e-FILING REPORT COVER SHEET

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

REPORT NAME: Annual Report for the year ending December 31, 2015, (FERC Form 2)

COMPANY NAME: NW Natural

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ☒No ☐Yes

If yes, please submit only the cover letter electronically. Submit confidential information as directed in OAR 860-001-0070 or the terms of an applicable protective order.

If known, please select designation: ☐RE (Electric) ☒RG (Gas) ☐RW (Water) ☐RO (Other)

Report is required by: ☒OAR 860-027-0070

☐Statute

☐Order .

☐Other

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

If yes, enter docket number: RG 37

List applicable Key Words for this report to facilitate electronic search:
2014 Annual Report, for the year ending December 31, 2015, FERC Form 2

DO NOT electronically file with the PUC Filing Center:

- Annual Fee Statement form and payment remittance or
- OUS or RSPF Surcharge form or surcharge remittance or
- Any other Telecommunications Reporting or
- Any daily safety or safety incident reports or
- Accident reports required by ORS 654.715

Please file the above reports according to their individual instructions.

MARK R. THOMPSON
Manager, Rates & Regulatory Affairs
Tel: 503.721.2476
Fax: 503.721.2516
Email: mark.thompson@nwnatural.com

NW Natural

220 NW 2ND AVENUE
PORTLAND, OR 97209
TEL 503.226.4211
www.nwnatural.com

April 29, 2016

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
Post Office Box 1088
Salem, Oregon 97308-1088

Re: RG 37 – Annual Report for the year ending December 31, 2015
FERC Form 2 and Annual Report to Shareholders

In accordance with OAR 860-027-0070, Northwest Natural Gas Company, dba NW Natural (NW Natural or Company) files herewith its Annual Report to the Public Utility Commission of Oregon for the year ended December 31, 2015. The report is submitted on forms (FERC Form 2) provided by the Commission. Also attached is a copy of the Company's Annual Report to Shareholders.

Please address any correspondence on this matter to me, with copies to Brody Wilson, Controller, at the address above.

Sincerely,

/s/ Mark R. Thompson

Mark R. Thompson

Attachments

F.P.C. Form No. 2
UBI: 93-0256722

Form approved.
Budget Bureau No. 54-R009

NATURAL GAS COMPANIES
(Class A and B)

ANNUAL REPORT

OF

NORTHWEST NATURAL GAS COMPANY

(Exact Legal Name of Respondent)

If name was changed during year, show also the previous name and date of change

PORTLAND, OREGON

(Address of Principal Business Office at End of Year)

TO THE

PUBLIC UTILITY COMMISSION OF OREGON

AND

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

FOR THE

YEAR ENDED DECEMBER 31, 2015

Name, Title, and address of officer or other person to whom should be addressed any communication concerning this report:

Brody J. Wilson, Chief Accounting Officer, Controller & Assistant Treasurer
220 N.W. Second Avenue
Portland, Oregon 97209

THIS FILING IS		
Item 1: ■ An Initial (Original) Submission	OR ☐	Resubmission No. ____

Form 2 Approved
OMB No.1902-0028
(Expires 09/30/2017)

Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2016)

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

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

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
NW Natural Gas Company	**End of** 12/31/15

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).

FERC FORM NO. 2:
ANNUAL REPORT OF MAJOR NATURAL GAS COMPANIES

IDENTIFICATION

01 Exact Legal Name of Respondent Northwest Natural Gas Company	**02 Year of Report** Dec. 31, 2015
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) 220 N.W. Second Avenue, Portland, Oregon 97209	
05 Name of Contact Person Brody J. Wilson	**06 Title of Contact Person** Chief Accounting Officer, Controller & Assistant Treasurer
07 Address of Contact Person (Street, City, State, Zip Code) 220 N.W. Second Avenue, Portland, Oregon 97209	

08 Telephone of Contact Person, Including Area Code (503) 226-4211	**09 This Report is** X An Original A Resubmission	**10 Date of Report (Mo, Day, Yr)** May 1, 2016

ATTESTATION

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 Brody J. Wilson	**12 Title** Chief Accounting Officer, Controller & Assistant Treasurer
13 Signature	**14 Date Signed (Mo, Day, Yr)** 04/27/2016

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

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

List of Schedules (Natural Gas Company

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

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

List of Schedules (Natural Gas Company

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

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

☐ Four copies will be submitted
☐ No annual report to stockholders is prepared

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

GENERAL INFORMATION

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

Brody J. Wilson — Chief Accounting Officer, Controller & Assistant Treasurer
220 N.W. Second Avenue — Portland, Oregon 97209

2. Prove the name of the State under the laws of which respondent is incorporated and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

State of Oregon — January 10, 1910

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership of trusteeship was created, and 9d) date when possession by receiver or trustee ceased.

NOT APPLICABLE

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

GAS SERVICE IN OREGON AND WASHINGTON

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

(1) ☐ Yes . . .Enter the date when such independent account was initially engaged: ________________
(2) ☒ No

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.

2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.

3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

4. In column (b) designate type of control of the respondent as "D" for direct, an "I" for indirect, or a "J" for joint control.

DEFINITIONS

1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

LINE NO.	NAME OF COMPANY CONTROLLED (a)	TYPE OF CONTROL (b)	KIND OF BUSINESS (c)	Percent Voting Stock Owned (d)	Footnote Ref. (e)
1	Gill Ranch Storage, LLC	I	Gas storage	100%	1
2	NW Natural Energy, LLC	D	Intermediate holding company	100%	2
3	NW Natural Gas Storage, LLC	I	Gas storage	100%	3
4	NNG Financial Corporation	D	Financing and investments	100%	4
5	Trail West Holdings, LLC	I/J	Intermediate holding company	50%	5
6	Trail West Pipeline, LLC	I/J	Gas transmission company	*	6
7	BL Credit Holdings, LLC	I/J	Non-operating company	*	7
8	Northwest Biogas, LLC	J	Biodigester company	50%	8
9	KB Pipeline Company	I	Gas transmission company	100%	9
10	Northwest Energy Corporation	D	Intermediate holding company	100%	10
11	Northwest Energy Sub Corporation	I	Non-operating company	100%	11
12	NWN Gas Reserves, LLC	I	Gas reserves	100%	12

1 Gill Ranch Storage, LLC, a wholly-owned subsidiary of NW Natural Gas Storage, LLC, was formed in 2007 as part of a joint project with Pacific Gas & Electric to develop, own and operate an underground natural gas storage facility near Fresno, California. Gill Ranch began commercial operations in 2010.

2 NW Natural Energy, LLC, a wholly-owned subsidiary, is a holding company. Primarily used for gas storage and other non-utility investments.

3 NW Natural Gas Storage, LLC, a wholly-owned subsidiary of NW Natural Energy, LLC, primarily contains the operating employees for our gas storage businesses.

4 NNG Financial Corporation, a wholly-owned subsidiary, commenced operations in September 1990. NNG Financial Corporation holds certain non-utility financial investments but its assets primarily consist of an active wholly-owned subsidiary KB Pipeline Company.

5 Trail West Holdings, LLC (formerly Palomar Gas Holdings, LLC) a joint venture with TransCanada American Investments, Ltd. and 50% ownership subsidiary of NW Natural Energy, LLC, is designed to be the holding company for Trail West operating companies.

6 Trail West Pipeline, LLC (formerly Palomar Gas Transmission, LLC), wholly-owned by Trail West Holdings, LLC, was formed in 2007 to develop an interstate gas pipeline.

7 BL Credit Holdings, LLC, wholly-owned by Trail West Pipeline, LLC, is currently not operating.

8 Northwest Biogas, LLC, an equal joint venture with BEF Renewable Incorporated, was formed in 2008 to develop a biodigester.

9 KB Pipeline company, a wholly-owned subsidiary of NNG Financial Corporation, owns a 10% interest in an interstate natural gas pipeline.

10 Northwest Energy Corporation, is a wholly-owned subsidiary, primarily used as a holding company of NWN Gas Reserves, LLC.

11 Northwest Energy Sub Corporation, is an inactive and indirect subsidiary.

12 NWN Gas Reserves, LLC, a wholly-owned subsidiary of Northwest Energy Corporation, was formed in 2012 as part of a joint venture with Encana Oil & Gas (USA) Inc. to develop, own and operate gas reserves. In 2014, Encana Oil & Gas (USA) Inc. sold its interest in the gas reserves to Jonah Energy LLC.

* These companies are 100% owned indirectly through our joint venture Trail West Holdings, LLC.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

SECURITY HOLDERS AND VOTING POWERS

1. Give the names and addresses of the 10 security holders of the respondent who, at the date of the latest closing of the stock book or compilation of list of stockholders of the respondent, prior to the end of the year, had the highest voting powers in the respondent, and state the number of votes which each would have had the right to cast on that date if a meeting were then in order. If any such holder held in trust, give in a footnote the known particulars of the trust (whether voting trust, etc.), duration of trust, and principal holders of beneficiary interests in the trust. If the stock book was not closed or a list of stockholders was not compiled within one year prior to the end of the year, or if since the previous compilation of a list of stockholders, some other class of security has become vested with voting rights, then show such 10 security holders as of the close of the year. Arrange the names of the security holders in the order of voting power, commencing with the highest. Show in column (a) the titles of officers and directors included in such list of 10 security holders.
2. If any security other than stock carries voting rights, explain in a supplemental statement the circumstances whereby such security became vested with voting rights and give other important particulars (details) concerning the voting rights of such security. State whether voting rights are actual or contingent; if contingent, describe the contingency.
3. If any class or issue of security has any special privileges in the election of directors, trustees or managers, or in the determination of corporate action by any method, explain briefly in a footnote.
4. Furnish details concerning any options, warrants, or rights outstanding at the end of the year for others to purchase securities of the respondent or any securities or other assets owed by the respondent, including prices, expiration dates, and other material information relating to exercise of the options, warrants, or rights. Specify the amount of such securities or assets so entitled to be purchased by any officer, director, associated company, or any of the ten largest security holders. This instruction is inapplicable to convertible securities or to any securities substantially all of which are outstanding in the hands of the general public where the options, warrants, or rights were issued on a prorata basis.

1. Give date of the latest closing of the stock book prior to end of year, and, in a footnote,state the purpose of such closing:	2. State the total number of votes cast at the latest general meeting prior to the end of year for election of directors of the respondent and number of such votes cast by proxy. Total: By proxy:	3. Give the date and place of such meeting: Date: Place: Portland, Oregon Location: Northwest Natural Gas Company Headquarters

Line No.	Name (Title) and Address of Security Holder (a)	VOTING SECURITIES Number of votes as of (date): 10/31/2015 Total Votes (b)	Common Stock (c)	Preferred Stock (d)	Other (e)
4	TOTAL votes of all voting securities	27,371,642	27,371,642		
5	TOTAL number of security holders	5,747	5,747		
6	TOTAL votes of security holders listed below	24,900,804	24,900,804		
7					
8					
9					
10	See Page 107 (Continued)				
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

Name of Report	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

SECURITY HOLDERS AND VOTING POWERS (Continued)

Line No.	Name and Address (1a) (a)	Shares of Common Stock (b)	Percentage of Stock Outstanding (Voting Control) (c)
1	Cede & Company (1)	24,699,131	90.24%
2	P. O. Box 20		
3	Bowling Green Station		
4	New York, NY 10004-1408		
5			
6	David H. Anderson & (2)	49,792	0.18%
7	Susan S. Anderson JT TEN		
8	1688 Leslie Ln		
9	Lake Oswego, OR 97034-2179		
10			
11	Gregg S. Kantor (3)	30,727	0.11%
12	1709 SW Westwood Court		
13	Portland, OR 97239		
14			
15	Wachovia Bank N.A. TTEE (4)	25,817	0.09%
16	Northwest Natural Gas Co Umbrella TR for Directors		
17	DTD 1-1-91 Restated 12/15/05 for A/C Exec Serv		
18	One West Fourth St NC 6251		
19	Winston-Salem, NC 27101		
20			
21	Daniel J. Clement &	19,727	0.07%
22	Elizabeth J. Clement JT TEN		
23	303 Lakeside Drive		
24	Lewisburg, PA 17837		
25			
26	Mary Susan Pape (5)	18,319	0.07%
27	3693 North Shasta Loop		
28	Eugene, OR 97405		
29			
30	Wachovia Bank N.A. TTEE (6)	18,062	0.07%
31	Northwest Natural Gas Co Umbrella TR for Directors		
32	DTD 1-1-91 Restated 12/15/05 NEDSCP A/C Exec Serv		
33	One West Fourth St NC 6251		
34	Winston-Salem, NC 27101		
35			
36	Mervin J. Schafer & Sharan L. Schafer, Trustees of	14,312	0.05%
37	Mervin J. & Sharan L. Schafer Living Trust UA DTD Sept. 16, 2011		
38	P.O. Box 3288		
39	Salem, OR 97302-0288		
40			
41	Robert C. Reverman & Patricia H. Reverman, Trustees of	12,725	0.05%
42	The Reverman Family Trust UTD 1/12/1994		
43	170 Kala Heights Drive		
44	Port Townsend, WA 98368-9596		
45			
46	Margaret J. Reckers Successor Trustee	12,192	0.04%
47	Charles W. Reckers Trust U/A DTD 2-3-94		
48	15522 SW 114th Court, #52		
49	Tigard, OR 97224-3312		
50			
51	(1) Per Schedule 13G/A's filed with the SEC by BlackRock, Inc., 55 East 52nd Street, New York, NY 10055, Parnassus Investments, 1 Market Street, Suite 1600, San Francisco, CA 94105, and The Vanguard Group, Inc., 100 Vanguard Boulevard, Malvern, PA 19355, as of December 31, 2015, each held shares through Cede & Company, and was a beneficial owner of 10%, 9.44%, and 7.76%, respectively, of NW Natural common stock. Additionally, pursuant to NW Natural's Proxy Solicitor, D.F. King & Co., Inc., as of December 31, 2015, Duff & Phelps Investment Management, Dimensional Fund Advisors, State Street Global Advisors, GAMCO Investors, Inc., Bank of New York Mellon Corp., Invesco Powershares Capital Management LLC, and JP Morgan Chase Investment Management, each held shares through Cede & Company, and was a beneficial owner of 2.9%, 2.7%, 2.3%, 1.9%, 1.5%, 1.4% and 1.2%, respectively, of NW Natural common stock.		
52	(2) President and Chief Operating Officer		
53	(3) Chief Executive Officer		
54	(4) Current, Retired and Former Directors - Timothy P. Boyle, Martha L. Byorum, John D. Carter, Tod R. Hamacheck, Wayne D. Kuni, Randall C. Papé & Richard L. Woolworth		
55	(5) Beneficiary of former director		
56	(6) Current, Retired and Former Directors - Timothy P. Boyle, Martha L. Byorum, John D. Carter, Thomas E. Dewey, C. Scott Gibson, Tod R. Hamacheck, Wayne D. Kuni, Richard G. Reiten, Robert L. Ridgley, Melody Teppola, Russell F. Tromely & Richard L. Woolworth		

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SECURITY HOLDERS AND VOTING POWERS (Continued)

Line No.	Name and Address (1a) (a)	Shares of Common Stock (b)		Percentage of Stock Outstanding (Voting Control) (c)
57		Stock Options	Stock Rights for	
58		for Officers	for Officers	
59	Officers	as of 12/31/2015	as of 12/31/2015 [1]	
60	David H. Anderson	42,000	20,800	*
61	Lea Anne Doolittle	18,000	10,710	*
62	Shawn M. Filippi	2,400	2,079	*
63	Gregory C. Hazelton	0	12,244	*
64	Kimberly A. Heiting	9,400	4,525	*
65	Thomas J. Imeson	0	7,628	*
66	Gregg S. Kantor	100,000	57,410	*
67	Margaret D. Kirkpatrick	22,500	12,703	*
68	C. Alex Miller	8,100	6,165	*
69	MardiLyn Saathoff	12,000	8,368	*
70	David A. Weber	11,000	964	*
71	David R. Williams	11,500	7,977	*
72	Brody J. Wilson	0	4,798	*
73	Grant M. Yoshihara	11,500	7,977	*
76	(1) Includes performance based stock and performance based restricted stock units			
78	* Less than one percent.			

Name of Respondent	This Report is:	Date of Report	Year of Report
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IMPORTANT CHANGES DURING THE 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 Systems 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 or 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 know 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 exent 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.

See Page 108 (Continued)

IMPORTANT CHANGES DURING THE YEAR (Continued)

1. None
2. None
3. None
4. None
5. None
6. None
7. None
8. Bargaining unit pay increase of 3.00% effective December 1, 2015. Non-bargaining unit salary increase of 3.00% effective March 1, 2015.
9. See Page 122-A Footnote 15 - Environmental Matters
10. None
11. **Increase or decrease in annual revenues caused by important rate changes:**

OREGON

The PGA and other related filings were made in the fall. The combined effects of these filings were approved in a number of dockets through OPUC Order 15-323 on October 19, 2015. The approval of these filings decreased the Company’s annual Oregon revenues by $56.7 million, or 8.4 percent, passing through certain purchased gas cost adjustments, adjustments made to permanent base rates for certain approved programs, and technical adjustments amortizing the Company's deferred revenue and gas costs accounts. As of June 30, 2015, 631,826 customers were affected.
The Company's requests for reauthorization of deferred accounting in UM 1496 and UM 1027 were both granted for one year beginning November 1, 2015.

WASHINGTON

The PGA and energy efficiency filings were made in the fall. The new rates were allowed to go into effect, by operation of law, for service on and after November 1, 2015 at the WUTC Open Meeting held on October 29, 2015. The PGA filing revised rates for changes in purchased gas costs and both the PGA and energy efficiency filings updated temporary rate adjustments to amortize balances in deferred accounts. The combined effects of these filings decreased the Company’s annual Washington revenues by $11.9 million, or 16.3 percent. As of June 30, 2015, 75,692 customers were affected.

12. Effective January 1, 2015: MardiLyn Saathoff was appointed Senior Vice President and General Counsel and Margaret Kirkpatrick retired December 31, 2015. Kim Heiting was appointed to her new position Vice President Communications and Chief Marketing Officer. Shawn Filippi was appointed Vice President and Corporate Secretary. In addition, effective June 30, 2015, Steve Feltz retired and Gregory C. Hazelton became Senior Vice President and Chief Financial Officer. Effective August 1, 2015, Greg Kantor relinquished his position as President while retaining his position as Chief Executive Officer, and David Anderson became President in addition to Chief Operating Officer.

13. None

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
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COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Reference Page Number (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31/14 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	2,731,336,911	2,647,078,245
3	Construction Work in Progress (107)	200-201	39,288,188	24,885,892
4	TOTAL Utility Plant (Total of lines 2 and 3)	-	2,770,625,099	2,671,964,137
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 111, 115)	200-201	(1,193,310,914)	(1,146,628,259)
6	Net Utility Plant (Total of line 4 less 5)	-	1,577,314,185	1,525,335,878
7	Nuclear Fuel (120.1-120.4, 120.6)	-	-	-
8	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	-	-	-
9	Net Nuclear Fuel (Total of line 7 less 8)	-	-	-
10	Net Utility Plant (Total of lines 6 and 9)	-	1,577,314,185	1,525,335,878
11	Utility Plant Adjustments (116)	122	-	-
12	Gas Stored-Base Gas (117.1)	220	14,148,391	14,018,464
13	System Balancing Gas (117.2)	220	-	-
14	Gas Stored in Reservoirs and Pipelines-Noncurrent (117.3)	220	-	-
15	Gas Owned to System Gas (117.4)	220	-	-
16	**OTHER PROPERTY AND INVESTMENTS**			
17	Nonutility Property (121)	204-209	69,214,249	71,822,008
18	(Less) Accum. Prov. for Depreciation and Amortization (122)	-	(16,080,973)	(16,012,369)
19	Investments in Associated Companies (123)	222-223	-	-
20	Investment in Subsidiary Companies (123.1)	224-225	306,201,325	314,012,743
21	(For Cost of Account 123.1, See Footnote Page 224, line 40)	-		
22	Noncurrent Portion of Allowances	-	-	-
23	Other Investments (124)	222-223	54,170,226	54,228,346
24	Sinking Funds (125)	-	-	-
25	Depreciation Fund (126)	-	-	-
26	Amortization Fund - Federal (127)	-	-	-
27	Other Special Funds (128)	-	-	-
28	Long-Term Portion of Derivative Assets (175)	-	27,000	-
29	Long-Term Portion of Derivative Assets - Hedges (176)	-	-	-
30	TOTAL Other Property and Investments (Total of lines 17-20, 22-29)	-	413,531,827	424,050,728
31	**CURRENT AND ACCRUED ASSETS**			
32	Cash (131)	-	680,216	4,920,695
33	Special Deposits (132-134)	-	1,040,813	934,669
34	Working Funds (135)	-	166,200	167,550
35	Temporary Cash Investments (136)	222-223	5,917,872	5,222,337
36	Notes Receivable (141)	-	-	-
37	Customer Accounts Receivable (142)	-	61,319,904	59,937,985
38	Other Accounts Receivable (143)	-	4,661,713	6,252,229
39	(Less) Accum. Prov. for Uncollectible Accounts-Credit (144)	-	(873,732)	(969,458)
40	Notes Receivable from Associated Companies (145)	-	-	-
41	Accounts Receivable from Associated Companies (146)	-	110,218	10,474,171
42	Fuel Stock (151)	-	-	-
43	Fuel Stock Expense Undistributed (152)	-	-	-

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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)	Balance at End of Previous Year 12/31/14 (d)
44	Residuals (Elec) and Extracted Products (Gas) (153)	-	-	-
45	Plant Material and Operating Supplies (154)	-	10,387,768	8,682,228
46	Merchandise (155)	-	848,083	854,406
47	Other Material and Supplies (156)	-	-	-
48	Nuclear Materials Held for Sale (157)	-	-	-
49	Allowances (158.1 and 158.2)	-	-	-
50	(Less) Noncurrent Portion of Allowances	-	-	-
51	Stores Expenses Undistributed (163)	-	-	-
52	Gas Stored Underground - Current (164.1)	220	53,712,868	61,415,922
53	Liq. Natural Gas Stored and Held for Processing (164.2-164.3)	220	5,498,113	6,494,160
54	Prepayments (165)	230	28,601,382	28,699,047
55	Advances for Gas (166-167)	-	-	-
56	Interest and Dividends Receivable (171)	-	-	-
57	Rents Receivable (172)	-	-	-
58	Accrued Utility Revenues (173)	-	57,987,485	57,963,192
59	Miscellaneous Current and Accrued Assets (174)	-	-	-
60	Derivative Instrument Assets (175)	-	3,165,000	625,000
61	(Less) Long-Term Portion of Derivative Instrument Assets (175)	-	(27,000)	-
62	Derivative Instrument Assets - Hedges (176)	-	(419,000)	(382,000)
63	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)	-	-	-
64	TOTAL Current and Accrued Assets (Total of lines 32 thru 63)	-	232,777,903	251,292,133
65	**DEFERRED DEBITS**			
66	Unamortized Debt Expense (181)	259	8,011,909	9,416,521
67	Extraordinary Property Losses (182.1)	230	-	-
68	Unrecovered Plant and Regulatory Study Costs (182.2)	230	-	-
69	Other Regulatory Assets (182.3)	232	47,426,552	51,804,552
70	Prelim. Survey and Investigation Charges (Electric) (183)	-	-	-
71	Prelim. Survey and Invest. Charges (Gas) (183.1, 183.2)	-	14,845	-
72	Clearing Accounts (184)	-	269,898	166,535
73	Temporary Facilities (185)	-	-	
74	Miscellaneous Deferred Debits (186)	233	379,644,218	361,793,493
75	Def. Losses from Disposition of Utility Plant (187)	-	-	-
76	Research, Devel. and Demonstration Expend. (188)	-	-	-
77	Unamortized Loss on Reacquired Debt (189)	260	2,830,100	3,186,368
78	Accumulated Deferred Income Taxes (190)	234-235	-	23,785,213
79	Unrecovered Purchased Gas Costs (191)	-	(12,357,269)	19,575,835
80	Total Deferred Debits (Total of lines 66 thru 79)		425,840,253	469,728,517
81	Total Assets and Other Debits (Total of lines 10-15, 30,64,and 80		2,663,612,559	2,684,425,720

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
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COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS

Line No.	Title of Account (a)	Reference Page Number (b)	Current Year End of Quarter/Year Balance (c)	Balance at End of Previous Year 12/31/14 (d)
1	**PROPRIETARY CAPITAL**			
2	Common Stock Issued (201)	250-251	381,473,806	373,442,832
3	Preferred Stock Issued (204)	250-251	-	-
4	Capital Stock Subscribed (202, 205)	252	-	-
5	Stock Liability for Conversion (203, 206)	252	-	-
6	Premium on Capital Stock (207)	252	-	-
7	Other Paid-In Capital (208-211)	253	1,649,864	1,649,864
8	Installments Received on Capital Stock (212)	252	20,657	24,249
9	(Less) Discount on Capital Stock (213)	254	-	-
10	(Less) Capital Stock Expense (214)	254	-	-
11	Retained Earnings (215, 215.1, 216)	118-119	442,145,578	435,967,764
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	(35,758,812)	(28,950,289)
13	(Less) Reacquired Capital Stock (217)	250-251	-	-
14	Accumulated Other Comprehensive Income (219)	117	(7,162,202)	(10,075,949)
15	TOTAL Proprietary Capital (Total of lines 2 thru 14)	-	782,368,891	772,058,471
16	**LONG-TERM DEBT**			
17	Bonds (221)	256-257	601,700,000	641,700,000
18	(Less) Reacquired Bonds (222)	256-257	-	-
19	Advances from Associated Companies (223)	256-257	-	-
20	Other Long-Term Debt (224)	256-257	-	-
21	Unamortized Premium on Long-Term Debt (225)	258-259	-	-
22	(Less) Unamortized Discount on Long-Term Debt-Dr. (226)	258-259	-	-
23	(Less) Current Portion of Long-Term Debt	256	(25,000,000)	(40,000,000)
24	TOTAL Long-Term Debt (Total of lines 17 thru 23)	-	576,700,000	601,700,000
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases - Noncurrent (227)	-	155,033	714,289
27	Accumulated Provision for Property Insurance (228.1)	-	124,000	24,000
28	Accumulated Provision for Injuries and Damages (228.2)	-	125,559,048	95,672,313
29	Accumulated Provision for Pensions and Benefits (228.3)	-	243,828,023	256,339,627
30	Accumulated Miscellaneous Operating Provisions (228.4)	-	-	-
31	Accumulated Provision for Rate Refunds (229)	-	-	-

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
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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 (c)	Balance at End of Previous Year 12/31/14 (d)
32	Long-Term Portion of Derivative Instrument Liabilities	-	3,447,000	3,515,000
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges	-	-	-
34	Asset Retirement Obligations (230)	-	-	-
35	TOTAL Other Noncurrent Liabilities (Total of lines 26 thru 34)	-	373,113,104	356,265,229
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Current Portion of Long-term Debt	-	25,000,000	40,000,000
38	Notes Payable (231)	-	270,035,306	234,700,000
39	Accounts Payable (232)	-	70,406,993	85,356,259
40	Notes Payable to Associated Companies (233)	-	-	-
41	Accounts Payable to Associated Companies (234)	-	4,933,043	7,003,934
42	Customer Deposits (235)	-	5,531,369	5,772,279
43	Taxes Accrued (236)	262-263	2,484,593	8,991,541
44	Interest Accrued (237)	-	5,873,323	5,949,573
45	Dividends Declared (238)	-	-	-
46	Matured Long-Term Debt (239)	-	-	-
47	Matured Interest (240)	-	-	-
48	Tax Collections Payable (241)	-	6,842,318	6,297,908
49	Miscellaneous Current and Accrued Liabilities (242)	268	8,192,637	8,484,569
50	Obligations Under Capital Leases-Current (243)	-	(155,033)	(714,289)
51	Derivative Instrument Liabilities (244)	-	25,539,000	33,409,000
52	(Less) Long-Term Portion of Derivative Instrument Liabilities	-	(3,447,000)	(3,515,000)
53	Derivative Instrument Liabilities - Hedges (245)	-	-	-
54	(Less) Long-Term Portion of Derivative Instrument Liabilities - Hedges	-	-	-
55	TOTAL Current and Accrued Liabilities (Total of lines 37 thru 54)	-	421,236,549	431,735,774
56	**DEFERRED CREDITS**			
57	Customer Advances for Construction (252)	-	3,346,865	3,192,328
58	Accumulated Deferred Investment Tax Credits (255)	-	47,567	165,881
59	Deferred Gains from Disposition of Utility Plant (256)	-	-	-
60	Other Deferred Credits (253)	269	7,461,031	8,064,186
61	Other Regulatory Liabilities (254)	278	13,322,753	11,557,175
62	Unamortized Gain on Reacquired Debt (257)	260	-	-
63	Accumulated Deferred Income Taxes - Accelerated Amortization (281)	-	-	-
64	Accumulated Deferred Income Taxes - Other Property (282)	-	-	-
65	Accumulated Deferred Income Taxes - Other (283)	276-277	486,015,799	499,686,676
66	TOTAL Deferred Credits (Total of lines 49 thru 55)	-	510,194,015	522,666,246
67	TOTAL Liabilities and Other Credits (Total of lines 15, 24, 35, 55 and 66)	-	2,663,612,559	2,684,425,720

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
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NCOME FOR THE YEAR

1. Report amounts for accounts 412 and 413, Revenue and Expenses from Utility Plant Leased to Others, in another utility column (i, j) in a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
2. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
3. Report data for lines 8, 10, and 11 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1, and 407.2.

Line No.	Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current Three Months Ended Quarterly Only No Fourth Quarter (e)	Prior Three Months Ended Quarterly Only No Fourth Quarter (f)
1	**UTILITY OPERATING INCOME**					
2	Operating Revenues (400)	300-301	720,244,341	750,415,902		
3	Operating Expenses					
4	Operation Expenses (401)	320-325	464,337,689	479,496,737		
5	Maintenance Expenses (402)	320-325	12,490,955	13,352,819		
6	Depreciation Expense (403)	336-338	74,409,793	72,659,709		
7	Depreciation Expense for Asset Retirement Costs (403.1)		-	-		
8	Amort. & Depl. of Utility Plant (404-405)	336-338	-	-		
9	Amort. of Utility Plant Acu. Adjustment (406)	336-338	-	-		
10	Amort of Prop. Losses, Unrecovered Plant and Regulatory Study Costs (407.1)		-	-		
11	Amort. of Conversion Expenses (407.2)		-	-		
12	Regulatory Debits (407.3)		3,513,050	-		
13	(Less) Regulatory Credits (407.4)		-	-		
14	Taxes Other Than Income Taxes (408.1)	262-263	46,223,362	45,985,528		
15	Income Taxes - Federal (409.1)	262-263	23,878,816	(3,215,480)		
16	- Other (409.1)	262-263	4,806,220	(4,882,951)		
17	Provision for Deferred Income Taxes (410.1)	276-277	32,864,099	104,801,901		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	276-277	24,793,556	52,716,717		
19	Investment Tax Credit Adj. - Net (411.4)		(148,314)	(353,341)		
20	(Less) Gains from Disp. of Utility Plant (411.6)		-	-		
21	Losses from Disp. of Utility Plant (411.7)		-	-		
22	(Less) Gains from Disposition of Allowances (411.8)		-	-		
23	Losses from Disposition of Allowances (411.9)		-	-		
24	Accretion Expense (411.10)		-	-		
25	TOTAL Utility Operating Expenses (Total of lines 4 thru 24)		637,582,114	655,128,205		
26	Net Utility Operating income (Enter Total of line 2 less 25) (Carry forward to page 116, line 27)		82,662,227	95,287,697		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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STATEMENT OF INCOME FOR THE YEAR (Continued)

4. Explain in a footnote if the previous year's figures are different from that reported in prior reports.

5. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles, lines 2 to 23, and report the information in the blank space on page 122 or in a supplemental statement.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
		720,244,341	750,415,902			2
						3
		464,337,689	479,496,737			4
		12,490,955	13,352,819			5
		74,409,793	72,659,709			6
		-	-			7
		-	-			8
		-	-			9
		-	-			10
		-	-			11
		3,513,050	-			12
		-	-			13
		46,223,362	45,985,528			14
		23,878,816	(3,215,480)			15
		4,806,220	(4,882,951)			16
		32,864,099	104,801,901			17
		24,793,556	52,716,717			18
		(148,314)	(353,341)			19
		-	-			20
		-	-			21
		-	-			22
		-	-			23
		-	-			24
		637,582,114	655,128,205			25
		82,662,227	95,287,697			26

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

STATEMENT OF INCOME FOR THE YEAR (Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 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)	-	82,662,227	95,287,697		
28	**Other Income and Deductions**					
29	Other Income	-				
30	Nonutility Operating Income	-				
31	Revenues From Merch, Jobbing and Contract Work (415)	-	4,768,567	4,611,207		
32	(Less) Costs and Exp. of Merch, Job & Contract Work (416)	-	4,840,450	4,501,323		
33	Revenues From Nonutility Operations (417)	-	25,961,149	26,321,256		
34	(Less) Expenses of Nonutility Operations (417.1)	-	12,842,637	13,037,973		
35	Nonoperating Rental Income (418)	-	372,940	493,969		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	(6,808,523)	(7,812,475)		
37	Interest and Dividend Income (419)	-	2,802,538	3,419,957		
38	Allow. for Other Funds Used During Constr (419.1)	-	-	-		
39	Miscellaneous Nonoperating Income (421)	-	20,865	44,252		
40	Gain on disposition of Property (421.1)	-	-	-		
41	TOTAL Other Income (Total of lines 31 thru 40)		9,434,449	9,538,870		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)	-	-	-		
44	Miscellaneous Amortization (425)	-	-	-		
45	Donations (426.1)	340	1,291,986	1,101,067		
46	Life Insurance (426.2)	-	(2,187,796)	(1,969,862)		
47	Penalties (426.3)	-	314	15,037		
48	Expenditures for Certain Civic, Political and Related Activities (426.4)	-	1,544,920	1,163,186		
49	Other Deductions (426.5)	-	134,954	125,874		
50	TOTAL Other Income Deductions (Total of Lines 43 thru 49)	340	784,378	435,302		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	687,029	677,463		
53	Income Taxes - Federal (409.2)	262-263	1,609,275	12,622,937		
54	Income Taxes - Other (409.2)	262-263	350,356	2,761,218		
55	Provision for Deferred Inc. Taxes (410.2)	272-277	101,298	(11,036,712)		
56	(Less) Provision for Deferred Inc. Taxes - Cr. (411.2)	272-277	639,348	1,104,805		
57	Investment Tax Credit Adj. - Net (411.5)	-	-	-		
58	(Less) Investment Tax Credits (420)	-	-	-		
59	TOTAL Taxes on Other Inc. and Ded. (Total of 52 thru 58)		2,108,610	3,920,101		
60	Net Other Income and Deductions (Total of Lines 41, 50, 59)		6,541,461	5,183,467		
61	**Interest Charges**					
62	Interest on Long-Term Debt (427)	256-257	35,178,050	37,920,494		
63	Amortization of Debt Disc. and Expense (428)	258-259	1,302,745	1,369,268		
64	Amortization of Loss on Reacquired Debt (428.1)	260	356,268	387,606		
65	(Less) Amort. of Premium on Debt - Credit (429)	256-257	-	-		
66	(Less) Amortization of Gain on Reacquired Debt - Credit (429.1)	-	-	-		
67	Interest on Debt to Assoc. Companies (430)	340	-	-		

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

STATEMENT OF INCOME FOR THE YEAR (Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current Three Months Ended Quarterly Only No Fourth Quarter (e)	Prior Three Months Ended Quarterly Only No Fourth Quarter (f)
68	Other Interest Expense (431)	340	2,165,011	1,694,964		
69	(Less) Allow. for Borrowed Funds Used During Const.-Cr. (432)	-	159,970	117,417		
70	Net Interest Charges (Total of lines 62 thru 69) (See note 1 below)		38,842,104	41,254,915		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		50,361,584	59,216,249		
72	**Extraordinary Items**					
73	Extraordinary Income (434)	-	-	-		
74	(Less) Extraordinary Deductions (435)	-	-	-		
75	Net Extraordinary Items (Total of line 73 less 74)		-	-		
76	Income Taxes - Federal and Other (409.3)	262-263	-	-		
77	Extraordinary Items After Taxes (Total of line 75 less line 76)		-	-		
78	Net Income (Total of lines 71 and 77)		50,361,584	59,216,249		

Note 1: Line 70 Detail

Utility interest expense	37,774,353	40,145,066
Non-Utility interest expense	1,067,751	1,109,849
Total interest expense, line 70 above	38,842,104	41,254,915

Note 2: Accounting standards allow for the capitalization of all or part of an incurred cost that would otherwise be charged to expense if a regulator provides orders that create probable recovery of past costs through future revenues. NW Natural Gas Company accrues interest as specified by regulatory order on certain regulatory balances at our authorized rate of return (ROR). This ROR includes both a debt and equity component, which we are allowed to recover from customers in the form of a carrying cost on regulatory deferred account balances. The equity component of our ROR is not an incurred cost that would otherwise be charged to expense, and therefore is not capitalized and recognized as income for financial reporting purposes. This leads to a difference in reported Net Income between the FERC Form 2 and the Form 10-K filed with the Securities & Exchange Commission (SEC).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A resubmission		Dec. 31, 2015

Statement of Accumulated Comprehensive Income and Hedging Activities

1. Report the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report 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)	Current Year Amount (in dollars) (b)
1	Beginning AOCI Balance	(10,075,949)
2	Unrealized Gains/losses on available-for-sale securities, net of tax	-
3	Pension liability adjustment, net of tax	1,561,183
4	Amortization of pension liabilities, net of tax	1,352,564
5	Foreign currency hedges, net of tax	-
6	Change in unrealized loss from hedging, net of tax	-
7	Cash flow hedges, net of tax	-
8	Other adjustments, net of tax	-
9	Ending Balance of AOCI	(7,162,202)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A resubmission		Dec. 31, 2015

STATEMENT OF RETAINED EARNINGS FOR THE YEAR

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 Year Amount (in dollars) (c)	Previous Year Amount (in dollars) (d)
	UNAPPROPRIATED RETAINED EARNINGS			
1	Balance - Beginning of Year		435,967,764	419,032,410
2	Changes (Identify by prescribed retained earnings accounts)			
3	Adjustments to Retained Earnings (Account 439)			
3.01	Credit:		-	-
3.02	Credit: Other Comprehensive Income		-	-
3.03	Credit:		-	-
4	TOTAL Credits to Retained Earrings (Account 439) (Total of lines 3.01 thru 3.03)		-	-
4.01	Debit: Capital Stock Expense		-	-
4.02	Debit: Stock Repurchase		-	-
4.03	Debit: Other Comprehensive Income		-	-
4.04	Debit: Unearned Compensation		-	-
5	TOTAL Debits to Retained Earnings (Account 439) (Total of lines 4.01 thru 4.04)		-	-
6	Balance Transferred from Income (Account 433 less Account 418.1)		57,170,107	67,028,724
7	Appropriations of Retained Earnings (Account 436)			
7.01			-	-
7.02			-	-
8	TOTAL Appropriations of Retained Earnings (Account 436) (Total of lines 7.01 thru 7.02)		-	-
9	Dividends Declared - Preferred and Preference Stock (Account 437))			
9.01	Preferred Stock		-	-
9.02			-	-
10	TOTAL Dividends Declared - Preferred Stock (Account 437) (Total of lines 9.01 thru 9.02)		-	-
11	Dividends Declared - Common Stock (Account 438)			
11.01	Common Stock Cash Dividends		(50,992,293)	(50,093,378)
11.02	Stock Dividends		-	-
12	TOTAL Dividends Declared - Common Stock (Account 438) (Total of lines 11.01 thru 11.02)		(50,992,293)	(50,093,378)
13	Transfers from Acct. 216.1, Unappropriated Undistributed Subsidiary Earnings		-	-
13.01	Other Changes (Explain) (see Note 1 below)		-	8
14	Balance - End of Year (Total of lines 1, 4, 5, 6, 8, 10, 12, and 13)		442,145,578	435,967,764

Note 1: Other Changes are immaterial rounding differences.

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A resubmission	(Mo, Da, Yr)	Dec. 31, 2015

STATEMENT OF RETAINED EARNINGS FOR THE YEAR (Continued)

6. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
7. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservations or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
8. At lines 3, 4, 7, 9, 11, and 15, add rows as necessary to report all data. When rows are added, the additional row numbers should follow in sequence, e.g., 3.01, 3.02, etc.

