 1	Level 2	Level 3	Other(1)	Total
As of September 30, 2011					
Assets:					
Commodity derivatives	$ -	$ 9,233	$ -	$ (6,686)	$ 2,547
Money market mutual funds(2)	12,259	-	-	-	12,259
	$ 12,259	$ 9,233	$ -	$ (6,686)	$ 14,806
Liabilities - Commodity derivatives	$ -	$ (60,179)	$ -	$ 6,686	$ (53,493)
As of December 31, 2010					
Assets:					
Commodity derivatives	$ -	$ 6,712	$ -	$ (6,680)	$ 32
Money market mutual funds(2)	82,275	-	-	-	82,275
	$ 82,275	$ 6,712	$ -	$ (6,680)	$ 82,307
Liabilities - Commodity derivatives	$ -	$ (74,038)	$ -	$ 6,680	$ (67,358)

(1) Represents netting under master netting arrangements.

(2) Amounts are included in cash, special deposits and other special funds on the Balance Sheets. The fair value of these money market mutual funds approximates cost.

Derivative contracts are recorded on the Balance Sheets as either assets or liabilities and are stated at fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. When available, the fair value of derivative contracts is estimated using unadjusted quoted prices for identical contracts in the market in which the Respondent transacts. When quoted prices for identical contracts are not available, the Respondent uses forward price curves. Forward price curves represent the Respondent's estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates. The Respondent bases its forward price curves upon market price quotations, when available, or internally developed and commercial models, with internal and external fundamental data inputs. Market price quotations are obtained from independent energy brokers, exchanges, direct communication with market participants and actual transactions executed by the Respondent. Market price quotations for certain major natural gas trading hubs are generally readily obtainable for the applicable term of the Respondent’s outstanding derivative contracts; therefore, the Respondent’s forward price curves for those locations and periods reflect observable market quotes. The estimated fair value of these derivative contracts is a function of underlying forward commodity prices, related volatility, counterparty creditworthiness and duration of contracts. Refer to Note 4 for further discussion regarding the Respondent’s risk management and hedging activities.

The Respondent’s investments in money market mutual funds are accounted for as available-for-sale securities and are stated at fair value. A readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value.

(4) Risk Management and Hedging Activities

The Respondent is exposed to the impact of market fluctuations in natural gas prices as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, customer usage, storage and transportation constraints. The Respondent does not engage in a material amount of proprietary trading activities.

The Respondent has established a risk management process that is designed to identify, assess, monitor, report, manage and mitigate each of the various types of risk involved in its business. To mitigate a portion of its natural gas price risk, the Respondent uses commodity derivative contracts generally at fixed prices to hedge natural gas for operational and preferred deferred delivery (“PDD”) storage, storage losses, fuel requirements and other transactions. The Respondent uses natural gas commodity swaps to hedge the margin on forecasted gas sales and purchases required for operational storage balancing purposes, to hedge the margin on anticipated future PDD storage contracts and to hedge the cost of replacing forecasted storage losses. For certain designated markets, certain customers pay a fixed price of $.09 per decatherm (“dth”) of volumes delivered to purchase compressor fuel and system use gas from the Respondent. The Respondent estimates it will be required to purchase an annual average of 2.1 bcf of natural gas through October 2022 to meet these requirements based on an average system requirements factor of 1.7% of volumes delivered. The Respondent’s contracts with these customers provide service through October 2019, with annual renewal options for one customer to continue service through October 2022. As of September 30, 2011, the Respondent had purchased gas and entered into swap agreements covering substantially all of the expected contractual requirements through October 2022.

Interest rate risk exists on future debt issuances. The Respondent manages its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. Additionally, the Respondent may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, to mitigate the Respondent’s exposure to interest rate risk. The Respondent does not hedge all of its commodity price and interest rate risks, thereby exposing the unhedged portion to changes in market prices.

There have been no significant changes in the Respondent’s accounting policies related to derivatives. Refer to Note 3 for additional information on derivative contracts.

The following table, which excludes contracts that qualify for the normal purchases or normal sales exception afforded by GAAP, summarizes the fair value of the Respondent's derivative contracts, on a gross basis, and reconciles those amounts to the amounts presented on a net basis on the Balance Sheets (in thousands):

	Derivative Assets(1)		Derivative Liabilities(1)		
	Current	Noncurrent	Current	Noncurrent	Total
As of September 30, 2011					
Designated as hedging contracts(2)(3):					
Commodity assets	$ 8,281	$ -	$ -	$ 27	$ 8,308
Commodity liabilities	(5,620)	-	(16,941)	(36,290)	(58,851)
Total	2,661	-	(16,941)	(36,263)	(50,543)
Not designated as hedging contracts(2):					
Commodity assets	203	-	722	-	925
Commodity liabilities	(200)	-	(1,127)	-	(1,327)
Total	3	-	(405)	-	(402)
Total derivatives - net basis(4)	$ 2,664	$ -	$ (17,346)	$ (36,263)	$ (50,945)
As of December 31, 2010					
Designated as hedging contracts(2)(3):					
Commodity assets	$ -	$ -	$ 6,656	$ -	$ 6,656
Commodity liabilities	-	-	(24,737)	(45,813)	(70,550)
Total	-	-	(18,081)	(45,813)	(63,894)
Not designated as hedging contracts(2):					
Commodity assets	50	-	6	-	56
Commodity liabilities	(2)	-	(3,486)	-	(3,488)
Total	48	-	(3,480)	-	(3,432)
Total derivatives - net basis(4)	$ 48	$ -	$ (21,561)	$ (45,813)	$ (67,326)

(1) Derivative assets are included in other current and accrued assets on the Balance Sheets. Derivative liabilities are included in current and accrued liabilities on the Balance Sheets.

(2) Derivative contracts within these categories subject to master netting arrangements are presented on a net basis on the Balance Sheets.

(3) As of September 30, 2011 and December 31, 2010, a regulatory asset of $48.7 million and $50.1 million, respectively, was recorded for those commodity derivatives generally included in regulated rates.

(4) The net notional amounts of outstanding commodity derivative contracts with fixed price terms that comprise the mark-to-market values included above is 20 million dth and 27 million dth of natural gas purchases as of September 30, 2011 and December 31, 2010, respectively.

Designated as Hedging Contracts

The following table reconciles the beginning and ending balances of the Respondent's accumulated other comprehensive loss (pre-tax) and summarizes pre-tax gains and losses on commodity derivative contracts designated and qualifying as cash flow hedges recognized in other comprehensive income ("OCI"), as well as amounts reclassified to earnings for the nine-month periods ended September 30 (in thousands):

	2011	2010

Beginning balance(1)	$ 2,475	$ 17,926
Changes in fair value recognized in OCI	(1,320)	43,263
Net gains reclassified to gas operating revenues	1,631	2,146
Net losses reclassified to operating expenses	(1,501)	(3,866)
Ending balance(1)	$ 1,285	$ 59,469

(1) Certain derivative contracts have settled and the fair value at the date of settlement remains in accumulated other comprehensive loss and is recognized in earnings when the forecasted transactions impact earnings.

Realized gains and losses on hedges and hedge ineffectiveness are recognized on the Statements of Income as gas operating revenues or operating expenses depending upon the nature of the item being hedged. For the nine-month periods ended September 30, 2011 and 2010, hedge ineffectiveness was insignificant. As of September 30, 2011, the Respondent had cash flow hedges with expiration dates extending through June 2012 and $1.5 million of pre-tax net unrealized losses are forecasted to be reclassified from accumulated other comprehensive loss into earnings over the next twelve months as contracts settle.

Not Designated as Hedging Contracts

For the Respondent's commodity derivatives not designated as hedging contracts, the settled amount is generally included in regulated rates. Accordingly, the net unrealized gains and losses associated with interim price movements on contracts that are accounted for as derivatives and probable of inclusion in regulated rates are recorded as regulatory assets or liabilities. The following table reconciles the beginning and ending balances of the Respondent's regulatory assets and summarizes the pre-tax gains and losses on commodity derivative contracts recognized in regulatory assets, as well as amounts reclassified to earnings for the nine-month periods ended September 30 (in thousands):

	2011	2010
Beginning balance	$ 50,124	$ -
Changes in fair value recognized in regulatory assets	4,807	-
Net losses reclassified to gas operating revenues	(2,004)	-
Net losses reclassified to operating expenses	(4,271)	-
Ending balance	$ 48,656	$ -

For the Respondent's commodity derivatives not designated as hedging contracts and for which changes in fair value are not recorded as a regulatory asset, unrealized gains and losses are recognized on the Statements of Income as gas operating revenues for sales contracts and as operating expenses for purchase contracts. The Respondent recognized pre-tax losses of $0.2 million and $4.7 million for the nine-month periods ended September 30, 2011 and 2010, respectively, which are included in operating expenses on the Statements of Income.

Credit Risk

The Respondent extends unsecured credit to energy marketing companies, financial institutions and other market participants in conjunction with its derivative contracts. Credit risk relates to the risk of loss that might occur as a result of nonperformance by counterparties on their contractual obligations to make or take delivery of natural gas and to make financial settlements of these obligations. Credit risk may be concentrated to the extent that one or more groups of counterparties have similar economic, industry or other characteristics that would cause their ability to meet contractual obligations to be similarly affected by changes in market or other conditions. In addition, credit risk includes not only the risk that a counterparty may default due to circumstances relating directly to it, but also the risk that a counterparty may default due to circumstances involving other market participants that have a direct or indirect relationship with the counterparty.

The Respondent analyzes the financial condition of each counterparty before entering into any transactions, establishes limits on the amount of unsecured credit to be extended to each counterparty and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To mitigate exposure to the financial risks of counterparties, the Respondent enters into netting arrangements that may include margining and cross-product netting agreements and obtains third-party guarantees, letters of credit and cash deposits. Counterparties may be assessed interest fees for delayed payments. If required, the Respondent exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

Collateral and Contingent Features

In accordance with industry practice, certain derivative contracts contain provisions that require the Respondent to maintain specific credit ratings from one or more of the major credit rating agencies on its unsecured debt. These derivative contracts may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features"). These rights can vary by contract and by counterparty. As of September 30, 2011, the Respondent's credit ratings from the three recognized credit rating agencies were investment grade.

The aggregate fair value of the Respondent's derivative contracts in liability positions with specific credit-risk-related contingent features totaled $60.2 million and $74.0 million as of September 30, 2011 and December 31, 2010, respectively, for which the Respondent had not posted collateral. If all credit-risk-related contingent features for derivative contracts in liability positions had been triggered as of September 30, 2011 and December 31, 2010, the Respondent would have been required to post $53.5 million and $67.4 million, respectively, of collateral. The Respondent's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation, or other factors.

(5) Employee Benefit Plans

The Respondent participates in pension and other postretirement benefit plans sponsored by MidAmerican Energy Company ("MEC"), an indirect wholly-owned subsidiary of MEHC. The Respondent's contributions to the various plans were $0.8 million and $1.9 million for the nine-month periods ended September 30, 2011 and 2010, respectively. The Respondent recorded a regulatory asset of $2.9 million and a regulatory liability of $16.7 million as of September 30, 2011 and a regulatory asset of $2.6 million and a regulatory liability of $16.1 million as of December 31, 2010, related to the amounts not yet recognized as a component of net periodic benefit costs that will be included in regulated rates. An offsetting affiliated company payable and receivable are included in other deferred credits and other property and investments, respectively, on the Balance Sheets. Amounts were allocated from MEC to the Respondent in accordance with the intercompany administrative service agreement.

(6) Commitments and Contingencies

Legal Matters

The Respondent is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. The Respondent does not believe that such normal and routine litigation will have a material impact on its financial results. The Respondent is also involved in other kinds of legal actions, some of which assert or may assert claims or seek to impose fines, penalties and other costs in substantial amounts and are described below.

The Respondent's storage gas has migrated from its certificated storage field boundaries near Cunningham, Kansas and has been produced on leaseholds held by Nash Oil & Gas, Inc. ("Nash"), L.D. Drilling Company ("LD Drilling") and Val Energy, Inc. ("Val Energy"). In order to mitigate its losses, the Respondent has initiated the following actions:

- In September 2009, the Respondent filed an application with the FERC to extend the boundaries of the Cunningham natural gas storage facility by 14,240 acres. In June 2010, FERC issued an order granting the Respondent Certificate Authority to extend the boundaries of the Cunningham natural gas storage facility by 12,320 acres. The Respondent extended good faith offers to the interested parties in the extension area, and in July 2010, filed a complaint in District Court to acquire the necessary interests by eminent domain. The Respondent has either acquired leases or purchased the property on approximately 3,580 acres, or 29%, of the extension area. In June 2011, the Respondent filed a motion for preliminary injunction seeking access to the extension area to construct the facilities necessary to implement its containment plan to control the migrating storage gas. A hearing on the access motion was held in October 2011 and a decision is expected by December 31, 2011.

- The Respondent filed a lawsuit in December 2008 against Nash, LD Drilling and Val Energy in the United States District Court for the District of Kansas ("District Court") for conversion, nuisance and unjust enrichment. Shortly after the FERC order granting the Respondent authority to expand the boundaries of the Cunningham natural gas storage facility was issued in June 2010, the Respondent filed a motion to shut-in the production of the third-party wells producing the Respondent's storage gas. In December 2010, the District Court granted the Respondent's motion and ordered all of the wells in the extension area to be shut-in, which was completed in February 2011. The defendants appealed the injunction order to the Tenth Circuit Court of Appeals and requested a stay. Oral argument on the appeal was held in November 2011 and a decision is pending.

- In December 2009, the Respondent filed a lawsuit in the 13th Judicial District, District Court, Pratt County, Kansas ("Pratt County State District Court") against ONEOK Field Services Company and Lumen Energy Corporation alleging conversion based on their purchase of the storage gas from the producers. In April 2010, the Pratt County State District Court granted the defendants' motion for summary judgment, finding that the Respondent does not have title to storage gas that has migrated beyond adjoining property. The Respondent appealed the decision to the Kansas Court of Appeals in April 2010, and the appeal was transferred to the Kansas Supreme Court at the Respondent's request. Oral argument was held in March 2011. A decision on the merits is expected in 2011.

The Respondent has recorded Cunningham storage gas losses of 13.7 bcf since 2004. The replacement cost of storage gas losses is $5.0 million and $9.8 million for the nine-month periods ended September 30, 2011 and 2010, respectively, which are included in operating expenses on the Statements of Income.

While it is not possible to predict with certainty the outcome of the aforementioned litigation and other contingencies, the Respondent believes that the ultimate resolution of these matters will not have a material adverse effect on the Respondent's financial results.

(7) Recent Debt Transactions

In April 2011, the Respondent issued $200.0 million of 4.25% Senior Notes due June 1, 2021. The net proceeds were used to partially repay the Respondent's $250.0 million, 7.0% Senior Notes due June 1, 2011.

(8) Asset Retirement Obligations

In May 2011, the United States Army Corps of Engineers Galveston District ("Galveston District") sent a letter to the Respondent in response to the Respondent's request to abandon in place certain pipelines located in offshore Texas waters. The Galveston District has determined that one of the pipelines, which is located in San Antonio Bay, must be removed. The remaining pipelines, as identified in the Respondent's request, will be allowed to be abandoned in place pending approval of modifications to the existing permits for those pipelines. As a result, the Respondent's asset retirement obligation decreased $12.0 million primarily due to the changes in its assumptions regarding the removal of its offshore Texas facilities. Refer to Notes 2 and 8 of the Notes to the FERC Form No. 2 for the year ended December 31, 2010 for additional information on asset retirement obligations.

(9) Other Related Party Transactions

The Respondent provided gas transportation, storage and other services to MEC totaling $40.9 million and $41.1 million for the nine-month periods ended September 30, 2011 and 2010, respectively. MEC provides certain administrative and management services, including executive, financial, legal, human resources, payroll and tax, to the Respondent. Expenses incurred by MEC and billed to the Respondent are based on the individual services and expense items provided and were $5.1 million and $5.7 million for the nine-month periods ended September 30, 2011 and 2010, respectively. MEC also provided electricity and other services to the Respondent of $0.3 million and $0.7 million for the nine-month periods ended September 30, 2011 and 2010, respectively. The Respondent reimbursed MEC $39.8 million and $31.7 million for the nine-month periods ended September 30, 2011 and 2010, respectively, for payroll, healthcare benefits and other benefit payments that MEC processed on behalf of the Respondent.

MEHC provides certain administrative and management services, including executive, financial, legal and tax, to the Respondent. Expenses incurred by MEHC and billed to the Respondent are based on the individual services and expense items provided and were $1.4 million and $2.5 million for the nine-month periods ended September 30, 2011 and 2010, respectively. Income tax transactions with MEHC resulted in receipts of $1.8 million and net payments of $33.5 million for the nine-month periods ended September 30, 2011 and 2010, respectively.

The Respondent provides operating, administrative and management services, including executive, financial, regulatory and legal, to MEHC and certain subsidiaries. Expenses incurred by the Respondent and billed to MEHC are based on the individual services and expense items provided. Intercompany expenses were $0.3 million and $0.4 million for the nine-month periods ended September 30, 2011 and 2010, respectively. As of September 30, 2011 and December 31, 2010, the Respondent had net accounts payable to MEHC and certain subsidiaries for intercompany transactions totaling $0.8 million and $1.1 million, respectively.

The Respondent provides certain administrative and management services, including executive, financial, regulatory and legal, to Kern River Gas Transmission Company ("Kern River"), an indirect wholly-owned subsidiary of MEHC. The Respondent billed Kern River $0.8 million and $0.5 million for the nine-month periods ended September 30, 2011 and 2010, respectively, for these services.

The Respondent provides risk management services to Kern River, pursuant to a service agreement dated August 1, 2008. The Respondent relinquishes all risks, liabilities, losses and profits associated with these risk management services. For the nine-month periods ended September 30, 2011 and 2010, the Respondent entered into specific risk management transactions that settled on behalf of Kern River totaling $0.5 million and $1.9 million, respectively. As of September 30, 2011 and December 31, 2010, the Respondent recorded on the Balance Sheets a derivative asset and derivative liability of $- million and $0.1 million, respectively. The derivative asset is included in other current and accrued assets. As of September 30, 2011 and December 31, 2010, the Respondent had an insignificant net receivable from Kern River.