Line No.	Item (a)	Current Year Amount (in dollars) (b)	Previous Year Amount (in dollars) (c)
	APPROPRIATED RETAINED EARNINGS (Account 215) State balance and purpose of each appropriated retained earnings amount at end of year and give accounting entries for any applications of appropriated retained earnings during the year.		
15.01			
15.02			
15.03			
15.04			
15.05			
15.06			
15.07			
16	TOTAL Appropriated Retained Earnings (Account 215)	-	-
	APPROPRIATED RETAINED EARNINGS - AMORTIZATION RESERVE, FEDERAL (Account 215.1) State below the total amount set aside through appropriations of retained earnings, as of the end of the year, in compliance with the provisions of Federally granted hydroelectric project licenses held by the respondent. If any reductions or changes other than the normal annual credits hereto have been made during the year, explain such items in a footnote.		
17	TOTAL Appropriated Retained Earnings - Amortization Reserve, Federal (Account 215.1)	-	-
18	TOTAL Appropriated Retained Earnings (Accounts 215, 215.1) (Total of lines 16 amd 17)	-	-
19	TOTAL Retained Earnings (Account 215, 215.1, 216) (Total of lines 14 and 18) (see Note 1 below)	442,145,578	435,967,764
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (ACCOUNT 216.1)		
20	Balance - Beginning of Year (Debit or Credit)	(28,950,289)	(21,137,814)
21	Equity in Earnings for Year (Credit) (Account 418.1)	(6,808,523)	(7,812,475)
22	(Less) Dividends Received (Debit)	-	-
23	Other Changes (Explain)	-	-
24	Balance - End of year (Total of lines 20 thru 23)	(35,758,812)	(28,950,289)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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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; (d) Identify separately such items as investments, fixed assets, intangibles,etc.
2. Information about noncash investing and financing activities should be provided on page 122. Provide also on page 122 a reconciliation between "Cash and Cash Equivalents at End of Year" 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 on page 122 the amounts of interest paid (net of amounts 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 on page 122. 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 Amount (b)	Previous Year Amount (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 72(c) on page 116)	50,361,584	59,216,249
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	75,692,746	74,008,054
5	Amortization of (Specify)	-	-
5.01	FAS 109 Deferred Taxes	(4,378,000)	(4,378,000)
5.02	FAS 109 Regulatory Asset	4,378,000	4,378,000
6	Deferred Income Taxes (Net)	14,492,336	14,048,678
7	Investment Tax Credit Adjustments (Net)	(118,314)	(201,305)
8	Net (Increase) Decrease in Receivables	10,476,824	(309,157)
9	Net (Increase) Decrease in Inventory	8,699,101	(16,581,578)
10	Net (Increase) Decrease in Allowances Inventory	-	-
11	Net Increase (Decrease) in Payables and Accrued Expenses	(23,603,356)	507,705
12	Minimum Pension Liability Adjustment	2,913,747	(3,717,479)
13	Unrealized loss from price risk management activities	2,706,753	30,964,000
14	(Less) Allowance for Other Funds Used During Construction	(159,970)	(117,417)
15	(Less) Undistributed Earnings from Subsidiary Companies	6,808,523	7,812,475
16	Other: Net (Increase) Decrease in Unbilled Revenues	(24,293)	3,563,853
16.01	Deferred Debits - Net	15,867,066	22,863,910
16.02	Net (Increase) Decrease in Other Current Assets & Liab.	(12,904,159)	(18,308,790)
16.03	Other - Noncurrent Liab., Deferred Credits, & Other Invest.	5,374,415	8,913,708
16.04	Unearned Compensation	3,503,289	1,278,582
17	Net Cash Provided by (Used in) Operating Activities		
18	(Total of lines 2 thru 16.04)	160,086,292	183,941,488
19			
20	Cash Flows from Investment Activities:		
21	Construction and Acquisition of Plant (including land):		
22	Gross Additions to Utility Plant (less nuclear fuel)	(115,284,976)	(116,212,385)
23	Gross Additions to Nuclear Fuel	-	-
24	Gross Additions to Common Utility Plant	-	-
25	Gross Additions to Nonutility Plant	(1,208,318)	124,418
26	(Less) Allowance for Other Funds Used During Constr.	159,970	117,417
27	Other:	1,364,720	287,584
28	Cash Outflows for Plant (Total of lines 22 thru 27)	(114,968,604)	(115,682,966)
29			
30	Acquisition of Other Noncurrent Assets (d)	-	-
31	Proceeds from Disposal of Noncurrent Assets (d)	1,161,476	1,391,531
32		-	-
33	Investments in & Advances to Assoc. & Sub. Companies	-	-
34	Contributions & Advances from Assoc. & Sub. Companies	1,002,895	(8,190,458)
35	Disposition of Investments in (and Advances to)		
36	Associated and Subsidiary Companies	-	-
37		-	-
38	Purchase of Investment Securities (a)	-	-
39	Proceeds from Sales of Investment Securities (a)	-	-

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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STATEMENT OF CASH FLOWS (Continued)

Line No.	DESCRIPTION (See Instructions for explanation of codes) (a)	Current Year Amount	Previous Year Amount
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		-	-
48	Net Cash Provided by (Used in) Investing Activities		
49	(Total of lines 28 thru 47)	(112,804,233)	(122,481,893)
50			
51	Cash Flows from Financing Activities:		
52	Proceeds from Issuance of:		
53	Long-Term Debt (b)	-	-
54	Preferred Stock	-	-
55	Common Stock	3,875,244	8,986,000
56	Other: Capital Leases	-	-
57	Net Increase in Short-Term Debt (c)	35,335,306	46,500,000
58			
59	Cash Provided by Outside Sources (Total of lines 53 thru 58)	39,210,550	55,486,000
60			
61	Payments for Retirement of:		
62	Long-Term Debt (b)	(40,000,000)	(60,000,000)
63	Preferred Stock	-	-
64	Common Stock	-	-
65	Other: Capital Leases	(689,505)	(824,213)
66	Net Increase (Decrease) in Short-Term Debt (c)	-	-
67			
67	Capital Stock Expense	-	-
68	Dividends on Preferred Stock	-	-
69	Dividends on Common Stock	(49,243,254)	(50,093,378)
70	Net Cash Provided by (Used in) Financing Activities		
71	(Total of lines 59 thru 69)	(50,722,209)	(55,431,591)
72			
73	Net Increase (Decrease) in Cash and Cash Equivalents		
74	(Total of lines 18, 49, and 71)	(3,440,150)	6,028,004
75			
76	Cash and Cash Equivalents at Beginning of Period	11,245,251	5,217,247
77			
78	Cash and Cash Equivalents at End of Period	7,805,101	11,245,251

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

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.

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 measuremenet 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 where 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.

See Pages 122-A

NORTHWEST NATURAL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND PRINCIPLES OF CONSOLIDATION

The accompanying consolidated financial statements represent the consolidated results of Northwest Natural Gas Company (NW Natural or the Company) and all companies we directly or indirectly control, either through majority ownership or otherwise. We have two core businesses: our regulated local gas distribution business, referred to as the utility segment, which serves residential, commercial, and industrial customers in Oregon and southwest Washington; and our gas storage businesses, referred to as the gas storage segment, which provides storage services for utilities, gas marketers, electric generators, and large industrial users from facilities located in Oregon and California. In addition, we have investments and other non-utility activities we aggregate and report as other.

Our core utility business assets and operating activities are largely included in the parent company, NW Natural. Our direct and indirect wholly-owned subsidiaries include NW Natural Energy, LLC (NWN Energy), NW Natural Gas Storage, LLC (NWN Gas Storage), Gill Ranch Storage, LLC (Gill Ranch), NNG Financial Corporation (NNG Financial), Northwest Energy Corporation (Energy Corp), and NW Natural Gas Reserves, LLC (NWN Gas Reserves). Investments in corporate joint ventures and partnerships we do not directly or indirectly control, and for which we are not the primary beneficiary, are accounted for under the equity method, which includes NWN Energy's investment in Trail West Holdings, LLC (TWH) and NNG Financial's investment in Kelso-Beaver (KB) Pipeline. NW Natural and its affiliated companies are collectively referred to herein as NW Natural. The consolidated financial statements are presented after elimination of all intercompany balances and transactions, except for amounts required to be included under regulatory accounting standards to reflect the effect of such regulation. In this report, the term "utility" is used to describe our regulated gas distribution business, and the term "non-utility" is used to describe our gas storage businesses and other non-utility investments and business activities.

Certain prior year balances in our consolidated financial statements and notes have been reclassified to conform with the current presentation. These reclassifications had no effect on our prior year's consolidated results of operations, financial condition, or cash flows.

2. SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles in the United States of America (GAAP) requires management to make estimates and assumptions that affect reported amounts in the consolidated financial statements and accompanying notes. Actual amounts could differ from those estimates, and changes would most likely be reported in future periods. Management believes the estimates and assumptions used are reasonable.

Industry Regulation

Our principal businesses are the distribution of natural gas, which is regulated by the OPUC and WUTC, and natural gas storage services, which are regulated by either the FERC or the CPUC, and to a certain extent by the OPUC and WUTC. Accounting records and practices of our regulated businesses conform to the requirements and uniform system of accounts prescribed by these regulatory authorities in accordance with U.S. GAAP. Our businesses regulated by the OPUC, WUTC, and FERC earn a reasonable return on invested capital from approved cost-based rates, while our business regulated by the CPUC earns a return to the extent we are able to charge competitive prices above our costs (i.e. market-based rates).

In applying regulatory accounting principles, we capitalize or defer certain costs and revenues as regulatory assets and liabilities pursuant to orders of the OPUC or WUTC, which provide for the recovery of revenues or expenses from, or refunds to, utility customers in future periods, including a return or a carrying charge in certain cases.

At December 31, the amounts deferred as regulatory assets and liabilities were as follows:

In thousands	Regulatory Assets 2015	Regulatory Assets 2014
Current:		
Unrealized loss on derivatives[1]	$ 22,092	$ 29,889
Gas costs	8,717	21,794
Environmental costs[2]	9,270	—
Decoupling[3]	18,775	7,505
Other[4]	10,324	9,374
Total current	$ 69,178	$ 68,562
Non-current:		
Unrealized loss on derivatives[1]	$ 3,447	$ 3,515
Pension balancing[5]	43,748	32,541
Income taxes	43,049	47,427
Pension and other postretirement benefit liabilities	184,223	201,845
Environmental costs[2]	76,584	58,859
Gas costs	1,949	5,971
Other[4]	17,711	18,750
Total non-current	$ 370,711	$ 368,908

In thousands	Regulatory Liabilities 2015	Regulatory Liabilities 2014
Current:		
Gas costs	$ 14,157	$ 5,700
Unrealized gain on derivatives[1]	2,659	240
Other[4]	13,111	13,165
Total current	$ 29,927	$ 19,105
Non-current:		
Gas costs	$ 8,869	$ 2,507
Unrealized gain on derivatives[1]	27	—
Accrued asset removal costs[6]	327,047	311,238
Other[4]	3,344	3,460
Total non-current	$ 339,287	$ 317,205

(1) Unrealized gains or losses on derivatives are non-cash items and, therefore, do not earn a rate of return or a carrying charge. These amounts are recoverable through utility rates as part of the annual Purchased Gas Adjustment (PGA) mechanism when realized at settlement.

(2) Environmental costs relate to specific sites approved for regulatory deferral by the OPUC and WUTC. In Oregon, we earn a carrying charge on cash amounts paid, whereas amounts accrued but not yet paid do not earn a carrying charge until expended. We also accrue a carrying charge on insurance proceeds for amounts owed to customers. In Washington, a carrying charge related to deferred amounts will be determined in a future proceeding. Current environmental costs represent remediation costs management expects to collect from customers in the next 12 months. Amounts included in this estimate are still subject to a prudence and earnings test review by the OPUC and do not include the $5 million base rate rider. The amounts allocable to Oregon are recoverable through utility rates, subject to an earnings test. See Note 15.

(3) This deferral represents the margin adjustment resulting from differences between actual and expected volumes.

(4) These balances primarily consist of deferrals and amortizations under approved regulatory mechanisms. The accounts being amortized typically earn a rate of return or carrying charge.

(5) The deferral of certain pension expenses above or below the amount set in rates was approved by the OPUC, with recovery of these deferred amounts through the implementation of a balancing account, which includes the expectation of lower net periodic benefit costs in future years. Deferred pension expense balances include accrued interest at the utility's authorized rate of return, with the equity portion of interest income recognized when amounts are collected in rates.

(6) Estimated costs of removal on certain regulated properties are collected through rates. See "Accounting Policies—*Plant, Property, and Accrued Asset Removal Costs*" below.

The amortization period for our regulatory assets and liabilities ranges from less than one year to an indeterminable period. Our regulatory deferrals for gas costs payable are generally amortized over 12 months beginning each November 1 following the gas contract year during which the deferred gas costs are recorded. Similarly, most of our other regulatory deferred accounts are amortized over 12 months. However, certain regulatory account balances, such as income taxes, environmental costs, pension liabilities, and accrued asset removal costs, are large and tend to be amortized over longer periods once we have agreed upon an amortization period with the respective regulatory agency.

We believe all costs incurred and deferred at December 31, 2015 are prudent. We annually review all regulatory assets and liabilities for recoverability and more often if circumstances warrant. If we should determine that all or a portion of these regulatory assets or liabilities no longer meet the criteria for continued application of regulatory accounting, then we would be required to write off the net unrecoverable balances in the period such determination is made.

Environmental Regulatory Accounting

On February 20, 2015, the OPUC issued an Order (2015 Order) addressing outstanding implementation items related to the Site Remediation and Recovery Mechanism (SRRM). Under the Order, $15 million of $95 million in total environmental remediation expenses deferred through 2012 were disallowed. The OPUC found the $95 million to be prudent but disallowed the $15 million from rate recovery based on its determination of how an earnings test should apply to years between 2003 and 2012, with adjustments for other factors the OPUC deemed relevant. We recognized the $15 million pre-tax disallowance, or $9.1 million after-tax charge, during the first quarter of 2015. The charge was recorded in operations and maintenance expense. Also, as a result of the order, we recognized $5.3 million pre-tax of interest income related to the equity earnings on our deferred environmental expenses.

On January 27, 2016, the OPUC issued an Order addressing the outstanding issues. In November 2015, we began collecting revenues from customers through the SRRM. These collections are included in utility operating revenues and are offset by environmental remediation expense included in operating expense. See Note 15 and Note 16 regarding our SRRM.

New Accounting Standards

Recently Adopted Accounting Pronouncement

PRESENTATION OF DEFERRED TAXES. On November 20, 2015, the FASB (Financial Accounting Standards Board) issued ASU 2015-17, "Balance Sheet Classification of Deferred Taxes." The ASU requires deferred tax liabilities and assets to be classified as noncurrent in a classified statement of financial position. The new requirements are effective for us beginning January 1, 2017 and may be applied either prospectively to all deferred tax liabilities and assets or retrospectively to all periods presented. We have early adopted the change in accounting principle on a prospective basis, and it is reflected within our consolidated balance sheet for the period ended December 31, 2015. Prior periods were not retrospectively adjusted.

Recently Issued Accounting Pronouncements

BENEFIT PLAN ACCOUNTING. On July 31, 2015, the FASB issued ASU 2015-12, "Plan Accounting: Defined Benefit Pension Plans, Defined Contribution Pension Plans, and Health and Welfare Benefit Plans." The ASU outlines a three part update. Only part two of the update is applicable for us, which simplifies the investment disclosure requirements for employee benefit plans by allowing certain disclosures at an aggregated level, reducing the number of ways assets must be grouped and analyzed, and no longer requiring investment strategy disclosures for certain investments. The new requirements are effective for us beginning January 1, 2016, with early adoption permitted. We will be required to apply the disclosure guidance retrospectively and do not expect the ASU to materially affect our financial statements and disclosures.

FAIR VALUE MEASUREMENT. On May 1, 2015, the FASB issued ASU 2015-07, "Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or its Equivalent)." The ASU removes the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share practical expedient and also removes certain disclosure requirements. The new requirements are effective for us beginning January 1, 2016 with retrospective application to all periods presented required and early adoption permitted. We do not expect the ASU to materially affect our financial statements and disclosures.

INTANGIBLES - GOODWILL AND OTHER - INTERNAL-USE SOFTWARE. On April 15, 2015 the FASB issued ASU 2015-05, "Customer's Accounting for Fees Paid in a Cloud Computing Arrangement." The ASU provides customers guidance on how to determine whether a cloud computing arrangement includes a software license. The new requirements are effective for us beginning January 1, 2016. The ASU can be applied prospectively or retrospectively and early adoption is permitted. We intend to apply the guidance prospectively and do not expect the ASU to materially affect our financial statements and disclosures.

DEBT ISSUANCE COSTS. On April 7, 2015, the FASB issued ASU 2015-03, "Simplifying the Presentation of Debt Issuance Costs," which requires the presentation of debt issuance costs in the balance sheet as a direct deduction from the associated debt liability. The new requirements are effective for us beginning January 1, 2016. The new guidance will be applied on a retrospective basis. We do not expect the ASU to materially affect our financial statements and disclosures.

REVENUE RECOGNITION. On May 28, 2014, the FASB issued ASU 2014-09 "Revenue From Contracts with Customers." The underlying principle of the guidance requires entities to recognize revenue depicting the transfer of goods or services to customers at amounts the entity is expected to be entitled to in exchange for those goods or services. The model provides a five-step approach to revenue recognition: (1) identify the contract(s) with the customer; (2) identify the separate performance obligations in the contract(s); (3) determine the transaction price; (4) allocate the transaction price to separate performance obligations; and (5) recognize revenue when, or as, each performance obligation is satisfied. The new requirements prescribe either a full retrospective or simplified transition adoption method. On August 12, 2015, the FASB deferred the effective date by one year to January 1, 2018 for annual reporting periods beginning after December 15, 2017. The FASB also permitted early adoption of the standard, but not before the original effective date of January 1, 2017. We are currently assessing the effect of this standard on our financial statements and disclosures.

Accounting Policies

Plant, Property, and Accrued Asset Removal Costs

Plant and property are stated at cost, including capitalized labor, materials and overhead. In accordance with regulatory accounting standards, the cost of acquiring and constructing long-lived plant and property generally includes an allowance for funds used during construction (AFUDC) or capitalized interest. AFUDC represents the regulatory financing cost incurred when debt and equity funds are used for construction (see "*AFUDC*" below). When constructed assets are subject to market-based rates rather than cost-based rates, the financing costs incurred during construction are included in capitalized interest in accordance with U.S. GAAP, not as regulatory financing costs under AFUDC.

In accordance with long-standing regulatory treatment, our depreciation rates consist of three components: one based on the average service life of the asset, a second based on the estimated salvage value of the asset, and a third based on the asset's estimated cost of removal. We collect, through rates, the estimated cost of removal on certain regulated properties through depreciation expense, with a corresponding offset to accumulated depreciation. These removal costs are non-legal obligations as defined by regulatory accounting guidance. Therefore, we have included these costs as non-current regulatory liabilities rather than as accumulated depreciation on our consolidated balance sheets. In the rate setting process, the liability for removal costs is treated as a reduction to the net rate base on which the regulated utility has the opportunity to earn its allowed rate of return.

The costs of utility plant retired or otherwise disposed of are removed from utility plant and charged to accumulated depreciation for recovery or refund through future rates. Gains from the sale of regulated assets are generally deferred and refunded to customers. For non-utility assets, we record a gain or loss upon the disposal of the property, and the gain or loss is recorded in operating income in the consolidated statements of comprehensive income.

Our provision for depreciation of utility property, plant, and equipment is recorded under the group method on a straight-line basis with rates computed in accordance with depreciation studies approved by regulatory authorities. The weighted-average depreciation rate for utility assets in service was approximately 2.8% for 2015, 2014, and 2013, reflecting the approximate weighted-average economic life of the property. This includes 2015 weighted-average depreciation rates for the following asset categories: 2.7% for transmission and distribution plant, 2.2% for gas storage facilities, 4.6% for general plant, and 2.7% for intangible and other fixed assets.

AFUDC. Certain additions to utility plant include AFUDC, which represents the net cost of debt and equity funds used during construction. AFUDC is calculated using actual interest rates for debt and authorized rates for ROE, if applicable. If short-term debt balances are less than the total balance of construction work in progress, then a composite AFUDC rate is used to represent interest on all debt funds, shown as a reduction to interest charges, and on ROE funds, shown as other income. While cash is not immediately recognized from recording AFUDC, it is realized in future years through rate recovery resulting from the higher utility cost of service. Our composite AFUDC rate was 0.4% in 2015, and 0.3% in 2014 and 2013, respectively.

IMPAIRMENT OF LONG-LIVED ASSETS. We review the carrying value of long-lived assets whenever events or changes in circumstances indicate the carrying amount of the assets may not be recoverable. Factors that would necessitate an impairment assessment of long-lived assets include a significant adverse change in the extent or manner in which the asset is used, a significant adverse change in legal factors or business climate that could affect the value of the asset, or a significant decline in the observable market value or expected future cash flows of the asset, among others.

When such factors are present, we assess the recoverability by determining whether the carrying value of the asset will be recovered through expected future cash flows. An asset is determined to be impaired when the carrying value of the asset exceeds the expected undiscounted future cash flows from the use and eventual disposition of the asset. If an impairment is indicated, we record an impairment loss for the difference between the carrying value and the fair value of the long-lived assets. Fair value is estimated using appropriate valuation methodologies, which may include an estimate of discounted cash flows.

We determined there were no long-lived asset impairments in 2015; however our Gill Ranch Storage facility within our Gas Storage Segment was reviewed for impairment. The undiscounted cash flows are in excess of the carrying value of the asset and no impairment was indicated. The cash flows assume a recovery of storage pricing and the ability to contract with higher value customers. Accordingly, if storage pricing does not improve and/or new higher value customers are not obtained, future analysis may result in an impairment of these long-lived assets.

Cash and Cash Equivalents

For purposes of reporting cash flows, cash and cash equivalents include cash on hand plus highly liquid investment accounts with original maturity dates of three months or less. At December 31, 2015 and 2014, outstanding checks of approximately $2.5 million and $5.5 million, respectively, were included in accounts payable.

Revenue Recognition and Accrued Unbilled Revenue

Utility revenues, derived primarily from the sale and transportation of natural gas, are recognized upon delivery of the gas commodity or service to customers. Revenues include accruals for gas delivered but not yet billed to customers based on estimates of deliveries from meter reading dates to month end (accrued unbilled revenue). Accrued unbilled revenue is dependent upon a number of factors that require management's judgment, including total gas receipts and deliveries, customer use by billing cycle, and weather factors. Accrued unbilled revenue is reversed the following month when actual billings occur. Our accrued unbilled revenue at December 31, 2015 and 2014 was $58.0 million.

Non-utility revenues are derived primarily from the gas storage segment. At our Mist underground storage facility, revenues are primarily firm service revenues in the form of fixed monthly reservation charges. At our Gill Ranch facility, firm storage services resulting from short-term and long-term contracts are typically recognized in revenue ratably over the term of the contract regardless of the actual storage capacity utilized. In addition, we also have asset management service revenue from an independent energy marketing company that optimizes commodity, storage, and pipeline capacity release transactions. Under this agreement, guaranteed asset management revenue is recognized using a straight-line, pro-rata methodology over the term of each contract. Revenues earned above the guaranteed amount are recognized as they are earned.

Revenue Taxes

Revenue-based taxes are primarily franchise taxes, which are collected from customers and remitted to taxing authorities. Revenue taxes are included in operating revenues in the statement of comprehensive income. Revenue taxes were $18.0 million, $18.8 million, and $19.0 million for 2015, 2014, and 2013, respectively.

Accounts Receivable and Allowance for Uncollectible Accounts

Accounts receivable consist primarily of amounts due for natural gas sales and transportation services to utility customers, plus amounts due for gas storage services. We establish an allowance for uncollectible accounts (allowance) for trade receivables, including accrued unbilled revenue, based on the aging of receivables, collection experience of past due account balances including payment plans, and historical trends of write-offs as a percent of revenues. A specific allowance is established and recorded for large individual customer receivables when amounts are identified as unlikely to be partially or fully recovered. Inactive accounts are written-off against the allowance after they are

120 days past due or when deemed uncollectible. Differences between our estimated allowance and actual write-offs will occur based on a number of factors, including changes in economic conditions, customer creditworthiness, and natural gas prices. The allowance for uncollectible accounts is adjusted quarterly, as necessary, based on information currently available.

Inventories

Utility gas inventories, which consist of natural gas in storage for the utility, are stated at the lower of average cost or net realizable value. The regulatory treatment of utility gas inventories provides for cost recovery in customer rates. Utility gas inventories injected into storage are priced in inventory based on actual purchase costs. Utility gas inventories withdrawn from storage are charged to cost of gas during the current period at the weighted-average inventory cost.

Gas storage inventories, which primarily represent inventories at the Gill Ranch storage facility, mainly consist of natural gas received as fuel-in-kind from storage customers. Gas storage inventories are valued at the lower of average cost or net realizable value. Cushion gas is not included in our inventory balances, is recorded at original cost, and classified as a long-term plant asset.

Materials and supplies inventories consist of both utility and non-utility inventories and are stated at the lower of average cost or net realizable value.

Our utility and gas storage inventories totaled $59.3 million and $68.0 million at December 31, 2015 and 2014, respectively. At December 31, 2015 and 2014, our materials and supplies inventories totaled $11.6 million and $9.8 million, respectively.

Gas Reserves

Gas reserves are payments to acquire and produce natural gas reserves. Gas reserves are stated at cost, adjusted for regulatory amortization, with the associated deferred tax benefits recorded as liabilities on the balance sheet. The current portion is calculated based on expected gas deliveries within the next fiscal year. We recognize regulatory amortization of this asset on a volumetric basis calculated using the estimated gas reserves and the estimated therms extracted and sold each month. The amortization of gas reserves is recorded to cost of gas along with gas production revenues and production costs. See Note 11.

Derivatives

Derivatives are measured at fair value and recognized as either assets or liabilities on the balance sheet. Changes in the fair value of the derivatives are recognized currently in earnings unless specific regulatory or hedge accounting criteria are met. Accounting for derivatives and hedges provides an exception for contracts intended for normal purchases and normal sales for which physical delivery is probable. In addition, certain derivative contracts are approved by regulatory authorities for recovery or refund through customer rates. Accordingly, the changes in fair value of these approved contracts are deferred as regulatory assets or liabilities pursuant to regulatory accounting principles. Our financial derivatives generally qualify for deferral under regulatory accounting. Our index-priced physical derivative contracts also qualify for regulatory deferral accounting treatment.

Derivative contracts entered into for utility requirements after the annual PGA rate has been set and during the PGA year are subject to the PGA incentive sharing mechanism. In Oregon we participate in a PGA sharing mechanism under which we are required to select either an 80% or 90% deferral of higher or lower gas costs such that the impact on current earnings from the gas cost sharing is either 20% or 10% of gas cost differences compared to PGA prices, respectively. For the PGA year in Oregon beginning November 1, 2015, we selected the 80% deferral of gas cost differences, and for the PGA years in Oregon beginning November 1, 2014, and 2013, we selected a 90% deferral of gas cost differences. In Washington, 100% of the differences between the PGA prices and actual gas costs are deferred. See Note 13.

Our financial derivatives policy sets forth the guidelines for using selected derivative products to support prudent risk management strategies within designated parameters. Our objective for using derivatives is to decrease the volatility of gas prices, earnings, and cash flows without speculative risk. The use of derivatives is permitted only after the risk exposures have been identified, are determined to exceed acceptable tolerance levels, and are determined necessary to support normal business activities. We do not enter into derivative instruments for trading purposes.

Fair Value

In accordance with fair value accounting, we use the following fair value hierarchy for determining inputs for our debt, pension plan assets, and our derivative fair value measurements:

- Level 1: Valuation is based on quoted prices for identical instruments traded in active markets;
- Level 2: Valuation is based on quoted prices for similar instruments in active markets, quoted prices for identical or similar instruments in markets that are not active, and model-based valuation techniques for which all significant assumptions are observable in the market; and
- Level 3: Valuation is generated from model-based techniques that use significant assumptions not observable in the market. These unobservable assumptions reflect our own estimates of assumptions market participants would use in valuing the asset or liability.

When developing fair value measurements, it is our policy to use quoted market prices whenever available, or to maximize the use of observable inputs and minimize the use of unobservable inputs when quoted market prices are not available. Fair values are primarily developed using industry-standard models that consider various inputs including: (a) quoted future prices for commodities; (b) forward currency prices; (c) time value; (d) volatility factors; (e) current market and contractual prices for underlying instruments; (f) market interest rates and yield curves; (g) credit spreads; and (h) other relevant economic measures.

Income Taxes

We account for income taxes under the asset and liability method, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. Under this method, deferred tax assets and liabilities are determined on the basis of the differences between the financial statement and tax basis of assets and liabilities using enacted tax rates in effect for the year in which the differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the enactment date period unless a regulatory Order specifies deferral of the effect of the change in tax rates over a longer period of time.

Deferred income tax assets and liabilities are also recognized for temporary differences where the deferred income tax benefits or expenses have previously been flowed through in the ratemaking process of the regulated utility. Regulatory tax assets and liabilities are recorded on these deferred tax assets and liabilities to the extent the Company believes they will be recoverable from or refunded to customers in future rates. At December 31, 2015 and 2014, regulatory income tax assets of $47.4 million and $51.8 million, respectively, were recorded, a portion of which is recorded in current assets. These regulatory income tax assets primarily represent future rate recovery of deferred tax liabilities, resulting from differences in utility plant financial statement and tax bases and utility plant removal costs, which were previously flowed through for rate making purposes and to take into account the additional future taxes, which will be generated by that recovery. These deferred tax liabilities, and the associated regulatory income tax assets, are currently being recovered through customer rates.

Deferred investment tax credits on utility plant additions, which reduce income taxes payable, are deferred for financial statement purposes and amortized over the life of the related plant.

The Company recognizes interest and penalties related to unrecognized tax benefits, if any, within income tax expense and accrued interest and penalties within the related tax liability line in the consolidated balance sheets. No accrued interest or penalties for uncertain tax benefits have been recorded. See Note 9.

Environmental Contingencies

Loss contingencies are recorded as liabilities when it is probable a liability has been incurred and the amount of the loss is reasonably estimable in accordance with accounting standards for contingencies. Estimating probable losses requires an analysis of uncertainties that often depend upon judgments about potential actions by third parties. Accruals for loss contingencies are recorded based on an analysis of potential results.

With respect to environmental liabilities and related costs, we develop estimates based on a review of information available from numerous sources, including completed studies and site specific negotiations. It is our policy to accrue the full amount of such liability when information is sufficient to reasonably estimate the amount of probable liability. When information is not available to reasonably estimate the probable liability, or when only the range of probable liabilities can be estimated and no amount within the range is more likely than another, it is our policy to accrue at the low end of the range. Accordingly, due to numerous uncertainties surrounding the course of environmental remediation and the preliminary nature of several site investigations, in some cases, we may not be able to reasonably estimate the high end of the range of possible loss. In those cases we have disclosed the nature of the potential loss and the fact that the high end of the range cannot be reasonably estimated. See Note 15.

Subsequent Events

See Note 16 for information regarding the resolution of the environmental SRRM docket.

3. EARNINGS PER SHARE

Basic earnings per share are computed using net income and the weighted average number of common shares outstanding for each period presented. Diluted earnings per share are computed in the same manner, except it uses the weighted average number of common shares outstanding plus the effects of the assumed exercise of stock options and the payment of estimated stock awards from other stock-based compensation plans that are outstanding at the end of each period presented. Antidilutive stock awards are excluded from the calculation of diluted earnings per common share. Diluted earnings per share are calculated as follows:

In thousands, except per share data	2015	2014	2013
Net income	$ 53,703	$ 58,692	$ 60,538
Average common shares outstanding - basic	27,347	27,164	26,974
Additional shares for stock-based compensation plans (See Note 6)	70	59	53
Average common shares outstanding - diluted	27,417	27,223	27,027
Earnings per share of common stock - basic	$ 1.96	$ 2.16	$ 2.24
Earnings per share of common stock - diluted	$ 1.96	$ 2.16	$ 2.24
Additional information:			
Antidilutive shares	12	18	26

4. SEGMENT INFORMATION

We primarily operate in two reportable business segments: local gas distribution and gas storage. We also have other investments and business activities not specifically related to one of these two reporting segments, which are aggregated and reported as other. We refer to our local gas distribution business as the utility, and our gas storage segment and other as non-utility. Our utility segment also includes the utility portion of our Mist underground storage facility in Oregon and NWN Gas Reserves, which is a wholly-owned subsidiary of Energy Corp. Our gas storage segment includes NWN Gas Storage, which is a wholly-owned subsidiary of NWN Energy, Gill Ranch, which is a wholly-owned subsidiary of NWN Gas Storage, the non-utility portion of Mist, and all third-party asset management services. Other includes NNG Financial and NWN Energy's equity investment in TWH, which is pursuing development of a cross-Cascades transmission pipeline project.

Local Gas Distribution

Our local gas distribution segment is a regulated utility principally engaged in the purchase, sale, and delivery of natural gas and related services to customers in Oregon and southwest Washington. As a regulated utility, we are responsible for building and maintaining a safe and reliable pipeline distribution system, purchasing sufficient gas supplies from producers and marketers, contracting for firm and interruptible transportation of gas over interstate pipelines to bring gas from the supply basins into our service territory, and re-selling the gas to customers subject to rates, terms, and conditions approved by the OPUC or WUTC. Gas distribution also includes taking customer-owned gas and transporting it from interstate pipeline connections, or city gates, to the customers' end-use facilities for a fee, which is approved by the OPUC or WUTC. Approximately 89% of our customers are located in Oregon and 11% in Washington. On an annual basis, residential and commercial customers typically account for around 60% of our utility's total volumes delivered and 90% of our utility's margin. Industrial customers largely account for the remaining volumes and utility margin. A small amount of utility margin is also derived from miscellaneous services, gains or losses from an incentive gas cost sharing mechanism, and other service fees.

Industrial sectors we serve include: pulp, paper, and other forest products; the manufacture of electronic, electrochemical and electrometallurgical products; the processing of farm and food products; the production of various mineral products; metal fabrication and casting; the production of machine tools, machinery and textiles; the manufacture of asphalt, concrete and rubber; printing and publishing; nurseries; government and educational institutions; and electric generation. No individual customer or industry group accounts for over 10% of our utility revenues or utility margins.

Gas Storage

Our gas storage segment includes natural gas storage services provided to customers primarily from two underground natural gas storage facilities, our Gill Ranch gas storage facility, and the non-utility portion of our Mist gas storage facility. In addition to earning revenue from customer storage contracts, we also use an independent energy marketing company to provide asset management services for utility and non-utility capacity, the results of which are included in this business segment.

Mist Gas Storage Facility

Earnings from non-utility assets at our Mist facility in Oregon are primarily related to firm storage capacity revenues. Earnings for the Mist facility also include revenue, net of amounts shared with utility customers, from management of utility assets at Mist and upstream capacity when not needed to serve utility customers. We retain 80% of the pre-tax income from these services when the costs of the capacity have not been included in utility rates, or 33% of the pre-tax income when the costs have been included in utility rates. The remaining 20% and 67%, respectively, are recorded to a deferred regulatory account for crediting back to utility customers.

Gill Ranch Gas Storage Facility
Gill Ranch has a joint project agreement with Pacific Gas and Electric Company (PG&E) to own and operate the Gill Ranch underground natural gas storage facility near Fresno, California. Gill Ranch has a 75% undivided ownership interest in the facility and is also the operator of the facility, which offers storage services to the California market at market-based rates, subject to CPUC regulation including, but not limited to, service terms and conditions and tariff regulations. Although this is a jointly owned property, each owner is independently responsible for financing its share of the Gill Ranch natural gas storage facility. Revenues are primarily related to firm storage capacity as well as asset management revenues.

Other
We have non-utility investments and other business activities, which are aggregated and reported as other.

Other primarily consists of an equity method investment in TWH, which was formed to build and operate an interstate gas transmission pipeline in Oregon (TWP) and other pipeline assets in NNG Financial. For more information on TWP, see Note 12. Other also includes some corporate operating and non-operating revenues and expenses that cannot be allocated to utility operations.

NNG Financial's assets primarily consist of an active, wholly-owned subsidiary which owns a 10% interest in an 18-mile interstate natural gas pipeline. NNG Financial's total assets were $0.7 million and $0.8 million at December 31, 2015 and 2014, respectively.

Segment Information Summary
Inter-segment transactions were insignificant for the periods presented. The following table presents summary financial information concerning the reportable segments:

In thousands	Utility	Gas Storage	Other	Total
2015				
Operating revenues	$ 702,210	$ 21,356	$ 225	$ 723,791
Depreciation and amortization	74,410	6,513	—	80,923
Income from operations	119,215	5,032	1	124,248
Net income	53,391	174	138	53,703
Capital expenditures	115,272	3,048	—	118,320
Total assets at December 31, 2015	2,800,018	261,750	14,924	3,076,692
2014				
Operating revenues	$ 731,578	$ 22,235	$ 224	$ 754,037
Depreciation and amortization	72,660	6,533	—	79,193
Income from operations	138,711	3,987	267	142,965
Net income (loss)	58,587	(364)	469	58,692
Capital expenditures	117,322	2,770	—	120,092
Total assets at December 31, 2014	2,775,011	273,813	16,121	3,064,945
2013				
Operating revenues	$ 727,182	$ 31,112	$ 224	$ 758,518
Depreciation and amortization	69,420	6,485	—	75,905
Income from operations	128,066	14,669	11	142,746
Net income	54,920	5,569	49	60,538
Capital expenditures	137,466	1,458	—	138,924
Total assets at December 31, 2013	2,644,367	310,097	16,447	2,970,911

Utility Margin

Utility margin is a financial measure consisting of utility operating revenues, which are reduced by revenue taxes, the associated cost of gas, and environmental recovery revenues. The cost of gas purchased for utility customers is generally a pass-through cost in the amount of revenues billed to regulated utility customers. Environmental recovery revenues represent collections received from customers through our environmental recovery mechanism in Oregon. These collections are offset by the amortization of environmental liabilities, which is presented as environmental remediation expense in our operating expenses. By subtracting cost of gas and environmental remediation expense from utility operating revenues, utility margin provides a key metric used by our chief operating decision maker in assessing the performance of the utility segment. The gas storage segment and other emphasize growth in operating revenues as opposed to margin because they do not incur a product cost (i.e. cost of gas sold) like the utility and, therefore, use operating revenues and net income to assess performance.

The following table presents additional segment information concerning utility margin:

In thousands	2015	2014	2013
Utility margin calculation:			
Utility operating revenues [1]	$ 702,210	$ 731,578	$ 727,182
Less: Utility cost of gas	327,305	365,490	373,298
Environmental remediation expense	3,513	—	—
Utility margin	$ 371,392	$ 366,088	$ 353,884

(1) Utility operating revenues include environmental recovery revenues, which are collections received from customers through our environmental recovery mechanism in Oregon, offset by environmental remediation expense.

5. COMMON STOCK

Common Stock

As of December 31, 2015 and 2014, we had 100 million shares of common stock authorized. As of December 31, 2015, we had reserved 78,857 shares for issuance of common stock under the Employee Stock Purchase Plan (ESPP) and 297,879 shares under our Dividend Reinvestment and Direct Stock Purchase Plan (DRPP). At the Company's election, shares sold through our DRPP may be purchased in the open market or through original issuance of shares reserved for issuance under the DRPP. In July 2015 we moved DRPP to open market purchases.

The Restated Stock Option Plan (SOP) was terminated with respect to new grants in 2012; however, options granted before the Restated SOP was terminated will remain outstanding until the earlier of their expiration, forfeiture, or exercise. There were 352,688 options outstanding at December 31, 2015, which were granted prior to termination of the plan.

Stock Repurchase Program

We have a share repurchase program under which we may purchase our common shares on the open market or through privately negotiated transactions. We currently have Board authorization through May 2016 to repurchase up to an aggregate of the greater of 2.8 million shares or $100 million. No shares of common stock were repurchased pursuant to this program during the year ended December 31, 2015. Since the plan’s inception in 2000, a total of 2.1 million shares have been repurchased at a total cost of $83.3 million.

Summary of Changes in Common Stock

The following table shows the changes in the number of shares of our common stock issued and outstanding:

In thousands	Shares
Balance, December 31, 2012	26,917
Sales to employees under ESPP	16
Stock-based compensation	42
Sales to shareholders under DRPP	100
Balance, December 31, 2013	27,075
Sales to employees under ESPP	24
Stock-based compensation	83
Sales to shareholders under DRPP	102
Balance, December 31, 2014	27,284
Sales to employees under ESPP	19
Stock-based compensation	78
Sales to shareholders under DRPP	46
Balance, December 31, 2015	27,427

6. STOCK-BASED COMPENSATION

Our stock-based compensation plans are designed to promote stock ownership in NW Natural by employees and officers. These compensation plans include a Long-Term Incentive Plan (LTIP), an ESPP, and a Restated SOP.

Long-Term Incentive Plan

The LTIP is intended to provide a flexible, competitive compensation program for eligible officers and key employees. Under the LTIP, shares of common stock are authorized for equity incentive grants in the form of stock, restricted stock, restricted stock units, stock options, or performance shares. An aggregate of 850,000 shares were authorized for issuance as of December 31, 2015. Shares awarded under the LTIP may be purchased on the open market or issued as original shares.

Of the 850,000 shares of common stock authorized for LTIP awards at December 31, 2015, there were 186,979 shares available for issuance under any type of award and 250,000 shares available for option grants. This assumes market, performance, and service based grants currently outstanding are awarded at the target level. There were no outstanding grants of restricted stock or stock options under the LTIP at December 31, 2015 or 2014. The LTIP stock awards are compensatory awards for which compensation expense is based on the fair value of stock awards, with expense being recognized over the performance and vesting period of the outstanding awards.

Performance Shares

Since the LTIP's inception in 2001, performance shares, which incorporate market, performance, and service-based factors, have been granted annually with three-year performance periods. The following table summarizes performance share expense information:

Dollars in thousands	Shares[(1)]	Expense During Award Year[(2)]	Total Expense for Award
Estimated award:			
2013-2015 grant[(3)]	8,465	$ 312	$ 1,240
Actual award:			
2012-2014 grant	8,621	582	1,821
2011-2013 grant	9,819	390	960

(1) In addition to common stock shares, a participant also receives a dividend equivalent cash payment equal to the number of shares of common stock received on the award payout multiplied by the aggregate cash dividends paid per share during the performance period.

(2) Amount represents the expense recognized in the third year of the vesting period noted above.

(3) This represents the estimated number of shares to be awarded as of December 31, 2015 as certain performance share measures had been achieved. Amounts are subject to change with final payout amounts authorized by the Board of Directors in February 2016.

The aggregate number of performance shares granted and outstanding at the target and maximum levels were as follows:

Dollars in thousands	Performance Share Awards Outstanding		2015	Cumulative Expense
Performance Period	Target	Maximum	Expense	December 31, 2015
2013-15	34,100	68,200	$ 312	$ 1,240
2014-16	39,725	79,450	632	1,250
2015-17	43,950	87,900	853	853
Total	117,775	235,550	$ 1,797	

For the 2013-2015 performance period, awards will be based on total shareholder return (TSR factor) relative to a peer group of gas distribution companies over the three-year performance period and on performance results achieved relative to specific core and non-core strategies (strategic factor). In addition to the TSR and strategic factors, the 2014-2016 and 2015-2017 performance period awards also included weighting for EPS and Return on Invested Capital (ROIC) factors. Compensation expense is recognized in accordance with accounting standards for stock-based compensation and calculated based on performance levels achieved and an estimated fair value using the Monte-Carlo method. The weighted-average grant date fair value of unvested shares at December 31, 2015 and 2014 was $49.09 and $42.06 per share, respectively. The weighted-average grant date fair value of shares vested during the year was $46.64 per share and for shares granted during the year was $51.78 per share. As of December 31, 2015, there was $2.3 million of unrecognized compensation expense related to the unvested portion of performance awards expected to be recognized through 2017.

Restricted Stock Units

In 2012, the Company began granting RSUs under the LTIP instead of stock options under the Restated SOP. Generally, the RSUs awarded are forfeitable and include a performance-based threshold as well as a vesting period of 4 years from the grant date. Upon vesting, the RSU holder is issued one share of common stock plus a cash payment equal to the total amount of dividends paid per share between the grant date and vesting date of that portion of the RSU. The fair value of an RSU is equal to the closing market price of the Company's common stock on the grant date. During 2015, total RSU expense was $1.3 million compared to $0.9 million in 2014. As of December 31, 2015, there was $2.6 million of unrecognized compensation cost from grants of RSUs, which is expected to be recognized over a period extending through 2019.

Information regarding the RSU activity is summarized as follows:

	Number of RSUs	Weighted - Average Price Per RSU
Nonvested, December 31, 2012	24,864	$ 47.57
Granted	25,748	45.38
Vested	(5,455)	48.01
Forfeited	(590)	46.58
Nonvested, December 31, 2013	44,567	46.27
Granted	38,765	42.19
Vested	(12,060)	46.52
Forfeited	(478)	45.47
Nonvested, December 31, 2014	70,794	44.00
Granted	37,264	46.29
Vested	(19,003)	44.81
Forfeited	(468)	44.99
Nonvested, December 31, 2015	88,587	44.78

Restated Stock Option Plan

The Restated SOP was terminated for new option grants in 2012; however, options granted before the plan terminated will remain outstanding until the earlier of their expiration, forfeiture, or exercise. Any new grants of stock options would be made under the LTIP.

Options under the Restated SOP were granted to officers and key employees designated by a committee of our Board of Directors. All options were granted at an option price equal to the closing market price on the date of grant and may be exercised for a period up to 10 years and seven days from the date of grant. Option holders may exchange shares they have owned for at least 6 months, valued at the current market price, to purchase shares at the option price.

Information regarding the Restated SOP activity is summarized as follows:

	Option Shares	Weighted - Average Price Per Share	Intrinsic Value *(In millions)*
Balance outstanding, December 31, 2012	529,925	$ 42.22	$ 1.3
Exercised	(33,800)	32.16	0.3
Forfeited	(3,975)	43.72	n/a
Balance outstanding, December 31, 2013	492,150	42.89	0.6
Exercised	(69,662)	39.82	0.5
Forfeited	(6,400)	43.59	n/a
Balance outstanding, December 31, 2014	416,088	43.40	2.7
Exercised	(62,900)	39.96	0.5
Forfeited	(500)	45.74	n/a
Balance outstanding and exercisable, December 31, 2015	352,688	44.00	2.3

During 2015, cash of $2.5 million was received for stock options exercised and $0.1 million related tax expense was recognized. During 2015, 2014, and 2013, the total fair value of options that vested was $0.2 million, $0.4 million and $0.5 million, respectively. The weighted average remaining life of options exercisable and outstanding at December 31, 2015 was 3.6 years.

Employee Stock Purchase Plan

The ESPP allows employees to purchase common stock at 85% of the closing price on the trading day immediately preceding the initial offering date, which is set annually. Each eligible employee may purchase up to $21,227 worth of stock through payroll deductions over a 12-month period, with shares issued at the end of the 12-month subscription period.

Stock-Based Compensation Expense

Stock-based compensation expense is recognized as operations and maintenance expense or is capitalized as part of construction overhead. The following table summarizes the financial statement impact of stock-based compensation under our LTIP, Restated SOP and ESPP:

In thousands	2015	2014	2013
Operations and maintenance expense, for stock-based compensation	$ 2,673	$ 2,309	$ 1,876
Income tax benefit	(1,012)	(861)	(765)
Net stock-based compensation effect on net income	$ 1,661	$ 1,448	$ 1,111
Amounts capitalized for stock-based compensation	$ 661	$ 597	$ 331

7. DEBT

Short-Term Debt

Our primary source of short-term funds is from the sale of commercial paper and bank loans. In addition to issuing commercial paper or bank loans to meet seasonal working capital requirements, short-term debt is used temporarily to fund capital requirements. Commercial paper and bank loans are periodically refinanced through the sale of long-term debt or equity securities. Our commercial paper program is supported by one or more committed credit facilities.

In the fourth quarter of 2015, we entered into a short-term credit facility loan totaling $50 million, as a short-term bridge through our peak heating season, which was repaid on February 4, 2016.

At December 31, 2015, total short-term debt outstanding was $270 million, which includes $220 million of commercial paper and a $50 million credit facility. At December 31, 2014 total short-term debt outstanding was $234.7 million, which was comprised entirely of commercial paper. The weighted average interest rate at December 31, 2015 and 2014 was 0.6% and 0.4%, respectively.

The carrying cost of our commercial paper approximates fair value using Level 2 inputs, due to the short-term nature of the notes. See Note 2 for a description of the fair value hierarchy. At December 31, 2015, our commercial paper had a maximum maturity of 77 days and an average maturity of 36 days.

We have a $300 million credit agreement, with a feature that allows us to request increases in the total commitment amount up to a maximum amount of $450 million. The maturity of the agreement is December 20, 2019. We have a letter of credit of $100 million. Any principal and unpaid interest owed on borrowings under the agreement is due and payable on or before the expiration date. There were no outstanding balances under the agreement and no letters of credit issued or outstanding at December 31, 2015 and 2014.

The credit agreement requires that we maintain credit ratings with Standard & Poor's (S&P) and Moody's Investors Service, Inc. (Moody's) and notify the lenders of any change in our senior unsecured debt ratings or senior secured debt ratings, as applicable, by such rating agencies. A change in our debt ratings is not an event of default, nor is the maintenance of a specific minimum level of debt rating a condition of drawing upon the credit facility. However, interest rates on any loans outstanding under the credit facility are tied to debt ratings, which would increase or decrease the cost of any loans under the credit facility when ratings are changed.

The credit agreement also requires us to maintain a consolidated indebtedness to total capitalization ratio of 70% or less. Failure to comply with this covenant would entitle the lenders to terminate their lending commitments and accelerate the maturity of all amounts outstanding. We were in compliance with this covenant at December 31, 2015 and 2014.

Long-Term Debt

The issuance of first mortgage bonds (FMBs), which includes our medium-term notes, under the Mortgage and Deed of Trust (Mortgage) is limited by eligible property, adjusted net earnings and other provisions of the Mortgage. The Mortgage constitutes a first mortgage lien on substantially all of our utility property.

Maturities and Outstanding Long-Term Debt

Retirement of long-term debt for each of the 12-month periods through December 31, 2020 and thereafter are as follows:

In thousands	
Year	
2016	$ 25,000
2017	40,000
2018	22,000
2019	30,000
2020	75,000
Thereafter	409,700

The following table presents our debt outstanding as of December 31:

In thousands	2015	2014
First Mortgage Bonds		
4.70 % Series B due 2015	—	40,000
5.15 % Series B due 2016	25,000	25,000
7.00 % Series B due 2017	40,000	40,000
6.60 % Series B due 2018	22,000	22,000
8.31 % Series B due 2019	10,000	10,000
7.63 % Series B due 2019	20,000	20,000
5.37 % Series B due 2020	75,000	75,000
9.05 % Series A due 2021	10,000	10,000
3.176 % Series B due 2021	50,000	50,000
3.542% Series B due 2023	50,000	50,000
5.62 % Series B due 2023	40,000	40,000
7.72 % Series B due 2025	20,000	20,000
6.52 % Series B due 2025	10,000	10,000
7.05 % Series B due 2026	20,000	20,000
7.00 % Series B due 2027	20,000	20,000
6.65 % Series B due 2027	19,700	19,700
6.65 % Series B due 2028	10,000	10,000
7.74 % Series B due 2030	20,000	20,000
7.85 % Series B due 2030	10,000	10,000
5.82 % Series B due 2032	30,000	30,000
5.66 % Series B due 2033	40,000	40,000
5.25 % Series B due 2035	10,000	10,000
4.00 % due 2042	50,000	50,000
	601,700	641,700
Subsidiary Senior Secured Debt		
Gill Ranch debt due 2016	—	20,000
	601,700	661,700
Less: Current maturities	25,000	40,000
Total long-term debt	$ 576,700	$ 621,700

Subsidiary Senior Secured Debt

On December 18, 2015, Gill Ranch repaid $20 million of fixed-rate senior secured debt outstanding with an interest rate of 7.75%, which included a make whole interest provision using available cash and cash flows from operations, including cash from intercompany receivables.

Retirements of Long-Term Debt

The utility redeemed $40 million of FMBs with a coupon rate of 4.70% in June 2015.

Fair Value of Long-Term Debt

Our outstanding debt does not trade in active markets. We estimate the fair value of our debt using utility companies with similar credit ratings, terms, and remaining maturities to our debt that actively trade in public markets. These valuations are based on Level 2 inputs as defined in the fair value hierarchy. See Note 2.

The following table provides an estimate of the fair value of our long-term debt, including current maturities of long-term debt, using market prices in effect on the valuation date:

	December 31,	
In thousands	2015	2014
Carrying amount	$ 601,700	$ 661,700
Estimated fair value	667,168	756,808

8. PENSION AND OTHER POSTRETIREMENT BENEFIT COSTS

We maintain a qualified non-contributory defined benefit pension plan, non-qualified supplemental pension plans for eligible executive officers and other key employees, and other postretirement employee benefit plans. We also have qualified defined contribution plans (Retirement K Savings Plan) for all eligible employees. The qualified defined benefit pension plan and Retirement K Savings Plan have plan assets, which are held in qualified trusts to fund retirement benefits. Effective January 1, 2007 and 2010, the qualified defined benefit retirement plans and postretirement benefits for non-union employees and union employees, respectively, were closed to new participants. These plans were not available to employees of our non-utility subsidiaries. Non-union and union employees hired or re-hired after December 31, 2006 and 2009, respectively, and employees of NW Natural subsidiaries are provided an enhanced Retirement K Savings Plan benefit.

The following table provides a reconciliation of the changes in benefit obligations and fair value of plan assets, as applicable, for the pension and other postretirement benefit plans, excluding the Retirement K Savings Plan, and a summary of the funded status and amounts recognized in the consolidated balance sheets as of December 31:

	Postretirement Benefit Plans			
	Pension Benefits		Other Benefits	
In thousands	2015	2014	2015	2014
Reconciliation of change in benefit obligation:				
Obligation at January 1	$ 487,278	$ 391,089	$ 32,072	$ 28,754
Service cost	8,267	7,213	527	483
Interest cost	18,360	18,198	1,179	1,252
Plan amendments[(1)]	—	—	(3,435)	—
Net actuarial (gain) loss	(32,354)	90,710	2,724	3,454
Benefits paid	(35,923)	(19,932)	(2,018)	(1,871)
Obligation at December 31	$ 445,628	$ 487,278	$ 31,049	$ 32,072
Reconciliation of change in plan assets:				
Fair value of plan assets at January 1	$ 279,164	$ 267,062	$ —	$ —
Actual return on plan assets	(9,599)	19,957	—	—
Employer contributions	15,696	12,077	2,018	1,871
Benefits paid	(35,923)	(19,932)	(2,018)	(1,871)
Fair value of plan assets at December 31	$ 249,338	$ 279,164	$ —	$ —
Funded status at December 31	$ (196,290)	$ (208,114)	$ (31,049)	$ (32,072)

(1) We amended our qualified defined benefit pension plan to establish a health retirement account (HRA) plan for participants. The HRA plan permits participants to obtain reimbursement of health care expenses on a nontaxable basis, and the amendment is effective April 1, 2016.

Our qualified defined benefit pension plan has an aggregate benefit obligation of $411.8 million and $451.2 million at December 31, 2015 and 2014, respectively, and fair values of plan assets of $249.3 million and $279.2 million, respectively.

The following table presents amounts realized through regulatory assets or in other comprehensive loss (income) for the years ended December 31:

	Regulatory Assets						Other Comprehensive Loss (Income)		
	Pension Benefits			Other Postretirement Benefits			Pension Benefits		
In thousands	2015	2014	2013	2015	2014	2013	2015	2014	2013
Net actuarial loss (gain)	$ 419	$ 83,027	$ (51,892)	$ 2,724	$ 3,454	$ (4,283)	$ (2,549)	$ 7,221	$ (3,302)
Amortization of:									
Prior service cost	(230)	(230)	(230)	(197)	(197)	(197)	—	7	7
Actuarial loss	(16,372)	(9,823)	(16,744)	(554)	(221)	(733)	(2,236)	(1,091)	(1,550)
Total	$ (16,183)	$ 72,974	$ (68,866)	$ 1,973	$ 3,036	$ (5,213)	$ (4,785)	$ 6,137	$ (4,845)

The following table presents amounts recognized in regulatory assets and accumulated other comprehensive loss (AOCL) at December 31:

	Regulatory Assets				AOCL	
	Pension Benefits		Other Postretirement Benefits		Pension Benefits	
In thousands	2015	2014	2015	2014	2015	2014
Prior service cost (credit)	$ 406	$ 637	$ (3,143)	$ 488	$ 1	$ 2
Net actuarial loss	176,894	192,846	10,067	7,898	11,870	16,604
Total	$ 177,300	$ 193,483	$ 6,924	$ 8,386	$ 11,871	$ 16,606

The following table presents amounts recognized in AOCL and the changes in AOCL related to our non-qualified employee benefit plans:

	Year Ended December 31,	
In thousands	2015	2014
Beginning balance	$ (10,076)	$ (6,358)
Amounts reclassified to AOCL	2,549	(7,221)
Amounts reclassified from AOCL:		
Amortization of prior service costs	—	(7)
Amortization of actuarial losses	2,236	1,091
Total reclassifications before tax	4,785	(6,137)
Tax (benefit) expense	(1,871)	2,419
Total reclassifications for the period	2,914	(3,718)
Ending balance	$ (7,162)	$ (10,076)

In 2016, an estimated $13.3 million will be amortized from regulatory assets to net periodic benefit costs, consisting of $13.5 million of actuarial losses, and $0.2 million of prior service credits. A total of $1.3 million will be amortized from AOCL to earnings related to actuarial losses in 2016.

Our assumed discount rate for the pension plan and other postretirement benefit plans was determined independently based on the Citigroup Above Median Curve (discount rate curve), which uses high quality corporate bonds rated AA- or higher by S&P or Aa3 or higher by Moody's. The discount rate curve was applied to match the estimated cash flows in each of our plans to reflect the timing and amount of expected future benefit payments for these plans.

Our assumed expected long-term rate of return on plan assets for the qualified pension plan was developed using a weighted average of the expected returns for the target asset portfolio. In developing the expected long-term rate of return assumption, consideration was given to the historical performance of each asset class in which the plans' assets are invested and the target asset allocation for plan assets.

Our investment strategy and policies for qualified pension plan assets held in the retirement trust fund were approved by our retirement committee, which is composed of senior management with the assistance of an outside investment consultant. The policies set forth the guidelines and objectives governing the investment of plan assets. Plan assets are invested for total return with appropriate consideration for liquidity, portfolio risk and return expectations. All investments are expected to satisfy the prudent investments rule under the Employee Retirement Income Security Act of 1974. The approved asset classes may include cash and short-term investments, fixed income, common stock and convertible securities, absolute and real return strategies, real estate, and investments in NW Natural securities. Plan assets may be invested in separately managed accounts or in commingled or mutual funds. Investment re-balancing takes place periodically as needed, or when significant cash flows occur, in order to maintain the allocation of assets within the stated target ranges. The retirement trust fund is not currently invested in NW Natural securities.

The following table presents the pension plan asset target allocation at December 31, 2015:

Asset Category	Target Allocation
U.S. large cap equity	18.0%
U.S. small/mid cap equity	10.0
Non-U.S. equity	18.0
Emerging markets equity	5.0
Long government/credit	20.0
High yield bonds	5.0
Emerging market debt	5.0
Real estate funds	7.0
Absolute return strategy	12.0

Our non-qualified supplemental defined benefit plan obligations were $33.8 million and $36.1 million at December 31, 2015 and 2014, respectively. These plans are not subject to regulatory deferral, and the changes in actuarial gains and losses, prior service costs and transition assets, or obligations are recognized in AOCL, net of tax until they are amortized as a component of net periodic benefit cost. These are unfunded, non-qualified plans with no plan assets; however, we indirectly fund a significant portion of our obligations with company- and trust-owned life insurance and other assets.

Our other postretirement benefit plans are unfunded plans but are subject to regulatory deferral. The actuarial gains and losses, prior service costs and transition assets or obligations for these plans are recognized as a regulatory asset.

Net periodic benefit costs consist of service costs, interest costs, the amortization of actuarial gains and losses and the expected returns on plan assets, which are based in part on a market-related valuation of assets. The market-related valuation reflects differences between expected returns and actual investment returns with the differences recognized over a three-year or less period from the year in which they occur, thereby reducing year-to-year net periodic benefit cost volatility.

The following table provides the components of net periodic benefit cost for the Company's pension and other postretirement benefit plans for the years ended December 31:

	Pension Benefits			Other Postretirement Benefits		
In thousands	2015	2014	2013	2015	2014	2013
Service cost	$ 8,267	$ 7,213	$ 8,698	$ 527	$ 483	$ 656
Interest cost	18,360	18,198	16,400	1,179	1,252	1,157
Expected return on plan assets	(20,676)	(19,496)	(18,721)	—	—	—
Amortization of prior service costs	231	223	223	197	197	197
Amortization of net actuarial loss	18,609	10,914	18,294	554	221	734
Net periodic benefit cost	24,791	17,052	24,894	2,457	2,153	2,744
Amount allocated to construction	(6,834)	(4,625)	(6,712)	(808)	(702)	(856)
Amount deferred to regulatory balancing account[1]	(8,241)	(4,578)	(9,115)	—	—	—
Net amount charged to expense	$ 9,716	$ 7,849	$ 9,067	$ 1,649	$ 1,451	$ 1,888

(1) The deferral of defined benefit pension expenses above or below the amount set in rates was approved by the OPUC, with recovery of these deferred amounts through the implementation of a balancing account. The balancing account includes the expectation of higher net periodic benefit costs than costs recovered in rates in the near-term with lower net periodic benefit costs than costs recovered in rates expected in future years. Deferred pension expense balances include accrued interest at the utility's authorized rate of return, with the equity portion of the interest recognized when amounts are collected in rates. See Note 2.

Net periodic benefit costs are reduced by amounts capitalized to utility plant based on approximately 25% to 35% payroll overhead charge. In addition, a certain amount of net periodic benefit costs are recorded to the regulatory balancing account for pensions. Net periodic pension cost less amounts charged to capital accounts and regulatory balancing accounts are expenses recognized in earnings.

The following table provides the assumptions used in measuring periodic benefit costs and benefit obligations for the years ended December 31:

	Pension Benefits			Other Postretirement Benefits		
	2015	2014	2013	2015	2014	2013
Assumptions for net periodic benefit cost:						
Weighted-average discount rate	3.82%	4.71%	3.84%	3.74%	4.45%	3.56%
Rate of increase in compensation	3.25-5.0%	3.25-5.0%	3.25-5.0%	n/a	n/a	n/a
Expected long-term rate of return	7.50%	7.50%	7.50%	n/a	n/a	n/a
Assumptions for year-end funded status:						
Weighted-average discount rate	4.21%	3.85%	4.73%	4.00%	3.74%	4.45%
Rate of increase in compensation	3.25-4.5%	3.25-5.0%	3.25-5.0%	n/a	n/a	n/a
Expected long-term rate of return	7.50%	7.50%	7.50%	n/a	n/a	n/a

The assumed annual increase in health care cost trend rates used in measuring other postretirement benefits as of December 31, 2015 was 7.50% for both pre- and post-65 populations. These trend rates apply to both medical and prescription drugs. Medical costs and prescription drugs are assumed to decrease gradually each year to a rate of 4.75% by 2024.

Assumed health care cost trend rates can have a significant effect on the amounts reported for the health care plans; however, other postretirement benefit plans have a cap on the amount of costs reimbursable from the Company. A one percentage point change in assumed health care cost trend rates would have the following effects:

In thousands	1% Increase	1% Decrease
Effect on net periodic postretirement health care benefit cost	$ 100	$ (74)
Effect on the accumulated postretirement benefit obligation	742	(665)

We review mortality assumptions annually and will update for material changes as necessary. In 2015, we adopted the Society of Actuaries Scale MP-2015, which projects a mortality detriment compared to the previous table used, thereby decreasing benefit plan liabilities.

The following table provides information regarding employer contributions and benefit payments for the qualified pension plan, non-qualified pension plans and other postretirement benefit plans for the years ended December 31, and estimated future contributions and payments:

In thousands	Pension Benefits	Other Benefits
Employer Contributions:		
2014	$ 12,077	$ 1,871
2015	15,696	2,018
2016 (estimated)	16,695	2,035
Benefit Payments:		
2013	18,855	1,895
2014	19,932	1,871
2015	35,923	2,018
Estimated Future Benefit Payments:		
2016	21,589	2,035
2017	22,028	2,060
2018	22,974	2,073
2019	23,950	2,132
2020	26,242	2,178
2021-2025	134,736	11,068

Employer Contributions to Company-Sponsored Defined Benefit Pension Plans

We make contributions to our qualified defined benefit pension plans based on actuarial assumptions and estimates, tax regulations and funding requirements under federal law. The Pension Protection Act of 2006 (the Act) established funding requirements for defined benefit plans. The Act establishes a 100% funding target over seven years for plan years beginning after December 31, 2008. In 2012 the Moving Ahead for Progress in the 21st Century Act (MAP-21) legislation changed several provisions affecting pension plans, including temporary funding relief and Pension Benefit Guaranty Corporation (PBGC) premium increases, which reduces the level of minimum required contributions in the near-term but generally increases contributions in the long-run and increases the operational costs of running a pension plan. In 2014, the Highway and Transportation Funding Act (HATFA) was signed and extends certain aspects of MAP-21 as well as modifies the phase-out periods for the limitations.

Our qualified defined benefit pension plan is currently underfunded by $162.5 million at December 31, 2015. Including the impacts of MAP-21 and HATFA, we made cash contributions totaling $14.1 million to our qualified defined benefit pension plan for 2015. During 2016, we expect to make contributions of approximately $14.5 million to this plan.

Multiemployer Pension Plan

In addition to the Company-sponsored defined benefit plans presented above, prior to 2014 we contributed to a multiemployer pension plan for our utility's union employees known as the Western States Office and Professional Employees International Union Pension Fund (Western States Plan). The plan's employer identification number is 94-6076144. Effective December 22, 2013, we withdrew from the plan, which was a noncash transaction. Vested participants will receive all benefits accrued through the date of withdrawal. As the plan was underfunded at the time of withdrawal, we were assessed a withdrawal liability of $8.3 million, plus interest, which requires NW Natural to pay $0.6 million each year to the plan for 20 years beginning in July 2014. The cost of the withdrawal liability was deferred to a regulatory account on the balance sheet.

We made payments of $0.6 million for 2015, and as of December 31, 2015 the liability balance was $7.8 million. For 2014 and 2013, contributions to the plan were $0.4 million and $0.5 million, respectively, which was approximately 4% to 5% of the total contributions to the plan by all employer participants in those years.

Defined Contribution Plan

The Retirement K Savings Plan is a qualified defined contribution plan under Internal Revenue Code Section 401(k). Employer contributions totaled $3.7 million, $3.4 million, and $2.2 million for 2015, 2014, and 2013, respectively. The Retirement K Savings Plan includes an Employee Stock Ownership Plan.

Deferred Compensation Plans

The supplemental deferred compensation plans for eligible officers and senior managers are non-qualified plans. These plans are designed to enhance the retirement savings of employees and to assist them in strengthening their financial security by providing an incentive to save and invest regularly.

Fair Value

Below is a description of the valuation methodologies used for assets measured at fair value. In cases where the pension plan is invested through a collective trust fund or mutual fund, our custodian uses the fund's market value. The custodian also provides the market values for investments directly owned.

U.S. LARGE CAP EQUITY and U.S. SMALL/MID CAP EQUITY. These are level 1 and 2 assets. The level 1 assets consist of directly held stocks and mutual funds with a readily determinable fair value, including a published net asset value (NAV). The level 2 assets consist of mutual funds where NAV is not published but the investment can be readily disposed of at NAV or market value. Directly held stocks are valued at the closing price reported in the active market on which the individual security is traded, and mutual funds are valued at NAV. This asset class includes investments primarily in U.S. common stocks.

NON-U.S. EQUITY. These are level 1 and 2 assets. The level 1 assets consist of directly held stocks, and the level 2 assets consist of a commingled trust where the NAV/unit price is not published but the investment can be readily disposed of at the NAV/unit price. Directly held stocks are valued at the closing price reported in the active market on which the individual security is traded, and the commingled trust is valued at the unit price of the trust. This asset class includes investments primarily in foreign equity common stocks.

EMERGING MARKETS EQUITY. This is a level 2 asset consisting of an open-end mutual fund where the NAV price is not published but the investment can be readily disposed of at the NAV. This asset class includes investments primarily in common stocks in emerging markets.

FIXED INCOME. This is a level 2 asset consisting of a mutual fund, valued at NAV, where NAV is not published, but the investment can be readily disposed of at the NAV. This asset class includes investments primarily in investment grade debt and fixed income securities.

LONG GOVERNMENT/CREDIT. These are level 1 and 2 assets. The level 1 assets consist of a fixed-income mutual fund with readily determinable fair value, including a published NAV. The level 2 assets consist of a commingled trust and directly held fixed-income securities whose values are determined by closing prices if available and by matrix prices for illiquid securities. This asset class includes long duration fixed income investments primarily in U.S. treasuries, U.S. government agencies, municipal securities, mortgage-backed securities, asset-backed securities, as well as U.S. and international investment-grade corporate bonds.

HIGH YIELD BONDS. This is a level 2 asset consisting of a limited partnership where valuation is not published but the investment can be readily disposed of at market value. This asset class includes investments primarily in high yield bonds.

EMERGING MARKET DEBT. This is a level 1 asset consisting of a mutual fund with a readily determinable fair value, including a published NAV. This asset class includes investments primarily in emerging market debt.

REAL ESTATE FUNDS. This is a level 1 asset consisting of a mutual fund with a readily determinable fair value, including a published NAV. This asset class includes investments primarily in real estate investment trust (REIT) equity securities globally.

ABSOLUTE RETURN STRATEGY. This is a level 2 asset consisting of a hedge fund of funds where the valuation is not published but the investment can be readily disposed of at unit price. The hedge fund of funds is valued at the weighted average value of investments in various hedge funds, which in turn are valued at the closing price of the underlying securities. This asset class primarily includes investments in common stocks and fixed income securities.

REAL RETURN STRATEGY. This is a Level 1 asset representing a mutual fund with a readily determinable fair value, including a published NAV. This asset class includes an investment in a broad range of assets primarily including fixed income, high-yield bonds and emerging market debt.

CASH AND CASH EQUIVALENTS. This is a Level 2 asset representing mutual funds without published NAV's but the investment can be readily disposed of at the NAV. The mutual funds are valued at the NAV of the shares held by the plan at the valuation date. This asset class includes money market mutual funds.

The preceding valuation methods may produce a fair value calculation that is not indicative of net realizable value or reflective of future fair values. Although we believe these valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different fair value measurement at the reporting date.

Investment securities are exposed to various financial risks including interest rate, market and credit risks. Due to the level of risk associated with certain investment securities, it is reasonably possible that changes in the values of our investment securities will occur in the near term and such changes could materially affect our investment account balances and the amounts reported as plan assets available for benefit payments.

The following table presents the fair value of plan assets, including outstanding receivables and liabilities, of the retirement trust fund:

In thousands	December 31, 2015			
Investments	Level 1	Level 2	Level 3	Total
U.S. large cap equity	$ 44,528	$ —	$ —	$ 44,528
U.S. small/mid cap equity	23,495	—	—	23,495
Non-U.S. equity	20,725	22,823	—	43,548
Emerging markets equity	—	11,120	—	11,120
Long government/credit	—	48,456	—	48,456
High yield bonds	—	12,298	—	12,298
Emerging market debt	7,746	—	—	7,746
Real estate funds	17,261	—	—	17,261
Absolute return strategy	—	36,758	—	36,758
Cash and cash equivalents	—	4,116	—	4,116
Total investments	$ 113,755	$ 135,571	$ —	$ 249,326

	December 31, 2014			
Investments	Level 1	Level 2	Level 3	Total
U.S. large cap equity	$ 39,405	$ 122	$ —	$ 39,527
U.S. small/mid cap equity	27,172	85	—	27,257
Non-U.S. equity	16,369	17,221	—	33,590
Emerging markets equity	—	7,145	—	7,145
Fixed income	—	598	—	598
Long government/credit	40,584	40,235	—	80,819
High yield bonds	—	13,087	—	13,087
Emerging market debt	9,133	—	—	9,133
Real estate funds	18,890	—	—	18,890
Absolute return strategy	—	37,065	—	37,065
Real return strategy	8,308	—	—	8,308
Cash and cash equivalents	—	1,720	—	1,720
Total investments	$ 159,861	$ 117,278	$ —	$ 277,139

	December 31,	
Receivables	2015	2014
Accrued interest and dividend income	$ 486	$ 510
Due from broker for securities sold	88	1,694
Total receivables	$ 574	$ 2,204
Liabilities		
Due to broker for securities purchased	$ 562	$ 179
Total investment in retirement trust	$ 249,338	$ 279,164

9. INCOME TAX

The following table provides a reconciliation between income taxes calculated at the statutory federal tax rate and the provision for income taxes reflected in the consolidated statements of comprehensive income for December 31:

Dollars in thousands	2015	2014	2013
Income taxes at federal statutory rate	$31,310	$35,117	$35,785
Increase (decrease):			
Current state income tax, net of federal tax benefit	4,195	4,666	4,674
Amortization of investment tax credits	(118)	(201)	(271)
Differences required to be flowed-through by regulatory commissions	2,357	2,357	2,357
Gains on company and trust-owned life insurance	(766)	(689)	(864)
Other, net	(1,225)	393	24
Total provision for income taxes	$35,753	$41,643	$41,705
Effective tax rate	40.0%	41.5%	40.8%

The decrease in the effective income tax rate for 2015 compared to 2014 was primarily due to the benefits of depletion deductions from gas reserves activity. The increase from 2014 compared to 2013 was primarily the result of a $0.6 million income tax charge in 2014 related to a higher statutory tax rate in Oregon, which required the revaluation of deferred tax balances.

The provision (benefit) for current and deferred income taxes consists of the following at December 31:

In thousands	2015	2014	2013
Current			
Federal	$ 10,558	$ 14,823	$ (62)
State	61	24	(11)
	10,619	14,847	(73)
Deferred			
Federal	18,729	18,635	35,109
State	6,405	8,161	6,669
	25,134	26,796	41,778
Total provision for income taxes	$ 35,753	$ 41,643	$ 41,705

The following table summarizes the total provision (benefit) for income taxes for the utility and non-utility business segments for December 31:

In thousands	2015	2014	2013
Utility:			
Current	$ 15,890	$ 24,317	$ (73)
Deferred	20,834	19,518	38,073
Deferred investment tax credits	(118)	(201)	(271)
	36,606	43,634	37,729
Non-utility business segments:			
Current	(5,271)	(9,470)	—
Deferred	4,418	7,479	3,976
	(853)	(1,991)	3,976
Total provision for income taxes	$ 35,753	$ 41,643	$ 41,705

The following table summarizes the tax effect of significant items comprising our deferred income tax accounts at December 31:

In thousands	2015	2014
Deferred tax liabilities:		
Plant and property	$ 408,342	$ 386,732
Regulatory income tax assets	47,427	51,805
Regulatory liabilities	46,400	55,776
Non-regulated deferred tax liabilities	49,683	48,683
Total	$ 551,852	$ 542,996
Deferred tax assets:		
Pension and postretirement obligations	$ 4,666	$ 6,537
Alternative minimum tax credit carryforward	16,699	16,788
Loss and credit carryforwards	514	12,657
Total	21,879	35,982
Deferred income tax liabilities, net	529,973	507,014
Deferred investment tax credits	48	166
Deferred income taxes and investment tax credits	$ 530,021	$ 507,180

Management assesses the available positive and negative evidence to estimate if sufficient taxable income will be generated to utilize the existing deferred tax assets. Based upon this assessment, we have determined we are more likely than not to realize all deferred tax assets recorded as of December 31, 2015.

The Company estimates it has Oregon net operating loss (NOL) carryforwards of $3.9 million at December 31, 2015. The NOL carryforwards will be carried forward to reduce our current tax liability in future years. We anticipate that we will be able to utilize the NOL carryforwards before they begin to expire in 2028. Alternative minimum tax (AMT) credits of $16.7 million, general business credits of $0.3 million, and charitable contribution carryforwards of $2.3 million are also available. The AMT credits do not expire, and we anticipate fully using the general business credits and charitable contribution carryforwards before they begin to expire in 2033 and 2016, respectively.

As a result of certain realization requirements prescribed in the accounting guidance for income taxes, the tax benefit of statutory depletion is recognized no earlier than the year in which the depletion is deductible on the Company's federal income tax return. Income tax expense was decreased by $0.9 million in 2015 as a result of realizing deferred depletion benefit from 2013 and 2014. This benefit is included in Other in the statutory rate reconciliation table.

Uncertain tax positions are accounted for in accordance with accounting standards that require management's assessment of the anticipated settlement outcome of material uncertain tax positions taken in a prior year, or planned to be taken in the current year. Until such positions are sustained, we would not recognize the uncertain tax benefits resulting from such positions. No reserves for uncertain tax positions existed as of December 31, 2015, 2014, or 2013.

The Company's examination by the Internal Revenue Service (IRS) for tax years 2009 through 2011 was completed during the first quarter of 2014. The examination did not result in a material change to the returns as originally filed or previously adjusted for net operating loss carrybacks. The IRS Compliance Assurance Process (CAP) examinations of the 2013 and 2014 tax years were completed in the first and fourth quarters of 2015, respectively. There were no material changes to these returns as filed. The 2015 year is currently under IRS CAP examination. The Company's 2016 CAP application has been accepted by the IRS. Under the CAP program the Company works with the IRS to identify and resolve material tax matters before the tax return is filed each year. As of December 31, 2015, tax year 2012 remains open for federal examination, and tax years 2012 through 2015 remain open for state examination.

10. PROPERTY, PLANT, AND EQUIPMENT

The following table sets forth the major classifications of our property, plant, and equipment and accumulated depreciation at December 31:

In thousands	2015	2014
Utility plant in service	$2,745,485	$2,661,097
Utility construction work in progress	39,288	24,886
Less: Accumulated depreciation	867,377	836,510
Utility plant, net	1,917,396	1,849,473
Non-utility plant in service	296,839	297,295
Non-utility construction work in progress	7,768	9,282
Less: Accumulated depreciation	39,340	34,457
Non-utility plant, net	265,267	272,120
Total property, plant, and equipment	$2,182,663	$2,121,593
Capital expenditures in accrued liabilities	$ 8,985	$ 8,757

The weighted average depreciation rate was 2.8% for utility assets and 2.2% for non-utility assets in 2015, 2014, and 2013.

Accumulated depreciation does not include the accumulated provision for asset removal costs of $327.0 million and $311.2 million at December 31, 2015 and 2014, respectively. These accrued asset removal costs are reflected on the balance sheet as regulatory liabilities. See Note 2. During 2014, we acquired $1.3 million of equipment under capital leases. In 2015, we did not acquire any equipment under capital leases.

11. GAS RESERVES

We have invested $188 million through our gas reserves program in the Jonah Field located in Wyoming as of December 31, 2015. Gas reserves are stated at cost, net of regulatory amortization, with the associated deferred tax benefits recorded as liabilities on the balance sheet. Our investment in gas reserves provides long-term price protection for utility customers and currently incorporates two agreements: the original agreement with Encana Oil & Gas (USA) Inc. under which we invested $178 million and the amended agreement with Jonah Energy LLC under which an additional $10 million was invested.

We entered into our original agreements with Encana in 2011 under which we hold working interests in certain sections of the Jonah Field. Gas produced in these sections is sold at prevailing market prices, and revenues from such sales, net of associated operating and production costs and amortization, are credited to the utility's cost of gas. The cost of gas, including a carrying cost for the rate base investment, is included in our annual Oregon PGA filing, which allows us to recover these costs through customer rates. Our net investment under the original agreement earns a rate of return.

In March 2014, we amended the original gas reserves agreement in order to facilitate Encana's proposed sale of its interest in the Jonah field to Jonah Energy. Under the amendment, we ended the drilling program with Encana, but increased our working interests in our assigned sections of the Jonah field. We also retained the right to invest in new wells with Jonah Energy. The amended agreements allow us to invest in additional wells on a well-by-well basis with drilling costs and resulting gas volumes shared at our amended proportionate working interest for each well in which we invest. We elected to participate in some of the additional wells drilled in 2014, and may have the opportunity to participate in more wells in the future.

In September 2015, the OPUC adopted an all-party settlement, under which volumes produced from the additional wells drilled in 2014 are included in our Oregon PGA beginning November 1, 2015 at a fixed rate of $0.4725 per therm, which approximates the 10-year hedge rate plus financing costs at the inception of the investment.

Gas reserves acted to hedge the cost of gas for approximately 11% and 10% of our utility's gas supplies for the years ended December 31, 2015 and 2014, respectively.

The following table outlines our net gas reserves investment at December 31:

In thousands	2015	2014
Gas reserves, current	$ 17,094	$ 20,020
Gas reserves, non-current	170,453	167,190
Less: Accumulated amortization	55,901	37,910
Total gas reserves[1]	131,646	149,300
Less: Deferred taxes on gas reserves	27,203	18,551
Net investment in gas reserves[1]	$ 104,443	$ 130,749

(1) Our investment in additional wells included in total gas reserves was $8.0 million ($4.3 million net of deferred taxes) and $9.2 million ($8.4 million net of deferred taxes) at December 31, 2015 and December 31, 2014, respectively.

Our investment is included on our balance sheet under gas reserves with our maximum loss exposure limited to our current investment balance.

12. INVESTMENTS

Investments include financial investments in life insurance policies, which are accounted for at cash surrender value, net of policy loans, and equity investments in certain partnerships and limited liability companies, which are accounted for under the equity method. The following table summarizes our other investments at December 31:

In thousands	2015	2014
Investments in life insurance policies	$ 52,308	$ 52,366
Investments in gas pipeline	13,866	13,962
Other	1,892	1,910
Total other investments	$ 68,066	$ 68,238

Investment in Life Insurance Policies

We have invested in key person life insurance contracts to provide an indirect funding vehicle for certain long-term employee and director benefit plan liabilities. The amount in the above table is reported at cash surrender value, net of policy loans.

Investments in Gas Pipeline

TWP, a wholly-owned subsidiary of TWH, is pursuing the development of a new gas transmission pipeline that would provide an interconnection with our utility distribution system. NWN Energy, a wholly-owned subsidiary of NW Natural owns 50% of TWH, and 50% is owned by TransCanada American Investments Ltd., an indirect wholly-owned subsidiary of TransCanada Corporation.

VIE Analysis
TWH is a VIE, with our investment in TWP reported under equity method accounting. We have determined we are not the primary beneficiary of TWH's activities as we only have a 50% share of the entity and there are no stipulations that allow us a disproportionate influence over it. Our investments in TWH and TWP are included in other investments on our balance sheet. If we do not develop this investment, then our maximum loss exposure related to TWH is limited to our equity investment balance, less our share of any cash or other assets available to us as a 50% owner. Our investment balance in TWH was $13.4 million at December 31, 2015 and 2014.

Impairment Analysis
Our investments in nonconsolidated entities accounted for under the equity method are reviewed for impairment at each reporting period and following updates to our corporate planning assumptions. If it is determined a loss in value is other than temporary, a charge is recognized for the difference between the investment's carrying value and its estimated fair value. Fair value is based on quoted market prices when available or on the present value of expected future cash flows. Differing assumptions could affect the timing and amount of a charge recorded in any period.

In 2011, TWP withdrew its original application with the FERC for a proposed natural gas pipeline in Oregon and informed FERC that it intended to re-file an application to reflect changes in the project scope aligning the project with the region's current and future gas infrastructure needs. TWP continues working with customers in the Pacific Northwest to further understand their gas transportation needs and determine the commercial support for a revised pipeline proposal. A new FERC certificate application is expected to be filed to reflect a revised scope based on these regional needs.

Our equity investment was not impaired at December 31, 2015 as the fair value of expected cash flows from planned development exceeded our remaining equity investment of $13.4 million at December 31, 2015. However, if we learn that the project is not viable or will not go forward, then we could be required to recognize a maximum charge of up to approximately $13.4 million based on the current amount of our equity investment, net of cash and working capital at TWP. We will continue to monitor and update our impairment analysis as required.

13. DERIVATIVE INSTRUMENTS

We enter into financial derivative contracts to hedge a portion of our utility's natural gas sales requirements. These contracts include swaps, options and combinations of option contracts. We primarily use these derivative financial instruments to manage commodity price variability. A small portion of our derivative hedging strategy involves foreign currency exchange contracts.

We enter into these financial derivatives, up to prescribed limits, primarily to hedge price variability related to our physical gas supply contracts as well as to hedge spot purchases of natural gas. The foreign currency forward contracts are used to hedge the fluctuation in foreign currency exchange rates for pipeline demand charges paid in Canadian dollars.

In the normal course of business, we also enter into indexed-price physical forward natural gas commodity purchase contracts and options to meet the requirements of utility customers. These contracts qualify for regulatory deferral accounting treatment.

We also enter into exchange contracts related to the third-party asset management of our gas portfolio, some of which are derivatives that do not qualify for hedge accounting or regulatory deferral, but are subject to our regulatory sharing agreement. These derivatives are recognized in operating revenues in our gas storage segment, net of amounts shared with utility customers.