For the nine-month periods ended September 30, 2011 and 2010, the Respondent received demand promissory notes bearing interest at a 30-day LIBOR plus a fixed per annum rate from MEHC in exchange for cash of $80.0 million and $160.0 million, respectively. The Respondent received $- million and $65.0 million from MEHC in exchange for demand promissory notes for the nine-month periods ended September 30, 2011 and 2010, respectively. The balance of the demand promissory notes as of September 30, 2011 and December 31, 2010 was $230.0 million and $150.0 million, respectively. Interest income of $1.1 million and $2.9 million was recorded for the nine-month periods ended September 30, 2011 and 2010, respectively.

The Respondent distributed dividends on common stock of $69.0 million and $- million through its parent company to MEHC for the nine-month periods ended September 30, 2011 and 2010, respectively.

(10) Components of Accumulated Other Comprehensive Income

Accumulated other comprehensive income consists of losses from changes in fair value on cash flow hedges of $0.9 million, net of tax of $0.6 million, and $0.7 million, net of tax of $0.5 million, as of September 30, 2011 and December 31, 2010, respectively.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q3

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

Line No.	Item (a)	Total Company For the Current Quarter/Year
1	UTILITY PLANT	
2	In Service	
3	Plant in Service (Classified)	3,346,266,505
4	Property Under Capital Leases	
5	Plant Purchased or Sold	
6	Completed Construction not Classified	21,703,195
7	Experimental Plant Unclassified	
8	TOTAL Utility Plant (Total of lines 3 thru 7)	3,367,969,700
9	Leased to Others	
10	Held for Future Use	585,866
11	Construction Work in Progress	25,265,642
12	Acquisition Adjustments	
13	TOTAL Utility Plant (Total of lines 8 thru 12)	3,393,821,208
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	1,256,612,777
15	Net Utility Plant (Total of lines 13 and 14)	2,137,208,431
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION	
17	In Service:	
18	Depreciation	1,119,618,076
19	Amortization and Depletion of Producing Natural Gas Land and Land Rights	
20	Amortization of Underground Storage Land and Land Rights	6,528,989
21	Amortization of Other Utility Plant	130,362,531
22	TOTAL In Service (Total of lines 18 thru 21)	1,256,509,596
23	Leased to Others	
24	Depreciation	
25	Amortization and Depletion	
26	TOTAL Leased to Others (Total of lines 24 and 25)	
27	Held for Future Use	
28	Depreciation	103,181
29	Amortization	
30	TOTAL Held for Future Use (Total of lines 28 and 29)	103,181
31	Abandonment of Leases (Natural Gas)	
32	Amortization of Plant Acquisition Adjustment	
33	TOTAL Accum. Provisions (Should agree with line 14 above)(Total of lines 22, 26, 30, 31, and 32)	1,256,612,777

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

Line No.	Electric (c)	Gas (d)	Other (specify) (e)	Common (f)
1				
2				
3		3,346,266,505		
4				
5				
6		21,703,195		
7				
8		3,367,969,700		
9				
10		585,866		
11		25,265,642		
12				
13		3,393,821,208		
14		1,256,612,777		
15		2,137,208,431		
16				
17				
18		1,119,618,076		
19				
20		6,528,989		
21		130,362,531		
22		1,256,509,596		
23				
24				
25				
26				
27				
28		103,181		
29				
30		103,181		
31				
32				
33		1,256,612,777		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q3

Gas Plant in Service and Accumulated Provision for Depreciation by Function

1. Report below the original cost of plant in service by function. In addition to Account 101, include Account 102, and Account 106. Report in column (b) the original cost of plant in service and in column(c) the accumulated provision for depreciation and amortization by function.

Line No.	Item (a)	Plant in Service Balance at End of Quarter (b)	Accumulated Depreciation And Amortization Balance at End of Quarter (c)
1	Intangible Plant	178,100,707	110,477,001
2	Productions-Manufactured Gas		
3	Production and Gathering-Natural Gas	21,094,575	(17,533,199)
4	Products Extraction-Natural Gas		
5	Underground Gas Storage	363,589,953	139,888,451
6	Other Storage Plant	80,246,276	45,693,049
7	Base Load LNG Terminaling and Processing Plant		
8	Transmission	2,598,781,893	908,542,589
9	Distribution		
10	General	126,156,296	69,441,705
11	TOTAL (total of lines 1 thru 10)	3,367,969,700	1,256,509,596

Schedule Page: 210 Line No.: 3 Column: c

The accumulated depreciation reserve for production and gathering is related to Respondent's offshore pipeline facilities located in the Gulf of Mexico off the coasts of Texas and Louisiana. The balance is made up of the following components.

Plant Reserve	
Accumulated Depreciation	$ 32,463,071
Cost of Plant Retired	(29,773,632)
Accumulated Plant Reserve	$ 2,689,439
Negative Salvage	
Accumulated Provision	$ 1,453,584
Cost of Removal	(603,629)
Net Negative Salvage Provision	$ 849,955
Asset Retirement Obligation	
Accumulated Depreciation on ARO Capitalized	$ 891,650
Asset Retirement Obligation (ARO) Allowance	
Accumulated ARO Allowance (Annual Amount of $1,320,306 through March 31, 2011 and $4,325,087 beginning April 1, 2011)	$ 10,634,508
Accumulated Cost of ARO Retirements	(32,598,751)
Unrecovered Net ARO Costs	($ 21,964,243)
Accumulated Provision for Depreciation Gas Gathering	($ 17,533,199)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q3

Other Regulatory Assets (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning Current Quarter/Year (b)	Debits (c)	Written off During Quarter/Year Account Charged (d)	Written off During Period Amount Recovered (e)	Written off During Period Amount Deemed Unrecoverable (f)	Balance at End of Current Quarter/Year (g)
1	Computer systems development costs	1,456,196		407.3	1,092,147		364,049
2							
3	Deferred regulatory commission expense	4,423,478	151,636	928	297,104		4,278,010
4							
5	FAS 106 implementation deferral	1,539,861		926	256,643		1,283,218
6							
7	Asset retirement obligation	9,219,069	2,462,481	230	433,244		11,248,306
8							
9	Deferred FERC annual charge	442,560	1,720,553	928	442,560		1,720,553
10							
11	Deferred taxes associated with AFUDC Equity	14,785,177	217,354	421	63,507		14,939,024
12							
13	Other IMP related costs	1,689,259		407.3	1,266,944		422,315
14							
15	Deferred Migration Costs	2,163,904		921	162,293		2,001,611
16							
17	Deferred System Upgrade Costs	1,801,302		921	135,098		1,666,204
18							
19	Smartpigging/Hydro Testing	23,288,607	7,746,252	833,863	6,817,414		24,217,445
20							
21	Defined benefit pension plan	2,798,629	106,417				2,905,046
22							
23	Unrealized loss on derivatives, net	40,338,590	58,508,111	483,803	50,190,882		48,655,819
24							
25	Firm commitments/Encroachment Revaluation	3,001,676	4,845,709	813	3,719,004		4,128,381
26							
27	Electrical compression	(35,762)	35,762				
28							
29	Tracked fuel/UAF under-retention/PRA/electrical compression	13,965,341	643,463	813,855	5,518,992		9,089,812
30							
31	Interest rate lock	414,832		428	8,397		406,435
32							
33							
34							
35							
36							
37							
38							
39							
40	**Total**	**121,292,719**	**76,437,738**		**70,404,229**	**0**	**127,326,228**

Schedule Page: 232 Line No.: 1 Column: a

Regulatory Authorization

Line No.	Description	Regulatory Citation	Amortization Period
1	Computer systems development costs	RP92-1	Through 10/2011
3	Deferred regulatory commission expense	RP04-155	Over 60 months
5	FAS 106 implementation deferral	RP98-203	170 months through 12/2012
7	Asset retirement obligation	RP04-155	
9	Deferred FERC annual charge	18 CFR Sec 154.402	12 months ending September
11	Deferred income taxes associated with AFUDC equity	RP04-155	Based on life of plant
13	Other IMP related costs	RP92-1	Through 10/2011
15	Deferred Migration Costs	RP04-155	120 months through 11/2014
17	Deferred System Upgrade Costs	RP04-155	120 months through 11/2014
19	Smart Pigging/Hydrostatic Testing	RP04-155	Over 84 months
21	Defined benefit pension plan	AI07-1-000 & Order 710	
23	Unrealized loss on derivatives, net	Orders 552 & 627	
25	Firm commitments / encroachment revaluation	Orders 552 & 627	
27	Electrical compression	RP97-275	
29	Tracked fuel / UAF under-retention / PRA / electrical compression	RP97-275	
31	Interest rate lock (ref. $200M Sr Notes due 6-1-2021)	Not applicable	Through 05/2021

Name of Respondent Northern Natural Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q3

Other Regulatory Liabilities (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	Written off during Quarter/Period Account Credited (c)	Written off During Period Amount Refunded (d)	Written off During Period Amount Deemed Non-Refundable (e)	Credits (f)	Balance at End of Current Quarter/Year (g)
1	Penalty and Deferred Delivery Variance Charge Revenue Crediting Mechanism	429,905				62,802	492,707
2							
3	Interest Rate lock (ref. $100M Sr. Notes due 5-1-2015)	777,804	428	46,257			731,547
4							
5	Employee Benefits	16,530,911	128	120,436		300,704	16,711,179
6							
7							
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44							
45	**Total**	**17,738,620**		**166,693**	**0**	**363,506**	**17,935,433**

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

Regulatory Authorization

Line No.	Description	Regulatory Citation	Amortization Period
1	Penalty and deferred delivery variance charge revenue crediting mechanism	Order 637 A	
3	Interest rate lock (ref. $100M Sr. Notes due 5-1-2015)	Not applicable	Through 04/2015
5	Employee benefits	A107-1-000 & Order 710	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q3

Monthly Quantity & Revenue Data by Rate Schedule

1. Reference to account numbers in the USofA is provided in parentheses beside applicable data. Quantities must not be adjusted for discounts.
2. Total Quantities and Revenues in whole numbers
3. Report revenues and quantities of gas by rate schedule. Where transportation services are bundled with storage services, reflect only transportation Dth. When reporting storage, report Dth of gas withdrawn from storage and revenues by rate schedule.
4. Revenues in Column (c) include transition costs from upstream pipelines. Revenue (Other) in Column (e) includes reservation charges received by the pipeline plus usage charges, less revenues reflected in Columns (c) and (d). Include in Column (e), revenue for Accounts 490-495.
5. Enter footnotes as appropriate.