Notional Amounts
The following table presents the absolute notional amounts related to open positions on our derivative instruments:

	At December 31,	
In thousands	2015	2014
Natural gas (in therms):		
Financial	346,875	287,475
Physical	404,645	420,980
Foreign exchange	$ 9,025	$ 12,230

Purchased Gas Adjustment (PGA)
Derivatives entered into by the utility for the procurement or hedging of natural gas for future gas years generally receive regulatory deferral accounting treatment. Derivative contracts entered into after the start of the PGA period are subject to our PGA incentive sharing mechanism in Oregon. In general, our commodity hedging for the current gas year is completed prior to the start of the upcoming gas year, and hedge prices are reflected in our weighted-average cost of gas in the PGA filing. As of November 1, 2015, we reached our target hedge percentage of approximately 75% for the 2015-16 gas year. These hedge prices were included in the PGA filings and qualified for regulatory deferral.

Unrealized and Realized Gain/Loss

The following table reflects the income statement presentation for the unrealized gains and losses from our derivative instruments:

	December 31, 2015		December 31, 2014	
In thousands	Natural gas commodity	Foreign exchange	Natural gas commodity	Foreign exchange
Expense to cost of gas	$ (22,600)	$ (419)	$ (32,784)	$ (382)
Operating revenues	226	—	—	—
Less:				
Amounts deferred to regulatory accounts on balance sheet	22,434	419	32,782	382
Total gain (loss) in pre-tax earnings	$ 60	$ —	$ (2)	$ —

UNREALIZED GAIN/LOSS. Outstanding derivative instruments related to regulated utility operations are deferred in accordance with regulatory accounting standards. The cost of foreign currency forward and natural gas derivative contracts are recognized immediately in the cost of gas; however, costs above or below the amount embedded in the current year PGA are subject to a regulatory deferral tariff and therefore, are recorded as a regulatory asset or liability.

REALIZED GAIN/LOSS. We realized net losses of $37.7 million and net gains of $10.5 million for the years ended December 31, 2015 and 2014, respectively, from the settlement of natural gas financial derivative contracts. Realized gains and losses are recorded in cost of gas, deferred through our regulatory accounts, and amortized through customer rates in the following year.

Credit Risk Management of Financial Derivatives Instruments

No collateral was posted with or by our counterparties as of December 31, 2015 or 2014. We attempt to minimize the potential exposure to collateral calls by counterparties to manage our liquidity risk. Counterparties generally allow a certain credit limit threshold before requiring us to post collateral against loss positions. Given our counterparty credit limits and portfolio diversification, we have not been subject to collateral calls in 2015 or 2014. Our collateral call exposure is set forth under credit support agreements, which generally contain credit limits. We could also be subject to collateral call exposure where we have agreed to provide adequate assurance, which is not specific as to the amount of credit limit allowed, but could potentially require additional collateral in the event of a material adverse change.

Based upon current commodity financial swap and option contracts outstanding, which reflect unrealized losses of $23.2 million at December 31, 2015, we have estimated the level of collateral demands, with and without potential adequate assurance calls, using current gas prices and various credit downgrade rating scenarios for NW Natural as follows:

		Credit Rating Downgrade Scenarios			
In thousands	(Current Ratings) A+/A3	BBB+/ Baa1	BBB/ Baa2	BBB-/ Baa3	Specul-ative
With Adequate Assurance Calls	$ —	$ —	$ —	$4,852	$ 21,185
Without Adequate Assurance Calls	—	—	—	4,164	15,497

Our financial derivative instruments are subject to master netting arrangements; however, they are presented on a gross basis in our statement of financial position. The Company and its counterparties have the ability to set-off their obligations to each other under specified circumstances. Such circumstances may include a defaulting party, a credit change due to a merger affecting either party, or any other termination event.

If netted by counterparty, our derivative position would result in an asset of $2.7 million and a liability of $25.5 million as of December 31, 2015. As of December 31, 2014, our derivative position would have resulted in an asset of $0.2 million and a liability of $33.4 million.

We are exposed to derivative credit and liquidity risk primarily through securing fixed price natural gas commodity swaps to hedge the risk of price increases for our natural gas purchases made on behalf of customers. We utilize master netting arrangements through International Swaps and Derivatives Association contracts to minimize this risk along with collateral support agreements with counterparties based on their credit ratings. In certain cases we require guarantees or letters of credit from counterparties to meet our minimum credit requirement standards.
Our financial derivatives policy requires counterparties to have a certain investment-grade credit rating at the time the derivative instrument is entered into, and the policy specifies limits on the contract amount and duration based on each counterparty's credit rating. We do not speculate with derivatives; instead, we use derivatives to hedge our exposure above risk tolerance limits. Any increase in market risk created by the use of derivatives should be offset by the exposures they modify.

We actively monitor our derivative credit exposure and place counterparties on hold for trading purposes or require other forms of credit assurance, such as letters of credit, cash collateral or guarantees as circumstances warrant. Our ongoing assessment of counterparty credit risk includes consideration of credit ratings, credit default swap spreads, bond market credit spreads, financial condition, government actions and market news. We use a Monte-Carlo simulation model to estimate the change in credit and liquidity risk from the volatility of natural gas prices. The results of the model are used to establish earnings-at-risk trading limits. Our credit risk for all outstanding financial derivatives at December 31, 2015 extends to March 2018.

We could become materially exposed to credit risk with one or more of our counterparties if natural gas prices experience a significant increase. If a counterparty were to become insolvent or fail to perform on its obligations, we could suffer a material loss; however, we would expect such a loss to be eligible for regulatory deferral and rate recovery, subject to a prudence review. All of our existing counterparties currently have investment-grade credit ratings.

Fair Value

In accordance with fair value accounting, we include non-performance risk in calculating fair value adjustments. This includes a credit risk adjustment based on the credit spreads of our counterparties when we are in an unrealized gain position, or on our own credit spread when we are in an unrealized loss position. The inputs in our valuation models include natural gas futures, volatility, credit default swap spreads and interest rates. Additionally, our assessment of non-performance risk is generally derived from the credit default swap market and from bond market credit spreads. The impact of the credit risk adjustments for all outstanding derivatives was immaterial to the fair value calculation at December 31, 2015. As of December 31, 2015 and 2014, the net fair value was a liability of $22.8 million and a liability of $33.2 million, respectively, using significant other observable, or level 2, inputs. No level 3 inputs were used in our derivative valuations, and there were no transfers between level 1 or level 2 during the years ended December 31, 2015 and 2014. See Note 2.

14. COMMITMENTS AND CONTINGENCIES

Leases

We lease land, buildings and equipment under agreements that expire in various years, including a 99-year land lease that extends through 2108. Rental expense under operating leases was $5.5 million, $5.9 million, and $5.1 million for the years ended December 31, 2015, 2014, and 2013, respectively. The following table reflects the future minimum lease payments due under non-cancelable leases at December 31, 2015. These commitments relate principally to the lease of our office headquarters, underground gas storage facilities and computer equipment.

In thousands	Operating leases	Capital leases	Minimum lease payments
2016	$ 5,417	$ 564	$ 5,981
2017	5,363	156	5,519
2018	5,348	3	5,351
2019	5,313	—	5,313
2020	2,765	—	2,765
Thereafter	30,475	—	30,475
Total	$ 54,681	$ 723	$ 55,404

Gas Purchase and Pipeline Capacity Purchase and Release Commitments

We have signed agreements providing for the reservation of firm pipeline capacity under which we are required to make fixed monthly payments for contracted capacity. The pricing component of the monthly payment is established, subject to change, by U.S. or Canadian regulatory bodies. In addition, we have entered into long-term sale agreements to release firm pipeline capacity. We also enter into short-term and long-term gas purchase agreements.

The aggregate amounts of these agreements were as follows at December 31, 2015:

In thousands	Gas Purchase Agreements	Pipeline Capacity Purchase Agreements	Pipeline Capacity Release Agreements
2016	$ 61,464	$ 79,487	$ 3,739
2017	—	79,370	—
2018	—	75,796	—
2019	—	75,683	—
2020	—	72,091	—
Thereafter	—	340,027	—
Total	61,464	722,454	3,739
Less: Amount representing interest	123	110,899	11
Total at present value	$ 61,341	$ 611,555	$ 3,728

Our total payments for fixed charges under capacity purchase agreements were $85.2 million for 2015, $94.3 million for 2014, and $98.2 million for 2013. Included in the amounts were reductions for capacity release sales of $4.4 million for 2015, $4.8 million for 2014, and $4.5 million for 2013. In addition, per-unit charges are required to be paid based on the actual quantities shipped under the agreements. In certain take-or-pay purchase commitments, annual deficiencies may be offset by prepayments subject to recovery over a longer term if future purchases exceed the minimum annual requirements.

<u>Environmental Matters</u>

Refer to Note 15 for a discussion of environmental commitments and contingencies.

15. ENVIRONMENTAL MATTERS

We own, or previously owned, properties that may require environmental remediation or action. We estimate the range of loss for environmental liabilities based on current remediation technology, enacted laws and regulations, industry experience gained at similar sites and an assessment of the probable level of involvement and financial condition of other potentially responsible parties (PRPs). When amounts are prudently expended related to site remediation, we have a recovery mechanism in place to collect 96.68% of remediation costs from Oregon customers, and we are allowed to defer environmental remediation costs allocated to customers in Washington annually until they are reviewed for prudence at a subsequent proceeding.

Our sites are subject to the remediation process prescribed by the Environmental Protection Agency (EPA) and the Department of Environmental Quality (ODEQ). The process begins with a remedial investigation (RI) to determine the nature and extent of contamination and then a risk assessment (RA) to establish whether the contamination at the site poses unacceptable risks to humans and the environment. Next, a feasibility study (FS) or an engineering evaluation/cost analysis (EE/CA) evaluates various remedial alternatives. It is at this point in the process when we are able to estimate a range of remediation costs and record a reasonable potential remediation liability, or make an adjustment to our existing liability. From this study, the regulatory agency selects a remedy and issues a Record of Decision (ROD).

After the ROD is issued, we negotiate a consent decree or consent judgment for designing and implementing the remedy. We have the ability to further refine estimates of remediation liabilities at that time.

Remediation may include treatment of contaminated media such as sediment, soil and groundwater, removal and disposal of media, or institutional controls such as legal restrictions on future property use. Following construction of the remedy, the EPA and ODEQ also have requirements for ongoing maintenance, monitoring and other post-remediation care that may continue for many years. Where appropriate and reasonably known, we will provide for these costs in our remediation liabilities described above.

Due to the numerous uncertainties surrounding the course of environmental remediation and the preliminary nature of several site investigations, in some cases, we may not be able to reasonably estimate the high end of the range of possible loss. In those cases, we have disclosed the nature of the possible loss and the fact that the high end of the range cannot be reasonably estimated where a range of potential loss is available. Unless there is an estimate within the range of possible losses that is more likely than other cost estimates within that range, we record the liability at the low end of this range. It is likely changes in these estimates and ranges will occur throughout the remediation process for each of these sites due to our continued evaluation and clarification concerning our responsibility, the complexity of environmental laws and regulations and the determination by regulators of remediation alternatives. In addition to remediation costs, we could also be subject to Natural Resource Damages (NRD) claims. We will assess the likelihood and probability of each claim and recognize a liability if deemed appropriate. As of December 31, 2015, we have not received any material NRD claims.

Environmental Sites

The following table summarizes information regarding liabilities related to environmental sites, which are recorded in other current liabilities and other noncurrent liabilities on the balance sheet at December 31:

	Current Liabilities		Non-Current Liabilities	
In thousands	2015	2014	2015	2014
Portland Harbor site:				
Gasco/Siltronic Sediments	$ 2,229	$ 1,767	$ 42,641	$ 38,019
Other Portland Harbor	1,972	1,934	5,073	4,338
Gasco Upland site	10,599	9,535	52,117	37,117
Siltronic Upland site	951	957	337	348
Central Service Center site	25	171	—	—
Front Street site	1,155	1,020	7,748	122
Oregon Steel Mills	—	—	179	179
Total	$ 16,931	$ 15,384	$ 108,095	$ 80,123

PORTLAND HARBOR SITE. The Portland Harbor is an EPA listed Superfund site that is approximately 10 miles long on the Willamette River and is adjacent to NW Natural's Gasco uplands and the Siltronic uplands sites. We are a PRP to the Superfund site and have joined with some of the other PRPs (the Lower Willamette Group or LWG) to develop a Portland Harbor Remedial Investigation/ Feasibility Study (RI/FS), which we submitted to the EPA in 2012. In August 2015, the EPA issued its own Draft Feasibility Study (Draft FS) for comment. The EPA Draft FS provides a new range of remedial costs for the entire Portland Harbor Superfund Site, which includes the Gasco/ Siltronic Sediment site, discussed below. The range of present value costs estimated by the EPA for various remedial alternatives for the entire Portland Harbor, as provided by the EPA's Draft FS, is $791 million to $2.45 billion. The range provided in the EPA's Draft FS is based on cost alternatives the EPA estimates to have an accuracy between -30% and +50% of actual costs, depending on the scope of work. While the EPA's Draft FS provides a higher range of costs than the LWG's submission in 2012, our potential liability is still a portion of the costs of the remedy the EPA will select for the entire Portland Harbor Superfund site. The cost of that remedy is expected to be allocated among more than 100 PRPs. We are participating in a non-binding allocation process in an effort to settle this potential liability. The new EPA Draft FS does not provide any additional clarification around allocation of costs.

We manage our liability related to the Superfund site as two distinct remediation projects, the Gasco/Siltronic Sediments and Other Portland Harbor projects.

Gasco/Siltronic Sediments. In 2009, NW Natural and Siltronic Corporation entered into a separate Administrative Order on Consent with the EPA to evaluate and design specific remedies for sediments adjacent to the Gasco uplands and Siltronic uplands sites. We submitted a draft EE/CA to the EPA in May 2012 to provide the estimated cost of potential remedial alternatives for this site. At this time, the estimated costs for the various sediment remedy alternatives in the draft EE/CA as well as costs for the additional studies and design work needed before the clean-up can occur, and for regulatory oversight throughout the clean-up range from $44.9 million to $350 million. We have recorded a liability of $44.9 million for the sediment clean-up, which reflects the low end of the range. At this time, we believe sediments at this site represent the largest portion of our liability related to the Portland Harbor site, discussed above.

Other Portland Harbor. NW Natural incurs costs related to its membership in the LWG. NW Natural also incurs costs related to natural resource damages from these sites. The Company and other parties have signed a cooperative agreement with the Portland Harbor Natural Resource Trustee council to participate in a phased natural resource damage assessment to estimate liabilities to support an early restoration-based settlement of natural resource damage claims. Natural resource damage claims may arise only after a remedy for clean-up has been settled. We have recorded a liability for these claims which is at the low end of the range of the potential liability; the high end of the range cannot be reasonably estimated at this time. This liability is not included in the range of costs provided in the draft FS for the Portland Harbor or noted above.

GASCO UPLANDS SITE. A predecessor of NW Natural owned a former gas manufacturing plant that was closed in 1958 (Gasco site) and is adjacent to the Portland Harbor site described above. The Gasco site has been under investigation by us for environmental contamination under the ODEQ Voluntary Clean-Up Program. It is not included in the range of remedial costs for the Portland Harbor site noted above. We manage the Gasco site in two parts, the uplands portion and the groundwater source control action.

We submitted a revised Remedial Investigation Report for the uplands to ODEQ in May 2007. In March 2015, ODEQ approved the RA NW Natural submitted in 2010, enabling us to begin work on the FS in 2016. We have recognized a liability for the remediation of the uplands portion of the site which is at the low end of the range of potential liability; the high end of the range cannot be reasonably estimated at this time.

In September 2013, we completed construction of a groundwater source control system, including a water treatment station, at the Gasco site. We are working with ODEQ on monitoring the effectiveness of the system and at this time it is unclear what, if any, additional actions ODEQ may require subsequent to the initial testing of the system or as part of the final remedy for the uplands portion of the Gasco site. We have estimated the cost associated with the ongoing operation of the system and have recognized a liability which is at the low end of the range of potential cost. We cannot estimate the high end of the range at this time due to the uncertainty associated with the duration of running the water treatment station, which is highly dependent on the remedy determined for both the upland portion as well as the final remedy for our Gasco sediment exposure.

Beginning November 1, 2013, capital asset costs of $19.0 million for the Gasco water treatment station were placed into rates with OPUC approval. The OPUC deemed these costs prudent. Beginning November 1, 2014, the OPUC approved the application of $2.5 million from insurance proceeds plus interest to reduce the total amount of Gasco capital costs to be recovered through rate base. A portion of these proceeds was noncash in 2014.

OTHER SITES. In addition to those sites above, we have environmental exposures at four other sites: Siltronic, Central Service Center, Front Street and Oregon Steel Mills. Due to the uncertainty of the design of remediation, regulation, timing of the remediation and in the case of the Oregon Steel Mills site, pending litigation, liabilities for each of these sites have been recognized at their respective low end of the range of potential liability; the high end of the range could not be reasonably estimated at this time.

Siltronic Upland. A portion of the Siltronic property adjacent to the Gasco site was formerly owned by Portland Gas and Coke, NW Natural's predecessor. We are currently conducting an investigation of manufactured gas plant wastes on the uplands at this site for the ODEQ.

Central Service Center site. We are currently performing an environmental investigation of the property under the ODEQ's Independent Cleanup Pathway. This site is on ODEQ's list of sites with confirmed releases of hazardous substances, and cleanup is necessary.

Front Street site. The Front Street site was the former location of a gas manufacturing plant we operated (the former Portland Gas Manufacturing site, or PGM). At ODEQ's request, we conducted a sediment and source control investigation and provided findings to ODEQ. In December 2015, we completed a FS on the former Portland Gas Manufacturing site. The FS provided a range of $7.6 million to $12.9 million for remedial costs. We have recorded a liability at the low end of the range of possible loss as no alternative in the range is considered more likely than another. Further, we have recognized an additional liability of $1.3 million for additional studies and design costs as well as regulatory oversight throughout the clean-up that will be required to assist in ODEQ making a remedy selection and completing a design.

Oregon Steel Mills site. Refer to the "Legal Proceedings," below.

Site Remediation and Recovery Mechanism

We have a SRRM through which we track and have the ability to recover past deferred and future prudently incurred environmental remediation costs allocable to Oregon, subject to an earnings test.

REGULATORY ACTIVITIES. An Order from the OPUC in February 2015 deemed certain environmental remediation expenses and associated carrying costs deferred through March 31, 2014 prudent. Our settlement with insurance carriers resulting in insurance proceeds received was also deemed prudent in the Order. Under the Order, we were required to forgo the collection of $15 million out of approximately $95 million of environmental remediation expenses and associated carrying costs we had deferred through 2012. The OPUC disallowed this amount from rate recovery based on its determination of how an earnings test should apply to amounts deferred from 2003 to 2012, with adjustments for other factors the OPUC deemed relevant. See Note 2 for information regarding the regulatory disallowance of past deferred costs under the Order received from the OPUC in February 2015.

We submitted the required compliance filing demonstrating the proposed implementation of the Order and SRRM in March 2015. In September 2015, as a result of discussions with the parties, we withdrew our original compliance filing and submitted a revised filing. The parties raised three issues with our proposed implementation of the Order. First, the parties asserted that interest on the $15 million charge should be separately disallowed, in addition to the specified $15 million. This interest would total approximately $2.8 million. Second, the parties raised issues with how the state allocation rates from the Order are applied to our environmental remediation sites. Third, a customer group disagreed with our treatment of expenses put into the SRRM amortization account.

In addition, we requested clarification from the OPUC regarding the amount of Oregon-allocated insurance proceeds to be held in a secured account. In September

2015, the OPUC resolved the issue by adopting an all-party settlement, which provided that we did not need to obtain a secured account. Instead, under the order, insurance proceeds used to offset future environmental expenses will accrue interest at a rate equal to the five-year treasury rate plus 100 basis points. Currently, Oregon-allocated insurance proceeds total approximately $93 million on a pre-tax basis.

On January 27, 2016, the OPUC issued an Order addressing the outstanding issues. See Note 16 regarding this subsequent event.

COLLECTIONS FROM CUSTOMERS. The SRRM provides us with the ability to recover past deferred and future prudently incurred environmental remediation costs allocable to Oregon, subject to an earnings test. The SRRM created three classes of deferred environmental remediation expense:

- Pre-review - This class of costs represents remediation spend that has not yet been deemed prudent by the OPUC. Carrying costs on these remediation expenses are recorded at our authorized cost of capital. The Company anticipates the prudence review for annual costs and approval of the earnings test prescribed by the OPUC to occur by the third quarter of the following year.
- Post-review - This class of costs represents remediation spend that has been deemed prudent and allowed after applying the earnings test, but is not yet included in amortization. We earn a carrying cost on these amounts at a rate equal to the five-year treasury rate plus 100 basis points.
- Amortization - This class of costs represents amounts included in current customer rates for collection and is generally calculated as one-fifth of the post-review deferred balance. We earn a carrying cost equal to the amortization rate determined annually by the OPUC, which approximates a short-term borrowing rate. We included $8.4 million of deferred remediation expense approved by the OPUC for collection during the 2015-2016 PGA year.

In addition to the collection amount noted above, the Order also provides for the annual collection of $5 million from Oregon customers through a tariff rider. As we collect amounts from customers, we recognize these collections as revenue and separately amortize our deferred regulatory asset balance through operating expense.

We received total environmental insurance proceeds of approximately $150 million as a result of settlements from our litigation that was dismissed in July 2014. Under the OPUC Order, one-third of the Oregon allocated proceeds were applied to costs deferred through 2012, and the remaining two-thirds will be applied to costs over the next 20 years. Annually, the Order provided for the application of $5 million of insurance proceeds against deferred remediation expense deemed prudent in the same annual period; annual amounts not utilized are carried forward to apply against future prudently incurred costs. We accrue interest on the insurance proceeds in the customer's favor at a rate equal to the five-year treasury rate plus 100 basis points. As of December 31, 2015, we have applied $53.2 million of insurance proceeds to prudently incurred remediation costs.

The following table presents information regarding the total amount of cash paid for environmental sites and the total regulatory asset deferred as of December 31:

In thousands	2015	2014
Cash paid	$ 124,325	$ 113,740
Total regulatory asset deferral[1]	85,854	58,859
Current regulatory assets[2]	9,270	—
Long-term regulatory assets	76,584	58,859

(1) Includes cash paid, remaining liability and interest, net of insurance reimbursement, amounts collected from customers, and amounts reclassified to utility plant for the water treatment station.

(2) Environmental costs relate to specific sites approved for regulatory deferral by the OPUC and WUTC. In Oregon, we earn a carrying charge on cash amounts paid, whereas amounts accrued but not yet paid do not earn a carrying charge until expended. We also accrue a carrying charge on insurance proceeds for amounts owed to customers. In Washington, a carrying charge related to deferred amounts will be determined in a future proceeding. Current environmental costs represent remediation costs management expects to collect from customers in the next 12 months. Amounts included in this estimate are still subject to a prudence and earnings test review by the OPUC and do not include the $5 million base rate rider. The Oregon amounts are recoverable through utility rates, subject to an earnings test.

ENVIRONMENTAL EARNINGS TEST. The Order directed us to implement an annual environmental earnings test for our prudently incurred remediation expense. Prudently incurred Oregon allocated annual remediation expense and interest in excess of the $5 million tariff rider and $5 million insurance proceeds application plus interest on the insurance proceeds are recoverable through the SRRM, to the extent the utility earns at or below our authorized Return On Equity (ROE). To the extent the utility earns more than its authorized ROE in a year, the utility is required to cover environmental expenses and interest on expenses greater than the $10 million (plus interest from insurance proceeds) with those earnings that exceed its authorized ROE.

Under the Order, the OPUC will revisit the deferral and amortization of future remediation expenses, as well as the treatment of remaining insurance proceeds three years from the original Order, or earlier if the Company gains greater certainty about its future remediation costs, to consider whether adjustments to the mechanism may be appropriate.

WASHINGTON DEFERRAL. In Washington, cost recovery and carrying charges on amounts deferred for costs associated with services provided to Washington customers will be determined in a future proceeding. Annually, we review all regulatory assets for recoverability or more often if circumstances warrant. If we should determine all or a portion of these regulatory assets no longer meet the criteria for continued application of regulatory accounting, then we would be required to write off the net unrecoverable balances against earnings in the period such a determination is made.

Legal Proceedings

NW Natural is subject to claims and litigation arising in the ordinary course of business. Although the final outcome of any of these legal proceedings cannot be predicted with certainty, including the matter described below, we do not expect that the ultimate disposition of any of these matters will have a material effect on our financial condition, results of operations or cash flows. See also Part I, Item 3, "Legal Proceedings."

OREGON STEEL MILLS SITE. In 2004, NW Natural was served with a third-party complaint by the Port of Portland (the Port) in a Multnomah County Circuit Court case, Oregon Steel Mills, Inc. v. The Port of Portland. The Port alleges that in the 1940s and 1950s petroleum wastes generated by our predecessor, Portland Gas & Coke Company, and 10 other third-party defendants, were disposed of in a waste oil disposal facility operated by the United States or Shaver Transportation Company on property then owned by the Port and now owned by Evraz Oregon Steel Mills. The complaint seeks contribution for unspecified past remedial action costs incurred by the Port regarding the former waste oil disposal facility as well as a declaratory judgment allocating liability for future remedial action costs. No date has been set for trial. Although the final outcome of this proceeding cannot be predicted with certainty, we do not expect the ultimate disposition of this matter will have a material effect on our financial condition, results of operations or cash flows. For additional information regarding other commitments and contingencies, see Note 14.

16. SUBSEQUENT EVENT

On January 27, 2016, the Public Utility Commission of Oregon (OPUC) issued an Order (2016 OPUC Order) deciding the three issues raised as a result of our required Site Remediation Recovery Mechanism (SRRM) compliance filing. The OPUC ordered: (1) the disallowance of $2.8 million of interest earned on the previously disallowed environmental expenditures amounts; (2) the allocation of 96.68% of environmental remediation costs for all environmental sites to Oregon; and (3) our treatment of $13.8 million of expenses put into the SRRM amortization account was correct and in compliance with prior OPUC orders.

Under a prior OPUC order we were required to forgo collection of $15 million out of approximately $95 million of environmental remediation expenses and associated carrying costs that the Company had deferred through 2012 based on the OPUC's determination of how an earnings test should apply to amounts deferred from 2003 to 2012, with adjustments for other factors the OPUC deemed relevant. We recognized interest of approximately $2.8 million on the $15 million charge after that time. This interest is shown as a regulatory asset in our financial statements, and the disallowance will result in a $2.8 million pre-tax charge in the first quarter of 2016. Consistent with our accounting policy for recognition of regulatory actions, we recognize the financial impacts in the period in which the order was received.

With respect to allocation of 96.68% of environmental remediation costs to Oregon, we currently have a deferral order in Washington to defer environmental costs and insurance proceeds; however, recovery of those costs has not yet been determined. We have deferred costs for certain sites that only served Oregon customers and have, as a result of this order, determined it appropriate to reserve against 3.32% of these deferrals until resolution of recovery in Washington can be determined. The total reserve amount is approximately $0.5 million and will be recorded in the first quarter of 2016 in accordance with the Company's policy. Consistent with our compliance filing filed in September 2015, the OPUC also ordered the same allocation factors should be applied to insurance proceeds, resulting in the application of 96.68% of the Company's recovered insurance proceeds to Oregon.

With respect to a third issue raised in the proceeding by a customer group that the Company should not be allowed to apply and recover portions of the SRRM amounts in 2013, 2014, and 2015 because that would constitute retroactive ratemaking, the OPUC ordered in the Company's favor. The OPUC ordered our treatment of $13.8 million of expenses put into the SRRM amortization account, to be amortized over five years, was correct and complied with the original order. For more information regarding our SRRM, see Note 15.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

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

Line No.	Item (a)	Total (b)
1	**UTILITY PLANT**	
2	In Service	
3	Plant in Service (Classified)	2,541,747,048
4	Property Under Capital Leases	-
5	Plant Purchased or Sold	-
6	Completed Construction not Classified	188,666,708
7	Experimental Plant Unclassified	-
8	TOTAL Utility Plant (Total of lines 3 thru 7)	2,730,413,756
9	Leased to Others	-
10	Held for Future Use	923,155
11	Construction Work in Progress	39,288,188
12	Acquisition Adjustments	-
13	TOTAL Utility Plant (Total of lines 8 thru 12)	2,770,625,099
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	1,193,310,914
15	Net Utility Plant (Enter Total of line 13 less 14)	1,577,314,185
16	**DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION**	
17	In Service:	
18	Depreciation	1,143,142,678
19	Amortization and Depl. of Producing Natural Gas Land and Land Rights	-
20	Amortization. of Underground Storage Land and Land Rights	25,143
21	Amortization. of Other Utility Plant	72,377,670
22	Salvage Work In Progress	-
23	Less Removal Work In Progress	22,234,577
24	TOTAL In Service (Total of lines 18 thru 23)	1,193,310,914
25	Leased to Others	
26	Depreciation	-
27	Amortization and Depletion	-
28	TOTAL Leased to Others (Total of lines 26 and 27)	-
29	Held for Future Use	
30	Depreciation	-
31	Amortization	-
32	TOTAL Held for Future Use (Total of lines 30 and 31)	-
33	Abandonment of Leases (Natural Gas)	-
34	Amortization of Plant Acquisition Adjustment	-
35	TOTAL Accumulated Provisions (Should agree with line 14 above) (Total of lines 24, 28, 32, 33, and 34)	1,193,310,914

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

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

Electric (c)	Gas (d)	Other (Specify) (e)	Common (f)	Line No.
				1
				2
	2,541,747,048			3
	-			4
	-			5
	188,666,708			6
	-			7
	2,730,413,756			8
	-			9
	923,155			10
	39,288,188			11
	-			12
	2,770,625,099			13
	1,193,310,914			14
	1,577,314,185			15
				16
				17
	1,143,142,678			18
	-			19
	25,143			20
	72,377,670			21
	-			22
	22,234,577			23
	1,193,310,914			24
				25
	-			26
	-			27
	-			28
				29
	-			30
	-			31
	-			32
	-			33
	-			34
	1,193,310,914			35

ACCOUNT SUMMARY BY FUNTIONAL CLASS
NW Natural

Period Beginning: Jan 2015
Period Ending: Dec 2015

Functional Class / FERC Plant Account		Beginning Balance	Additions	Retirements	Transfers	Adjustments	Ending Balance
UTILITY							
Intangible Plant							
301	ORGANIZATION	$1,174	$0	$0	$0	$0	$1,174
302	FRANCHISES & CONSENTS	83,621	0	0	0	0	83,621
303.1	COMPUTER SOFTWARE	53,335,387	5,129,339	(1,073,332)	0	(443,935)	56,947,459
303.2	CUSTOMER INFORMATION SYSTEM	32,348,168	0	0	0	0	32,348,168
303.3	INDUSTRIAL & COMMERCIAL BIL	4,146,951	0	0	0	0	4,146,951
303.4	CRMS	682,893	0	0	0	0	682,893
303.5	POWERPLANT SOFTWARE	0	0	0	0	0	0
	Intangible Plant Subtotal	90,598,194	5,129,339	(1,073,332)	0	(443,935)	94,210,266
Production Plant - Oil Gas							
304.1	LAND	24,998	0	0	0	0	24,998
305.2	P P O G STRU & IMPR-SEWER S	0	0	0	0	0	0
305.5	P P O G STRU & IMPR-OTHER Y	13,156	0	0	0	0	13,156
312.3	P P O G FUEL HANDLING AND S	0	0	0	0	0	0
318.3	P P O G LIGHT OIL REFINING	144,896	0	0	0	0	144,896
318.5	P P O G TAR PROCESSING	243,551	0	0	0	0	243,551
325	NATURAL GAS PROD AND GATHER	0	0	0	0	0	0
327	NATURAL GAS PROD & GATHERIN	0	0	0	0	0	0
328	NATURAL GAS PROD AND GATHER	0	0	0	0	0	0
331	NATURAL GAS PROD & GATHERIN	0	0	0	0	0	0
332	NATURAL GAS PROD & GATHERIN	0	0	0	0	0	0
333	NATURAL GAS PROD & GATHERIN	0	0	0	0	0	0
334	NATURAL GAS PROD & GATHERIN	0	0	0	0	0	0
	Production Plant - Oil Gas Subtotal	426,601	0	0	0	0	426,601
Production Plant - Other							
305.11	GAS PRODUCTION - COTTAGE G	8,320	0	0	0	0	8,320
305.17	STRUCTURES MIXING STATION	46,587	0	0	0	0	46,587
311	P P OTHER-LIQUEFIED PETROLE	0	0	0	0	0	0
311.4	P P OTHER-L P G GRANGER	0	0	0	0	0	0
311.7	LIQUIFIED GAS EQUIPMENT COO	4,033	0	0	0	0	4,033
311.8	LIQUIFIED GAS EQUIPMENT LIN	4,209	0	0	0	0	4,209
319	GAS MIXING EQUIPMENT GASCO	185,448	0	0	0	0	185,448
	Production Plant - Other Subtotal	248,597	0	0	0	0	248,597

ACCOUNT SUMMARY BY FUNTIONAL CLASS
NW Natural

Period Beginning: Jan 2015
Period Ending: Dec 2015

Functional Class FERC Plant Account		Beginning Balance	Additions	Retirements	Transfers	Adjustments	Ending Balance
UTILITY							
Natural Gas Underground Storage							
350.1	LAND	106,549	0	0	0	0	106,549
350.2	RIGHTS-OF-WAY	109,625	0	0	0	0	109,625
351	STRUCTURES AND IMPROVEMENTS	7,139,428	68,816	0	0	0	7,208,244
352	WELLS	20,047,076	0	0	0	0	20,047,076
352.1	STORAGE LEASEHOLD & RIGHTS	3,938,491	0	0	0	0	3,938,491
352.2	RESERVOIRS	5,844,618	0	0	0	1,427,935	7,272,553
352.3	NON-RECOVERABLE NATURAL GAS	6,440,890	0	0	0	0	6,440,890
353	LINES	6,552,220	0	0	0	0	6,552,220
354	COMPRESSOR STATION EQUIPMENT	29,528,531	85,727	0	0	1,737,553	31,351,811
355	MEASURING / REGULATING EQUIPM	6,700,892	0	0	0	458,515	7,159,407
356	PURIFICATION EQUIPMENT	297,363	0	0	0	0	297,363
357	OTHER EQUIPMENT	1,331,924	105	0	0	0	1,332,029
	Natural Gas Underground Storage Subtotal	88,037,608	154,648	-	-	3,624,002	91,816,259
Local Storage Plant							
360.11	LAND - LNG LINNTON	83,598	0	0	0	0	83,598
360.12	LAND - LNG NEWPORT	536,675	0	0	0	0	536,675
360.2	LAND - OTHER	106,557	0	0	0	0	106,557
361.11	STRUCTURES & IMPROVEMENTS	4,540,966	53,825	0	0	0	4,594,791
361.12	STRUCTURES & IMPROVEMENTS	4,659,407	(2,668)	0	0	0	4,656,739
361.2	STRUCTURES & IMPROVEMENTS -	26,757	0	0	0	0	26,757
362.11	GAS HOLDERS - LNG LINNTON	2,690,579	53,825	0	0	0	2,744,404
362.12	GAS HOLDERS - LNG NEWPORT	5,791,956	0	0	0	0	5,791,956
362.2	GAS HOLDERS - LNG OTHER	1,600	0	0	0	0	1,600
363.11	LIQUEFACTION EQUIP. - LINN	2,921,686	53,825	0	0	0	2,975,511
363.12	LIQUEFACTION EQUIP - NEWPO	7,308,111	0	0	0	0	7,308,111
363.21	VAPORIZING EQUIP - LINNTON	2,629,836	53,824	0	0	0	2,683,660
363.22	VAPORIZING EQUIP - NEWPORT	3,594,015	70,347	0	0	0	3,664,362
363.31	COMPRESSOR EQUIP - LINNTON	180,903	0	0	0	0	180,903
363.32	COMPRESSOR EQUIPMENT - NE	1,390,926	0	0	0	0	1,390,926
363.41	MEASURING & REGULATING EQU	1,091,077	5,026	0	0	151,562	1,247,665
363.42	MEASURING & REGULATING EQU	113,414	0	0	0	0	113,414
363.5	CNG REFUELING FACILITIES	3,051,295	0	0	0	0	3,051,295
363.6	LNG REFUELING FACILITIES	739,473	0	0	0	0	739,473
	Local Storage Plant Subtotal	41,458,832	288,003	-	0	151,562	41,898,397

ACCOUNT SUMMARY BY FUNTIONAL CLASS
NW Natural

Period Beginning: Jan 2015
Period Ending: Dec 2015

Functional Class FERC Plant Account		Beginning Balance	Additions	Retirements	Transfers	Adjustments	Ending Balance
UTILITY							
Transmission Plant							
365.1	LAND	89,772	0	0	0	0	89,772
365.2	LAND RIGHTS	6,455,177	0	0	0	0	6,455,177
366.3	STRUCTURES & IMPROVEMENTS -	1,041,984	0	0	0	0	1,041,984
367	MAINS	141,350,713	5,089,921	0	0	(102,846)	146,337,788
367.21	NORTH MIST TRANSMISSION LI	1,994,582	0	0	0	0	1,994,582
367.22	SOUTH MIST TRANSMISSION LI	14,949,264	0	0	0	0	14,949,264
367.23	SOUTH MIST TRANSMISSION LI	34,881,341	0	0	0	0	34,881,341
367.24	11.7M S MIST TRANS LINE	17,466,182	0	0	0	0	17,466,182
367.25	12M NORTH S MIST TRANS	18,613,651	0	0	0	0	18,613,651
367.26	38M NORTH S MIST TRANS	68,232,676	0	0	0	0	68,232,676
368	TRANSMISSION COMPRESSOR	0	0	0	0	0	0
369	MEASURING & REGULATE STATION	3,969,549	0	0	0	0	3,969,549
370	COMMUNICATION EQUIPMENT	0	0	0	0	0	0
	Transmission Plant Subtotal	309,044,892	5,089,921	0	0	(102,846)	314,031,967
Distribution Plant							
374.1	LAND	86,775	0	0	0	0	86,775
374.2	LAND RIGHTS	1,883,762	0	0	0	0	1,883,762
375	STRUCTURES & IMPROVEMENTS	80,217	0	0	0	0	80,217
376.11	MAINS < 4"	533,315,130	17,927,346	(308,781)	0	(244,648)	550,689,047
376.12	MAINS 4" & >	487,995,324	16,988,626	(531,012)	0	347,493	504,800,431
377	COMPRESSOR STATION EQUIPMENT	969,942	0	0	0	(151,562)	818,380
378	MEASURING & REG EQUIP - GENER	30,803,478	872,660	0	0	0	31,676,138
379	MEASURING & REG EQUIP - GATE	4,808,325	930,789	0	0	(303)	5,738,811
380	SERVICES	683,750,905	27,681,471	(1,293,428)	0	0	710,138,948
381	METERS	80,715,533	4,102,898	(1,126,709)	0	0	83,691,722
381.1	METERS (ELECTRONIC)	1,464,473	77,201	0	0	0	1,541,674
381.2	ERT (ENCODER RECEIVER TRANS	38,878,016	2,206,039	(607,184)	0	504	40,477,375
382	METER INSTALLATIONS	60,734,963	2,452,818	(3,438,321)	0	(200)	59,749,260
382.1	METER INSTALLATIONS (ELECTR	481,020	0	0	0	0	481,020
382.2	ERT INSTALLATION (ENCODER	9,586,884	0	(113,714)	0	0	9,473,170
383	HOUSE REGULATORS	1,278,985	205,693	0	0	0	1,484,678

ACCOUNT SUMMARY BY FUNTIONAL CLASS
NW Natural

Period Beginning: Jan 2015
Period Ending: Dec 2015

Functional Class FERC Plant Account		Beginning Balance	Additions	Retirements	Transfers	Adjustments	Ending Balance
UTILITY							
386	OTHER PROPERTY ON CUSTOMERS P	0	0	0	0	0	0
387.1	CATHODIC PROTECTION TESTING	173,859	0	0	0	0	173,859
387.2	CALORIMETERS @ GATE STATIONS	96,424	0	0	0	0	96,424
387.3	METER TESTING EQUIPMENT	72,671	0	0	0	0	72,671
	Distribution Plant Subtotal	1,937,176,687	73,445,542	(7,419,149)	0	(48,716)	2,003,154,364
General Plant							
389	LAND	9,609,258	1,585,854	0	0	0	11,195,112
390	STRUCTURES & IMPROVEMENTS	54,853,432	3,525,468	0	0	0	58,378,900
390.1	SOURCE CONTROL PLANT	18,590,295	0	0	0	0	18,590,295
391.1	OFFICE FURNITURE & EQUIPMEN	9,873,075	554,813	0	0	0	10,427,888
391.2	COMPUTERS	22,897,389	2,862,978	(10,029,192)	0	443,935	16,175,110
391.3	ON SITE BILLING	-	0	0	0	0	0
391.4	CUSTOMER INFORMATION SYSTEM	-	0	0	0	0	0
392	TRANSPORTATION EQUIPMENT	29,801,585	6,088,187	(1,390,921)	0	0	34,498,851
393	STORES EQUIPMENT	119,406	0	0	0	0	119,406
394	TOOLS - SHOP & GARAGE EQUIPUI	16,305,218	428,234	0	0	0	16,733,452
395	LABORATORY EQUIPMENT	68,293	0	0	0	0	68,293
396	POWER OPERATED EQUIPMENT	8,625,589	1,126,133	(581,404)	0	0	9,170,318
397	GEN PLANT-COMMUNICATION EQU	88,322	0	0	0	0	88,322
397.1	MOBILE	475,621	0	0	0	0	475,621
397.2	OTHER THAN MOBILE & TELEMET	1,690,854	0	0	0	0	1,690,854
397.3	TELEMETERING - OTHER	4,718,757	(29,206)	0	0	0	4,689,551
397.4	TELEMETERING - MICROWAVE	1,522,718	124,078	0	0	0	1,646,796
397.5	TELEPHONE EQUIPMENT	394,587	96,155	0	0	0	490,742
398	GEN PLANT-MISCELLANEOUS EQU	-	0	0	0	0	0
398.1	PRINT SHOP	83,249	0	0	0	0	83,249
398.2	KITCHEN EQUIPMENT	12,812	0	0	0	0	12,812
398.3	JANITORIAL EQUIPMENT	14,873	0	0	0	0	14,873
398.4	INSTALLED IN LEASED BUILDINGS	10,120	0	0	0	0	10,120
398.5	OTHER MISCELLANEOUS EQUIPMENT	66,739	0	0	0	0	66,739
	General Plant Subtotal	179,822,192	16,362,694	(12,001,517)	0	443,935	184,627,304
	Utility Property Grand Total	$2,646,813,603	$100,470,148	($20,493,998)	$0	$3,624,002	$2,730,413,756