Line No.	Item (a)	Month 1 Quantity (b)	Month 1 Revenue Costs and Take-or-Pay (c)	Month 1 Revenue (GRI & ACA) (d)	Month 1 Revenue (Other) (e)	Month 1 Revenue (Total) (f)
1	Total Sales (480-488)	2,115,052			8,621,086	8,621,086
2	Transportation of Gas for Others (489.2 and 489..3)					
3	CS-1	1,720,595			27,830	27,830
4	TF	24,856,165		46,578	8,960,932	9,007,510
5	TFX	42,526,624		81,173	14,643,258	14,724,431
6	GS-T					
7	TI	4,712,438		8,685	372,503	381,188
8	SMS	1,406,704			915,448	915,448
9	Less: CS-1 units	-1,720,595				
10	Less: SMS units in other rate schedules	-1,406,704				
11						
12						
13						
14						
15						
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q3

Monthly Quantity & Revenue Data by Rate Schedule (continued)

Line No.	Item (a)	Month 1 Quantity (b)	Month 1 Revenue Costs and Take-or-Pay (c)	Month 1 Revenue (GRI & ACA) (d)	Month 1 Revenue (Other) (e)	Month 1 Revenue (Total) (f)
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63	Total Transportation (Other than Gathering)	72,095,227		136,436	24,919,971	25,056,407
64	Storage (489.4)					
65	FDD-1	231,942			6,842,515	6,842,515
66	IDD-1	1,247,485			302,037	302,037
67	PDD-1	4,511,452			594,925	594,925
68						
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89						
90	Total Storage	5,990,879			7,739,477	7,739,477
91	Gathering (489.1)					
92	Gathering-Firm					
93	Gathering-Interruptible	685,460			23,717	23,717
94	Total Gathering (489.1)	685,460			23,717	23,717
95	Additional Revenues					
96	Products Sales and Extraction (490-492)	72			310	310
97	Rents (493-494)				7,906	7,906
98	Other Gas Revenues (495)				58,595	58,595
99	(Less) Provision for Rate Refunds					
100	Total Additional Revenues	72			66,811	66,811
101	Total Operating Revenues (Total of Lines 1,63,90,94 & 100)	80,886,690		136,436	41,371,062	41,507,498

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q3

Monthly Quantity & Revenue Data by Rate Schedule

1. Reference to account numbers in the USofA is provided in parentheses beside applicable data. Quantities must not be adjusted for discounts.
2. Total Quantities and Revenues in whole numbers
3. Report revenues and quantities of gas by rate schedule. Where transportation services are bundled with storage services, reflect only transportation Dth. When reporting storage, report Dth of gas withdrawn from storage and revenues by rate schedule.
4. Revenues in Column (c) include transition costs from upstream pipelines. Revenue (Other) in Column (e) includes reservation charges received by the pipeline plus usage charges, less revenues reflected in Columns (c) and (d). Include in Column (e), revenue for Accounts 490-495.
5. Enter footnotes as appropriate.

Line No.	Month 2 Quantity (g)	Month 2 Revenue Costs and Take-or-Pay (h)	Month 2 Revenue (GRI & ACA) (i)	Month 2 Revenue (Other) (j)	Month 2 Revenue (Total) (k)	Month 3 Quantity (l)	Month 3 Revenue Costs and Take-or-Pay (m)	Month 3 Revenue (GRI & ACA) (n)	Month 3 Revenue (Other) (o)	Month 3 Revenue (Total) (p)
1	1,110,469			4,824,176	4,824,176	31,110			205,320	205,320
2	[redacted]									
3	1,891,286			30,358	30,358	1,765,374			26,738	26,738
4	25,649,223		49,268	8,996,290	9,045,558	25,528,588		48,362	8,949,341	8,997,703
5	37,887,255		71,596	14,307,393	14,378,989	32,282,609		61,576	14,134,360	14,195,936
6										
7	4,604,712		9,392	333,833	343,225	4,049,709		7,277	309,427	316,704
8	1,583,444			918,972	918,972	1,235,430			911,877	911,877
9	-1,891,286					-1,765,374				
10	-1,583,444					-1,235,430				
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Monthly Quantity & Revenue Data by Rate Schedule (continued)

Line No.	Month 2 Quantity (g)	Month 2 Revenue Costs and Take-or-Pay (h)	Month 2 Revenue (GRI & ACA) (i)	Month 2 Revenue (Other) (j)	Month 2 Revenue (Total) (k)	Month 3 Quantity (l)	Month 3 Revenue Costs and Take-or-Pay (m)	Month 3 Revenue (GRI & ACA) (n)	Month 3 Revenue (Other) (o)	Month 3 Revenue (Total) (p)
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63	68,141,190		130,256	24,586,846	24,717,102	61,860,906		117,215	24,331,743	24,448,958
64	[redacted]									
65	553,971			6,815,084	6,815,084	202,188			6,860,547	6,860,547
66	2,082,893			206,597	206,597	1,092,653			160,174	160,174
67	1,437,529			836,563	836,563	1,318,148			963,487	963,487
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90	4,074,393			7,858,244	7,858,244	2,612,989			7,984,208	7,984,208
91	[redacted]									
92										
93	679,502			23,511	23,511	606,032			20,969	20,969
94	679,502			23,511	23,511	606,032			20,969	20,969
95	[redacted]									
96	792			3,346	3,346	53			208	208
97				7,906	7,906				8,626	8,626
98				129,428	129,428				110,288	110,288
99										
100	792			140,680	140,680	53			119,122	119,122
101	74,006,346		130,256	37,433,457	37,563,713	65,111,090		117,215	32,661,362	32,778,577

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q3

Natural Gas Company- Gas Revenues and Dekatherms

1. Report below in columns (b), (d) and (f) natural gas operating revenues for each prescribed account year to date

2. In column (f) report the quantity of Dekatherms sold of natural gas year to date.

Line No.	Title of Account (a)	Total Operating Revenues Year to Date Current Qtr (b)	Dekatherms of Natural Gas Year to Date Current Qtr (c)
1	(480) Residential Sales		
2	(481) Commercial and Industrial Sales	4,851,755	338,215
3	(482) Other Sales to Public Authorities		
4	(483) Sales for Resale	34,657,749	8,230,354
5	(484) Interdepartmental Sales		
6	Total Sales (Lines 1 to 5)	39,509,504	8,568,569
7	485 Intracompany Transfers		
8	487 Forfeited Discounts		
9	488 Miscellaneous Service Revenues		
10	489.1 Revenues from Transportation of Gas of Others Through Gathering Facilities	216,182	6,430,631
11	489.2 Revenues from Transportation of Gas of Others Through Transmission Facilities	339,896,006	677,901,730
12	489.3 Revenues from Transportation of Gas of Others Through Distribution Facilities		
13	489.4 Revenues from Storing Gas of Others	48,002,782	100,991,870
14	490 Sales of Prod. Ext. from Natural Gas		
15	491 Revenues from Natural Gas Proc. by Others		
16	492 Incidental Gasoline and Oil Sales	225,352	
17	493 Rent from Gas Property	73,074	
18	494 Interdepartmental Rents		
19	495 Other Gas Revenues	3,253,846	
20	Subtotal:	431,176,746	
21	496 (Less) Provision for Rate Refunds		
22	TOTAL	431,176,746	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q3

Gas Production and Other Gas Supply Expenses

Report the amount of gas production and other gas supply expenses year to date

Line No.	Account (a)	Year to Date (b)	
1	Production Expenses		
2	Manufactured Gas Production		
3	Total Manufactured Gas Production (700-742)		
4	Natural Gas Production and Gathering		
5	(750-760) Operation	63,416	
6	(761-769) Maintenance	791	
7	Total Natural Gas Production and Gathering (lines 5 and 6)	64,207	
8	Production Extraction		
9	(770-783) Operation		
10	(784-791) Maintenance		
11	Total Production Extraction (lines 9 and 10)		
12	(795-798) Exploration and Development Expenses		
13	Other Gas Supply Expenses		
14	Operation		
15	(800) Natural Gas Well Head Purchases		
16	(800.1) Natural Gas Well Head Purchases, Intra company Transfers		
17	(801) Natural Gas Field Line Purchases		
18	(802) Natural Gasoline Plant Outlet Purchases		
19	(803) Natural Gas Transmission Line Purchases	46,760,715	
20	(804) Natural Gas City Gate Purchases		
21	(804.1) Liquefied Natural Gas Purchases		
22	(805) Other Gas Purchases	(11,941,074)	
23	(805.1) (Less) Purchase Gas Cost Adjustments		
24	Total Purchased Gas (lines 15 through 23)	34,819,641	
25	(806) Exchange Gas	(3,697,616)	
26	Purchased Gas Expenses		
27	(807.1) Well Expense - Purchased Gas		
28	(807.2) Operation of Purchased Gas Measuring Stations		
29	(807.3) Maintenance of Purchased Gas Measuring Stations		
30	(807.4) Purchased Gas Calculations Expenses		
31	(807.5) Other Purchased Gas Expenses		
32	Total Purchased Gas Expenses (lines 27 thru 31)		
33	(808.1) Gas Withdrawn from Storage-Debit	72,584,878	
34	(808.2) (Less) Gas Delivered to Storage - Credit	64,020,106	
35	(809.1) Withdrawals of Liquefield Natural Gas for Processing - Debit		
36	(809.2) (Less) Deliveries of Natural Gas Processing - Credit		
37	Gas Used in Utility Operation - Credit		
38	(810) Gas Used for Compressor Station Fuel - Credit	29,532,435	
39	(811) Gas Used for Products Extraction - Credit		
40	(812) Gas Used for Other Utility Operations - Credit	13,844,383	
41	Total Gas Used in Utility Operations - Credit (Lines 38 thru 40)	43,376,818	
42	(813) Other Gas Supply Expense	7,884,251	
43	Total Other Gas Supply Expenses (Lines 24, 25, 32, 33, thru 36, 42, less 41)	4,194,230	
44	Total Production Expenses (Lines 3,7,11,12, and 43)	4,258,437	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q3

Natural Gas Storage, Terminaling, Processing Services

Report the amount of natural gas storage, terminaling, processing, transmission and distribution expenses year to date.

Line No.	Account (a)	Year to Date Quarter (b)	
1	NATURAL GAS STORAGE, TERMINALING AND PROCESSING EXPENSES		
2	UNDERGROUND STORAGE EXPENSES		
3	(814-826) Operations	8,684,861	
4	(830-837) Maintenance	4,673,944	
5	Total Underground Storage Expenses (Lines 3 and 4)	13,358,805	
6	OTHER STORAGE EXPENSES		
7	(840-842.3) Operations	2,935,574	
8	(843.1-843.9) Maintenance	1,778,317	
9	Total Other Storage Expenses (lines 7 and 8)	4,713,891	
10	LIQUEFIED NATURAL GAS TERMINALING AND PROCESSING		
11	(844.1-846.2) Operations		
12	(847.1-847.8) Maintenance		
13	Total Liquefied Natural Gas Terminaling and Processing (Lines 11 and 12)		
14	TRANSMISSION EXPENSES		
15	Transmission Operation Expenses		
16	(850) Operation Supervision and Engineering	4,097,649	
17	(851) System Control and Load Dispatching	1,916,761	
18	(852) Communication System Expenses	1,175,518	
19	(853) Compressor Station Labor and Expenses	7,361,308	
20	(854) Gas for Compressor Station Fuel	27,887,823	
21	(855) Other Fuel and Power for Compressor Stations	1,953,241	
22	(856) Mains Expenses	16,615,549	
23	(857) Measuring and Regulating Station Expenses	3,226,374	
24	(858) Transmission and Compression of Gas by Others	11,959	
25	(859) Other Expenses	982,956	
26	(860) Rents	91,673	
27	Total Transmission Operation Expenses (Lines 16 through 26)	65,320,811	
28	Transmission Maintenance Expenses		
29	(861) Maintenance Supervision and Engineering	594	
30	(862) Maintenance of Structures and Improvements	978,814	
31	(863) Maintenance of Mains	10,217,723	
32	(864) Maintenance of Compressor Station Equipment	10,121,927	
33	(865) Maintenance of Measuring and Regulating Equipment	1,960,721	
34	(866) Maintenance of Communication Equipment	91,003	
35	(867) Maintenance of Other Equipment	540,433	
36	Total Transmission Maintenance Expenses (Lines 29 through 35)	23,911,215	
37	Total Transmission Expenses (lines 27 and 36)	89,232,026	
38	DISTRIBUTION EXPENSES		
39	(870-881) Operation Expenses		
40	(885-894) Maintenance		
41	Total Distribution Expenses (Lines 39 and 40)		
42	Total (lines 5,9,13,37 and 41)	107,304,722	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q3

Gas Customer Accounts, Service, Sales, Administrative and General Expenses

Report the amount of expenses for customer accounts, service, sales, and administrative and general expenses year to date.

Line No.	Account (a)	Year to Date Quarter (b)	
1	(901-905) Customer Accounts Expenses		
2	(907-910) Customer Service and Information Expenses	20,437	
3	(911-916) Sales Expenses	755,933	
4	8. ADMINISTRATIVE AND GENERAL EXPENSES		
5	Operations		
6	920 Administrative and General Salaries	23,469,794	
7	921 Office Supplies and Expenses	10,055,670	
8	(Less) 922 Administrative Expenses Transferred-Credit	903,713	
9	923 Outside Services Employed	5,147,118	
10	924 Property Insurance	836,048	
11	925 Injuries and Damages	856,034	
12	926 Employee Pensions and Benefits	10,156,154	
13	927 Franchise Requirements		
14	928 Regulatory Commission Expenses	2,195,498	
15	(Less) 929 Duplicate Charges-Credit		
16	930.1 General Advertising Expenses		
17	930.2 Miscellaneous General Expenses	57,244	
18	931 Rents	624,173	
19	TOTAL Operation (Total of lines 6 through 18)	52,494,020	
20	Maintenance		
21	932 Maintenance of General Plant	1,024	
22	TOTAL Administrative and General Expenses (Total of lines 19 and 21)	52,495,044	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q3

Depreciation, Depletion and Amortization of Gas Plant (Accts 403, 403.1, 404.1, 404.2, 404.3, 405) (Except Amort of Acqusition Adjustments)

1. Report the year to date amounts of depreciation expense, asset retirement cost depreciation, depletion and amortization, except amortization of acquisition adjustments for the accounts indicated and classified according to the plant functional groups described.

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization and Depletion of Other Gas Plant (Accounts 404.1, 404.2 and 404.3) (d)
1	Intangible Plant	0	0	4,104,209
2	Production Plant, Manufacturing Plant	0	0	0
3	Production and Gathering Plant - Natural Gas	2,579,670	0	0
4	Products Extraction - Natural Gas	0	0	0
5	Underground Gas Storage Plant	4,074,949	0	225,306
6	Other Storage Plant	710,240	0	0
7	Base Load LNG Terminaling and Processing Plant	0	0	0
8	Processing Plant	0	0	0
9	Transmission Plant	27,251,733	0	898,906
10	Distribution Plant	0	0	0
11	General Plant	8,025,299	0	0
12	Common Plant	0	0	0
13	TOTAL GAS (Lines 1 through 12)	42,641,891	0	5,228,421

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q3

Depreciation, Depletion and Amortization of Gas Plant (Accts 403, 403.1, 404.1, 404.2, 404.3, 405) (Except Amort of Acqusition Adjustments)

1. Report the year to date amounts of depreciation expense, asset retirement cost depreciation, depletion and amortization, except amortization of acquisition adjustments for the accounts indicated and classified according to the plant functional groups described.

Line No.	Amortization of Other Gas Plant (Account 405) (e)	Total (b) to (e)				
1	0	4,104,209				
2	0	0				
3	0	2,579,670				
4	0	0				
5	0	4,300,255				
6	0	710,240				
7	0	0				
8	0	0				
9	0	28,150,639				
10	0	0				
11	0	8,025,299				
12	0	0				
13	0	47,870,312				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q3