ACCOUNT SUMMARY BY FUNTIONAL CLASS
NW Natural

Period Beginning: Jan 2015
Period Ending: Dec 2015

Functional Class / FERC Plant Account		Beginning Balance	Additions	Retirements	Transfers	Adjustments	Ending Balance
NON-UTILITY							
Intangible Plant							
303.1	COMPUTER SOFTWARE	$163,357	$0	$0	$0	$0	$163,357
303.2	CUSTOMER INFORMATION SYSTEM	61,429	0	0	0	0	61,429
Non Utility	Intangible Plant Subtotal	224,786	0	0	0	0	224,786
Natural Gas Underground Storage							
352	WELLS	16,940,451	0	0	0	0	16,940,451
352.1	STORAGE LEASEHOLD & RIGHTS	1,020	0	0	0	0	1,020
352.2	RESERVOIRS	4,989,436	0	0	0	(1,427,935)	3,561,501
353	LINES	1,649,744	0	0	0	0	1,649,744
354	COMPRESSOR STATION EQUIPMENT	14,676,125	171,575	0	0	(1,737,553)	13,110,147
355	MEASURING / REGULATING EQUIPM	9,267,567	(588)	0	0	(458,515)	8,808,464
357	OTHER EQUIPMENT	63,256	0	0	0	0	63,256
Non Utility	Natural Gas Underground Storage Subtotal	47,587,600	170,987	0	0	(3,624,002)	44,134,585
Transmission Plant							
368	TRANSMISSION COMPRESSOR	7,723,454	0	0	0	0	7,723,454
Non Utility	Transmission Plant Subtotal	7,723,454	0	0	0	0	7,723,454
Distribution Plant							
376.12	MAINS 4" & >	878,618	0	0	0	0	878,618
Non Utility	Distribution Plant Subtotal	878,618	0	0	0	0	878,618
General Plant							
389	LAND	438,739	0	0	0	0	438,739
390	STRUCTURES & IMPROVEMENTS	218,156	0	0	0	0	218,156
Non Utility	General Plant Subtotal	656,895	0	0	0	0	656,895
Non Utility Other							
121.1	NON-UTIL PROP-DOCK	1,946,033	0	0	0	0	1,946,033
121.2	NON-UTIL PROP-LAND	125,102	0	0	0	0	125,102
121.3	NON-UTIL PROP-OIL ST	2,616,313	0	0	0	0	2,616,313

Oregon and Washington - Account 121001-121045 Pages 204-209

ACCOUNT SUMMARY BY FUNTIONAL CLASS
NW Natural

Period Beginning: Jan 2015
Period Ending: Dec 2015

Functional Class FERC Plant Account		Beginning Balance	Additions	Retirements	Transfers	Adjustments	Ending Balance
NON-UTILITY							
121.7	NON-UTIL PROP-APPL CENTER	61,113	0	0	0	0	61,113
121.8	NON-UTIL PROP-STORAGE	288,112	0	(192,074)	0	0	96,038
Non Utility	Other	5,036,673	0	(192,074)	0	0	4,844,599
	Non Utility Property Grand Total	$62,108,025	$171,394	($192,074)	$0	($3,624,002)	$58,463,343

Non Utility Property Summary		
	Non Utility Property Grand Total	$58,463,343
121117	Gas Stored Underground - St. Helens	3,800,189
121707-8	Construction Work in Progress Non Utility	6,950,717
Balance Sheet Total for Non Utility Property		$69,214,249

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

Gas Property And Capacity Leased From Others

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

Line No.	Name of Lessor (a)	(b)	Description of Lease (c)	Lease Payments for Current Year (d)
1	Northwest Pipeline		Pipeline Capacity	50,259,916
2	TMC "Nova and ANG"		Pipeline Capacity	12,423,195
3	Foris BC		Pipeline Capacity	7,469,730
4	TransCanada "Gas Trans NW"		Pipeline Capacity	5,778,873
5	One Pacific Square LLC		Corporate Headquarter Building	4,329,648
6	Tenaska Marketing Ventures		Pipeline Capacity	1,898,619
7	AECO Gas Storage		Pipeline Capacity	826,130
8	TMC "Southern Crossing"		Pipeline Capacity	757,620
9	J Aron		Pipeline Capacity	654,496
10	International Paper		Pipeline Capacity	478,880
11	KB Pipeline		Pipeline Capacity	224,258
12	Coos County Pipeline		Pipeline Capacity	199,632
13	TC Gas Storage		Pipeline Capacity	102,904
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42	**Total**			85,403,901

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

Gas Plant Held for Future Use (Account 105)

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

Line No.	Description and Location of Property (a)	Date Originally Included in this account (b)	Date Expected to be Used In Utility Service (c)	Balance at End of Year (d)
1				
2	Underground Storage	07/2009	Undetermined	127,921
3	Easement	11/2011	Undetermined	136,720
4	Willamette Valley Crossing - Engineering Costs	05/2015	Undetermined	658,514
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50				923,155

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

Construction Work in Progress-Gas (Account 107)

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

Line No.	Description of Project (a)	Construction Work in Progress-Gas (Account 107) (b)	Estimated Additional Cost of Project (c)
1	North Mist	14,470,563	110,529,437
2	Mains and Service Jobs	7,936,775	2,549,597
3	Misc IS Projects	6,595,773	1,508,538
4	Newport LNG Readiness	6,391,150	2,697,758
5	Other	1,564,637	370,073
6	Portland LNG Readiness	1,430,317	609,525
7	Misc Facilities Projects	898,973	527,245
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45	**Total**	39,288,188	118,792,173

Name of Respondent	This Report is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

GENERAL DESCRIPTION OF CONSTRUCTION OVERHEAD PROCEDURE

1. For each construction overhead explain: (a) the nature and extent of work, etc., the overhead charges are intended to cover, (b) the general procedure for determining the amount capitalized, (c) the method of distribution to construction jobs, (d) whether different rates are applied to different types of construction, (e) basis of diffenrentiation in rates for different types of construction, and (f) whether the overhead is directly or indirectly assigned.

2. Show below the computation of allowance for funds used during construction rates, in accordance with the provisions of Gas Plant Instructions 3 917) of the Uniform System of Accounts.

3. Where a net-of-tax rate for borrowed funds is used, show the appropriate tax effect adjustment to the computations below in a manner that clearly indicates the amount of reduction in the gross rate for tax effects.

Annual Report of Northwest Natural Gas Company Year Ended December 31, 2015

GENERAL DESCRIPTION OF CONSTRUCTION OVERHEAD PROCEDURE

1. a) Engineering Department overhead covers transmission and distribution system planning, design work, drafting and platting of construction work.

Distribution Department overhead covers transmission and distribution system work scheduling, field supervision and processing of work completed.

Administrative work overhead includes Purchasing, Accounting and general office expense.

General Services Department overhead covers planning and supervision of general plant improvements and facilities.

b) Charges during the year are segratated into overhead accounts based on the proportion of activity devoted to construction work.

c) Construction Overheads are being charged to individual work orders based upon overhead rates for different types of projects. Rates are determined by type of project using the annual capital budget and annual construction overhead budget.

d) Different rates are applied to different types of construction based on the annual capital budget for each type of plant.

e) Actual construction overhead rates applied to types of work in 2015

a. Production, Storage, Transmission and Distribution plant	59%
b. Meters	67%
c. General Plant	27%
d. Non-Utility Property	1%

f) Direct assignment of construction overhead capitalized during 2015:
$ 42,198,987

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (AFUDC)
AFUDC is applied to previous month's ending balance plus half of current month's expenditures of Construction Work in Progress (CWIP).

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

GENERAL DESCRIPTION OF CONSTRUCTION OVERHEAD PROCEDURE (CONTINUED)

COMPUTATION OF ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION RATES

For Line (5), column (d) below, enter the rate granted in the last rate proceeding. If not available, use the average rate earned during the preceding 3 years.

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

Line No.	Title (a)		Amount (b)	Capitalization Ration (percent) (c)		Cost Rate Percentage (d)
	(1) Average Short-Term Debt	S	193,802,000			
	(2) Short-Term Interest				s	0.41
	(3) Long-Term Debt	D	601,700,000	43.52	d	6.152
	(4) Preferred Stock	P	-	-	p	-
	(5) Common Equity	C	780,972,535	56.48	c	9.5
	(6) Total Capitalization		-	100.00		
	(7) Average Construction Work in Progress	W	43,942,410			

2.	Gross Rates for Borrowed Funds	s(S/W)+d[(D/(D+P+C))(1-(S/W)]	7.32
3.	Rate for Other Funds	[1-(S/W)] [p(P/(D+P+C)+c(C/(D+P+C)]	18.30
4.	Weighted Average Rate Actually Used for the Year		
	a. Rate for Borrowed Funds -		0.41
	b. Rate for Other Funds -		

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS
NW NATURAL

Period Beginning: Jan 2015
Period Ending: Dec 2015

Functional Class / FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve
UTILITY									
Intangible Plant									
301	ORGANIZATION	$0	$0	$0	$0	$0	$0	$0	$0
302	FRANCHISES & CONSENTS	0	0	0	0	0	0	0	0
303.1	COMPUTER SOFTWARE	19,453,461	2,366,005	(1,073,332)	0	0	(12,941)	0	20,733,193
303.2	CUSTOMER INFORMATION SYSTEM	32,348,168	0	0	0	0	0	0	32,348,168
303.3	INDUSTRIAL & COMMERCIAL BIL	4,146,951	0	0	0	0	0	0	4,146,951
303.4	CRMS	374,476	154,607	0	0	0	0	0	529,083
303.5	POWERPLANT SOFTWARE	0	0	0	0	0	0	0	0
	Intangible Plant Subtotal	56,323,056	2,520,612	(1,073,332)	0	0	(12,941)	0	57,757,395
Production Plant - Oil Gas									
304.1	LAND	0	0	0	0	0	0	0	0
305.2	P P O G STRU & IMPR-SEWER S	0	0	0	0	0	0	0	0
305.5	P P O G STRU & IMPR-OTHER Y	13,814	0	0	0	0	0	0	13,814
312.3	P P O G FUEL HANDLING AND S	0	0	0	0	0	0	0	0
318.3	P P O G LIGHT OIL REFINING	152,141	0	0	0	0	0	0	152,141
318.5	P P O G TAR PROCESSING	255,729	0	0	0	0	0	0	255,729
325	NATURAL GAS PROD AND GATHER	0	0	0	0	0	0	0	0
327	NATURAL GAS PROD & GATHERIN	0	0	0	0	0	0	0	0
328	NATURAL GAS PROD AND GATHER	0	0	0	0	0	0	0	0
331	NATURAL GAS PROD & GATHERIN	0	0	0	0	0	0	0	0
332	NATURAL GAS PROD & GATHERIN	0	0	0	0	0	0	0	0
333	NATURAL GAS PROD & GATHERIN	0	0	0	0	0	0	0	0
334	NATURAL GAS PROD & GATHERIN	0	0	0	0	0	0	0	0
	Production Plant - Oil Gas Subtotal	421,683	0	0	0	0	0	0	421,683
Production Plant - Other									
305.11	GAS PRODUCTION - COTTAGE G	8,736	0	0	0	0	0	0	8,736
305.17	STRUCTURES MIXING STATION	51,246	0	0	0	0	0	0	51,246
311	P P OTHER-LIQUEFIED PETROLE	(0)	0	0	0	0	0	0	(0)
311.4	P P OTHER-L P G GRANGER	0	0	0	0	0	0	0	0
311.7	LIQUIFIED GAS EQUIPMENT COO	8,066	0	0	0	0	0	0	8,066
311.8	LIQUIFIED GAS EQUIPMENT LIN	6,585	0	0	0	0	0	0	6,585
319	GAS MIXING EQUIPMENT GASCO	194,720	0	0	0	0	0	0	194,720
	Production Plant - Other Subtotal	269,353	0	0	0	0	0	0	269,353

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS

NW NATURAL

Period Beginning: Jan 2015
Period Ending: Dec 2015

Functional Class / FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve
UTILITY									
Natural Gas Underground Storage									
350.1	LAND	0	0	0	0	0	0	0	0
350.2	RIGHTS-OF-WAY	23,367	1,776	0	0	0	0	0	25,143
351	STRUCTURES AND IMPROVEMENTS	2,420,511	122,144	0	0	0	0	0	2,542,655
352	WELLS	10,560,588	414,974	0	0	0	0	0	10,975,562
352.1	STORAGE LEASEHOLD & RIGHTS	1,440,015	76,801	0	0	0	0	0	1,516,816
352.2	RESERVOIRS	1,721,701	136,611	0	0	0	380,287	0	2,238,599
352.3	NON-RECOVERABLE NATURAL GAS	3,077,618	121,089	0	0	0	0	0	3,198,707
353	LINES	2,771,168	134,976	0	0	0	0	0	2,906,144
354	COMPRESSOR STATION EQUIPMENT	15,525,294	818,342	0	0	0	688,663	0	17,032,299
355	MEASURING / REGULATING EQUIPM	3,952,667	152,044	0	0	0	163,412	0	4,268,123
356	PURIFICATION EQUIPMENT	210,321	7,375	0	0	0	0	0	217,696
357	OTHER EQUIPMENT	766,647	30,368	0	0	0	0	0	797,015
	Natural Gas Underground Storage Subtotal	42,469,899	2,016,501	0	0	0	1,232,361	0	45,718,760
Local Storage Plant									
360.11	LAND - LNG LINNTON	0	0	0	0	0	0	0	0
360.12	LAND - LNG NEWPORT	0	0	0	0	0	0	0	0
360.2	LAND - OTHER	0	0	0	0	0	0	0	0
361.11	STRUCTURES & IMPROVEMENTS	1,683,223	246,695	0	0	0	0	0	1,929,918
361.12	STRUCTURES & IMPROVEMENTS	2,251,279	142,547	0	0	0	0	0	2,393,826
361.2	STRUCTURES & IMPROVEMENTS -	10,028	466	0	0	0	0	0	10,494
362.11	GAS HOLDERS - LNG LINNTON	2,199,125	63,281	0	0	0	0	0	2,262,406
362.12	GAS HOLDERS - LNG NEWPORT	5,281,034	157,541	0	0	0	0	0	5,438,575
362.2	GAS HOLDERS - LNG OTHER	1,151	21	0	0	0	0	0	1,172
363.11	LIQUEFACTION EQUIP. - LINN	2,465,662	84,207	0	0	0	0	0	2,549,869
363.12	LIQUEFACTION EQUIP - NEWPO	7,067,748	59,929	0	0	0	0	0	7,127,677
363.21	VAPORIZING EQUIP - LINNTON	2,587,862	36,849	0	0	0	0	0	2,624,711
363.22	VAPORIZING EQUIP - NEWPORT	2,609,196	3,195	0	0	0	0	0	2,612,391
363.31	COMPRESSOR EQUIP - LINNTON	197,047	9,850	0	0	0	0	0	206,897
363.32	COMPRESSOR EQUIPMENT - NE	247,128	65,513	0	0	0	0	0	312,641
363.41	MEASURING & REGULATING EQU	597,923	491	0	0	0	5,849	0	604,263
363.42	MEASURING & REGULATING EQU	116,630	839	0	0	0	0	0	117,469
363.5	CNG REFUELING FACILITIES	1,297,064	31,733	0	0	0	0	0	1,328,797
363.6	LNG REFUELING FACILITIES	739,473	0	0	0	0	0	0	739,473
	Local Storage Plant Subtotal	29,351,573	903,157	0	0	0	5,849	0	30,260,579

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS
NW NATURAL

Period Beginning: Jan 2015
Period Ending: Dec 2015

Functional Class FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve
UTILITY									
Transmission Plant									
365.1	LAND	0	0	0	0	0	0	0	0
365.2	LAND RIGHTS	1,642,326	122,003	0	0	0	0	0	1,764,329
366.3	STRUCTURES & IMPROVEMENTS -	256,648	20,319	0	0	0	0	0	276,967
367	MAINS	18,986,575	4,371,605	0	0	0	(6,219)	0	23,351,961
367.21	NORTH MIST TRANSMISSION LI	979,770	50,061	0	0	0	0	0	1,029,831
367.22	SOUTH MIST TRANSMISSION LI	9,565,979	367,724	0	0	0	0	0	9,933,703
367.23	SOUTH MIST TRANSMISSION LI	10,895,030	931,269	0	0	0	0	0	11,826,299
367.24	11.7M S MIST TRANS LINE	4,367,353	452,342	0	0	0	0	0	4,819,695
367.25	12M NORTH S MIST TRANS	4,335,890	485,782	0	0	0	0	0	4,821,672
367.26	38M NORTH S MIST TRANS	16,100,013	1,773,923	0	0	0	0	0	17,873,936
368	TRANSMISSION COMPRESSOR	(9)	0	0	0	0	0	0	(9)
369	MEASURING & REGULATE STATION	1,232,219	106,384	0	0	0	0	0	1,338,603
370	COMMUNICATION EQUIPMENT	0	0	0	0	0	0	0	0
	Transmission Plant Subtotal	70,260,768	8,823,733	0	0	0	(6,219)	0	79,078,282
Distribution Plant									
374.1	LAND	0	0	0	0	0	0	0	0
374.2	LAND RIGHTS	1,137,774	141,282	0	0	0	0	0	1,279,056
375	STRUCTURES & IMPROVEMENTS	80,168	200	0	0	0	0	0	80,368
376.11	MAINS < 4"	287,164,980	13,582,693	(308,781)	(1,175,395)	9,810	(4,628)	0	299,268,679
376.12	MAINS 4" & >	190,827,010	11,966,182	(531,012)	(1,669,460)	10,734	10,847	0	200,614,301
377	COMPRESSOR STATION EQUIPMENT	597,668	19,510	0	0	0	(5,849)	0	611,329
378	MEASURING & REG EQUIP - GENER	10,158,103	669,223	0	0	0	0	0	10,827,326
379	MEASURING & REG EQUIP - GATE	1,561,839	223,000	0	0	0	(1)	0	1,784,838
380	SERVICES	361,540,360	18,845,939	(1,293,428)	(2,577,664)	0	0	0	376,515,207
381	METERS	20,417,050	1,875,761	(1,126,709)	0	0	0	0	21,166,102
381.1	METERS (ELECTRONIC)	681,747	302,521	0	0	0	0	0	984,268
381.2	ERT (ENCODER RECEIVER TRANS	14,541,641	2,636,900	(607,184)	0	0	14	0	16,571,371
382	METER INSTALLATIONS	10,847,618	1,420,159	(3,438,321)	0	0	(13)	0	8,829,443
382.1	METER INSTALLATIONS (ELECTR	29,044	11,490	0	0	0	0	0	40,534
382.2	ERT INSTALLATION (ENCODER	3,877,220	634,308	(113,714)	0	0	0	0	4,397,814
383	HOUSE REGULATORS	130,101	39,916	0	0	0	0	0	170,017
386	OTHER PROPERTY ON CUSTOMERS P	0	0	0	0	0	0	0	0
387.1	CATHODIC PROTECTION TESTING	139,519	956	0	0	0	0	0	140,475
387.2	CALORIMETERS @ GATE STATIONS	96,424	0	0	0	0	0	0	96,424
387.3	METER TESTING EQUIPMENT	72,671	0	0	0	0	0	0	72,671
	Distribution Plant Subtotal	903,900,939	52,370,041	(7,419,149)	(5,422,518)	20,543	370	0	943,450,226

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS
NW NATURAL

Period Beginning: Jan 2015
Period Ending: Dec 2015

Functional Class FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve
UTILITY									
General Plant									
389	LAND	437,351	0	0	0	0	0	0	437,351
390	STRUCTURES & IMPROVEMENTS	7,227,695	1,079,253	0	0	0	0	0	8,306,948
390.1	SOURCE CONTROL PLANT	1,315,013	975,990	0	0	0	0	0	2,291,003
391.1	OFFICE FURNITURE & EQUIPMEN	5,677,642	799,643	0	0	0	0	0	6,477,285
391.2	COMPUTERS	19,598,592	3,758,878	(10,029,192)	0	0	12,941	0	13,341,219
391.3	ON SITE BILLING	0	0	0	0	0	0	0	0
391.4	CUSTOMER INFORMATION SYSTEM	0	0	0	0	0	0	0	0
392	TRANSPORTATION EQUIPMENT	9,193,319	1,562,258	(1,390,921)	0	234,987	0	0	9,599,643
393	STORES EQUIPMENT	119,406	0	0	0	0	0	0	119,406
394	TOOLS - SHOP & GARAGE EQUIPUI	9,159,344	1,150,687	0	0	4,301	0	0	10,314,332
395	LABORATORY EQUIPMENT	68,293	0	0	0	0	0	0	68,293
396	POWER OPERATED EQUIPMENT	3,526,515	182,038	(581,404)	0	150,376	0	0	3,277,525
397	GEN PLANT-COMMUNICATION EQU	20,565	6,545	0	0	0	0	0	27,110
397.1	MOBILE	401,156	3,234	0	0	0	0	0	404,390
397.2	OTHER THAN MOBILE & TELEMET	1,690,854	0	0	0	0	0	0	1,690,854
397.3	TELEMETERING - OTHER	2,988,131	3,321	0	0	0	0	0	2,991,452
397.4	TELEMETERING - MICROWAVE	917,244	15,889	0	0	0	0	0	933,133
397.5	TELEPHONE EQUIPMENT	93,501	78,997	0	0	0	0	0	172,498
398	GEN PLANT-MISCELLANEOUS EQU	0	0	0	0	0	0	0	0
398.1	PRINT SHOP	83,249	0	0	0	0	0	0	83,249
398.2	KITCHEN EQUIPMENT	2,561	525	0	0	0	0	0	3,086
398.3	JANITORIAL EQUIPMENT	14,873	0	0	0	0	0	0	14,873
398.4	INSTALLED IN LEASED BUILDINGS	10,120	0	0	0	0	0	0	10,120
398.5	OTHER MISCELLANEOUS EQUIPMENT	66,739	0	0	0	0	0	0	66,739
	General Plant Subtotal	62,612,163	9,617,259	(12,001,517)	0	389,664	12,941	0	60,630,509
	Utility Property Grand Total	$1,163,710,459	$76,108,980	($20,493,998)	($5,422,518)	$410,207	$1,232,361	$0	$1,215,545,491
NON UTILITY									
Intangible Plant									
303.1	COMPUTER SOFWARE	$31,211	$7,041	$0	$0	$0	$0	$0	$38,252
303.2	CUSTOMER INFORMATION SYSTEM	33,677	4,275	0	0	0	0	0	37,952
Non Utility	Intangible Plant Subtotal	64,888	11,316	0	0	0	0	0	76,204

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS
NW NATURAL

Period Beginning: Jan 2015
Period Ending: Dec 2015

Functional Class FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve
NON UTILITY									
Natural Gas Underground Storage									
352	WELLS	2,897,870	350,667	0	0	0	0	0	3,248,537
352.1	STORAGE LEASEHOLD & RIGHTS	161	20	0	0	0	0	0	181
352.2	RESERVOIRS	1,039,144	78,731	0	0	0	(380,287)	0	737,588
353	LINES	286,345	33,985	0	0	0	0	0	320,330
354	COMPRESSOR STATION EQUIPMENT	4,026,791	363,726	0	0	0	(688,663)	0	3,701,854
355	MEASURING / REGULATING EQUIPM	1,696,887	194,466	0	0	0	(163,412)	0	1,727,941
357	OTHER EQUIPMENT	7,271	1,442	0	0	0	0	0	8,713
Non Utility	Natural Gas Underground Storage Subtotal	9,954,470	1,023,037	0	0	0	(1,232,362)	0	9,745,146
Transmission Plant									
368	TRANSMISSION COMPRESSOR	1,609,866	238,655	0	0	0	0	0	1,848,521
Non Utility	Transmission Plant Subtotal	1,609,866	238,655	0	0	0	0	0	1,848,521
Distribution Plant									
376.12	MAINS 4" & >	171,959	21,319	0	0	0	0	0	193,278
Non Utility	Distribution Plant Subtotal	171,959	21,319	0	0	0	0	0	193,278
General Plant									
389	LAND	0	0	0	0	0	0	0	0
390	STRUCTURES & IMPROVEMENTS	21,946	3,974	0	0	0	0	0	25,920
Non Utility	General Plant Subtotal	21,946	3,974	0	0	0	0	0	25,920
Non Utility Other									
121.1	NON-UTIL PROP-DOCK	1,951,925	(4,858)	0	0	0	0	0	1,947,067
121.2	NON-UTIL PROP-LAND	0	0	0	0	0	0	0	0
121.3	NON-UTIL PROP-OIL ST	2,211,494	3,360	0	0	0	0	0	2,214,854
121.7	NON-UTIL PROP-APPL CENTER	25,823	4,219	0	0	0	0	0	30,042
121.8	NON-UTIL PROP-STORAGE	(1)	0	0	0	0	0	0	(1)
Non Utility	Other	4,189,241	2,721	0	0	0	0	0	4,191,962
	Non Utility Property Grand Total	$16,012,369	$1,301,022	$0	$0	$0	($1,232,361)	$0	$16,080,973

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS
NW NATURAL

Period Beginning: Jan 2015
Period Ending: Dec 2015

Functional Class FERC Plant Account	Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve
TOTAL SUMMARY ALL UTILITY DEPRECIATION RESERVES 12/31/2015								
UTILITY								
108010	($32,807,990)							
108011	915,334,567							
108012	12,325,961							
108013	(2,707,754)							
108014	(395,452)							
108015	3,372,088							
108100	0							
108102	325,933,648							
108002	(5,791,902)							
108003	(25,992)							
108004	308,317							
108666	0							
SUBTOTAL		1,215,545,491						
ADD:								
108001 REMOVAL WORK IN PROCESS		(22,234,577)						
TOTAL UTILITY DEPRECIATION		$1,193,310,914						
TOTAL SUMMARY ALL NON-UTILITY RESERVES DEPRECIATION								
NON UTILITY								
122026	$1,034							
122027	4,293,054							
122028	11,276,832							
122029	(531,316)							
122100	0							
122102	1,113,338							
122002	(71,969)							
TOTAL NON UTILITY DEPRECIATION		$16,080,973						

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

GAS STORED (ACCOUNTS 117.1, 117.2, 117.3, 117.4, 164.1, 164.2, AND 164.3)

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

Line No.	Description (a)	(Account 117.1, 117.2, 117.3, 117.4, 117.5, 117.6, 117.7, 117.8) (b)	(Account (c)	Noncurrent (Account (d)	(Account (e)	Current (Account 164.12 & 164-16 & 164.32 (f)	LNG (Account 164.21, 164.22, 164.23) (g)	LNG (Account 164.35, 164.36) (h)	Total (i)
1	Balance at Beginning of Year	$ 14,018,464				$ 61,415,922	$ 6,494,160	$ -	$ 81,928,546
2	Gas Delivered to Storage	$ 224,516				$ 19,681,557	$ 476,594	$ -	$ 20,382,667
3	Gas Withdrawn from Storage	$ 94,589				$ 27,384,611	$ 1,472,641	$ -	$ 28,951,841
4	Other Debits and Credits	$ -				$ -	$ -	$ -	$ -
5	Balance at End of Year	$ 14,148,391				$ 53,712,868	$ 5,498,113	$ -	$ 73,359,372
6	Dekatherms	6,584,528				14,605,720	1,249,481	-	22,439,729
7	Amount Per Dekatherm	$ 2.15				$ 3.68	$ 4.40	$ -	$ 3.27

Footnotes:

1. Independent engineering studies are the basis for separation between noncurrent and current inventory.
2. See Notes to Consolidated Financial Statements for method used to report inventories of gas in storage (page 122-A).

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

INVESTMENTS (Accounts 123, 124, 136)

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

Line No.	Description of Investment (a)	* (b)	Book Cost at Beginning of Year (If book cost is different from cost to respondent, give cost to respondent in a footnote and explain difference.) (c)	Purchases or Additions During Year (d)
1	Account 123		None	None
2				
3	Account 124			
4				
5	Investment - Encana Gas Reserve - 124045*		-	-
6	Amortization of Encana Gas Reserve - 124046*		-	-
7				
8				
9				
10				
11	Investment in Life Insurance (transfer from 186 Deferred Debits) -		52,366,167	1,662,839
12	124100-124109			
13				
14	Investment in Vancouver Land - 124301		1,862,179	-
15				
16				
17				
18	Total Account 124		54,228,346	1,662,839
19				
20				
21				
22				
23	Account 136 Temporary Cash Investments			
24				
25	Marketable Securities - 136002, 136032		1,389,344	405,926
26				
27	OLGA Investment Account - 136100		831,779	4,199,232
28				
29	OLIEE Investment Account - 136104		2,879,263	4,727,076
30				
31	Smart Inv - 136105		121,951	1,642,087
32				
33	Total Account 136		5,222,337	10,974,321
34				
35				
36				
37	* Effective January 1, 2013, NWN Gas Reserves, LLC was moved			
38	under Northwest Energy Corporation.			
39	See Page 103 for further information.			
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

INVESTMENTS (Accounts 123, 124, 136) (Continued)

List each note giving date of issuance, maturity date, and specifying whether note is a renewal. Designate any advances due from officers, directors, stockholders, or employees.

3. Designate with an asterisk in column (b) any securities, notes or accounts that were pledged, and in a footnote state the name of pledges and purpose of the pledge.
4. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and cite Commission, date of authorization, and case or docket number.
5. Report in column (h) interest and dividend revenues from investments including such revenues from securities disposed of during the year.
6. In column (i) report for each investment disposed of during the year the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if different from cost) and the selling price thereof, not including any dividend or interest adjustment includible in column (h).

Sales or Other Dispositions During Year (e)	Principal Amount or No. of Shares at End of year (f)	Book Cost at End of Year (If book cost is different from cost to respondent, give cost to respondent in a footnote and explain difference.) (g)	Revenues for Year (h)	Gain or Loss from Investment Disposed of (i)	Line No.
None	None	None	None		1
					2
					3
					4
-	-	-	-		5
-	-	-	-		6
					7
					8
					9
					10
1,720,959	52,308,047	52,308,047	-		11
					12
					13
-	1,862,179	1,862,179	-		14
					15
					16
					17
1,720,959	54,170,226	54,170,226	-		18
					19
					20
					21
					22
					23
					24
60	1,795,210	1,795,210	-		25
					26
4,189,646	841,365	841,365	-		27
					28
4,458,180	3,148,159	3,148,159	-		29
					30
1,630,900	133,138	133,138	-		31
					32
10,278,786	5,917,872	5,917,872	-		33
					34
					35
					36
					37
					38
					39
					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

INVESTMENT IN SUBSIDIARY COMPANIES (Account 123.1)

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

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	NNG Financial Corporation	6/28/1990		459,939
2	(Short term Financing and Investments)			
3				
4	Northwest Natural Energy LLC	5/26/2009		159,171,212
5	(Holding Company)			
6				
7	Northwest Biogas, LLC	3/23/2009		47,189
8	(Biodigestor Company)			
9				
10	Northwest Energy Corporation	11/1/2001		154,334,403
11	(Holding Company)			
12				
13				
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34				
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36				
37				
38				
39				
40	TOTAL Cost of Account 123.1		Total	314,012,743

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

INVESTMENT IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

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

Equity in Subsidiary Earnings for Year (e)	Additional Investment for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
(91,279)	-	368,660		1
				2
				3
(6,700,456)	13,164,106	165,634,862		4
				5
				6
(16,788)	-	30,401		7
				8
				9
(4,538,771)	(9,628,230)	140,167,402		10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
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				28
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				38
				39
(11,347,294)	3,535,876	306,201,325		40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

PREPAYMENTS (Account 165)

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

Line No.	(a)	Balance at End of Year (in dollars) (b)
1	Prepaid Insurance	2,864,031
2	Prepaid Demand Charges	2,044,000
3	Prepaid Taxes	16,486,576
4	Miscellaneous Prepayments	7,206,775
5	TOTAL	28,601,382

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include the date of loss, the date of Commission authorization to use Account 182.1 and period of amortization (mo, yr, to mo, yr)] (a)	Balance at Beginning of Year (b)	Total Amount of Loss (c)	Losses Recognized During Year (d)	WRITTEN OFF DURING YEAR Account Charged (e)	WRITTEN OFF DURING YEAR Amount (f)	Balance at End of Year (g)
7	None						
8							
9							
10							
11							
12							
13							
14							
15	TOTAL						0

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (Account 182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission authorization to use Account 182.2 and period of amortization (mo, yr, to mo, yr)] (a)	Balance at Beginning of Year (b)	Total Amount of Charges (c)	Costs Recognized During Year (d)	WRITTEN OFF DURING YEAR Account Charged (e)	WRITTEN OFF DURING YEAR Amount (f)	Balance at End of Year (g)
16	None						
17							
18							
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21							
22							
23							
24							
25							
26	TOTAL						0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

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.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning Year (b)	Debits (Credits) (c)	Written off During Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	Balance at End of Current Year (f)
1						
2						
3	DEFERRED INC. TAXES (Page 261B-2)	$ 51,804,552	$(4,378,000)	$ -	$ -	$ 47,426,552
4						
5						
6						
7	OTHER REGULATORY ASSETS	$ 51,804,552	$ (4,378,000)	$ -	$ -	$ 47,426,552
8	(Page 111 Line 69)					
9						
10						
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41						
42	TOTAL	$ 51,804,552	$ (4,378,000)	$ -	$ -	$ 47,426,552

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

MISCELLANEOUS DEFERRED DEBITS (Account 186)

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

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Yr (b)	DEBITS Amount (c)	Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1						
2	Pension and Other Retirement Benefits	201,845,190	418,846		18,040,880	184,223,156
3						
4	Pension Deferral	32,540,903	11,206,956		-	43,747,859
5						
6	Environmental	95,507,313	29,518,736		-	125,026,049
7						
8	Regulatory Receivable - Environmental	(30,357,551)	(68,761,055)		(59,947,256)	(39,171,350)
9						
10	Deferred Derivative Activity	33,404,000	91,481,000		99,346,000	25,539,000
11						
12	Leasehold Improvements Amortized Over Remaining Life	1,283,210	145,905		586,451	842,664
13						
14	AMR Deferral	334	6,247		6,581	-
15						
16	Unbilled Revenue	(1,777,414)	11,390,123		12,031,753	(2,419,044)
17						
18	Other	215,307	173,552,923		173,560,540	207,690
19						
20	OR - Decoupling	13,640,786	40,653,674		29,170,389	25,124,071
21						
22	OR - Deferred Industrial DSM	4,478,303	6,474,938		5,191,128	5,762,113
23						
24	OR - Warm	380,852	3,854,345		4,213,419	21,778
25						
26	OR - Pension Withdrawal	7,229,543	275,208		540,727	6,964,024
27						
28	WA - Pension Withdrawal	834,644	31,772		62,427	803,989
29						
30	WA - Energy Efficiency	2,226,335	2,702,594		2,374,392	2,554,537
31						
32	WA - Low Income	341,738	810,883		734,939	417,682
33						
34						
35	TOTAL	361,793,493	303,763,095		285,912,370	379,644,218

Name of Report	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
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Accumulated Deferred Income Taxes (Account 190)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Changes During Year Amounts Debited to Account 410.1 (c)	Changes During Year Amounts Credited to Account 411.1 (d)
1	Account 190			
2	Electric			
3	Gas	23,785,213	-	-
4				
5	Total (Total of lines 2 thru 4)	23,785,213	-	-
6				
7	TOTAL Account 190 (Total of lines 5 thru 6)	23,785,213	-	-
8	Classification of TOTAL			
9	Federal Income Tax	18,741,941	-	-
10	State Income Tax	5,043,272	-	-
11	Local Income Tax	-	-	-

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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Accumulated Deferred Income Taxes (Account 190) (continued)

Changes During Year Amounts Debited to Account 410.2 (e)	Changes During Year Amounts Credited to Account 411.2 (f)	Adjustments Debits Account No. (g)	Adjustments Debits Amount (h)	Adjustments Credits Account No. (i)	Adjustments Credits Amount (j)	Balance at End of Year (k)	Line No.
							1
-	-	-	-		-	-	2
-	-	-	-	190100, 190102	23,785,213	-	3
							4
-	-	-	-		23,785,213	-	5
							6
-	-	-	-		23,785,213	-	7
							8
-	-	-	-		18,741,941	-	9
-	-	-	-		5,043,272	-	10
-	-	-	-		-	-	11

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CAPITAL STOCK (Account 201 and 204)

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

Line No.	Class and Series of Stock and Name of Stock Exchange	Number of Shares Authorized by Charter	Par or Stated Value Per Share	Call Price at End of Year
	(a)	(b)	(c)	(d)
1	Common Stock	100,000,000	N/A	
2				
3				
4				
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

CAPITAL STOCK (Accounts 201 and 204) (Continued)

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

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent.)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
27,427,106	381,473,806					1
						2
						3
						4
						5
						6
						7
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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

CAPITAL STOCK SUBSCRIBED, CAPITAL STOCK LIABILITY FOR CONVERSION, PREMIUM ON CAPITAL STOCK, AND INSTALLMENTS RECEIVED ON CAPITAL STOCK (Accounts 202, 203, 205, 206, 207 and 212)

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

Line No.	Name of Account and Description of Item (a)	* (b)	Number of Shares (c)	Amount (d)
1	Account 202 - Common Stock Subscribed			NONE
2				
3	Account 205 - Preferred Stock Subscribed			NONE
4				
5	Account 203 and 206 - Capital Stock Liability for Conversion			NONE
6				
7	Account 207 - Premium on Capital Stock:			NONE
8				
10	Account 212 - Installments Received on Capital Stock			20,657
11				
12				
13				
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39	TOTAL			20,657

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A resubmission	(Mo, Da, Yr)	Dec. 31, 2015

OTHER PAID IN CAPITAL (Accounts 208 - 211)

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

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

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

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

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

Line No.	Item (a)	Amount (b)
1	Account 208 - Donations Received from Stockholders	NONE
2		
3	Account 209 - Reduction in Par or Stated Value of Capital Stock	NONE
4		
5	Account 210 - Gain on Resale or Cancellation of Reacquired Capital Stock	
6		
7	Balance At Beginning of Year	1,649,864
8		
9	Credit:	-
10		
11		
12	Debit:	-
13		
14	Balance at End of Year	1,649,864
15		
16		
17	Account 211 - Miscellaneous Paid-In Capital	NONE
18		
19		
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40	TOTAL	1,649,864

Name of Respondent	This Report Is:	Date of Report	Year of Report
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DISCOUNT ON CAPITAL STOCK (ACCOUNT 213)

1. Report the balance at end of year of discount on capital stock for each class and series of capital stock. Use as many rows as necessary to report all data.

2. If any change occurred during the year in the balance with respect to any class or series of stock, attach a statement giving details of the change. State the reason for any charge-off during the year and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	N/A	-
2		
3		
4		
5		
6		
7		
8		
9		
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11		
12		
13		
14		

CAPITAL STOCK EXPENSE (ACCOUNT 214)

1. Report the balance at end of year of capital stock expenses for each class and series of capital stock. Use as many rows as necessary to report all data. Number the rows in sequence starting from the last row number used for Discount on Capital Stock above.

2. If any change occurred during the year in the balance with respect to any class or series of stock, attach a statement giving details of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
16	Capital Stock Expense	-
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
	TOTAL	-

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
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SECURITIES ISSUED OR ASSUMED AND SECURITIES REFUNDED OR RETIRED DURING THE YEAR

1. Furnish a supplemental statement briefly describing security financing and refinancing transactions during the year and the accounting for the securities, discounts, premiums, expenses, and related gains or losses.

2. Provide details showing the full accounting for the total principal amounts, par value, or stated value of each class and series of security issued, assumed, retired, or refunded and the accounting for premiums, discounts, expenses, and gains or losses relating to the securities. Set forth the facts of the accounting clearly with regard to redemption premiums, unamortized discounts, expenses, and gain or losses relating to securities retired or refunded, including the accounting for such amounts carried in the respondent's accounts at the date of the refunding or refinancing transactions with respect to securities previously refunded or retired.

3. Include in the identification of each class and series of security, as appropriate, the interest or dividend rate, nominal date of issuance, maturity date, aggregate principal amount, par value or stated value, and number of shares. Give also the issuance of redemption price and name of the principal underwriting firm through which the security transactions were consummated.

4. Where the accounting for amounts relating to securities refunded or retired is other than that specified in General Instruction 17 of the Uniform System of Accounts, cite the Commission authorization for the different accounting and state the accounting method.

5. For securities assumed, give the name of the company for which the liability on the securities was assumed as well as details of the transactions whereby the respondent undertook to pay obligations of another company. If any unamortized discount, premiums, expenses, and gains or losses were taken over onto the respondent's books, furnish details of these amounts with amounts relating to refunded securities clearly earmarked.

Class of Security	Underwriter of Payee	Date	Stated or Par Value per Share	Number of Shares	Principal Amount or Par Value
Debt Securities Issued					
None					
	Total Debt Issued				$ -
Common Stock					
Common Stock issuance expenses:					
Stock option plan	Issued by Company		NA	62,900	$ 3,275,062
LTIP	Issued by Company		NA	5,089	1,155,797
RSU	Issued by Company		NA	10,129	429,059
ESPP	Issued by Company		NA	19,064	741,590
DRIP/OCP	Issued by Company		NA	46,197	2,124,308
Stock repurchase	Reaquired by Company		NA	-	-
	Total Common Stock			143,379	$ 7,725,816

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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LONG-TERM DEBT (Account 221, 222, 223, and 224)

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

Line No.	Class and Series of Obligation and Name of Stock Exchange (a)	Date of Maturity (c)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (d)
1	**Account 221**		
2	First Mortgage Bonds		
3			
4			
5			
6	4.700% Series B	06-22-2015	-
7	5.150% Series B	12-15-2016	25,000,000
8	7.000% Series B	08-01-2017	40,000,000
9	6.600% Series B	03-16-2018	22,000,000
10	8.310% Series B	09-21-2019	10,000,000
11	7.630% Series B	12-09-2019	20,000,000
12	5.370% Series B	02-01-2020	75,000,000
13	9.050% Series A	08-13-2021	10,000,000
14	3.176% Series B	09-15-2021	50,000,000
15	3.542% Series B	08-19-2023	50,000,000
16	5.620% Series B	11-21-2023	40,000,000
17	7.720% Series B	09-01-2025	20,000,000
18	6.520% Series B	12-01-2025	10,000,000
19	7.050% Series B	10-15-2026	20,000,000
20	7.000% Series B	05-21-2027	20,000,000
21	6.650% Series B	11-10-2027	19,700,000
22	6.650% Series B	06-01-2028	10,000,000
23	7.740% Series B	08-29-2030	20,000,000
24	7.850% Series B	09-01-2030	10,000,000
25	5.820% Series B	09-24-2032	30,000,000
26	5.660% Series B	02-25-2033	40,000,000
27	5.250% Series B	06-21-2035	10,000,000
28	4.000%	10-31-2042	50,000,000
29			
30			
31			
32			
33			
34			
35			
36			
37	Total First Mortgage Bonds		601,700,000
38			
39	**Account 239**		
40	Less: Debt due with-in one year		(25,000,000)
41			
42			
43			
44			
45			
46			
47			
48			
49	**Account 222 and 223**		
50	None		
51	TOTAL		576,700,000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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LONG-TERM DEBT (Accounts 221, 222, 223 and 224) (Continued)

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

INTEREST FOR YEAR		HELD BY RESPONDENT			
Rate (in %) (e)	Amount (f)	Reacquired Bonds (Acct. 222) (g)	Sinking and Other Funds (h)	Redemption Price Per $100 at End of Year (i)	Line No.
					1
					2
					3
					4
					5
4.700%	893,000			N/A	6
5.150%	1,287,500			N/A	7
7.000%	2,800,000			N/A	8
6.600%	1,452,000			N/A	9
8.310%	831,000			N/A	10
7.630%	1,526,000			N/A	11
5.370%	4,027,500			N/A	12
9.050%	905,000			N/A	13
3.176%	1,588,000			N/A	14
3.542%	1,771,000			N/A	15
5.620%	2,248,000			N/A	16
7.720%	1,544,000			N/A	17
6.520%	652,000			N/A	18
7.050%	1,410,000			N/A	19
7.000%	1,400,000			N/A	20
6.650%	1,310,050			N/A	21
6.650%	665,000			N/A	22
7.740%	1,548,000			N/A	23
7.850%	785,000			N/A	24
5.820%	1,746,000			N/A	25
5.660%	2,264,000			N/A	26
5.250%	525,000			N/A	27
4.000%	2,000,000			N/A	28
					29
					30
					31
					32
					33
					34
					35
					36
	35,178,050				37
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	35,178,050				51

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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UNAMORTIZED DEBT EXPENSE, PREMIUM AND DISCOUNT ON LONG-TERM DEBT (Accounts 181, 225, 226)

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

Line No.	Designation of Long-Term Debt (a)		Principal Amount of Debt Issued (b)	Total Expense Premium or Discount (c)	AMORTIZATION PERIOD Date From (d)	AMORTIZATION PERIOD Date To (e)
1	**Account 181**					
2	First Mortgage Bonds					
3						
4						
5						
6	4.700%		40,000,000	341,898	6/1/2005	6/22/2015
7	5.150%		25,000,000	277,676	12/15/2006	12/15/2016
8	7.000%		40,000,000	375,600	8/1/1997	8/1/2017
9	6.600%	[2]	22,000,000	1,344,884	3/17/1998	3/16/2018
10	8.310%	[1]	10,000,000	1,111,757	9/21/1994	9/21/2019
11	7.630%		20,000,000	195,421	12/9/1999	12/9/2019
12	5.370%	[7]	75,000,000	10,862,808	3/25/2009	2/1/2020
13	9.050%		10,000,000	115,333	8/13/1991	8/13/2021
14	3.176%		50,000,000	605,155	9/12/2011	9/15/2021
15	3.542%		50,000,000	638,179	8/19/2013	8/19/2023
16	5.620%	[6]	40,000,000	3,325,438	11/21/2003	11/21/2023
17	7.720%	[4]	20,000,000	1,286,261	9/6/2000	9/1/2025
18	6.520%		10,000,000	90,146	12/1/1995	12/1/2025
19	7.050%		20,000,000	175,940	10/15/1996	10/15/2026
20	7.000%		20,000,000	153,906	5/20/1997	5/21/2027
21	6.650%	[8]	19,700,000	162,800	11/10/1997	11/10/2027
22	6.650%		10,000,000	98,300	6/1/1998	6/1/2028
23	7.740%	[3]	20,000,000	1,504,914	8/29/2000	8/29/2030
24	7.850%	[5]	10,000,000	753,107	9/6/2000	9/1/2030
25	5.820%		30,000,000	390,382	9/24/2002	9/24/2032
26	5.660%		40,000,000	356,663	2/25/2003	2/25/2033
27	5.250%		10,000,000	97,974	6/21/2005	6/21/2035
28	4.000%		50,000,000	509,105	10/30/2012	10/31/2042
29	Shelf Registraion Expense		-	-	N/A	N/A
30	Line of Credit		-	-	N/A	N/A
31						
32						
33						
34						
35						
36			641,700,000	24,773,647		
37						
38						

39 [1] Includes premium and umamortized cost on early redemption of 9.8% series bonds ($1,044,111 allocated to the 8.31% series, and $835,723 allcoated to the 8.26% series).

40 [2] Includes $910,800 premium and $222,664 unamortized costs on early redemption of 9.125% series bonds allocated to the 6.60% series.

41 [3] Includes $992,143 premium, $178,966 unamortized costs on early redemption of 9.75% series bonds, and $148,605 unamortized costs on early redemption of 15.375% series bonds allocated to the 7.74% series.

42 [4] Includes $826,786 premium, $149,139 unamortized costs on early redemption of 9.75% series bonds, and $123,837 unamortized costs on early redemption of 15.375% series bonds allocated to the 7.72% series.

43 [5] Includes $496,071 premium, $89,483 unamortized costs on early redemption of 9.75% series bonds, and $74,302 unamortized costs on early redemption of 15.375% series bonds allocated to the 7.85% series.

44 [6] Includes $150,000 premium and $405,971 unamortized costs on early redemption of 7.50% series bonds, $413,600 premium and $1,116,479 unamortized costs on early redemption of 7.52% series bonds and $730,000 premium and $136,800 unamortized costs on early redemption of 7.25% series bonds allocated to 5.62% series.

45 [7] Includes $10,096,000 costs paid on interest rate hedge loss and $298,058 unamortized costs on shelf registration, allocated to 5.37% series.

46 [8] In November 2009 one investor exercised its right under a one-time put option to redeem $0.3 million of the $20 million outstanding. This one-time put option has now expired, and the remaining $19.7 million remaining principal outstanding is expected to be redeemed at maturity in November 2027.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

UNAMORTIZED DEBT EXPENSE, PREMIUM AND DISCOUNT ON LONG-TERM DEBT (Accounts 181, 225, 226) (Cont.)

5. Furnish in a footnote details regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

6. Identify separately undisposed amounts applicable to issues which were redeemed in prior years.

7. Explain any debits and credits other than amortization debited to Account 428, Amortization of Debt Discount and Expense, or credited to Account 429, Amortization of Premium on Debt - Credit.

Balance at Beginning of Year (f)	Debits During Year (g)	Credits During Year (h)	Balance at End of Year (i)	Line No.
				1
				2
				3
				4
				5
14,245		14,245	-	6
54,330		27,768	26,562	7
63,772		3,523	60,249	8
33,909		10,572	23,337	9
12,750		2,700	10,050	10
48,023		9,768	38,255	11
5,159,326		986,652	4,172,674	12
25,280		3,840	21,440	13
403,435		60,516	342,919	14
550,963		63,815	487,148	15
166,064		18,624	147,440	16
79,616		7,464	72,152	17
32,750		3,000	29,750	18
69,193		5,868	63,325	19
48,515		20,393	28,122	20
69,608		5,424	64,184	21
43,953		3,276	40,677	22
96,118		6,168	89,950	23
48,692		3,108	45,584	24
231,105		13,020	218,085	25
216,038		11,892	204,146	26
66,640		3,264	63,376	27
496,657		17,845	478,812	28
1,041,751	67,182	-	1,108,933	29
343,788	28,359	197,408	174,739	30
				31
				32
				33
				34
				35
Total 9,416,521	95,541	1,500,153	8,011,909	36
				37
				38
				39
	Total above	1,500,153		40
	Less Shelf Registration Expense	0		41
	Less LOC amortized to interest expense	(197,408)		42
	Amortization Expense per P&L	1,302,745		43
				44
				45
				46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

UNAMORTIZED LOSS AND GAIN ON REACQUIRED DEBT (Accounts 189, 257)

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

Line No,	Designation of Long-Term Debt (a)	Date Reac-quired (b)	Principal of Debt Reacquired (c)	Net Gain or Net Loss (d)	Balance at Beginning of Year (e)	Balance at End of Year (f)
1	**Account 189**					
6						
7	First Mortgage Bonds					
8						
9						
10	9.80%	11/01/93	24,938,000	(2,170,710)	198,360	156,600
11	9.13%	04/01/98	18,000,000	(1,133,464)	180,724	123,844
12	9.75% (1)	09/29/00	50,000,000	(3,079,332)	1,503,060	1,393,080
13	7.52% (2)	07/01/03	11,000,000	(1,530,079)	675,750	599,250
14	7.50% (3)	07/01/03	4,000,000	(555,971)	245,602	217,798
15	7.25%	08/18/03	20,000,000	(866,800)	382,872	339,528
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38	TOTAL				3,186,368	2,830,100

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northwest Natural Gas Co.	(1) X An Original (2) A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

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

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

Line No.		Combined Amounts	Elimination	NW Natural Gas Company 93-0256722	NNG Financial Corporation 93-1034064	NW Energy Corporation 93-1329989
1						
2	**NET INCOME FOR THE YEAR PER (PAGE 116a)**	$50,361,584	$5,711,538	$49,279,033	($91,279)	($4,537,708)
3						
4	TAXABLE INCOME (LOSS) NOT RECORDED ON BOOKS:	576,276	-	576,276	-	-
5	CONTRIBUTIONS IN AID OF CONSTRUCTION	4,009,744	-	4,009,744	-	-
6	ENVIRONMENTAL RECOVERIES	179	-	179	-	-
7	OTHER INCOME					
8						
9	**EXPENSES RECORDED ON BOOKS NOT DEDUCTED ON RETURN:**					
10	ACCRUED VACATION	108,299	-	108,299	-	-
11	BOND AMORTIZATION	356,268	-	356,268	-	-
12	DEFERRED DIRECTORS FEES	420,858	-	420,858	-	-
13	NONDEDUCTIBLE MEALS AND ENTERTAINMENT	318,281	-	318,281	-	-
14	NONDEDUCTIBLE POLITICAL, SOCIAL AND OTHER	501,772	-	501,772	-	-
15	OTHER INCOME	1,097,594	-	1,097,594	-	-
16	PENALTIES	314	-	314	-	-
17	DEFERRED COMPENSATION	279,019	-	279,019	-	-
18	STOCK BASED COMPENSATION	52,865	-	52,865	-	-
19	EMPLOYEE STOCK PURCHASE PLAN	130,779	-	130,779	-	-
20	GAS RESERVES INVESTMENT	7,200,000	-	-	-	7,200,000
21	INCOME FROM SUBSIDIARIES	11,220	-	11,220	-	-
22	REGULATORY REVENUE & COST ADJUSTMENTS	7,870,861	-	7,870,861	-	-
23	SEC. 263A INVENTORY ADJUSTMENTS	400,000	-	400,000	-	-
24	PENSION ADJUSTMENTS	2,240,918	-	2,240,918	-	-
25	PREPAID INSURANCE	103,445	-	103,445	-	-
26	PROPERTY TAX ADJUSTMENT - ACCRUAL TO CASH	85,989	-	85,989	-	-
27	SEC REGULATORY INTEREST	5,523,053	-	5,523,053	-	-
28	FEDERAL TAX PROVISION	27,104,998	3,076,015	28,329,043	(49,153)	(4,250,907)
29	STATE TAX PROVISION	6,405,253	654,279	3,736,083	(5,200)	2,020,091
30						
31						
32	**BOOK INCOME NOT SUBJECT TO TAX:**					
33	COMPANY OWNED LIFE INSURANCE	2,187,796	-	2,187,796	-	-
34						
35						
36	**EXPENSES ALLOWABLE FOR TAX NOT ON BOOKS:**					
37	DEPLETION	3,300,000	-	-	-	3,300,000
38	BAD DEBT RESERVE	99,178	-	99,178	-	-
39	DEPREC - EXCESS OF TAX OVER BOOK DEPRECIATION	45,259,165	-	45,340,068	(80,903)	-
40	INVENTORY RESERVE	27,038	-	27,038	-	-
41	DIVIDENDS PAID TO AN ESOP	776,687	-	776,687	-	-
42	REMOVAL COSTS	1,175,000	-	1,175,000	-	-
43	CHARITABLE CONTRIBUTIONS	2,093,436	-	2,093,436	-	-
44	NET OPERATING LOSS DEDUCTION	29,772,473	-	2,834,599	4,231	26,933,644
45						
46	FEDERAL TAXABLE INCOME	$30,468,794	$9,441,832	$50,898,089	($68,960)	($29,802,168)

NORTHWEST NATURAL GAS CO AND SUBSIDIARIES
RECONCILIATION OF BOOK INCOME TO FEDERAL TAXABLE INCOME
TAX PROVISION FOR YEAR ENDED DECEMBER 31, 2015

LINE #			
1	**NET INCOME FOR THE YEAR PER (PAGE 116a)**		**$50,361,584**
2			
3	TAXABLE INCOME (LOSS) NOT RECORDED ON BOOKS:		
4	CONTRIBUTIONS IN AID OF CONSTRUCTION	576,276	
5	ENVIRONMENTAL RECOVERIES	4,009,744	
6	OTHER INCOME	179	
7			4,586,199
8	EXPENSES RECORDED ON BOOKS NOT DEDUCTED ON RETURN:		
9	ACCRUED VACATION	108,299	
10	BOND AMORTIZATION	356,268	
11	DEFERRED DIRECTORS FEES	420,858	
12	NONDEDUCTIBLE MEALS AND ENTERTAINMENT	318,281	
13	NONDEDUCTIBLE POLITICAL, SOCIAL AND OTHER	501,772	
14	OTHER INCOME	1,097,594	
15	PENALTIES	314	
16	DEFERRED COMPENSATION	279,019	
17	STOCK BASED COMPENSATION	52,865	
18	EMPLOYEE STOCK PURCHASE PLAN	130,779	
19	GAS RESERVES INVESTMENT	7,200,000	
20	INCOME FROM SUBSIDIARY	11,220	
21	REGULATORY REVENUE & COST ADJUSTMENTS	7,870,861	
22	SEC. 263A INVENTORY ADJUSTMENTS	400,000	
23	PENSION ADJUSTMENTS	2,240,918	
24	PREPAID INSURANCE	103,445	
25	PROPERTY TAX ADJUSTMENT - ACCRUAL TO CASH	85,989	
26	SEC REGULATORY INTEREST	5,523,053	
27	FEDERAL TAX PROVISION	27,104,998	
28	STATE TAX PROVISION	6,405,253	
29			60,211,785
30	BOOK INCOME NOT SUBJECT TO TAX:		
31	COMPANY OWNED LIFE INSURANCE	2,187,796	
32			2,187,796
33			
34	EXPENSES ALLOWABLE FOR TAX NOT ON BOOKS:		
35	DEPLETION	3,300,000	
36	BAD DEBT RESERVE	99,178	
37	DEPREC - EXCESS OF TAX OVER BOOK DEPRECIATION	45,259,165	
38	INVENTORY RESERVE	27,038	
39	DIVIDENDS PAID TO AN ESOP	776,687	
40	REMOVAL COSTS	1,175,000	
41	CHARITABLE CONTRIBUTIONS	2,093,436	
42	NET OPERATING LOSS DEDUCTION	29,772,473	
43			82,502,978
44	**FEDERAL TAXABLE INCOME**		**$ 30,468,794**

NORTHWEST NATURAL GAS CO AND SUBSIDIARIES
RECONCILIATION OF BOOK INCOME TO FEDERAL TAXABLE INCOME
TAX PROVISION FOR YEAR ENDED DECEMBER 31, 2015

LINE #			
1	**TAX COMPUTATION:**		
2			
3	FEDERAL INCOME TAX AT MARGINAL RATE		$ 10,664,078
4	FEDERAL ALTERNATIVE MINIMUM TAX		900,000
5			
6	ADJ: RESEARCH AND EXPERIMENTATION CREDIT	-	
7	ALTERNATIVE MINIMUM TAX CREDIT	-	
8	FUEL TAX CREDIT (FORM 4136)	(16,376)	
9	OTHER TAX CREDITS	-	
10			(16,376)
11			
12	PROVISION TO RETURN AND OTHER ADJUSTMENTS		(989,774)
13			
14	TOTAL FEDERAL CURRENT TAX PROVISION (Pg 261-B2)		**10,557,928**
15			
16	DEFERRED FEDERAL TAX PROVISION CURRENT YEAR - 2015		17,101,495
17	PROVISION TO RETURN AND OTHER ADJUSTMENTS		463,889
18			
19	ADJ: INVESTMENT TAX CREDIT APPLIED		
20	DEFERRED ALTERNATIVE MINIMUM TAX	(900,000)	
21	DEFERRED INVESTMENT TAX CREDIT	(118,314)	
22			(1,018,314)
23	TOTAL FEDERAL DEFERRED TAX PROVISION (Pg 261-B2)		**16,547,070**
24			
25	COMBINED FEDERAL INCOME TAX PROVISION		**$ 27,104,998**
26			
27			
28	ALLOCATION OF FEDERAL INCOME TAX PROVISION		
29			
30	NW NATURAL GAS CO.		
31	OPERATING		31,171,919
32	NON-OPERATING		785,794
33	GILL RANCH, LLC		(3,428,005)
34	NW GAS STORAGE, LLC		(122,863)
35	TRAIL WEST		(3,563)
36	NW ENERGY, LLC		(74,239)
37	TOTAL NW NATURAL GAS CO.		$ 28,329,043
38			
39	NNG FINANCIAL CORPORATION		
40	OPERATING		
41	NON-OPERATING		(49,153)
42	TOTAL NNG FINANCIAL CORPORATION		$ (49,153)
43			
44	NW ENERGY CORPORATION		
45	OPERATING		(4,250,907)
46	NON-OPERATING		-
47	TOTAL NW ENERGY CORPORATION		$ (4,250,907)
48			
49	**ELIMINATIONS**		3,076,015
50			
51	COMBINED FEDERAL INCOME TAX PROVISION		$ 27,104,998
52			
53	COMBINED FEDERAL AND STATE INCOME TAX PROVISION		
54	OPERATING		37,781,095
55	NON-OPERATING		1,421,581
56	NNG FINANCIAL CORPORATION		(59,612)
57	NW ENERGY CORPORATION		(4,905,185)
58	OTHER SMLLC'S AND PARTNERSHIPS		(4,397,016)
59	ELIMINATIONS		3,730,294
60	**PAGES 261-B2 CONTINUED (CURRENT & DEFERRED FEDERAL & STATE)**		**$ 33,571,157**

NORTHWEST NATURAL GAS CO AND SUBSIDIARIES
RECONCILIATION OF BOOK INCOME TO STATE TAXABLE INCOME
TAX PROVISION FOR YEAR ENDED DECEMBER 31, 2015

LINE #			
1	**NET INCOME FOR THE YEAR PER (PAGE 116a)**		**$ 50,361,584**
2			
3	TAXABLE INCOME (LOSS) NOT RECORDED ON BOOKS:		
4	CONTRIBUTIONS IN AID OF CONSTRUCTION	576,276	
5	ENVIRONMENTAL RECOVERIES	4,009,744	
6	OTHER INCOME	182	
7			4,586,202
8	EXPENSES RECORDED ON BOOKS NOT DEDUCTED ON RETURN:		
9	ACCRUED VACATION	108,299	
10	BOND AMORTIZATION	356,268	
11	DEFERRED DIRECTORS FEES	420,858	
12	NONDEDUCTIBLE MEALS AND ENTERTAINMENT	318,281	
13	NONDEDUCTIBLE POLITICAL, SOCIAL AND OTHER	501,772	
14	OTHER INCOME	1,097,594	
15	PENALTIES	314	
16	DEFERRED COMPENSATION	279,019	
17	STOCK BASED COMPENSATION	52,865	
18	EMPLOYEE STOCK PURCHASE PLAN	130,779	
19	GAS RESERVES INVESTMENT	7,200,000	
20	INCOME FROM SUBSIDIARY	11,220	
21	REGULATORY REVENUE & COST ADJUSTMENTS	7,870,861	
22	SEC. 263A INVENTORY ADJUSTMENTS	400,000	
23	PENSION ADJUSTMENTS	2,240,918	
24	PREPAID INSURANCE	103,445	
25	PROPERTY TAX ADJUSTMENT - ACCRUAL TO CASH	85,989	
26	SEC REGULATORY INTEREST	5,523,053	
27	FEDERAL TAX PROVISION (SEE ANALYSIS ABOVE)	27,104,998	
28	STATE TAX PROVISION (SEE ANALYSIS BELOW)	6,466,159	
29			60,272,691
30	BOOK INCOME NOT SUBJECT TO TAX:		
31	COMPANY OWNED LIFE INSURANCE	2,187,796	
32			2,187,796
33			
34	EXPENSES ALLOWABLE FOR TAX NOT ON BOOKS:		
35	BAD DEBT RESERVE	99,178	
36	DEPREC - EXCESS OF TAX OVER BOOK DEPRECIATION	55,349,207	
37	INVENTORY RESERVE	27,038	
38	DIVIDENDS PAID TO AN ESOP	776,687	
39	REMOVAL COSTS	1,175,000	
40	CHARITABLE CONTRIBUTIONS	2,093,436	
41	NET OPERATING LOSS DEDUCTION	53,512,134	
42			113,032,680
43	**STATE TAXABLE INCOME**		**$ -**

NORTHWEST NATURAL GAS CO AND SUBSIDIARIES
RECONCILIATION OF BOOK INCOME TO STATE TAXABLE INCOME
TAX PROVISION FOR YEAR ENDED DECEMBER 31, 2015

LINE #			
1	**TAX COMPUTATION:**		
2			
3	STATE INCOME TAX AT MARGINAL RATE		$ -
4	STATE ALTERNATIVE MINIMUM TAX **[1]**		-
5			
6	ADJ: RESEARCH AND EXPERIMENTATION CREDIT	-	
7	ALTERNATIVE MINIMUM TAX CREDIT	-	
8	DEPENDENT CARE TAX CREDIT	-	
9	ENERGY INCENTIVES PROGRAM	-	
10			-
11			
12	CURRENT STATE TAX PROVISION CURRENT YEAR -2015		-
13	PROVISION TO RETURN AND OTHER ADJUSTMENTS		60,906
14			
15	**TOTAL STATE CURRENT TAX PROVISION (Pg 261-B2)**		**60,906**
16			
17	DEFERRED STATE TAX PROVISION CURRENT YEAR - 2015		6,362,048
18	PROVISION TO RETURN AND OTHER ADJUSTMENTS		43,205
19			
20	ADJ: INVESTMENT TAX CREDIT APPLIED	-	
21	DEFERRED ALTERNATIVE MINIMUM TAX	-	
22	DEFERRED INVESTMENT TAX CREDIT	-	
23			-
24	**TOTAL STATE DEFERRED TAX PROVISION (Pg 261-B2)**		**6,405,253**
25			
26	**COMBINED STATE INCOME TAX PROVISION**		**$ 6,466,159**
27			
28			
29	**ALLOCATION OF STATE INCOME TAX PROVISION**		
30			
31	NW NATURAL GAS CO.		
32	OPERATING		6,609,176
33	NON-OPERATING		635,787
34	GILL RANCH, LLC		(725,595)
35	NW GAS STORAGE, LLC		(26,182)
36	TRAIL WEST		(778)
37	NW ENERGY, LLC		(15,791)
38			$ 6,476,617
39	NNG FINANCIAL CORPORATION		
40	OPERATING		(10,459)
41	NON-OPERATING		
42	TOTAL NNG FINANCIAL CORPORATION		$ (10,459)
43			
44	NW ENERGY CORPORATION		
45	OPERATING		(654,278)
46	NON-OPERATING		-
47	TOTAL NW ENERGY CORPORATION		$ (654,278)
48			
49	ELIMINATIONS		654,279
	COMBINED STATE INCOME TAX PROVISION		**$ 6,466,159**

[1] State minimum taxes measured on gross receipts are included in "Taxes other than income taxes", Page 114, Line 14.

NORTHWEST NATURAL GAS COMPANY
RECONCILIATION OF TAX ACCRUAL ACCOUNTS - CURRENT
YEAR ENDED DECEMBER 31, 2015

FEDERAL	Total	2006 ACCRUAL 236.026	2007 ACCRUAL 236.027	2008 ACCRUAL 236.028	2009 ACCRUAL 236.029	2010 ACCRUAL 236.020	2011 ACCRUAL 236.021	2012 ACCRUAL 236.022	2013 ACCRUAL 236.023	2014 ACCRUAL 236.024	2015 ACCRUAL 236.025
BALANCE AT 12/31/14 (Page 262)	**$ 6,731,262**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,731,262	$ -
ACCRUALS	(10,557,928)	-	-	-	-	-	-	-	-	1,006,153	(11,564,081)
PAYMENTS	17,000,000	-	-	-	-	-	-	-	-	-	17,000,000
TAX BENEFIT INCLUDED IN	-	-	-	-	-	-	-	-	-	-	
PREMIUM ON COMMON STOCK	106,059	-	-	-	-	-	-	-	-	-	106,059
OVERPAYMENT APPLIED	-	-	-	-	-	-	-	-	-	-	-
REFUNDS & REFUNDS PENDING	(2,000,000)	-	-	-	-	-	-	-	-	(2,000,000)	-
OTHER	(32,360)	-	-	-	-	-	-	-	-	-	(32,360)
BALANCE AT 12/31/15 (Page 263)	**$ 11,247,033**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,737,415	$ 5,509,618

UTILITY (409-03080)	$ 23,878,816
NON-UTILITY (409-03070 & 409-03075)	1,609,275
SUBTOTAL	25,488,091
NNGFC (409-23075)	(24,125)
NW ENERGY CORP (409-33080)	(10,120,520)
GILL RANCH STORAGE (409-43075)	(4,498,340)
NW GAS STORAGE (409-44001)	(210,523)
NW ENERGY (409-49001)	(73,029)
PALOMAR (409-49003)	(3,626)
ACCRUALS ABOVE (Page 261A&B)	**10,557,928**
OTHER (CURRENT/DEFERRED RECLASS)	-
CONSOLIDATED FORM 10-K	**$ 10,557,928**

STATE	Total	2006 ACCRUAL 236.026	2007 ACCRUAL 236.027	2008 ACCRUAL 236.028	2009 ACCRUAL 236.029	2010 ACCRUAL 236.030	2011 ACCRUAL 236.031	2012 ACCRUAL 236.032 & 236.082	2013 ACCRUAL 236.033 & 236.083	2014 ACCRUAL 236.034 & 236.084	2015 ACCRUAL 236.035 & 236.085
BALANCE AT 12/31/14 (Page 262)	**$ 997,868**	$ -	$ -	$ -	$ -	$ -	$ -	$ 38,105	$ 89,931	$ 869,832	$ -
ACCRUALS	(160,906)	-	-	-	-	-	-	-	-	(60,909)	(99,997)
TAX PAYMENTS	2,306,000	-	-	-	-	-	-	-	-	-	2,306,000
TAX BENEFIT INCLUDED IN	-	-	-	-	-	-	-	-	-	-	-
PREMIUM ON COMMON STOCK	22,560	-	-	-	-	-	-	-	-	-	22,560
OVERPAYMENT APPLIED	-	-	-	-	-	-	-	-	-	-	-
REFUNDS & REFUNDS PENDING	-	-	-	-	-	-	-	-	-	-	-
OTHER	-	-	-	-	-	-	-	-	-	-	-
BALANCE AT 12/31/15 (Page 263)	**$ 3,165,522**	$ -	$ -	$ -	$ -	$ -	$ -	$ 38,105	$ 89,931	$ 808,923	$ 2,228,563

UTILITY (409-03150 & 409-03146)	$ 4,806,220
NON-UTILITY (409-03135 & 409-03145)	350,356
SUBTOTAL	5,156,576
NNGFC (409-23145)	(5,259)
NW ENERGY CORP (409-33150)	(2,674,369)
GILL RANCH STORAGE (409-43145)	(2,285,365)
NW GAS STORAGE (409-44002)	(112,001)
NW ENERGY (409-49002)	(17,279)
PALOMAR (409-49004)	(1,397)
ACCRUALS ABOVE (Page 261A&B)	**60,906**
OTHER (CURRENT/DEFERRED RECLASS)	100,000
CONSOLIDATED FORM 10-K	**$ 160,906**

NORTHWEST NATURAL GAS COMPANY
RECONCILIATION OF TAX ACCRUAL ACCOUNTS - DEFERRED
YEAR ENDED DECEMBER 31, 2015

FEDERAL	TOTAL	FAS 109 AMT 283.011 - 017	UTILITY REGULATORY 283.021	NON-OPR 283.031	UTILITY DEPREC 283.061	UTILITY OTHER 283.071	STORAGE DEPREC 283.081	283.096 283.304 283.306
BALANCE AT 12/31/14 (Page 276)	**$ (403,721,753)**	$ (49,872,947)	$ (22,311,616)	$ 1,109,121	$ (313,618,622)	$ (15,717,840)	$ (8,726,626)	$ 5,416,776
ACCRUALS-NWN (CURRENT YEAR)	(6,124,046)	76,018	4,745,244	(1,133,302)	(15,088,690)	5,800,006	(523,323)	-
ACCRUALS-NWN (PROVISION TO RETURN)	(463,889)	30,000	1,629	374,371	(670,306)	(123,711)	(75,872)	-
ACCRUALS-TRUE-UP	-	-	-	-	-	-	-	-
OTHER	(1)	-	(1)	(0)	(1)	1	1	-
	(6,587,936)	106,018	4,746,872	(758,931)	(15,758,997)	5,676,296	(599,194)	-
OFFSET REG ASSET-FAS 109 (Page 232)(OR RATE)	-							
OFFSET REG ASSET-FAS 109 (Page 232)	4,378,000	4,378,000	-	-	-	-	-	-
OFFSET OTHER COMPREHENSIVE	-							
INCOME (OCI) & PENSION	(1,543,374)	-	-	-	-	-	-	(1,543,374)
TAX SHARING	-	-	-	-	-	-	-	-
RECLASSES	-	-	-	-	(645,077)	-	645,077	-
ELIMINATIONS	(3,076,015)	-	-	-	-	(3,076,015)	-	-
OTHER	(171,093)	-	-	-	-	(171,094)	-	1
BALANCE AT 12/31/15 (Page 235 & 277)	**$ (410,722,171)**	$ (45,388,929)	$ (17,564,744)	$ 350,190	$ (330,022,696)	$ (13,288,653)	$ (8,680,743)	$ 3,873,402

PAGE 276 UTILITY DEBITS 410 (03005 & 33006)	$ 27,747,679
PAGE 276 UTILITY CREDITS 411 (03015 & 33016)	(20,336,262)
PAGE 277 NON UTILITY DEBITS 410 (03000 & 03020)	(301,639)
PAGE 277 NON UTILITY CREDITS 411 (03020)	(521,842)
	6,587,936
DEFERRED ITC (411-03100 & 03115)	(118,314)
NNGFC DEFERREDS (410-23020)	(25,028)
NW ENERGY CORP DEFERREDS (410-33005 & 411-33015)	5,869,613
GILL RANCH STORAGE DEFERREDS (410-42977 & 411-42980)	1,070,335
NW GAS STORAGE DEFERREDS (410-44053 & 411-44053)	87,660
NW ENERGY DEFERREDS (410-49053 & 411-49053)	(1,210)
TRAIL WEST DEFERREDS	63
ELIMINATIONS	3,076,015
TOTAL FEDERAL DEFERRED TAX (Page 261A&B)	**16,547,070**
OTHER	-
CONSOLIDATED FORM 10-K	**$ 16,547,070**

STATE	TOTAL		UTILITY REGULATORY 283.022	NON-OPR 283.032	UTILITY DEPREC 283.062	UTILITY OTHER 283.072,.300	STORAGE DEPREC 283.082	283.097 283.305 283.307
BALANCE AT 12/31/14 (Page 276)	**$ (72,179,709)**	$ -	$ (4,563,572)	$ 246,178	$ (63,908,273)	$ (3,239,485)	$ (1,834,287)	$ 1,119,730
ACCRUALS-NWN (CURRENT YEAR)	(2,045,180)		545,294	(235,323)	(3,465,892)	1,224,341	(113,601)	
ACCRUALS-NWN (PROVISION TO RETURN)	(43,205)		347	79,630	(143,852)	36,808	(16,138)	
ACCRUALS-TRUE-UP	-							
OTHER	(1)			0	0	(1)	(0)	
	(2,088,387)	-	545,641	(155,692)	(3,609,744)	1,261,148	(129,739)	-
OFFSET REG ASSET-FAS 109 (Page 232)(OR RATE)	-							
OFFSET OTHER COMPREHENSIVE	-							
INCOME (OCI) & PENSION	(327,973)							(327,973)
CREDIT UTILIZED	-							
TAX SHARING	-							
RECLASSES	-				(137,210)		137,210	
ELIMINATIONS	(654,279)					(654,279)		
OTHER	(43,275)					(43,275)		
BALANCE AT 12/31/15 (Page 235 & 277)	**$ (75,293,622)**	$ -	$ (4,017,931)	$ 90,486	$ (67,655,227)	$ (2,675,891)	$ (1,826,816)	$ 791,756

PAGE 276 UTILITY DEBITS 410 (02985)	$ 6,260,250
PAGE 276 UTILITY CREDITS 411 (02980)	(4,457,294)
PAGE 277 NON UTILITY DEBITS 410 (03027 & 03140)	402,937
PAGE 277 NON UTILITY CREDITS 411 (02990)	(117,506)
	2,088,387
NNGFC DEFERREDS (410-23140)	(5,200)
NW ENERGY CORP DEFERREDS (410-32985 & 411-32980)	2,020,091
GILL RANCH STORAGE DEFERREDS (410-42053 & 411-42053)	1,559,770
NW GAS STORAGE DEFERREDS (411-44053)	85,819
NW ENERGY DEFERREDS (410-49980)	1,488
TRAIL WEST DEFERREDS	619
ELIMINATIONS	654,279
TOTAL STATE DEFERRED TAX (Page 261A&B)	**6,405,253**
OTHER	-
CONSOLIDATED FORM 10-K	**$ 6,405,253**

Name of Respondent	This Report is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.		Kind of Tax (See Instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Incl. in Account 165) (c)
1	**Federal Tax:**	Corporate Income - (see Page 261-B2 Cont)	(1,000,000)	5,731,262
2				
3		Payroll - FICA & Medicare	780,881	-
4		Payroll - Unemployment	385	-
5		Payroll - Severance	22,067	-
6		Payroll - Bonus	51,606	-
7		Diesel and Gasoline Tax	-	-
8		Other - U.S. Dept. of Transportation	-	-
9				
10		Miscellaneous	-	-
11				
12		Total Federal	(145,060)	5,731,262
13				
14				
15	**Oregon Tax:**	Corporate Excise (see Page 261-B2 Cont)	-	869,832
16		Payroll - Transit Authority	138,612	-
17		Payroll - Unemployment	14,961	-
18		Payroll - Workers Compensation	-	-
19				
20		Real & Personal Property - Accrued	-	-
21		Real & Personal Property - Prepaid	-	9,909,914
22				
23		Regulatory Commission Fee	-	-
24			-	-
25		Other - State Department of Energy		
26		Other - State Department of Energy (pre-certification)		
27		Other - State of Oregon Department of Transportation	-	-
28		Other - Storage Property Tax Reclassification	-	-
29		Other - State Excise Tax	-	-
30		Miscellaneous	-	-
31				
32				
33				
34				
35				
36				
37		Total State of Oregon	153,573	10,779,746
38				
39				
40				
41				
42	TOTAL		8,512	16,511,008

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

that the total tax for each State and subdivision can readily be ascertained.

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

Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)	BALANCE AT END OF YEAR Taxes Accrued (Account 236) (g)	BALANCE AT END OF YEAR Prepaid Taxes (Incl. in Account 165) (h)	Line No.
10,557,928	15,000,000	(73,699)	(7,900,000)	3,347,033	1
					2
7,014,620	6,644,101	1	1,151,401	-	3
48,200	48,380	-	205	-	4
-	-	4,338	26,405	-	5
-	68,709	71,748	54,645	-	6
51,538	51,538	-	-	-	7
-	-	-	-	-	8
					9
20,220	20,220	-	-	-	10
					11
17,692,506	21,832,948	2,388	(6,667,344)	3,347,033	12
					13
					14
(3)	2,125,000	(22,560)	-	3,017,395	15
578,167	577,857	-	138,922	-	16
733,765	733,709	-	15,017	-	17
-	-	-	-	-	18
					19
6,818,780	20,024,152	13,205,372	-	-	20
12,395,196	19,030	(12,440,273)	-	9,974,021	21
					22
1,697,120	1,697,120	-	-	-	23
					24
759,101	759,101	-	-	-	25
217,548	217,548	-	-	-	26
-	-	-	-	-	27
687,029	-	(687,029)	-	-	28
100,000	100,000	-	-	-	29
-	-	-	-	-	30
					31
					32
					33
					34
					35
					36
23,986,703	26,253,517	55,510	153,939	12,991,416	37
					38
					39
					40
					41
41,679,209	48,086,465	57,898	(6,513,405)	16,338,449	42

FEDERAL ADJUSTMENTS:	
TAX BENEFIT ON STOCK OPTIONS	106,059
OTHER	(32,360)
TOTAL	73,699
OREGON ADJUSTMENTS:	
TAX BENEFIT ON STOCK OPTIONS	22,560
TOTAL	22,560
PROPERTY TAX RECLASS (ACCRUED TO PREPAID)	13,205,372
STORAGE RECLASS	(687,029)
PROPERTY TAX BILLED TO OTHERS	(78,070)
	12,440,273
SEVERANCE ACCRUAL NOT CHARGED TO TAX	4,338
BONUS ACCRUAL NOT CHARGED TO TAX	71,748

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.	Kind of Tax (See Instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Incl. in Account 165) (c)
1	**Washington Tax:**		
2	Business & Occupation	-	-
3	Payroll - Unemployment	164	-
4	Real & Personal Property	1,735,236	-
5	Regulatory Commission	-	-
6	Utility Tax	428,499	-
7			
8	Other	-	-
9	Miscellaneous	-	-
10	Total State of Washington	2,163,899	-
11			
12	**California Tax:**		
13	Corporate Income	-	128,036
14	Franchise	-	-
15	Other	-	-
16			
17	Total State of California	-	128,036
18			
19	**Local Oregon Tax:**		
20	City & County business licenses & income tax	(87,253)	-
21	Franchise	6,906,382	-
22	Property taxes	-	-
23	Other	-	-
24	Miscellaneous	-	-
25	Total Local State of Oregon Tax Expense	6,819,129	-
26			
27	**Local California Tax:**	-	-
28	Property taxes	-	-
29	Other		
30			
31	Total Local State of California Tax Expense	-	-
32			
33			
34			
35			
36			
37			
38			
39			
40			
41	TOTAL	8,991,541	16,639,044

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

TAXES ACCRUED, PERPAID AND CHARGED DURING YEAR (Continued)

that the total tax for each State and subdivision can readily be ascertained.

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

Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)	BALANCE AT END OF YEAR: Taxes Accrued (Account 236) (g)	BALANCE AT END OF YEAR: Prepaid Taxes (Incl. in Account 165) (h)	Line No.
					1
117,440	117,440	-	-	-	2
6,549	6,491	-	222	-	3
1,597,496	1,447,400	-	1,885,332	-	4
143,086	143,086	-	-	-	5
2,717,931	2,760,383	-	386,047	-	6
					7
35,070	35,070	-	-	-	8
-	-	-	-	-	9
4,617,572	4,509,870	-	2,271,601	-	10
					11
					12
60,909	81,000	-	-	148,127	13
14,190	14,190	-	-	-	14
-	-	-	-	-	15
					16
75,099	95,190	-	- -	148,127	17
					18
					19
(54,331)	-	104,284	(37,300)	-	20
15,316,262	15,458,947	-	6,763,697	-	21
-	-	-	-	-	22
-	-	-	-	-	23
-	-	-	-	-	24
15,261,931	15,458,947	104,284	6,726,397	-	25
					26
					27
1,352,584	1,352,584	-	-	-	28
18,240	18,240	-	-	-	29
					30
1,370,824	1,370,824	-	-	-	31
					32
					33
					34
					35
					36
					37
					38
					39
					40
63,004,635	69,521,296	162,182	2,484,593	16,486,576	41

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

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

Line No.	Kind of Tax (See Instruction 5) (i)	Gas Account 408.1 409.1 (j)	Gas 9-107 (k)	Other Income and Deductions (Account 408.2, 409.2) (l)
1	**Federal Tax:**			
2	Corporate Income - NW Natural Corporation	23,878,816	-	1,609,275
3	Corporate Income - NNG Financial Corporation	-	-	-
4	Corporate Income - NW Energy Corporation	-	-	-
5				
6	Payroll - FICA & Medicare	4,341,767	2,478,513	-
7	Payroll - Unemployment	29,834	17,031	-
8	Diesel and Gasoline Tax	-	-	-
9				
10	Miscellaneous	-	-	-
11				
12	Total Federal Tax Expense	28,250,417	2,495,544	1,609,275
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
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26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40	TOTAL	28,250,417	2,495,544	1,609,275

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

that the total tax for each State and subdivision can readily be ascertained.