Gas Account - Natural Gas

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

Line No.	Item (a)	Ref. Page No. of (FERC Form Nos. 2/2-A) (b)	Total Amount of Dth Year to Date (c)	Current Three Months Ended Amount of Dth Quarterly Only
01	Name of System:			
2	GAS RECEIVED			
3	Gas Purchases (Accounts 800-805)		9,868,566	765,452
4	Gas of Others Received for Gathering (Account 489.1)	303	6,430,631	1,970,994
5	Gas of Others Received for Transmission (Account 489.2)	305	677,901,730	202,097,323
6	Gas of Others Received for Distribution (Account 489.3)	301		
7	Gas of Others Received for Contract Storage (Account 489.4)	307	92,166,335	51,948,480
8	Gas of Others Received for Production/Extraction/Processing (Account 490 and 491)			
9	Exchanged Gas Received from Others (Account 806)	328		
10	Gas Received as Imbalances (Account 806)	328	2,259,239	71,593
11	Receipts of Respondent's Gas Transported by Others (Account 858)	332	33,021	
12	Other Gas Withdrawn from Storage (Explain)		48,258,158	2,686,523
13	Gas Received from Shippers as Compressor Station Fuel		6,960,803	2,403,167
14	Gas Received from Shippers as Lost and Unaccounted for		265,988	408,684
15	Other Receipts (Specify) (footnote details)			
16	Total Receipts (Total of lines 3 thru 15)		844,144,471	262,352,216
17	GAS DELIVERED			
18	Gas Sales (Accounts 480-484)		8,568,569	3,256,631
19	Deliveries of Gas Gathered for Others (Account 489.1)	303	6,430,631	1,970,994
20	Deliveries of Gas Transported for Others (Account 489.2)	305	677,901,730	202,097,323
21	Deliveries of Gas Distributed for Others (Account 489.3)	301		
22	Deliveries of Contract Storage Gas (Account 489.4)	307	72,553,535	8,376,760
23	Gas of Others Delivered for Production/Extraction/Processing (Account 490 and 491)			
24	Exchange Gas Delivered to Others (Account 806)	328		
25	Gas Delivered as Imbalances (Account 806)	328	2,986,102	598,910
26	Deliveries of Gas to Others for Transportation (Account 858)	332	33,021	
27	Other Gas Delivered to Storage (Explain)		65,393,854	44,003,454
28	Gas Used for Compressor Station Fuel	509	6,794,892	1,356,326
29	Other Deliveries and Gas Used for Other Operations		1,941,814	338,196
30	Total Deliveries (Total of lines 18 thru 29)		842,604,148	261,998,594
31	GAS LOSSES AND GAS UNACCOUNTED FOR			
32	Gas Losses and Gas Unaccounted For		1,540,323	353,622
33	TOTALS			
34	Total Deliveries, Gas Losses & Unaccounted For (Total of lines 30 and 32)		844,144,471	262,352,216

Schedule Page: 520 Line No.: 3 Column: c

The 9,868,566 Dth represents gas purchases recorded to FERC account 803.

Schedule Page: 520 Line No.: 12 Column: c

The 48,258,158 Dth represents gas withdrawn from storage (includes third party and company owned gas).

Schedule Page: 520 Line No.: 27 Column: c

The 65,393,854 Dth represents gas injected into storage (includes third party and company owned gas).

Schedule Page: 520 Line No.: 29 Column: c

	Amount in Dth
Drip Shrinkage	16,033
Work Order	8,405
Gas Used in other O&M Operations	1,917,376
Total	1,941,814

Schedule Page: 520 Line No.: 3 Column: d

The 765,452 Dth represents gas purchases recorded to FERC account 803.

Schedule Page: 520 Line No.: 12 Column: d

The 2,686,523 Dth represents gas withdrawn from storage (includes third party and company owned gas).

Schedule Page: 520 Line No.: 27 Column: d

The 44,003,454 Dth represents gas injected into storage (includes third party and company owned gas).

Schedule Page: 520 Line No.: 29 Column: d

	Amount in Dth
Drip Shrinkage	917
Work Order	8,405
Gas Used in other O&M Operations	328,874
Total	338,196

Name of Respondent Northern Natural Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q3

Shipper Supplied Gas for the Current Quarter

1. Report monthly (1) shipper supplied gas for the current quarter and gas consumed in pipeline operations, (2) the disposition of any excess, the accounting recognition given to such disposition and the specific account(s) charged or credited, and (3) the source of gas used to meet any deficiency, the accounting recognition given to the gas used to meet the deficiency, including the accounting basis of the gas and the specific account(s) charged or credited.
2. On lines 7, 14, 22 and 30 report only the dekatherms of gas provided by shippers under tariff terms and conditions for gathering , production/ extraction/processing, transmission, distribution and storage service and the use of that gas for compressor fuel, other operational purposes and lost and unaccounted for. The dekatherms must be broken out by functional categories on Lines 2-6, 9-13, 16-21 and 24-29. The dekatherms must be reported in column (d) unless the company has discounted or negotiated rates which should be reported in columns (b) and (c).
3. On lines 7, 14, 22 and 30 report only the dollar amounts of gas provided by shippers under tariff terms and conditions for gathering, production/ extraction/processing, transmission, distribution and storage service and the use of that gas for compressor fuel, other operational purposes and lost and unaccounted for. The dollar amounts must be broken out by functional categories on Lines 2-6, 9-13, 16-21 and 23-29. The dollar amounts must be reported in column (h) unless the company has discounted or negotiated rates which should be reported in columns (f) and (g). The accounting should disclose the account(s) debited and credited in columns (m) and (n).
4. Indicate in a footnote the basis for valuing the gas reported in Columns (f), (g) and (h).
5. Report in columns (j), (k) and (l) the amount of fuel waived, discounted or reduced as part of a negotiated rate agreement.
6. On lines 32-37 report the dekatherms and dollar value of the excess or deficiency in shipper supplied gas broken out by functional category and whether recourse rate, discounted or negotiated rate.
7. On lines 39 through 51 report the dekatherms, the dollar amount and the account(s) credited in Column (o) for the dispositions of gas listed in column (a).
8. On lines 53 through 65 report the dekatherms, the dollar amount and the account(s) debited in Column (n) for the sources of gas reported in column (a).
9. On lines 66 and 67, report forwardhaul and backhaul volume in Dths of throughput.
10. Where appropriate, provide a full explanation of the allocation process used in reported numbers in a footnote.

Line No.	Item (a)	Month 1 Discounted rate Dth (b)	Month 1 Negotiated Rate Dth (c)	Month 1 Recourse Rate Dth (d)	Month 1 Total Dth (e)
1	**SHIPPER SUPPLIED GAS (LINES 13 AND 14 , PAGE 520)**				
2	Gathering			856,680	856,680
3	Production/Extraction/Processing				
4	Transmission				
5	Distribution				
6	Storage				
7	**Total Shipper Supplied Gas**			856,680	856,680
8	**LESS GAS USED FOR COMPRESSOR STATION FUEL (LINE 28, PAGE 520)**				
9	Gathering			406,560	406,560
10	Production/Extraction/Processing				
11	Transmission				
12	Distribution				
13	Storage				
14	**Total gas used in compressors**			406,560	406,560
15	**LESS GAS USED FOR OTHER DELIVERIES AND GAS USED FOR OTHER OPERATIONS (LINE 29, PAGE 520) (Footnote)**				
16	Gathering			110,647	110,647
17	Production/Extraction/Processing				
18	Transmission				
19	Distribution				
20	Storage				
21	Other Deliveries (specify) (footnote details)				
22	**Total Gas Used For Other Deliveries And Gas Used For Other Operations**			110,647	110,647
23	**LESS GAS LOST AND UNACCOUNTED FOR (LINE 32, PAGE 520)**				
24	Gathering			254,422	254,422
25	Production/Extraction/Processing				
26	Transmission				
27	Distribution				
28	Storage				
29	Other Losses (specify) (footnote details)				
30	**Total Gas Lost And Unaccounted For**			254,422	254,422

Shipper Supplied Gas for the Current Quarter (continued)

Line No.	Item (a)	Month 1 Discounted rate Dth (b)	Month 1 Negotiated Rate Dth (c)	Month 1 Recourse Rate Dth (d)	Month 1 Total Dth (e)
31	**NET EXCESS OR (DEFICIENCY)**				
32	Gathering			85,051	85,051
33	Production/Extraction				
34	Transmission				
35	Distribution				
36	Storage				
37	**Total Net Excess Or (Deficiency)**			85,051	85,051
38	**DISPOSITION OF EXCESS GAS:**				
39	Gas sold to others				
40	Gas used to meet imbalances				
41	Gas added to system gas				
42	Gas returned to shippers			85,051	85,051
43	Other (list)				
44					
45					
46					
47					
48					
49					
50					
51	**Total Disposition Of Excess Gas**			85,051	85,051
52	**GAS ACQUIRED TO MEET DEFICIENCY:**				
53	System gas				
54	Purchased gas				
55	Other (list)				
56	Gas to be recovered from shippers				
57					
58					
59					
60					
61					
62					
63					
64					
65	**Total Gas Acquired To Meet Deficiency**				

SEPARATION OF FORWARDHAUL AND BACKHAUL THROUGHPUT

66	Forwardhaul Volume in Dths for the Quarter	
67	Backhaul Volume in Dths for the Quarter	
68	**TOTAL (Lines 66 and 67)**	

Name of Respondent Northern Natural Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q3