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

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

Line No.	Gas 9-143 (m)	Account (n)	Amount (o)	Description (p)
1				
2			(4,785,518)	GRS, NWGS and NW Energy (current only)
3	-	409-23075	(24,125)	NNG Financial Corporation (current only)
4	-	409-33080	(10,120,520)	NW Energy Corporation (current only)
5				
6	-	236051	194,340	Payroll Clearing
7	-	236051	1,335	Payroll Clearing
8	-	165012	51,538	Vehicle Fuel Tax & Taxes & Licenses
9				
10	-	408-23185	20,220	Fees & Permits
11				
12	0		(14,662,730)	
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40	0		(14,662,730)	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give details of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.
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3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b) amounts credited to portion of prepaid taxes charged to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner

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

Line No.	Kind of Tax (See Instruction 5) (i)	Gas Account 408.1 409.1 (j)	Gas 9-107 (k)	Other Income and Deductions (Account 408.2, 409.2) (l)
1	**Oregon Tax:**			
2	Corporate Income - NW Natural Corporation	4,745,311	-	350,356
3	Corporate Income - NNG Financial Corporation	-	-	-
4	Corporate Income - NW Energy Corporation	-	-	-
5				
6	Payroll - Transit Authority	357,862	204,287	-
7	Payroll - Unemployment	454,171	259,265	-
8	Payroll - Workers Compensation	-	-	-
9				
10	Real & Personal Property - Accrued	19,218,655	682,350	
11	Real & Personal Property - Prepaid	-	-	
12	Real & Personal - Other	(687,029)	-	
13	Regulatory Commission Fee	1,697,120	-	
14				
15	Other - State Department of Energy	759,101	-	
16	Other - State Department of Energy (pre-certification)	217,548	-	
17	Other - State of Oregon Department of Transportation	-	-	
18	Other - Storage Property Tax Reclassification	-	-	687,029
19	Other - State Excise Tax	100,000	-	
20	Miscellaneous	-	-	
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34	Total Oregon Tax	26,862,739	1,145,902	1,037,385
35				
36				
37				
38				
39				
40	TOTAL	26,862,739	1,145,902	1,037,385

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

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

Line No.	Gas 9-143 (m)	Account (n)	Amount (o)	Description (p)
1				
2			(2,416,042)	GRS, NWGS, and NW Energy (current only)
3		409-23145	(5,259)	NNG Financial Corporation (current only)
4			(2,674,369)	NW Energy Corporation (current only)
5				
6		236051	16,018	Payroll Clearing
7		236051	20,329	Payroll Clearing
8			-	
9				
10			-	
11			-	
12			-	
13			-	
14				
15			-	
16			-	
17			-	
18			-	
19			-	
20			-	
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34	0		(5,059,323)	
35				
36				
37				
38				
39				
40	0		(5,059,323)	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAF

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

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

Line No.	Kind of Tax (See Instruction 5) (i)	Gas Account 408.1 409.1 (j)	Gas 9-107 (k)	Other Income and Deductions (Account 408.2, 409.2) (l)
1	**Washington State:**			
2	Business & Comp. Taxes	-	117,440	-
3	Payroll - Unemployment	4,054	2,314	-
4	Real & Personal Property	1,572,261	25,235	-
5	Regulatory Commission	143,086	-	-
6	Utility Tax (franchise tax)	2,717,931	-	-
7				
8	Other	35,070	-	-
9	Miscellaneous	-	-	-
10				
11				
12	Total State of Washington Tax Expense	4,472,402	144,989	0
13				
14	**California State:**			
15	Corporate Income	60,909	-	-
16	Franchise Tax	-	-	-
17				
18				
19	Total State of California Tax Expense	60,909	0	0
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40	TOTAL	4,533,311	144,989	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2014

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

that the total tax for each State and subdivision can readily be ascertained.

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

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

Line No.	Gas 9-143 (m)	Account (n)	Amount (o)	Description (p)
1				
2	-		-	
3	-	236051	181	Payroll Clearing
4	-		-	
5	-		-	
6	-		-	
7				
8	-		-	
9	-		-	
10				
11				
12	0		181	
13				
14				
15	-		-	
16	-		14,190	GRS, Gas Storage, NW Energy Franchise Tax
17				
18				
19	0		14,190	
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40	0		14,371	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

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

Line No.	Kind of Tax (See Instruction 5) (i)	Gas Account 408.1 409.1 (j)	Gas 9-107 (k)	Other Income and Deductions (Account 408.2, 409.2) (l)
1	**Local Oregon:**			
2	City & County business licenses & income tax	(54,331)	-	-
3	Franchise	15,316,262	-	-
4	Property taxes	-	-	-
5	Other	-	-	-
6				
7	Total Local State of Oregon Tax Expense	15,261,931	0	0
8				
9	**Local California:**			
10	Franchise	-	-	-
11	Property taxes	-	-	-
12	Other	-	-	-
13				
14	Total Local State of California Tax Expense			
15		0	0	0
16				
17				
18				
19				
20				
21				
22				
23				
24				
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36				
37				
38				
39				
40				
41	TOTAL	74,908,398	3,786,435	2,646,660

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued

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

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

Line No.	Gas 9-143 (m)	Account (n)	Amount (o)	Description (p)
1				
2	-		-	
3	-		-	
4	-		-	
5	-		-	
6				
7	-		-	
8				
9				
10	-		-	
11	-	408-43185	1,352,472	Property Tax
12	-	408-44180	18,353	Miscellaneous
13				
14	-		1,370,825	
15				
16				
17				
18				
19				
20				
21				
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38				
39				
40				
41	-		(18,336,857)	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

MISCELLANEOUS CURRENT AND ACCRUED LIABILITIES (Account 242)

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

Line No.	Item (a)	Balance at End of Year (b)
1	Public Purpose	5,144,352
2	OLGA Surcharge	1,362,917
3	Workers Compensation Claims	860,119
4	Deferred Revenue - Appliance Center	328,593
5	Western States	306,981
6	Other items, each less than $250,000	189,675
7		
8		
9		
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14		
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31		
32		
33		
34	TOTAL	8,192,637

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northwest Natural Gas Company	(1) X An Original (2) A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

Other Deferred Credits (Account 253)

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

Line No.	Section of Other Deffered Credits (a)	Balance at beginning of year (b)	Debit Contra Account (c)	Debit Amount (d)	Credits (e)	Balance at End of year (f)
1	Western States Pension Plan	8,064,186	-	603,155	-	7,461,031
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
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37						
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40						
41						
42						
43						
44						
45						
46						
47						
48	**Total**	8,064,186		603,155	-	7,461,031

Name of Report	**This Report is:**	**Date of Report (Mo, Da, Yr)**	**Year of Report**
Northwest Natural Gas Company	X An Original A resubmission		Dec. 31, 2015

Accumulated Deferred Income Taxes--Other Property (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to property not subject
2. At Other, include deferrals relating to other income and deductions.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Changes During Year Amounts Debited to Account 410.1 (c)	Changes During Year Amounts Debited to Account 411.1 (d)
1	Account 282			
2	Electric			
3	Gas			
4				
5	Total (Total of lines 2 thru 4)			
6				
7	TOTAL Account 282 (Total of lines 5 thru 6)			
8	Classification of TOTAL			
9	Federal Income Tax			
10	State Income Tax			
11	Local Income Tax			

See FERC Annual Report pages 276-277

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

Accumulated Deferred Income Taxes--Other Property (Account 282) (continued)

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

Changes During Year Amounts Debited to Account 410.2 (e)	Changes During Year Amounts Credited to Account 411.2 (f)	Adjustments Debits Account No. (g)	Adjustments Debits Amount (h)	Adjustments Credits Account No. (i)	Adjustments Credits Account No. (j)	Balance at End of Year (k)	Line No.
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11

See FERC Annual Report pages 276-277

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For Other (Specify), included deferrals related to other income and deductions.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Gas			
3.01	Deferred Income Taxes - FAS 109 & AMT	49,872,947	-	76,018
3.02	Revenue & Cost Gas Adjustments	26,875,188	9,201,693	12,312,599
3.03	Deferred Depreciation - Federal	313,618,622	17,760,896	2,001,899
3.04	Deferred Income Taxes - Other (Includes SB 408)	18,957,323	1,808,888	9,920,162
3.05	Deferred Depreciation - State	63,908,274	4,092,622	482,878
4.01	Other	-	-	-
4.02	Other - reclass	23,785,213	-	-
5	Total (Total of Lines 2 Thru 4)	497,017,566	32,864,099	24,793,556
6	Other (Specify) Non - Utility	9,205,615	-	-
6.01	Other Comprehensive Income - Federal	(5,416,776)	-	-
6.02	Other Comprehensive Income - State	(1,119,729)	-	-
7	TOTAL (Acct 283) (Total of lines 5 thru 6) (Page 113)	499,686,676	32,864,099	24,793,556
8	Classification of TOTAL			
9	Federal Income Tax	422,463,691	26,603,848	20,336,262
10	State Income Tax	77,222,985	6,260,251	4,457,294
11	Local Income Tax	-	-	-

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

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

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

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year Page 114	Line No.
		Acct. No.	Amount	Acct. No.	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
							3
-	-		-	186016	4,408,000	45,388,929	3.01
(2,181,606)	-		-		-	21,582,676	3.02
-	-	283061	645,077		-	330,022,696	3.03
-	-	283071	5,118,496		-	15,964,545	3.04
-	-	283062	137,209		-	67,655,227	3.05
-	-		-			-	4.01
-	-		-	190100, 190102	23,785,213	-	4.02
(2,181,606)	-		5,900,782		28,193,213	480,614,072	5
2,282,904	639,348		-	283031	782,286	10,066,885	6
-	-	218000	1,543,374		-	(3,873,402)	6.01
-	-	218000	327,973		-	(791,756)	6.02
101,298	639,348		7,772,129		28,975,499	486,015,799	7
							8
(301,639)	521,842		6,609,393		23,785,018	410,722,171	9
402,937	117,506		1,162,736		5,180,481	75,293,628	10
-	-		-		-	-	11

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

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 of Other Regulatory Liabilities (a)	Balance at Beginning of Yr (b)	DEBITS Amount (c)		CREDITS Amount (d)	Balance at End of Year (e)
1						
2	Storage Margin Share - Oregon (OPUC Advice 00-4 and					
3	later OPUC Advice 03-6)	9,665,263	9,541,406		9,294,311	9,418,168
4						
5	Storage Margin Share - Washington (UG 298)	1,223,451	1,223,451		1,218,806	1,218,806
6						
7	FAS 133 Short-Term Gross Gains (1)	107,000	3,830,000		6,216,000	2,493,000
8						
9	Other	561,461	2,298,612		1,929,930	192,779
10						
11						
12	(1) Temporary regulatory liabilities for mark-to-market					
13	adjustments					
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35	TOTAL	11,557,175	16,893,469		18,659,047	13,322,753

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

GAS OPERATING REVENUES (Account 400)

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

GAS OPERATING REVENUES (Continued)

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

OTHER REVENUES		TOTAL OPERATING REVENUES		DEKATHERM OF NATURAL GAS		
Amount for Current Year (f)	Amount for Previous Year (g)	Amount for Current Year (h)	Amount for Previous Year (i)	Amount for Current Year (j)	Amount for Previous Year (k)	Line No.
682,276,907	724,023,612	682,276,907	724,023,612	66,040,605	71,643,696	1
-	-	-	-			2
2,103,715	2,236,898	2,103,715	2,236,898			3
1,240,841	1,374,165	1,240,841	1,374,165			4
-	-	-	-	-	-	5
-	-	-	-	-	-	6
17,759,308	17,145,678	17,759,308	17,145,678	36,820,688	37,655,207	7
-	-	-	-			8
-	-	-	-			9
-	-	-	-			10
-	-	-	-			11
291,567	275,942	291,567	275,942			12
-	-	-	-			13
16,572,003	5,359,607	16,572,003	5,359,607			14
720,244,341	750,415,902	720,244,341	750,415,902			15
-	-	-	-			16
720,244,341	750,415,902	720,244,341	750,415,902			17

Name of Respondent Northwest Natural Gas Company	This Report is: X An Original A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 2015

OTHER GAS REVENUES (ACCOUNT 495)

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

Line No.	Description of Transaction (a)	Revenues (in dollars) (b)
1	Decoupling	17,948,954
2	Interstate Storage Credit	9,573,242
3	Decoupling Amortization	(7,761,047)
4	Oregon Amortizations	(1,918,509)
5	Washington Amortizations	(1,190,422)
6	Gas Reserves Credit	384,634
7	Warm Deferrals	(359,073)
8	WA Great Program	(300,227)
9	Other (Misc Gas Revenues - 5 items)	194,451
10		
11		
12		
13		
14		
15		
16		
17		
18	TOTAL	16,572,003

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

GAS OPERATION AND MAINTENANCE EXPENSES

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

Name of Respondent Northwest Natural Gas Company	This Report is: X An Original A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 2015

GAS OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	A2. Manufacturing Gas Production (con't.)		
2	Gas Raw Materials		
3	725 Coal Carbonized in Coke Ovens	-	-
4	726 Oil for Water Gas	-	-
5	727 Oil for Oil Gas	-	-
6	728 Liquefied Petroleum	-	-
7	729 Raw Materials for other Gas Processes	-	-
8	730 Residuals Expenses	-	-
9	731 Residuals Produced - Credit	-	-
10	732 Purification Expenses	-	-
11	733 Gas Mixing Expenses	-	-
12	734 Duplicate Charges - Credit	-	-
13	735 Miscellaneous Production Expenses	-	-
14	736 Rents	-	-
15	TOTAL Operations	-	-
16	Maintenance		
17	740 Maintenance Supervision and Engineering	-	-
18	741 Maintenance Structures and Improvements	-	-
19	742 Maintenance of Production Equipment	-	-
20	TOTAL Maintenance	-	-
21	TOTAL Manufacturing Gas Production	-	-

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

GAS OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

GAS OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account	Amount for Current Year	Amount for Previous Year
	(a)	(b)	(c)
59	C. Exploration and Development		
60	Operation		
61	795 Delay Rentals	-	-
62	796 Nonproductive Well Drilling	-	-
63	797 Abandoned Leases	-	-
64	798 Other Exploration	-	-
65	TOTAL Exploration and Development (Total of lines 61 thru 64)	-	-
66	D. Other Gas Supply Expenses		
67	Operation		
68	800 Natural Gas Well Head Purchases	-	-
69	800.1 Natural Gas Well Head Purchases, Intracompany Transfers	-	-
70	801 Natural Gas Field Line Purchases	12,526,769	4,501,634
71	802 Natural Gas Gasoline Plant Outlet Purchases	-	-
72	803 Natural Gas Transmission Line Purchases	-	-
73	804 Natural Gas City Gate Purchases	276,205,074	405,007,230
74	804.1 Liquefied Natural Gas Purchases	-	-
75	805 Other Gas Purchases	-	-
76	(Less) 805.1 Purchases Gas Cost Adjustments	30,509,751	(26,202,798)
77	TOTAL Purchased Gas (Total of Lines 68 thru 76)	319,241,594	383,306,066
78	806 Exchange Gas	-	-
79	Purchased Gas Expense		
80	807.1 Well Expense-Purchased Gas	-	-
81	807.2 Operation of Purchased Gas Measuring Stations	-	-
82	807.3 Maintenance of Purchased Gas Measuring Stations	-	-
83	807.4 Purchased Gas Calculations Expense	-	-
84	807.5 Other Purchased Gas Expenses	-	-
85	TOTAL Purchased Gas Expense (Total of lines 80 thru 84)	-	-

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

GAS OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account	Amount for Current Year	Amount for Previous Year
	(a)	(b)	(c)
86	808.1 Gas Withdrawn from Storage-Debit	22,363,301	39,518,736
87	(Less) 808.2 Gas Delivered to Storage-Credit	(14,075,913)	(57,151,137)
88	809.1 Withdrawals of Liquefied Natural Gas for Processing-Debit	-	-
89	(Less) 809.2 Deliveries of Natural Gas for Processing-Credit	-	-
90	Gas used in Utility Operation-Credit		
91	810 Gas Used for Compressor Station Fuel-Credit	-	-
92	811 Gas Used for Products Extraction-Credit	-	-
93	812 Gas Used for Other Utility Operations-Credit	(223,813)	(184,998)
94	TOTAL Gas Used in Utility Operations-Credit (lines 91 thru 93)	(223,813)	(184,998)
95	813 Other Gas Supply Expenses	-	-
96	TOTAL Other Gas Supply Exp. (Total of lines 77, 78, 85, 86-89,	327,305,169	365,488,667
	94, 95)	-	-
97	TOTAL Production Expenses (Total of lines 3, 30, 58, 65, 96)	327,305,169	365,488,667
98	2. NATURAL GAS STORAGE, TERMINALING AND PROCESSING		
	EXPENSES		
99	A. Underground Storage Expenses		
100	Operation		
101	814 Operation Supervision and Engineering	-	-
102	815 Maps and Records	-	-
103	816 Well Expenses	351,810	308,380
104	817 Lines Expenses	-	-
105	818 Compressor Station Fuel and Power	64,995	106,156
106	819 Compressor Station Fuel and Power	-	-
107	820 Measuring and Regulating Station Expenses	1,517,924	1,409,421
108	821 Purification Expenses	7,092	32,082
109	822 Exploration and Development	-	-
110	823 Gas Losses	-	-
111	824 Other Expenses	-	-
112	825 Storage Well Royalties	-	-
113	826 Rents	-	-
114	TOTAL Operation (Total of lines of 101 thru 113)	1,941,821	1,856,039

Name of Respondent	This Report is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

GAS OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account	Amount for Current Year	Amount for Previous Year
	(a)	(b)	(c)
115	Maintenance		
116	830 Maintenance Supervision and Engineering	-	-
117	831 Maintenance of Structures and Improvements	-	-
118	832 Maintenance of Reservoirs and Wells	172,969	171,385
119	833 Maintenance of Lines	-	-
120	834 Maintenance of Compressor Station Equipment	-	-
121	835 Maintenance of Measuring and Regulating Station Equip	-	-
122	836 Maintenance of Purification Equipment	-	-
123	837 Maintenance of Other Equipment	-	-
124	TOTAL Maintenance (Total of lines 116 thru 123)	172,969	171,385
125	TOTAL Underground Storage Expenses (lines 114 and 124)	2,114,790	2,027,424
126	B. Other Storage Expenses		
127	Operation		
128	840 Operation supervision and Engineering	49,732	67,322
129	841 Operation Labor and Expenses	-	-
130	842 Rents	-	-
131	842.1 Fuel	-	-
132	842.2 Power	-	-
133	842.3 Gas Losses	-	-
134	TOTAL Operation (Total of lines 128 thru 133)	49,732	67,322
135	Maintenance		
136	843.1 Maintenance Supervision and Engineering	-	-
137	843.2 Maintenance of Structures and Improvements	-	-
138	843.3 Maintenance of Gas Holders	-	-
139	843.4 Maintenance of Purification Equipment	-	-
140	843.5 Maintenance of Liquefaction Equipment	-	-
141	843.6 Maintenance of Vaporizing Equipment	-	-
142	843.7 Maintenance of Compressor Equipment	-	-
143	843.8 Maintenance of Measuring and Regulating Equipment	-	-
144	843.9 Maintenance of Other Equipment	-	-
145	TOTAL Maintenance (Total of lines 136 thru 144)	-	-
146	TOTAL Other Storage Expenses (Total of lines 134 and 145)	49,732	67,322

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

GAS OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account	Amount for Current Year	Amount for Previous Year
	(a)	(b)	(c)
147	C. Liquefied Natural Gas Terminaling and Processing Expenses		
148	Operation		
149	844.1 Operation Supervision and Engineering	1,010,665	1,526,195
150	844.2 LNG Processing Terminal Labor and Expenses	-	-
151	844.3 Liquefaction Processing Labor and Expenses	-	-
152	844.4 Liquefaction Transportation Labor and Expenses	-	-
153	844.5 Measuring and Regulating Labor and Expenses	-	-
154	844.6 Compressor Station Labor and Expenses	-	-
155	844.7 Communication system Expenses	-	-
156	844.8 System Control and Load Dispatching	-	-
157	845.1 Fuel	(26,068)	(106,987)
158	845.2 Power	-	-
159	845.3 Rents	-	-
160	845.4 Demurrage Charges	-	-
161	(Less) 845.5 Wharfage Receipts-Credit	-	-
162	845.6 Processing Liquefied of Vaporized Gas by Others	-	-
163	846.1 Gas Losses	-	-
164	846.2 Other Expenses	-	-
165	TOTAL Operation (Total of lines 149 thru 164)	984,597	1,419,208
166	Maintenance		
167	847.1 Maintenance Supervision and Engineering	-	-
168	847.2 Maintenance of Structures and Improvements	690,853	418,592
169	847.3 Maintenance of LNG Processing Terminal Equipment	-	-
170	847.4 Maintenance of LNG Transportation Equipment	-	-
171	847.5 Maintenance of Measuring and Regulating Equipment	-	-
172	847.6 Maintenance of Compressor Station Equipment	-	-
173	847.7 Maintenance of Communication Equipment	-	-
174	847.8 Maintenance of Other Equipment	-	-
175	TOTAL Maintenance (Total of lines 167 thru 174)	690,853	418,592
176	TOTAL Liquefied Nat Gas Terminaling and Proc Exp (Total of lines 165 & 175)	1,675,450	1,837,800
177	TOTAL Natural Gas Storage (Total of lines 125, 146, and 176)	3,839,972	3,932,546

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

GAS OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
178	3. TRANSMISSION EXPENSES		
179	Operation		
180	850 Operation Supervision and Engineering	-	-
181	851 System Control and Load Dispatching	-	-
182	852 Communication system Expenses	-	-
183	853 Compressor Station Labor and Expenses	-	-
184	854 Gas for Compressor Station Fuel	-	-
185	855 Other Fuel and Power for Compressor Stations	-	-
186	856 Mains Expenses	1,242,003	586,172
187	857 Measuring and Regulating Station Expenses	-	-
188	858 Transmission and Compression of Gas by Others	-	-
189	859 Other Expenses	-	-
190	860 Rents	-	-
191	TOTAL Operations (Total of lines 180 thru 190)	1,242,003	586,172
192	Maintenance		
193	861 Maintenance Supervision and Engineering	-	-
194	862 Maintenance of Structures and Improvements	-	-
195	863 Maintenance of Mains	298,839	2,044
196	864 Maintenance of Compressor Station Equipment	-	-
197	865 Maintenance of Measuring and Regulating Station Equipment	-	-
198	866 Maintenance of Communication Equipment	-	-
199	867 Maintenance of Other Equipment	-	-
200	TOTAL Maintenance (Total of lines 193 thru 199)	298,839	2,044
201	TOTAL Transmission Expenses (Total of lines 191 and 200)	1,540,842	588,216
202	4. DISTRIBUTION EXPENSES		
203	Operation		
204	870 Operation Supervision and Engineering	1,857,235	1,929,177
205	871 Distribution Load Dispatching	-	-
206	872 Compressor Station Labor and Expenses	-	-
207	873 Compressor Station Fuel and Power	-	-

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

GAS OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account		Amount for Current Year	Amount for Previous Year
	(a)		(b)	(c)
208	874	Mains and Services Expenses	7,187,107	7,425,683
209	875	Measuring and Regulating Station Expenses-General	(62,364)	33,566
210	876	Measuring and Regulating Station Expenses-Industrial	-	-
211	877	Measuring and Regulating Station Expenses-City Gas	525,029	435,137
212	878	Meter and House Regulator Expenses	5,479,890	5,031,475
213	879	Customer Installations Expenses	3,595,815	4,774,785
214	880	Other Expenses	943,134	774,721
215	881	Rents	203,357	210,450
216		TOTAL Operations (Total of lines 204 thru 215)	19,729,203	20,614,994
217	Maintenance			
218	885	Maintenance Supervision and Engineering	1,654,184	3,218,667
219	886	Maintenance of Structures and Improvements	-	-
220	887	Maintenance of Mains	2,123,391	2,049,739
221	888	Maintenance of Compressor Station Equipment	-	-
222	889	Maintenance of Measuring & Regulating Station Equipment -General	993,309	802,366
223	890	Maintenance of Meas. and Reg. Station Equipment-Industrial	66,663	-
224	891	Maintenance of Meas & Reg Station Equip-City Gate	803,416	85,951
225	892	Maintenance of Services	2,153,739	1,183,088
226	893	Maintenance of Meters and House Regulators	18,796	1,932,816
227	894	Maintenance of Other Equipment	-	18,207
228		TOTAL Maintenance (Total of lines 218 thru 227)	7,813,498	9,290,834
229		TOTAL Distribution Expenses (Total of lines 216 and 228)	27,542,701	29,905,828
230	5. CUSTOMER ACCOUNTS EXPENSES			
231	Operation			
232	901	Supervision	1,105,616	1,150,189
233	902	Meter Reading Expenses	673,417	641,220
234	903	Customer Records and Collection Expenses	14,383,977	14,754,598

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

GAS OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account	Amount for Current Year	Amount for Previous Year
	(a)	(b)	(c)
235	904 Uncollectible Accounts	760,110	629,883
236	905 Miscellaneous Customer Accounts Expenses	-	-
237	TOTAL Customer Accounts Expenses (Total of lines 232-236)	16,923,120	17,175,890
238	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSE		
239	Operation		
240	907 Supervision	2,808	6,396
	908 Customer Assistance Expense	222,161	214,771
242	909 Informational and Instructional Expenses	1,219,463	1,289,660
243	910 Miscellaneous Customer Service and Informational Expenses	144,992	166,688
244	TOTAL Customer Service & Information Expenses	1,589,424	1,677,515
	(Total of lines 240 thru 243)		
245	7. SALES EXPENSES		
246	Operation		
247	911 Supervision	121,662	125,829
248	912 Demonstration and Selling Expenses	2,091,822	2,297,080
249	913 Advertising Expenses	447,917	197,218
250	916 Miscellaneous Sales Expenses	1,054	23
251	TOTAL Sales Expenses (Total of lines 247 thru 250)	2,662,455	2,620,150
252	8. ADMINISTRATIVE AND GENERAL EXPENSES		
253	Operation		
254	920 Administrative and General Salaries	25,018,462	21,026,242
255	921 Office Supplies and Expenses	13,858,353	14,313,418
256	(Less) 922 Administrative Expenses Transferred - Credit	(16,081,996)	(15,636,673)
257	923 Outside Services Employed	7,520,702	6,847,903
258	924 Property Insurance	3,058,207	2,837,225
259	925 Injuries and Damages (See Note 1 Below)	16,482,759	(21,717)
260	926 Employee Pensions and Benefits	34,733,318	31,311,611
261	927 Franchise Requirements	-	-
262	928 Regulatory Commission Expenses	-	-
263	(Less) 929 Duplicate Charges - Credit	-	-
264	930.1 General Advertising Expenses	-	-
265	930.2 Miscellaneous General Expenses	2,542,586	2,498,816
266	931 Rents	4,777,774	4,813,955
267	TOTAL Operation (Total of lines 254 thru 266)	91,910,165	67,990,780
268	Maintenance		
269	935 Maintenance of General Plant	3,514,796	3,469,964
270	TOTAL Administrative and General Expenses (Total of	95,424,961	71,460,744
	lines 267 and 269)		
271	TOTAL Gas O & M Expenses (Total of lines 97,177,201,229,237	476,828,644	492,849,556
	,244,251,and 270)		

Note 1: Included in the amount for current year on line 259 is $15 million of environmental remediation expenses and associated carrying costs which the Company must forgo collection of under an Order from the Oregon Public Utility Commission issued in February 2015.

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

Gas Used in Utility Operations

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

Line No.	Purpose for Which Gas Was Used (a)	Account Charged (b)	Natural Gas: Gas Used (Dth) (c)	Natural Gas: Amount of Credit (in dollars) (d)	Manufactured Gas: Gas Used (Dth) (d)	Manufactured Gas: Amount of Credit (in dollars) (d)
1	810 Gas Used for Compressor Station Fuel - Credit					
2	811 Gas Used for Products Extraction - Credit					
3	Gas Shrinkage and Other Usage in Respondent's Own Processing					
4	Gas Shrinkage, etc. for Respondent's Gas Processed by Others					
5	812 Gas Used for Other Utility Operations - Credit (Report separately for each principal use. Group minor uses.)					
6	System - All Districts	Variable	102,499	223,813		
7	Storage Plants	Inventory	164,976		Included in the Cost of Inventory	
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45	**Total**		267,475	223,813		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

MISCELLANEOUS GENERAL EXPENSE (Account 930.2)

1. Provide the information requested below on miscellaneous general expenses
2. For Other Expenses, show the (a) purpose, (b) recipient and (c) amount of such items. List separately amounts of $250,000 or more however, amounts less than $250,000 may be grouped if the number of items so grouped is shown.

Line No.	Description (a)	Amount (in dollars) (b)
1	Industry association dues (2105)	$ 789,974
2		
3	Publishing and distributing information and reports to stockholders Annual Report; trustee, registrar, and transfer agent fees and expenses, and other expenses of servicing outstanding securities of the respondent (2065-5000)	97,167
4		
5	Other expenses (2966)	2,185
6		
7	Director's Fees and Expenses (4320)	1,551,877
8		
9	Annual Meeting (4290)	101,383
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40	TOTAL	2,542,586

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS
NW NATURAL

Period Beginning: Jan 2015
Period Ending: Dec 2015

Functional Class / FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve
UTILITY									
Intangible Plant									
301	ORGANIZATION	$0	$0	$0	$0	$0	$0	$0	$0
302	FRANCHISES & CONSENTS	0	0	0	0	0	0	0	0
303.1	COMPUTER SOFTWARE	19,453,461	2,366,005	(1,073,332)	0	0	(12,941)	0	20,733,193
303.2	CUSTOMER INFORMATION SYSTEM	32,348,168	0	0	0	0	0	0	32,348,168
303.3	INDUSTRIAL & COMMERCIAL BIL	4,146,951	0	0	0	0	0	0	4,146,951
303.4	CRMS	374,476	154,607	0	0	0	0	0	529,083
303.5	POWERPLANT SOFTWARE	0	0	0	0	0	0	0	0
	Intangible Plant Subtotal	56,323,056	2,520,612	(1,073,332)	0	0	(12,941)	0	57,757,395
Production Plant - Oil Gas									
304.1	LAND	0	0	0	0	0	0	0	0
305.2	P P O G STRU & IMPR-SEWER S	0	0	0	0	0	0	0	0
305.5	P P O G STRU & IMPR-OTHER Y	13,814	0	0	0	0	0	0	13,814
312.3	P P O G FUEL HANDLING AND S	0	0	0	0	0	0	0	0
318.3	P P O G LIGHT OIL REFINING	152,141	0	0	0	0	0	0	152,141
318.5	P P O G TAR PROCESSING	255,729	0	0	0	0	0	0	255,729
325	NATURAL GAS PROD AND GATHER	0	0	0	0	0	0	0	0
327	NATURAL GAS PROD & GATHERIN	0	0	0	0	0	0	0	0
328	NATURAL GAS PROD AND GATHER	0	0	0	0	0	0	0	0
331	NATURAL GAS PROD & GATHERIN	0	0	0	0	0	0	0	0
332	NATURAL GAS PROD & GATHERIN	0	0	0	0	0	0	0	0
333	NATURAL GAS PROD & GATHERIN	0	0	0	0	0	0	0	0
334	NATURAL GAS PROD & GATHERIN	0	0	0	0	0	0	0	0
	Production Plant - Oil Gas Subtotal	421,683	0	0	0	0	0	0	421,683
Production Plant - Other									
305.11	GAS PRODUCTION - COTTAGE G	8,736	0	0	0	0	0	0	8,736
305.17	STRUCTURES MIXING STATION	51,246	0	0	0	0	0	0	51,246
311	P P OTHER-LIQUEFIED PETROLE	(0)	0	0	0	0	0	0	(0)
311.4	P P OTHER-L P G GRANGER	0	0	0	0	0	0	0	0
311.7	LIQUIFIED GAS EQUIPMENT COO	8,066	0	0	0	0	0	0	8,066
311.8	LIQUIFIED GAS EQUIPMENT LIN	6,585	0	0	0	0	0	0	6,585
319	GAS MIXING EQUIPMENT GASCO	194,720	0	0	0	0	0	0	194,720
	Production Plant - Other Subtotal	269,353	0	0	0	0	0	0	269,353

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS
NW NATURAL

Period Beginning: Jan 2015
Period Ending: Dec 2015

Functional Class / FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve
UTILITY									
Natural Gas Underground Storage									
350.1	LAND	0	0	0	0	0	0	0	0
350.2	RIGHTS-OF-WAY	23,367	1,776	0	0	0	0	0	25,143
351	STRUCTURES AND IMPROVEMENTS	2,420,511	122,144	0	0	0	0	0	2,542,655
352	WELLS	10,560,588	414,974	0	0	0	0	0	10,975,562
352.1	STORAGE LEASEHOLD & RIGHTS	1,440,015	76,801	0	0	0	0	0	1,516,816
352.2	RESERVOIRS	1,721,701	136,611	0	0	0	380,287	0	2,238,599
352.3	NON-RECOVERABLE NATURAL GAS	3,077,618	121,089	0	0	0	0	0	3,198,707
353	LINES	2,771,168	134,976	0	0	0	0	0	2,906,144
354	COMPRESSOR STATION EQUIPMENT	15,525,294	818,342	0	0	0	688,663	0	17,032,299
355	MEASURING / REGULATING EQUIPM	3,952,667	152,044	0	0	0	163,412	0	4,268,123
356	PURIFICATION EQUIPMENT	210,321	7,375	0	0	0	0	0	217,696
357	OTHER EQUIPMENT	766,647	30,368	0	0	0	0	0	797,015
	Natural Gas Underground Storage Subtotal	42,469,899	2,016,501	0	0	0	1,232,361	0	45,718,760
Local Storage Plant									
360.11	LAND - LNG LINNTON	0	0	0	0	0	0	0	0
360.12	LAND - LNG NEWPORT	0	0	0	0	0	0	0	0
360.2	LAND - OTHER	0	0	0	0	0	0	0	0
361.11	STRUCTURES & IMPROVEMENTS	1,683,223	246,695	0	0	0	0	0	1,929,918
361.12	STRUCTURES & IMPROVEMENTS	2,251,279	142,547	0	0	0	0	0	2,393,826
361.2	STRUCTURES & IMPROVEMENTS -	10,028	466	0	0	0	0	0	10,494
362.11	GAS HOLDERS - LNG LINNTON	2,199,125	63,281	0	0	0	0	0	2,262,406
362.12	GAS HOLDERS - LNG NEWPORT	5,281,034	157,541	0	0	0	0	0	5,438,575
362.2	GAS HOLDERS - LNG OTHER	1,151	21	0	0	0	0	0	1,172
363.11	LIQUEFACTION EQUIP. - LINN	2,465,662	84,207	0	0	0	0	0	2,549,869
363.12	LIQUEFACTION EQUIP - NEWPO	7,067,748	59,929	0	0	0	0	0	7,127,677
363.21	VAPORIZING EQUIP - LINNTON	2,587,862	36,849	0	0	0	0	0	2,624,711
363.22	VAPORIZING EQUIP - NEWPORT	2,609,196	3,195	0	0	0	0	0	2,612,391
363.31	COMPRESSOR EQUIP - LINNTON	197,047	9,850	0	0	0	0	0	206,897
363.32	COMPRESSOR EQUIPMENT - NE	247,128	65,513	0	0	0	0	0	312,641
363.41	MEASURING & REGULATING EQU	597,923	491	0	0	0	5,849	0	604,263
363.42	MEASURING & REGULATING EQU	116,630	839	0	0	0	0	0	117,469
363.5	CNG REFUELING FACILITIES	1,297,064	31,733	0	0	0	0	0	1,328,797
363.6	LNG REFUELING FACILITIES	739,473	0	0	0	0	0	0	739,473
	Local Storage Plant Subtotal	29,351,573	903,157	0	0	0	5,849	0	30,260,579

Oregon and Washington Provision for Depreciation

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RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS
NW NATURAL

Period Beginning: Jan 2015
Period Ending: Dec 2015

Functional Class / FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve
UTILITY									
Transmission Plant									
365.1	LAND	0	0	0	0	0	0	0	0
365.2	LAND RIGHTS	1,642,326	122,003	0	0	0	0	0	1,764,329
366.3	STRUCTURES & IMPROVEMENTS -	256,648	20,319	0	0	0	0	0	276,967
367	MAINS	18,986,575	4,371,605	0	0	0	(6,219)	0	23,351,961
367.21	NORTH MIST TRANSMISSION LI	979,770	50,061	0	0	0	0	0	1,029,831
367.22	SOUTH MIST TRANSMISSION LI	9,565,979	367,724	0	0	0	0	0	9,933,703
367.23	SOUTH MIST TRANSMISSION LI	10,895,030	931,269	0	0	0	0	0	11,826,299
367.24	11.7M S MIST TRANS LINE	4,367,353	452,342	0	0	0	0	0	4,819,695
367.25	12M NORTH S MIST TRANS	4,335,890	485,782	0	0	0	0	0	4,821,672
367.26	38M NORTH S MIST TRANS	16,100,013	1,773,923	0	0	0	0	0	17,873,936
368	TRANSMISSION COMPRESSOR	(9)	0	0	0	0	0	0	(9)
369	MEASURING & REGULATE STATION	1,232,219	106,384	0	0	0	0	0	1,338,603
370	COMMUNICATION EQUIPMENT	0	0	0	0	0	0	0	0
	Transmission Plant Subtotal	70,260,768	8,823,733	0	0	0	(6,219)	0	79,078,282
Distribution Plant									
374.1	LAND	0	0	0	0	0	0	0	0
374.2	LAND RIGHTS	1,137,774	141,282	0	0	0	0	0	1,279,056
375	STRUCTURES & IMPROVEMENTS	80,168	200	0	0	0	0	0	80,368
376.11	MAINS < 4"	287,164,980	13,582,693	(308,781)	(1,175,395)	9,810	(4,628)	0	299,268,679
376.12	MAINS 4" & >	190,827,010	11,966,182	(531,012)	(1,669,460)	10,734	10,847	0	200,614,301
377	COMPRESSOR STATION EQUIPMENT	597,668	19,510	0	0	0	(5,849)	0	611,329
378	MEASURING & REG EQUIP - GENER	10,158,103	669,223	0	0	0	0	0	10,827,326
379	MEASURING & REG EQUIP - GATE	1,561,839	223,000	0	0	0	(1)	0	1,784,838
380	SERVICES	361,540,360	18,845,939	(1,293,428)	(2,577,664)	0	0	0	376,515,207
381	METERS	20,417,050	1,875,761	(1,126,709)	0	0	0	0	21,166,102
381.1	METERS (ELECTRONIC)	681,747	302,521	0	0	0	0	0	984,268
381.2	ERT (ENCODER RECEIVER TRANS	14,541,641	2,636,900	(607,184)	0	0	14	0	16,571,371
382	METER INSTALLATIONS	10,847,618	1,420,159	(3,438,321)	0	0	(13)	0	8,829,443
382.1	METER INSTALLATIONS (ELECTR	29,044	11,490	0	0	0	0	0	40,534
382.2	ERT INSTALLATION (ENCODER	3,877,220	634,308	(113,714)	0	0	0	0	4,397,814
383	HOUSE REGULATORS	130,101	39,916	0	0	0	0	0	170,017
386	OTHER PROPERTY ON CUSTOMERS P	0	0	0	0	0	0	0	0
387.1	CATHODIC PROTECTION TESTING	139,519	956	0	0	0	0	0	140,475
387.2	CALORIMETERS @ GATE STATIONS	96,424	0	0	0	0	0	0	96,424
387.3	METER TESTING EQUIPMENT	72,671	0	0	0	0	0	0	72,671
	Distribution Plant Subtotal	903,900,939	52,370,041	(7,419,149)	(5,422,518)	20,543	370	0	943,450,226

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS
NW NATURAL

Period Beginning: Jan 2015
Period Ending: Dec 2015

Functional Class FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve
UTILITY									
General Plant									
389	LAND	437,351	0	0	0	0	0	0	437,351
390	STRUCTURES & IMPROVEMENTS	7,227,695	1,079,253	0	0	0	0	0	8,306,948
390.1	SOURCE CONTROL PLANT	1,315,013	975,990	0	0	0	0	0	2,291,003
391.1	OFFICE FURNITURE & EQUIPMEN	5,677,642	799,643	0	0	0	0	0	6,477,285
391.2	COMPUTERS	19,598,592	3,758,878	(10,029,192)	0	0	12,941	0	13,341,219
391.3	ON SITE BILLING	0	0	0	0	0	0	0	0
391.4	CUSTOMER INFORMATION SYSTEM	0	0	0	0	0	0	0	0
392	TRANSPORTATION EQUIPMENT	9,193,319	1,562,258	(1,390,921)	0	234,987	0	0	9,599,643
393	STORES EQUIPMENT	119,406	0	0	0	0	0	0	119,406
394	TOOLS - SHOP & GARAGE EQUIPUI	9,159,344	1,150,687	0	0	4,301	0	0	10,314,332
395	LABORATORY EQUIPMENT	68,293	0	0	0	0	0	0	68,293
396	POWER OPERATED EQUIPMENT	3,526,515	182,038	(581,404)	0	150,376	0	0	3,277,525
397	GEN PLANT-COMMUNICATION EQU	20,565	6,545	0	0	0	0	0	27,110
397.1	MOBILE	401,156	3,234	0	0	0	0	0	404,390
397.2	OTHER THAN MOBILE & TELEMET	1,690,854	0	0	0	0	0	0	1,690,854
397.3	TELEMETERING - OTHER	2,988,131	3,321	0	0	0	0	0	2,991,452
397.4	TELEMETERING - MICROWAVE	917,244	15,889	0	0	0	0	0	933,133
397.5	TELEPHONE EQUIPMENT	93,501	78,997	0	0	0	0	0	172,498
398	GEN PLANT-MISCELLANEOUS EQU	0	0	0	0	0	0	0	0
398.1	PRINT SHOP	83,249	0	0	0	0	0	0	83,249
398.2	KITCHEN EQUIPMENT	2,561	525	0	0	0	0	0	3,086
398.3	JANITORIAL EQUIPMENT	14,873	0	0	0	0	0	0	14,873
398.4	INSTALLED IN LEASED BUILDINGS	10,120	0	0	0	0	0	0	10,120
398.5	OTHER MISCELLANEOUS EQUIPMENT	66,739	0	0	0	0	0	0	66,739
	General Plant Subtotal	62,612,163	9,617,259	(12,001,517)	0	389,664	12,941	0	60,630,509
	Utility Property Grand Total	$1,163,710,459	$76,108,980	($20,493,998)	($5,422,518)	$410,207	$1,232,361	$0	$1,215,545,491
NON UTILITY									
Intangible Plant									
303.1	COMPUTER SOFWARE	$31,211	$7,041	$0	$0	$0	$0	$0	$38,252
303.2	CUSTOMER INFORMATION SYSTEM	33,677	4,275	0	0	0	0	0	37,952
Non Utility	Intangible Plant Subtotal	64,888	11,316	0	0	0	0	0	76,204

Oregon and Washington Provision for Depreciation

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RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS
NW NATURAL

Period Beginning: Jan 2015
Period Ending: Dec 2015

Functional Class FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve
NON UTILITY									
Natural Gas Underground Storage									
352	WELLS	2,897,870	350,667	0	0	0	0	0	3,248,537
352.1	STORAGE LEASEHOLD & RIGHTS	161	20	0	0	0	0	0	181
352.2	RESERVOIRS	1,039,144	78,731	0	0	0	(380,287)	0	737,588
353	LINES	286,345	33,985	0	0	0	0	0	320,330
354	COMPRESSOR STATION EQUIPMENT	4,026,791	363,726	0	0	0	(688,663)	0	3,701,854
355	MEASURING / REGULATING EQUIPM	1,696,887	194,466	0	0	0	(163,412)	0	1,727,941
357	OTHER EQUIPMENT	7,271	1,442	0	0	0	0	0	8,713
Non Utility	Natural Gas Underground Storage Subtotal	9,954,470	1,023,037	0	0	0	(1,232,362)	0	9,745,146
Transmission Plant									
368	TRANSMISSION COMPRESSOR	1,609,866	238,655	0	0	0	0	0	1,848,521
Non Utility	Transmission Plant Subtotal	1,609,866	238,655	0	0	0	0	0	1,848,521
Distribution Plant									
376.12	MAINS 4" & >	171,959	21,319	0	0	0	0	0	193,278
Non Utility	Distribution Plant Subtotal	171,959	21,319	0	0	0	0	0	193,278
General Plant									
389	LAND	0	0	0	0	0	0	0	0
390	STRUCTURES & IMPROVEMENTS	21,946	3,974	0	0	0	0	0	25,920
Non Utility	General Plant Subtotal	21,946	3,974	0	0	0	0	0	25,920
Non Utility Other									
121.1	NON-UTIL PROP-DOCK	1,951,925	(4,858)	0	0	0	0	0	1,947,067
121.2	NON-UTIL PROP-LAND	0	0	0	0	0	0	0	0
121.3	NON-UTIL PROP-OIL ST	2,211,494	3,360	0	0	0	0	0	2,214,854
121.7	NON-UTIL PROP-APPL CENTER	25,823	4,219	0	0	0	0	0	30,042
121.8	NON-UTIL PROP-STORAGE	(1)	0	0	0	0	0	0	(1)
Non Utility	Other	4,189,241	2,721	0	0	0	0	0	4,191,962
	Non Utility Property Grand Total	$16,012,369	$1,301,022	$0	$0	$0	($1,232,361)	$0	$16,080,973

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS
NW NATURAL

Period Beginning: Jan 2015
Period Ending: Dec 2015

Functional Class / FERC Plant Account	Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve
TOTAL SUMMARY ALL UTILITY DEPRECIATION RESERVES 12/31/2015								
UTILITY								
108010	($32,807,990)							
108011	915,334,567							
108012	12,325,961							
108013	(2,707,754)							
108014	(395,452)							
108015	3,372,088							
108100	0							
108102	325,933,648							
108002	(5,791,902)							
108003	(25,992)							
108004	308,317							
108666	0							
SUBTOTAL		1,215,545,491						
ADD:								
108001 REMOVAL WORK IN PROCESS		(22,234,577)						
TOTAL UTILITY DEPRECIATION		$1,193,310,914						
TOTAL SUMMARY ALL NON-UTILITY RESERVES DEPRECIATION								
NON UTILITY								
122026	$1,034							
122027	4,293,054							
122028	11,276,832							
122029	(531,316)							
122100	0							
122102	1,113,338							
122002	(71,969)							
TOTAL NON UTILITY DEPRECIATION		$16,080,973						

Name of Respondent Northwest Natural Gas Company	This Report Is: X An Original A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 2015

DEPRECIATION, DEPLETION, AND AMORTIZATION OF GAS PLANT (Continued)

4. Add rows as necessary to completely report all data. Number the additional rows in sequence as 2.10, 3.10, 3.02, etc.

Section B. Factors Used in Estimating Depreciation Charges

Line No.	Functional Classification (a)	Plant Bases (thousands)	Applied Depreciation or Amortization Rates (percent) (c)
1	Production and Gathering Plant		
2	Offshore	N/A	N/A
3	Onshore	N/A	N/A
4	Underground Gas Storage Plant	135,951	2.26
5	Transmission Plant	N/A	N/A
6	Offshore	N/A	N/A
7	Onshore	N/A	N/A
8	General Plant	N/A	N/A
9			
10			
11			
12			
13			
14			
15			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

PARTICULARS CONCERNING CERTAIN INCOME DEDUCTIONS AND INTEREST CHARGES ACCOUNTS

Report the information specified below, in the order given, for the respective income deduction and interest charges accounts.