Shipper Supplied Gas for the Current Quarter

1. Report monthly (1) shipper supplied gas for the current quarter and gas consumed in pipeline operations, (2) the disposition of any excess, the accounting recognition given to such disposition and the specific account(s) charged or credited, and (3) the source of gas used to meet any deficiency, the accounting recognition given to the gas used to meet the deficiency, including the accounting basis of the gas and the specific account(s) charged or credited.
2. On lines 7, 14, 22 and 30 report only the dekatherms of gas provided by shippers under tariff terms and conditions for gathering , production/ extraction/processing, transmission, distribution and storage service and the use of that gas for compressor fuel, other operational purposes and lost and unaccounted for. The dekatherms must be broken out by functional categories on Lines 2-6, 9-13, 16-21 and 24-29. The dekatherms must be reported in column (d) unless the company has discounted or negotiated rates which should be reported in columns (b) and (c).
3. On lines 7, 14, 22 and 30 report only the dollar amounts of gas provided by shippers under tariff terms and conditions for gathering, production/ extraction/processing, transmission, distribution and storage service and the use of that gas for compressor fuel, other operational purposes and lost and unaccounted for. The dollar amounts must be broken out by functional categories on Lines 2-6, 9-13, 16-21 and 23-29. The dollar amounts must be reported in column (h) unless the company has discounted or negotiated rates which should be reported in columns (f) and (g). The accounting should disclose the account(s) debited and credited in columns (m) and (n).
4. Indicate in a footnote the basis for valuing the gas reported in Columns (f), (g) and (h).
5. Report in columns (j), (k) and (l) the amount of fuel waived, discounted or reduced as part of a negotiated rate agreement.
6. On lines 32-37 report the dekatherms and dollar value of the excess or deficiency in shipper supplied gas broken out by functional category and whether recourse rate, discounted or negotiated rate.
7. On lines 39 through 51 report the dekatherms, the dollar amount and the account(s) credited in Column (o) for the dispositions of gas listed in column (a).
8. On lines 53 through 65 report the dekatherms, the dollar amount and the account(s) debited in Column (n) for the sources of gas reported in column (a).
9. On lines 66 and 67, report forwardhaul and backhaul volume in Dths of throughput.
10. Where appropriate, provide a full explanation of the allocation process used in reported numbers in a footnote.

Line No.	Item (a)	Month 2 Discounted rate Dth (p)	Month 2 Negotiated Rate Dth (q)	Month 2 Recourse Rate Dth (r)	Month 2 Total Dth (s)
1	**SHIPPER SUPPLIED GAS (LINES 13 AND 14 , PAGE 520)**				
2	Gathering			995,481	995,481
3	Production/Extraction/Processing				
4	Transmission				
5	Distribution				
6	Storage				
7	**Total Shipper Supplied Gas**			995,481	995,481
8	**LESS GAS USED FOR COMPRESSOR STATION FUEL (LINE 28, PAGE 520)**				
9	Gathering			510,439	510,439
10	Production/Extraction/Processing				
11	Transmission				
12	Distribution				
13	Storage				
14	**Total gas used in compressors**			510,439	510,439
15	**LESS GAS USED FOR OTHER DELIVERIES AND GAS USED FOR OTHER OPERATIONS (LINE 29, PAGE 520) (Footnote)**				
16	Gathering			108,887	108,887
17	Production/Extraction/Processing				
18	Transmission				
19	Distribution				
20	Storage				
21	Other Deliveries (specify) (footnote details)				
22	**Total Gas Used For Other Deliveries And Gas Used For Other Operations**			108,887	108,887
23	**LESS GAS LOST AND UNACCOUNTED FOR (LINE 32, PAGE 520)**				
24	Gathering			116,514	116,514
25	Production/Extraction/Processing				
26	Transmission				
27	Distribution				
28	Storage				
29	Other Losses (specify) (footnote details)				
30	**Total Gas Lost And Unaccounted For**			116,514	116,514

Name of Respondent Northern Natural Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q3

Shipper Supplied Gas for the Current Quarter (continued)

Line No.	Item (a)	Month 2 Discounted rate Dth (p)	Month 2 Negotiated Rate Dth (q)	Month 2 Recourse Rate Dth (r)	Month 2 Total Dth (s)
31	**NET EXCESS OR (DEFICIENCY)**				
32	Gathering			259,641	259,641
33	Production/Extraction				
34	Transmission				
35	Distribution				
36	Storage				
37	**Total Net Excess Or (Deficiency)**			259,641	259,641
38	**DISPOSITION OF EXCESS GAS:**				
39	Gas sold to others				
40	Gas used to meet imbalances				
41	Gas added to system gas				
42	Gas returned to shippers			259,641	259,641
43	Other (list)				
44					
45					
46					
47					
48					
49					
50					
51	**Total Disposition Of Excess Gas**			259,641	259,641
52	**GAS ACQUIRED TO MEET DEFICIENCY:**				
53	System gas				
54	Purchased gas				
55	Other (list)				
56	Gas to be recovered from shippers				
57					
58					
59					
60					
61					
62					
63					
64					
65	**Total Gas Acquired To Meet Deficiency**				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q3

Shipper Supplied Gas for the Current Quarter

1. Report monthly (1) shipper supplied gas for the current quarter and gas consumed in pipeline operations, (2) the disposition of any excess, the accounting recognition given to such disposition and the specific account(s) charged or credited, and (3) the source of gas used to meet any deficiency, the accounting recognition given to the gas used to meet the deficiency, including the accounting basis of the gas and the specific account(s) charged or credited.
2. On lines 7, 14, 22 and 30 report only the dekatherms of gas provided by shippers under tariff terms and conditions for gathering , production/ extraction/processing, transmission, distribution and storage service and the use of that gas for compressor fuel, other operational purposes and lost and unaccounted for. The dekatherms must be broken out by functional categories on Lines 2-6, 9-13, 16-21 and 24-29. The dekatherms must be reported in column (d) unless the company has discounted or negotiated rates which should be reported in columns (b) and (c).
3. On lines 7, 14, 22 and 30 report only the dollar amounts of gas provided by shippers under tariff terms and conditions for gathering, production/ extraction/processing, transmission, distribution and storage service and the use of that gas for compressor fuel, other operational purposes and lost and unaccounted for. The dollar amounts must be broken out by functional categories on Lines 2-6, 9-13, 16-21 and 23-29. The dollar amounts must be reported in column (h) unless the company has discounted or negotiated rates which should be reported in columns (f) and (g). The accounting should disclose the account(s) debited and credited in columns (m) and (n).
4. Indicate in a footnote the basis for valuing the gas reported in Columns (f), (g) and (h).
5. Report in columns (j), (k) and (l) the amount of fuel waived, discounted or reduced as part of a negotiated rate agreement.
6. On lines 32-37 report the dekatherms and dollar value of the excess or deficiency in shipper supplied gas broken out by functional category and whether recourse rate, discounted or negotiated rate.
7. On lines 39 through 51 report the dekatherms, the dollar amount and the account(s) credited in Column (o) for the dispositions of gas listed in column (a).
8. On lines 53 through 65 report the dekatherms, the dollar amount and the account(s) debited in Column (n) for the sources of gas reported in column (a).
9. On lines 66 and 67, report forwardhaul and backhaul volume in Dths of throughput.
10. Where appropriate, provide a full explanation of the allocation process used in reported numbers in a footnote.

Line No.	Item (a)	Month 3 Discounted rate Dth (dd)	Month 3 Negotiated Rate Dth (ee)	Month 3 Recourse Rate Dth (ff)	Month 3 Total Dth (gg)
1	**SHIPPER SUPPLIED GAS (LINES 13 AND 14 , PAGE 520)**				
2	Gathering			959,690	959,690
3	Production/Extraction/Processing				
4	Transmission				
5	Distribution				
6	Storage				
7	**Total Shipper Supplied Gas**			959,690	959,690
8	**LESS GAS USED FOR COMPRESSOR STATION FUEL (LINE 28, PAGE 520)**				
9	Gathering			439,327	439,327
10	Production/Extraction/Processing				
11	Transmission				
12	Distribution				
13	Storage				
14	**Total gas used in compressors**			439,327	439,327
15	**LESS GAS USED FOR OTHER DELIVERIES AND GAS USED FOR OTHER OPERATIONS (LINE 29, PAGE 520) (Footnote)**				
16	Gathering			109,340	109,340
17	Production/Extraction/Processing				
18	Transmission				
19	Distribution				
20	Storage				
21	Other Deliveries (specify) (footnote details)				
22	**Total Gas Used For Other Deliveries And Gas Used For Other Operations**			109,340	109,340
23	**LESS GAS LOST AND UNACCOUNTED FOR (LINE 32, PAGE 520)**				
24	Gathering			(17,314)	(17,314)
25	Production/Extraction/Processing				
26	Transmission				
27	Distribution				
28	Storage				
29	Other Losses (specify) (footnote details)				
30	**Total Gas Lost And Unaccounted For**			(17,314)	(17,314)

Name of Respondent Northern Natural Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q3

Shipper Supplied Gas for the Current Quarter (continued)

Line No.	Item (a)	Month 3 Discounted rate Dth (dd)	Month 3 Negotiated Rate Dth (ee)	Month 3 Recourse Rate Dth (ff)	Month 3 Total Dth (gg)
31	**NET EXCESS OR (DEFICIENCY)**				
32	Gathering			428,337	428,337
33	Production/Extraction				
34	Transmission				
35	Distribution				
36	Storage				
37	**Total Net Excess Or (Deficiency)**			428,337	428,337
38	**DISPOSITION OF EXCESS GAS:**				
39	Gas sold to others				
40	Gas used to meet imbalances				
41	Gas added to system gas				
42	Gas returned to shippers			428,337	428,337
43	Other (list)				
44					
45					
46					
47					
48					
49					
50					
51	**Total Disposition Of Excess Gas**			428,337	428,337
52	**GAS ACQUIRED TO MEET DEFICIENCY:**				
53	System gas				
54	Purchased gas				
55	Other (list)				
56					
57					
58					
59					
60					
61					
62					
63					
64					
65	**Total Gas Acquired To Meet Deficiency**				

Name of Respondent Northern Natural Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q3

Shipper Supplied Gas for the Current Quarter (continued)

.

Line No.	Amount Collected (Dollars)				Volume (in Dth) Not Collected				Month 1 Account(s) Debited (n)	Month 1 Account(s) Credited (o)
	Month 1 Discounted Rate Amount (f)	Month 1 Negotiated Rate Amount (g)	Month 1 Recourse rate Amount (h)	Month 1 Total Amount (i)	Month 1 Waived Dth (j)	Month 1 Discounted Dth (k)	Month 1 Negotiated Dth (l)	Month 1 Total Dth (m)		
1										
2			3,781,085	3,781,085					805	805
3										
4										
5										
6										
7			3,781,085	3,781,085						
8										
9			1,794,718	1,794,718					854 & 819	810
10										
11										
12										
13										
14			1,794,718	1,794,718						
15										
16			488,656	488,656					See footnote	812
17										
18										
19										
20										
21										
22			488,656	488,656						
23										
24			1,122,829	1,122,829					813	812
25										
26										
27										
28										
29										
30			1,122,829	1,122,829						

Shipper Supplied Gas for the Current Quarter (continued)

Line No.	Amount Collected (Dollars)				Volume (in Dth) Not Collected				Month 1 Account(s) Debited (n)	Month 1 Account(s) Credited (o)
	Month 1 Discounted Rate Amount (f)	Month 1 Negotiated Rate Amount (g)	Month 1 Recourse rate Amount (h)	Month 1 Total Amount (i)	Month 1 Waived Dth (j)	Month 1 Discounted Dth (k)	Month 1 Negotiated Dth (l)	Month 1 Total Dth (m)		
31										
32			374,882	374,882						
33										
34										
35										
36										
37			374,882	374,882						
38										
39										
40										
41										
42			374,882	374,882					182.3	805
43										
44										
45										
46										
47										
48										
49										
50										
51			374,882	374,882						
52										
53										
54										
55										
56										
57										
58										
59										
60										
61										
62										
63										
64										
65										

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q3

Shipper Supplied Gas for the Current Quarter (continued)

.

Line No.	Amount Collected (Dollars)				Volume (in Dth) Not Collected				Month 2 Account(s) Debited (bb)	Month 2 Account(s) Credited (cc)
	Month 2 Discounted Rate Amount (t)	Month 2 Negotiated Rate Amount (u)	Month 2 Recourse rate Amount (v)	Month 2 Total Amount (w)	Month 2 Waived Dth (x)	Month 2 Discounted Dth (y)	Month 2 Negotiated Dth (z)	Month 2 Total Dth (aa)		
1										
2			4,338,663	4,338,663					805	805
3										
4										
5										
6										
7			4,338,663	4,338,663						
8										
9			2,225,820	2,225,820					854 & 819	810
10										
11										
12										
13										
14			2,225,820	2,225,820						
15										
16			474,813	474,813					See footnote	812
17										
18										
19										
20										
21										
22			474,813	474,813						
23										
24			508,081	508,081					813	812 & 823
25										
26										
27										
28										
29										
30			508,081	508,081						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q3

Shipper Supplied Gas for the Current Quarter (continued)

Line No.	Amount Collected (Dollars)				Volume (in Dth) Not Collected				Month 2 Account(s) Debited (bb)	Month 2 Account(s) Credited (cc)
	Month 2 Discounted Rate Amount (t)	Month 2 Negotiated Rate Amount (u)	Month 2 Recourse rate Amount (v)	Month 2 Total Amount (w)	Month 2 Waived Dth (x)	Month 2 Discounted Dth (y)	Month 2 Negotiated Dth (z)	Month 2 Total Dth (aa)		
31										
32			1,129,949	1,129,949						
33										
34										
35										
36										
37			1,129,949	1,129,949						
38										
39										
40										
41										
42			1,129,949	1,129,949					182.3	805
43										
44										
45										
46										
47										
48										
49										
50										
51			1,129,949	1,129,949						
52										
53										
54										
55										
56										
57										
58										
59										
60										
61										
62										
63										
64										
65										

Shipper Supplied Gas for the Current Quarter (continued)

.

Line No.	Amount Collected (Dollars)				Volume (in Dth) Not Collected				Month 3 Account(s) Debited (pp)	Month 3 Account(s) Credited (qq)
	Month 3 Discounted Rate Amount (hh)	Month 3 Negotiated Rate Amount (ii)	Month 3 Recourse rate Amount (jj)	Month 3 Total Amount (kk)	Month 3 Waived Dth (ll)	Month 3 Discounted Dth (mm)	Month 3 Negotiated Dth (nn)	Month 3 Total Dth (oo)		
1										
2			3,910,208	3,910,208					805	805
3										
4										
5										
6										
7			3,910,208	3,910,208						
8										
9			1,789,972	1,789,972					854 & 819	810
10										
11										
12										
13										
14			1,789,972	1,789,972						
15										
16			446,009	446,009					See footnote	812
17										
18										
19										
20										
21										
22			446,009	446,009						
23										
24			(70,674)	(70,674)					813	812
25										
26										
27										
28										
29										
30			(70,674)	(70,674)						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q3

Shipper Supplied Gas for the Current Quarter (continued)

Line No.	Amount Collected (Dollars)				Volume (in Dth) Not Collected				Month 3 Account(s) Debited (pp)	Month 3 Account(s) Credited (qq)
	Month 3 Discounted Rate Amount (hh)	Month 3 Negotiated Rate Amount (ii)	Month 3 Recourse rate Amount (jj)	Month 3 Total Amount (kk)	Month 3 Waived Dth (ll)	Month 3 Discounted Dth (mm)	Month 3 Negotiated Dth (nn)	Month 3 Total Dth (oo)		
31										
32			1,744,902	1,744,902						
33										
34										
35										
36										
37			1,744,902	1,744,902						
38										
39										
40										
41										
42			1,744,902	1,744,902					182.3	805
43										
44										
45										
46										
47										
48										
49										
50										
51			1,744,902	1,744,902						
52										
53										
54										
55										
56										
57										
58										
59										
60										
61										
62										
63										
64										
65										

Schedule Page: 521 Line No.: 9 Column: d

Gas used in compressors:

		Month 1 Gas Used (Dth)	Month 1 Amount ($)
Transmission	854	383,622	$1,693,461
Underground Storage	819	22,938	101,257
		406,560	$1,794,718

Schedule Page: 521 Line No.: 16 Column: d

Gas used for other operation purposes:

		Month 1 Gas Used (Dth)	Month 1 Amount ($)
LNG Compressor Station Fuel	842.1	8,250	$36,419
Line Operations	856	91,169	402,672
Purification Underground Storage	821	3,706	16,360
Other Underground Storage Operations	817	6,372	28,129
Other Compressor Station Fuel	819	1,150	5,076
		110,647	$488,656

Volume of gas used for other deliveries and gas used for other operations does not equal the volume reported on line 29 page 520. The variance is due to the exclusion of drip shrinkage and gas associated with work orders which is not considered shipper supplied gas.

Schedule Page: 521 Line No.: 9 Column: d

Gas used in compressors:

		Month 2 Gas Used (Dth)	Month 2 Amount ($)
Transmission	854	491,413	$2,142,855
Underground Storage	819	19,026	82,965
		510,439	$2,225,820

Schedule Page: 521 Line No.: 16 Column: d

Gas used for other operation purposes:

		Month 2 Gas Used (Dth)	Month 2 Amount ($)
LNG Compressor Station Fuel	842.1	0	$0
Line Operations	856	103,777	452,530
Purification Underground Storage	821	652	2,843
Other Underground Storage Operations	817	2,875	12,537
Other Compressor Station Fuel	819	1,583	6,903
		108,887	$474,813

Volume of gas used for other deliveries and gas used for other operations does not equal the volume reported on line 29 page 520. The variance is due to the exclusion of drip shrinkage and gas associated with work orders which is not considered shipper supplied gas.

Schedule Page: 521 Line No.: 9 Column: d

Gas used in compressors:

		Month 3 Gas Used (Dth)	Month 3 Amount ($)
Transmission	854	410,672	$1,673,085
Underground Storage	819	28,655	116,887
		439,327	$1,789,972

Schedule Page: 521 Line No.: 16 Column: d

Gas used for other operation purposes:

		Month 3 Gas Used (Dth)	Month 3 Amount ($)
LNG Compressor Station Fuel	842.1	4,514	$18,413
Line Operations	856	98,726	402,713
Purification Underground Storage	821	371	1,513
Other Underground Storage Operations	817	3,583	14,616
Other Compressor Station Fuel	819	2,146	8,754
		109,340	$446,009

Volume of gas used for other deliveries and gas used for other operations does not equal the volume reported on line 29 page 520. The variance is due to the exclusion of drip shrinkage and gas associated with work orders which is not considered shipper supplied gas.

Schedule Page: 521 Line No.: 56 Column: a

Deficiency gas to be recovered from shippers is recorded in a volumetric tracker.

Schedule Page: 521 Line No.: 64 Column: a

For Balance Sheet accounts carried and resolved volumetrically, the Respondent carries the balance priced at the end of the month Northern Natural Gas Demarcation index as published in Gas Daily.

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