(a) **Miscellaneous Amortization** (Account 425) - Describe the nature of items included in this account, the contra account charged, the total of amortization charges for the year, and the period of amortization.

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

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

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

Line No.	Item (a)		Amount (b)
1	Account 425	Miscellaneous Amortization	-
2			
3	Account 426.1	Donations	1,291,986
4	Account 426.2	Insurance Benefits	(2,187,796)
5	Account 426.3	Penalties - Internal Revenue	314
6	Account 426.4	Civic, Political and Related Activities (426.31-426.33 & 426.41-426.45)	1,544,920
7	Account 426.5	Other Deductions (426.05, 426.50-426.52)	134,954
8	Account 426.6	Diversification (426.60)	
9			
10		Total Account 426	784,378
11			
12	Account 430	Interest on Debt to Associated Companies	-
13			
14	Account 431	Other Interest Expense	
15		Notes Payable (431.1)	851,731
16		Miscellaneous (431.2-431.5)	1,313,280
17			
18		Total Account 431	2,165,011
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Name of Respondent	This Report Is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

REGULATORY COMMISSION EXPENSES (Account 928)

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

Line No.	Description (Furnish name of regulatory commission or body, the docket or case number, and a description of the case.) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expenses to Date (d)	Deferred in Account 186 at Beginning of Year (e)
1					
2					
3	**PUBLIC UTILITY COMMISSIONER OF OREGON:**				
4					
5	REGULATORY ISSUES	NONE	0	0	NONE
6					
7	LEAST COST PLANNING (LC60)	NONE	0	0	NONE
8					
9					
10	**WASHINGTON UTILITIES & TRANSPORTATION COMMISSION:**				
11					
12	REGULATORY ISSUES	NONE	0	0	NONE
13					
14	LEAST COST PLANNING (UG131473)	NONE	0	0	NONE
15					
16					
17	**FEDERAL ENERGY REGULATORY COMMISSION:**				
18					
19	REGULATORY ISSUES	NONE	0	0	NONE
20					
21					
22	**PROFESSIONAL SERVICES**				
23	CLASSIFIED TO FERC ACCOUNT 923	NONE	0	0	NONE
24					
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41					
42					
43	TOTAL		0	0	

Northwest Natural does not track expenses by formal regulatory cases.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

REGULATORY COMMISSION EXPENSES (Continued)

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

EXPENSES INCURRED DURING YEAR CHARGED CURRENTLY TO				AMORTIZED DURING YEAR			
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 186 (i)	Contra Account (j)	Amount (j)	Deferred in Account 186, End of Year (l)	Line No.
							1
							2
							3
							4
GAS	928	0	NONE	NONE		NONE	5
							6
GAS	928	0	NONE	NONE		NONE	7
							8
							9
							10
							11
GAS	928	0	NONE	NONE		NONE	12
							13
GAS	928	0	NONE	NONE		NONE	14
							15
							16
							17
							18
GAS	928	0	NONE	NONE		NONE	19
							20
							21
							22
GAS	928	0	NONE	NONE		NONE	23
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		0					43

Name of Respondent Northwest Natural Gas Company	This Report Is: X An Original A Resubmission	Date of Report	Year of Report Dec. 31, 2015

Employee Pensions and Benefits (Account 926)

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

Line No.	Expense (a)	Amount (b)
1	Pensions - defined benefit plans	5,697,337
2	Pensions - other	4,018,543
3	Post-retirement benefits other than pensions (PBOP)	1,648,461
4	Post-employment benefit plans	-
5	Other Benefits	23,368,977
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37	**Total**	34,733,318

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

DISTRIBUTION OF SALARIES AND WAGES

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

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

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	-	-	-
4	Transmission	-	-	-
5	Distribution	-	-	-
6	Customer Accounts	-	-	-
7	Customer Service and Informational	-	-	-
8	Sales	-	-	-
9	Administrative and General	-	-	-
10	TOTAL Operation (Total of lines 3 thru 9)	-	-	-
11	Maintenance			
12	Production	-	-	-
13	Transmission	-	-	-
14	Distribution	-	-	-
15	Administrative and General	-	-	-
16	TOTAL Maint. (Total of lines 12 thru 15)	-	-	-
17	Total Operation and Maintenance			
18	Production (Total of lines 3 and 12)	-	-	-
19	Transmission (Total of lines 4 and 13)	-	-	-
20	Distribution (Total of lines 5 and 14)	-	-	-
21	Customer Accounts (Line 6)	-	-	-
22	Customer Service and Informational (Line 7)	-	-	-
23	Sales (Line 8)	-	-	-
24	Administrative and General (Total of lines 9 and 15)	-	-	-
25	TOTAL Oper. and Maint. (Total of lines 18 thru 24)	-	-	-
26	Gas			
27	Operation			
28	Production - Manufactured Gas	-	-	-
29	Production - Nat. Gas (Including Expl. and Dev.)	-	-	-
30	Other Gas Supply	-	-	-
31	Storage, LNG Terminaling and Processing	1,747,823	179,764	1,927,587
32	Transmission	703,455	83,993	787,448
33	Distribution	15,982,179	1,930,501	17,912,680
34	Customer Accounts	8,413,505	884,064	9,297,569
35	Customer Service and Informational	1,478,921	151,442	1,630,363
36	Sales	1,230,381	125,695	1,356,076
37	Administrative and General	19,762,037	2,018,839	21,780,876
38	TOTAL Operation (Total of lines 28 thru 37)	49,318,301	5,374,298	54,692,599
39	Maintenance			
40	Production - Manufactured Gas	-	-	-
41	Production - Natural Gas	-	-	-
42	Other Gas Supply	-	-	-
43	Storage, LNG Terminaling and Processing	424,830	44,664	469,494
44	Transmission	1,429,263	148,935	1,578,198
45	Distribution	7,196,091	827,766	8,023,857
46	Administrative and General	1,150,501	128,599	1,279,100
47	TOTAL Maint. (Total of lines 40 thru 46)	10,200,685	1,149,964	11,350,649

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DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
48	Gas (Continued)			
49	Total Operation and Maintenance			
50	Production - Manufactured Gas (Lines 28 and 40)	-	-	-
51	Production - Nat. Gas (Including Expl. and Dev.) (Lines 29 and 41)	-	-	-
52	Other Gas Supply (Lines 30 and 42)	-	-	-
53	Storage, LNG Terminaling and Processing (Lines 31 and 43)	2,172,653	224,428	2,397,081
54	Transmission (Total of lines 32 and 44)	2,132,718	232,928	2,365,646
55	Distribution (Total of lines 33 and 45)	23,178,270	2,758,267	25,936,537
56	Customer Accounts (Total of line 34)	8,413,505	884,064	9,297,569
57	Customer Service and Informational (Total of line 35)	1,478,921	151,442	1,630,363
58	Sales (Total of line 36)	1,230,381	125,695	1,356,076
59	Administrative and General (Total of lines 37 and 46)	20,912,538	2,147,438	23,059,976
60	TOTAL Operation and Maintenance (Total of lines 50 thru 59)	59,518,986	6,524,262	66,043,248
61	Other Utility Departments			
62	Operation and Maintenance	-	-	-
63	TOTAL All Utility Dept. (Total of lines 25,60, and 62)	59,518,986	6,524,262	66,043,248
64	Utility Plant			
65	Construction (By Utility Departments)			
66	Electric Plant	-	-	-
67	Gas Plant	25,087,569	3,458,254	28,545,823
68	Other	-	-	-
69	TOTAL Construction (Total of lines 66 thru 68)	25,087,569	3,458,254	28,545,823
70	Plant Removal (By Utility Departments)			
71	Electric Plant	-	-	-
72	Gas Plant	-	-	-
73	Other	-	-	-
74	TOTAL Plant Removal (Total of lines 71 thru 73)	-	-	-
75	Other Accounts (Specify):			
75.01	Merchandising	903,779	-	903,779
75.02	Governmental	363,849	393,669	757,518
75.03	Acct Rec-NNG Financial Corporation	217	-	217
75.04	Acct Rec-Palomar	-	-	-
75.05	Acct Rec-Gill Ranch	128,262	-	128,262
75.06	Acct Rec-PGE Joint Meter Reading	120,219	-	120,219
75.07	Storage Business	548,646	-	548,646
75.08	Other Accounts Receivable	-	46,171	46,171
75.11				
75.12				
75.13				
75.14				
75.15				
75.16				
75.17				
75.18				
75.19				
76	TOTAL Other Accounts	2,064,972	439,840	2,504,812
77	TOTAL SALARIES AND WAGES	86,671,527	10,422,356	97,093,883

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

CHARGES FOR OUTSIDE PROFESSIONAL AND OTHER CONSULTATIVE SERVICES

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

Line No.	Description (a)	Amount (in dollars) (b)
1	LOY CLARK PIPELINE CO	$ 13,522,190
2	ANCHOR QEA LLC	4,299,261
3	SEVENSON ENVIRONMENTAL	3,412,987
4	K & D SERVICES OF OREGON	3,196,661
5	MARSH USA INC	2,592,429
6	LOCATING INC	2,329,495
7	ITRON INC	1,910,694
8	SOLAR TURBINES INC	1,705,826
9	ACTIVE TELESOURCE INC	1,442,931
10	FERGUSON ENTERPRISES INC	1,424,996
11	ADVANCE ENGINEERING CORP	1,413,586
12	COLORADO STRUCTURES INC	1,065,048
13	PRICEWATERHOUSECOOPERS LLP	1,012,781
14	DELL MARKETING LP	941,479
15	COURTNEY & SON INC	929,070
16	SURVEYS & ANALYSIS INC	913,687
17	D.P. NICOLI INC	846,486
18	PEARL LEGAL GROUP PC	843,843
19	MICHELS HOLDINGS INC	787,503
20	RAIMORE CONSTRUCTION LLC	769,810
21	STOEL RIVES LLP	742,813
22	NORDISK SYSTEMS INC	723,851
23	CREATIVE MEDIA DEVELOPMENT INC	708,367
24	T BAILEY INC	683,908
25	C-2 UTILITY CONTRACTORS LLC	650,049
26	AECOM TECHNICAL SERVICES INC	644,794
27	WOODRUFF-SAWYER & COMPANY	642,972
28	DELOITTE INC	640,811
29	HAHN AND ASSOCIATES INC	609,040
30	G A W INC	584,889
31	LOWER WILLAMETTE GROUP	580,334
32	GEOENGINEERS INC	546,291
33	AIMS/PVIC	525,226
34	ENERGY INSURANCE MUTUAL LTD	510,250
35	ADVANTEL INC	480,055
36	BAKER HUGHES	469,750
37	FES INVESTMENTS INC	434,770
38	AMERICAN GAS ASSOCIATION	418,569
39	SAP INDUSTRIES INC	390,356
40	WATER TRUCK SERVICE INC	372,844
41	BRIX PAVING	361,121
42	KNOTT INC	352,820
43	OPERATIONS TECHNOLOGY	335,000
44	THOMAS N SNAIR	325,586
45	PAPE' MACHINERY INC	313,054
46	CGI TECHNOLOGIES & SOLUTIONS I	304,716
47	STANDARD UTILITY CONTRACTORS	303,493
48	ARTISTIC EXCAVATION LLC	296,190
49	U S PRESSURE VESSELS	295,748
50	EN ENGINEERING LLC	275,430
51	MCDOWELL RACKNER & GIE TOTAL	274,228
52	ENDURO PIPELINE SERVICES INC	273,358
53	IMAGE GRAPHICS & LITHO INC	272,189
54	B4 CONSULTING INC	258,468
55	Vendors < $250k	1,613,283
56	TOTAL	$ 62,575,386

Name of Respondent	This Report Is:	Date of Report	Year of Report
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Transactions with Associated (Affiliated) Companies

1. Report below the information called for concerning all goods or services received from or provided to associated (affiliated) companies amounting to more than $250,000.
2. Sum under a description "Other", all of the aforementioned goods and services amounting to $250,000 or less.
3. Total under a description "Total", the total of all of the aforementioned goods and services.

4. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote the basis of the allocation.

Line No.	Description of the Goods or Service (a)	Name of Associated/Affiliated company (b)	Account(s) Charged or Credited (c)	Amount (d)
1	Goods or Services Provided by Affiliated Company			
2				
3	Shared services agreement - payroll	NW Natural Gas Storage LLC	Various	366,728
4	Shared services agreement - overhead	NW Natural Gas Storage LLC	Various	49,679
5				
6				
7	TOTAL			416,407
8				
9				
10				
11	Goods or Services Provided for Affiliated Company			
12				
13	Shared services agreement - payroll	NW Natural Energy LLC	Various	140,448
14	Shared services agreement - overhead	NW Natural Energy LLC	Various	21,015
15				
16	Shared services agreement - payroll	NW Natural Gas Storage LLC	Various	829,747
17	Shared services agreement - overhead	NW Natural Gas Storage LLC	Various	104,908
18				
19	Shared services agreement - payroll	Gill Ranch Storage LLC	Various	378,936
20	Shared services agreement - overhead	Gill Ranch Storage LLC	Various	178,588
21	Shared services agreement - other	Gill Ranch Storage LLC	Various	149,274
22				
23				
24	TOTAL			1,802,916
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

COMPRESSOR STATIONS

1. Report below details concerning compressor stations. Use the following subheading; field compressor stations, products extraction compressor stations, underground compressor stations, transmission compressor stations, distribution compressor stations, and other compressor stations.
2. For column (a), indicate the production areas where such stations are used. Group relatively small field compressor stations by production areas. Show the number of stations grouped. Identify any station held under a title other than full ownership. State in a footnote the name of owner or co-owner, the nature of respondent's title, and percent of ownership if jointly owned

Line No.	Name of station and location (a)	Number of Units at Station (b)	Certified Horsepower for Each Station (c)	Plant cost (d)
1	Underground Storage Compressors:			
2	Miller Station, Mist, Oregon	4	14,500	44,461,958
3	(Fuel used is natural gas)			
4				
5	Field Compressors: NON-UTILITY			
6	Molalla, Oregon	2	2,219	7,723,454
7	Deer Island, Oregon	1	1,680	2,587,038
8	(Fuel used is natural gas)			
9				
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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
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COMPRESSOR STATIONS (Continued)

Designate any station that was not operated during the past year. State in a footnote whether the book cost of such station has been retired in the books of account, or what disposition of the station and its book cost are contemplated. Designate any compressor units in transmission compressor stations installed and put into operation during the year and show in a footnote each unit's size and date the unit was placed in operation.
3. For Column (e), include the type of fuel or power, if other than natural gas. If two types of fuel or power are used, show separate entries for natural gas and the other fuel or Power.

Expenses (Except depreciation and taxes)			Operation Data			
Fuel or Power (e)	Other (f)	Gas for Compressor Fuel in Dth (g)	Total Compressor Hours of Operation During the Year (h)	Number of Compressors Operated at Time of Station Peak (i)	Date of Station Peak (j)	Line No.
						1
6,581		120,650	2,894	1	12/31/2015	2
						3
						4
						5
2,732		678	6*	N/A	N/A	6
3		1	1*	N/A	N/A	7
						8
						9
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		Note: Fuel used by the compressors				29
		is added to the value of the inventory				30
		and expensed as a cost of gas when				31
		the inventory is withdrawn from				32
		storage.				33
						34
						35

* Deer Island and Molalla Gate were run for maintenance purposes during the year, not run for production.

Name of Respondent Northwest Natural Gas Company	This Report Is: X An Original A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 2015

GAS STORAGE PROJECTS

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

Line No.	Item (a)	Gas Belonging to Respondent (Dth) (b)	Gas Belonging to Others (Dth) (c)	Total Amount (Dth) (d)
	STORAGE OPERATIONS (in Dth)			
1	Gas Delivered to Storage			
2	January	88,831		88,831
3	February	601,235		601,235
4	March	474,568		474,568
5	April	506,694		506,694
6	May	789,398		789,398
7	June	865,767		865,767
8	July	531,209		531,209
9	August	1,028,498		1,028,498
10	September	489,948		489,948
11	October	284,707		284,707
12	November	190,150		190,150
13	December	0		0
14	TOTAL (Total of Lines 2 Thru 13)	5,851,005		5,851,005
15	Gas Withdrawn from Storage			
16	January	1,422,382		1,422,382
17	February	728,951		728,951
18	March	183,044		183,044
19	April	415,831		415,831
20	May	11,393		11,393
21	June	29,442		29,442
22	July	29,941		29,941
23	August	26,513		26,513
24	September	29,246		29,246
25	October	225,013		225,013
26	November	1,067,402		1,067,402
27	December	1,520,534		1,520,534
28	TOTAL (Total of lines 16 thru 27)	5,689,692		5,689,692

Note: Storage withdrawals shown above include Jackson Prairie activity, net of fuel (gas measure at the city gate.)

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Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

GAS STORAGE PROJECTS

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

Line No.	Item (a)	Total Amount (Dth) (b)
	Storage Operations	
1	Total of Working Gas End of Year	15,855,201
2	Cushion Gas (Including Native Gas)	6,584,528
3	Total Gas in Reservoir (Total of Line 1 and 2)	22,439,729
4	Certificated Storage Capacity	NA
5	Number of Injection - Withdrawal Wells (Mist only)	22
6	Number of Observation Wells (Mist only)	23
7	Maximum Day's Withdrawal from Storage (All Underground Storage)	317,336
8	Date of Maximum Days' Withdrawal	12/31/15
9	LNG Terminal Companies	2
10	Number of Tanks	2
11	Capacity of Tanks (in Dth)	1,600,000
12	LNG Volumes	
13	Received at "Ship Rail"	0
14	Transferred to Tanks	155,242
15	Withdrawn from Tanks	330,089
16	"Boil Off" Vaporization Loss	0

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
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Transmission Lines

1. Report below, by state, the total miles of transmission lines of each transmission system operated by respondent at end of year.

2. Report separately any lines held under a title other than full ownership. Designate such lines with an asterisk, in column (b) and in a footnote state the name of the owner, or co-owner, nature of respondent's title, and percent of ownership if jointly owned.

3. Report separately any line that was not operated during the past year. Enter in a footnote the details and state whether the book cost of such a line, or any portion thereof, has been retired in the books of account, or what disposition of the line and its book costs are contemplated.

4. Report the number of miles of pipe to one decimal point.

Line No.	Designation (Identification) of Line or Group of Lines (a)	* (b)	Total Miles of Pipe (c')
1	State of Oregon		650.0
2	State of Washington		3.4
3			
4			
5	State of Oregon - Kelso - Beaver	*	1.0
6	State of Washington - Kelso - Beaver	*	17.0
7			
8	Note:		
9	* Kelso-Beaver is owned 10% by NW Natural dba KB Pipeline Company		
10	11% by US Gypsum Corp., and 79% by Portland General Electric (PGE)		
11	PGE is the operator.		
12	(1 mile of Kelso-Beaver Pipeline is located in the State of Oregon and 17 miles are		
13	located in the State of Washington).		
14			
15			
16	State of Oregon - Coos County Pipeline*	**	76.8
17			
18	Note:		
19	** Coos County Pipeline is operated by NW Natural on behalf of Coos County.		
20			
21			
22			
23			
24			
25			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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AUXILIARY PEAKING FACILITIES

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

Line No.	Location of Facility (a)	Type of Facility (b)	Maximum Daily Delivery Capacity of Facility Dth (c)	Cost of Facility (in dollars) (d)	Was Facility Operated On Day of Highest Transmission Peak Delivery Yes (e)	 No (f)
1	Portland, OR	LNG	120,000	14,138,646		No
2	Newport, OR	LNG	100,000	23,394,504		No
3	Mist, OR	Underground	520,000	135,950,843	Yes	
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Name of Respondent	This Report Is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

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 Dth as reported in the schedules indicated for the items of receipts and deliveries.
4. Indicate in a footnote the quantities of bundled sales and transportation gas and specify the line on which such quantities are listed.
5. If the respondent operates two or more systems which are not interconnected, submit separate pages for this purpose. Use copies of pages 520.
6. 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 of that were not transported through any interstate portion of the reporting pipeline.
7. Indicate in a footnote the specific gas purchase expense account(s) and related to which the aggregate volumes reported on Line 3 relate.
8. 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.
9. 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. (b)	Amount of Dth (c)
1	NAME OF SYSTEM:		
2	**GAS RECEIVED**		
3	Gas Purchases (Accounts 800-805)		66,692,662
4	Gas of Others Received for Gathering (Account 489.1)	303	N/A
5	Gas of Others Received for Transmission (Account 489.2)	305	N/A
6	Gas of Others Received for Distribution (Account 489.3) Transportation	301	36,820,688
7	Gas of Others Received for Contract Storage (Account 489.4)	307	N/A
8	Exchanged Gas Received from Others (Account 806)	328	N/A
9	Gas Received as Imbalances (Account 806)	328	N/A
10	Receipts of Respondent's Gas Transported by Others (Account 858)	332	N/A
11	Other Gas Withdrawn from Storage (Explain) Underground and LNG Storage	512	5,689,692
12	Gas Received from Shippers as Compressor Station Fuel		-
13	Gas Received from Shippers as Lost and Unaccounted for		-
14	Other Receipts (Specify) LPG		-
15	Total Receipts (Total of lines 3 thru 14)		109,203,042
16	**GAS DELIVERED**		
17	Gas Sales (Accounts 480-495)		66,040,605
18	Deliveries of Gas Gathered for Others (Account 489.1)	303	-
19	Deliveries of Gas Transported for Others (Account 489.2)	305	N/A
20	Deliveries of Gas Distributed for Others (Account 489.3) Transportation	301	36,820,688
21	Deliveries of Contract Storage Gas (Account 489.4)	307	N/A
22	Exchange Gas Delivered to Others (Account 806)	328	N/A
23	Gas Delivered as Imbalances (Account 806)	328	N/A
24	Deliveries of Gas to Others for Transportation (Account 858)	332	N/A
25	Other Gas Delivered to Storage (Explain) Underground and LNG Storage	512	5,851,005
26	Gas Used for Compressor Station Fuel	331	120,650
27	Other Deliveries (Specify) Co Use	331	146,825
28	Total Deliveries (Total of lines 17 thru 27)		108,979,773
29	**GAS UNACCOUNTED FOR**		
30	Production System Losses		-
31	Gathering System Losses		-
32	Transmission System Losses		-
33	Distribution System Losses		223,269
34	Storage System Losses - Leakage (0) and Mist Gas Loss (0)		-
35	Other Losses (Specify)		-
36	Total Unaccounted for (Total of lines 30 thru 35)		223,269
37	Total Deliveries & Unaccounted for (Total of lines 28 and 36)		109,203,042

NORTHWEST NATURAL GAS COMPANY

Washington Supplement to FERC Form 2

December 31, 2015

Name of Respondent	This Report is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

DATA REQUEST FOR STATISTICS REPORT

Line No.		Total Company Operations		Washington Operations	
		Current Year	Prior Year	Current Year	Prior Year
1	GAS SERVICE REVENUES				
2					
3	RESIDENTIAL SALES	$ 413,978,714	$ 440,587,499	$ 44,671,349	$ 48,552,041
4	COMMERCIAL SALES	214,247,037	226,090,431	18,389,235	20,388,328
5	INDUSTRIAL SALES	54,051,156	57,345,682	2,933,151	3,218,298
6	OTHER SALES	-	-	-	-
7	SALES FOR RESALE	-	-	-	-
8	TRANSPORTATION OF GAS OF OTHERS	17,759,308	17,145,678	2,051,574	1,892,887
9	OTHER OPERATING REVENUES	20,208,126	9,246,612	(1,144,153)	(2,483,770)
10					
11	TOTAL GAS SERVICE REVENUES	$ 720,244,341	$ 750,415,902	$ 66,901,156	$ 71,567,784
12					
13	THERMS OF GAS SOLD-TRANSPORTED				
14					
15	RESIDENTIAL SALES	345,177,984	390,310,921	39,854,370	44,729,671
16	COMMERCIAL SALES	217,799,581	243,865,082	18,055,349	20,497,469
17	INDUSTRIAL SALES	89,587,196	95,671,552	3,893,377	4,330,076
18	OTHER SALES (UNBILLED)	7,841,288	(13,410,598)	829,838	(1,416,607)
19	SALES FOR RESALE	-	-	-	-
20	TRANSPORTATION OF GAS OF OTHERS	368,206,885	376,552,067	19,200,206	18,697,593
21					
22	TOTAL THERMS OF GAS SOLD-TRANSPORTED	1,028,612,934	1,092,989,024	81,833,140	86,838,202
23					
24	AVERAGE NUMBER OF GAS CUSTOMERS PER MONTH				
25					
26	RESIDENTIAL SALES	641,095	633,023	69,561	67,868
27	COMMERCIAL SALES	65,870	65,813	6,235	6,202
28	INDUSTRIAL SALES	729	712	47	44
29	OTHER SALES	-	-	-	-
30	SALES FOR RESALE	-	-	-	-
31	TRANSPORTATION OF GAS OF OTHERS	327	212	33	20
32					
33					
34	TRANS. & DISTRN. MAINS - FEET (END OF YEAR)	75,192,888	74,729,675	9,361,651	9,236,270
35	NO. OF METERS IN SERV. & HELD IN RESERVE (AVE.)	798,297	793,805	77,858	77,559
36	AVERAGE B.T.U. CONTENT PER CU. FT.	1,059.2	1,038.6	1,063.3	1,040.8

(Next Page is 114)

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

WASHINGTON STATE - STATEMENT OF INCOME FOR THE YEAR

1. Report amounts for accounts 412 and 413, Revenue and Expenses from Utility Plant Leased to Others, in another utility column (i, j) in a similar manner to a utility department. Spread the amount(s) over lines 2 thru 24 as appropriate. Include these amounts in columns (c) and (d) totals.
2. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
3. Report data for lines 7, 9, and 10 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1, and 407.2.

Line No.	Account (a)	(Ref.) Page No. (b)	TOTAL Total Current Year (in dollars) (c)	Total Previous Year (in dollars) (d)
1	**UTILITY OPERATING INCOME**			
2	Operating Revenues (400)	300-301		
3	Operating Expenses			
4	Operation Expenses (401)	320-325		
5	Maintenance Expenses (402)	320-325		
6	Depreciation Expense (403)	336-338		
7	Amort. & Depl. of Utility Plant (404-405)	336-338		
8	Amort. of Utility Plant Acq. Adj. (406)	336-338		
9	Amort of Property Losses, Unrecovered Plant and Regulatory Study Costs (407.1)			
10	Amort. of Conversion Expenses (407.2)			
11	Regulatory Debits (407.3)			
12	(Less) Regulatory Credits (407.4)			
13	Taxes Other Than Income Taxes (408.1)	262-263		
14	Income Taxes - Federal (409.1)	262-263		
15	- Other (409.1)	262-263		
16	Provision for Deferred Income Taxes (410.1)	276-277		
17	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	276-277		
18	Investment Tax Credit Adj. - Net (411.4)			
19	(Less) Gains from Disp. of Utility Plant (411.6)			
20	Losses from Disp. of Utility Plant (411.7)			
21	(Less) Gains from Disposition of Allowances (411.8)			
22	Losses from Disposition of Allowances (411.9)			
23	TOTAL Utility Operating Expenses (Total of lines 4 thru 22)			
24	Net Utility Operating income (Enter Total of line 2 less 23) (Carry forward to page 116, line 25)			

INFORMATION NOT AVAILABLE

SEE FERC ANNUAL REPORT PAGES 114-116

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

WASHINGTON STATE - STATEMENT OF INCOME FOR THE YEAR (Continued)

4. Explain in a footnote if the previous year's figures are different from that reported in prior reports.

5. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles, lines 2 to 23, and report the information in the blank space on page 122 or in a supplemental statement.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year (in dollars) (e)	Previous Year (in dollars) (f)	Current Year (in dollars) (g)	Previous Year (in dollars) (h)	Current Year (in dollars) (i)	Previous Year (in dollars) (j)	Line No.
						1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24

INFORMATION NOT AVAILABLE

SEE FERC ANNUAL REPORT PAGES 114-116

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

WASHINGTON STATE - STATEMENT OF INCOME FOR THE YEAR (Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Total Current Year (in dollars) (c)	Total Previous Year (in dollars) (d)
25	Net Utility Operating Income (Carried forward from page 114)	-		
26	Other Income and Deductions			
27	Other Income	-		
28	Nonutility Operating Income	-		
29	Revenues From Merch, Jobbing and Contract Work (415)	-		
30	(Less) Costs and Exp. of Merch, Job & Contract Work (416)	-		
31	Revenues From Nonutility Operations (417)	-		
32	(Less) Expenses of Nonutility Operations (417.1)	-		
33	Nonoperating Rental Income (418 & 412)	-		
34	Equity in Earnings of Subsidiary Companies (418.1)	119		
35	Interest and Dividend Income (419)	-		
36	Allow. for Other Funds Used During Constr (419.1)	-		
37	Miscellaneous Nonoperating Income (421)	-		
38	Gain on disposition of Property (421.1)	-		
39	TOTAL Other Income (Total of lines 29 thru 38)			
40	Other Income Deductions			
41	Loss on Disposition of Property (421.4 Amortization)	-		
42	Miscellaneous Amortization (425)	340		
43	Miscellaneous Income Deductions (426.1-426.60)	340		
44	TOTAL Other Income Deductions (Total of Lines 41 thru 43)			
45	Taxes Applic. to Other Income and Deductions			
46	Taxes Other Than Income Taxes (408.2)	262-263		
47	Income Taxes - Federal (409.21,24,33)	262-264		
48	Income Taxes - Other (409.22,25,26)	262-265		
49	Provision for Deferred Inc. Taxes (410.21,22)	272-277		
50	(Less) Provision for Deferred Inc. Taxes - Cr. (411.21,22,410.33)	272-278		
51	Investment Tax Credit Adj. - Net (411.33)	-		
52	(Less) Investment Tax Credits (420)	-		
53	TOTAL Taxes on Other Inc. and Ded. (Total of 46 - 52)			
54	Net Other Income and Deductions (Total of Lines 39, 44, 53)			
55	Interest Charges			
56	Interest on Long-Term Debt (427.1,2,6)	256-257		
57	Amortization of Debt Disc. and Expense (428)	258-259		
58	Amortization of Loss on Reacquired Debt (428.1)	260		
59	(Less) Amort. of Premium on Debt - Credit (429)	256-257		
60	(Less) Amortization of Gain on Reacquired Debt - Credit (429.1)	258-259		
61	Interest on Debt to Assoc. Companies (430)	340		
62	Other Interest Expense (431)	340		
63	(Less) Allow. for Borrowed Funds Used During Const.-Cr. (432.1)	-		
64	Net Interest Charges (Total of lines 56 thru 63)			
65	Income Before Extraordinary Items (Total of lines 25, 54 and 64)			
66	Extraordinary Items			
67	Extraordinary Income (434)	-		
68	(Less) Extraordinary Deductions (435)	-		
69	Net Extraordinary Items (Total of line 67 less 68)			
70	Income Taxes - Federal and Other (409.3)	262-263		
71	Extraordinary Items After Taxes (Total of line 69 less line 70)			
72	Net Income (Total of lines 65 and 71)			

INFORMATION NOT AVAILABLE
SEE FERC ANNUAL REPORT PAGES 114-116

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

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

Line No.	Item (a)	Total (b)
1	**UTILITY PLANT**	
2	In Service	
3	Plant in Service (Classified)	216,687,704
4	Property Under Capital Leases	-
5	Plant Purchased or Sold	-
6	Completed Construction not Classified	19,957,944
7	Experimental Plant Unclassified	-
8	TOTAL Utility Plant (Total of lines 3 thru 7)	236,645,648
9	Leased to Others	-
10	Held for Future Use	-
11	Construction Work in Progress	109,781
12	Acquisition Adjustments	-
13	TOTAL Utility Plant (Total of lines 8 thru 12)	236,755,429
14	Accum. Prov. for Depr., Amort., & Depl.	98,748,547
15	Net Utility Plant (Total of line 13 less 14)	138,006,882
16	**DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION**	
17	In Service:	
18	Depreciation	97,975,652
19	Amort. and Depl. of Producing Natural Gas Land and Land Rights	-
20	Amort. of Underground Storage Land and Land Rights	-
21	Amort. of Other Utility Plant	1,884,624
22	Salvage Work In Progress	-
23	Less Removal Work in Progress	1,111,729
24	TOTAL in Service (Total of lines 18 thru 23)	98,748,547
25	Leased to Others	
26	Depreciation	-
27	Amortization and Depletion	-
28	TOTAL Leased to Others (Total of lines 26 and 27)	-
29	Held for Future Use	
30	Depreciation	-
31	Amortization	-
32	TOTAL Held for Future Use (Total of lines 30 and 31)	-
33	Abandonment of Leases (Natural Gas)	-
34	Amort. of Plant Acquisition Adjustment	-
35	TOTAL Accumulated Provisions (Should agree with line 14 above) (Total of lines 24, 28, 32, 33, and 34)	98,748,547

Name of Respondent	This Report Is:	Date of Report	Year of Report
	X An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	A Resubmission		Dec. 31, 2015

WASHINGTON STATE - SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION (Continued)

Electric (c)	Gas (d)	Other (Specify) (e)	Common (f)	Line No.
				1
				2
	216,687,704			3
	-			4
	-			5
	19,957,944			6
	-			7
	236,645,648			8
	-			9
	-			10
	109,781			11
	-			12
	236,755,429			13
	98,748,547			14
	138,006,882			15
				16
				17
	97,975,652			18
	-			19
	-			20
	1,884,624			21
	-			22
	1,111,729			23
	98,748,547			24
				25
	-			26
	-			27
	-			28
				29
	-			30
	-			31
	-			32
	-			33
	-			34
	-			
	98,748,547			35

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ACCOUNT SUMMARY BY FUNTIONAL CLASS
NW Natural

Period Beginning: Jan 2015
Period Ending: Dec 2015

Functional Class / FERC Plant Account		Beginning Balance	Additions	Retirements	Transfers	Adjustments	Ending Balance
UTILITY							
Intangible Plant							
301	ORGANIZATION	$322	$0	$0	$0	$0	$322
302	FRANCHISES & CONSENTS	125	0	0	0	0	125
303.1	COMPUTER SOFTWARE	0	0	0	0	0	0
303.2	CUSTOMER INFORMATION SYSTEM	1,859,863	0	0	0	0	1,859,863
303.3	INDUSTRIAL & COMMERCIAL BIL	0	0	0	0	0	0
303.4	CRMS	0	0	0	0	0	0
303.5	POWERPLANT SOFTWARE	0	0	0	0	0	0
	Intangible Plant Subtotal	1,860,310	0	0	0	0	1,860,310
Transmission Plant							
367	MAINS	1,000,754	14,735	0	0	0	1,015,489
	Transmission Plant Subtotal	1,000,754	14,735	0	0	0	1,015,489
Distribution Plant							
374.1	LAND	10,389	0	0	0	0	10,389
374.2	LAND RIGHTS	27,679	0	0	0	0	27,679
375	STRUCTURES & IMPROVEMENTS	30,845	0	0	0	0	30,845
376.11	MAINS < 4"	68,408,964	3,094,549	(22,029)	0	(84,522)	71,396,962
376.12	MAINS 4" & >	67,038,121	1,779,011	(105,881)	0	78,661	68,789,912
378	MEASURING & REG EQUIP - GENER	1,806,253	35,155	0	0	0	1,841,408
379	MEASURING & REG EQUIP - GATE	735,244	65,032	0	0	0	800,276
380	SERVICES	59,452,786	3,249,804	(51,883)	0	0	62,650,707
381	METERS	9,632,449	449,217	(39,955)	0	0	10,041,711
381.2	ERT (ENCODER RECEIVER TRANS	6,419,953	220,604	(71,268)	0	0	6,569,289
382	METER INSTALLATIONS	5,985,191	245,282	(324,717)	0	0	5,905,756
382.2	ERT INSTALLATION (ENCODER	953,907	0	(8,227)	0	0	945,680
383	HOUSE REGULATORS	35,777	0	0	0	0	35,777
386	OTHER PROPERTY ON CUSTOMERS P	0	0	0	0	0	0
387.2	CALORIMETERS @ GATE STATIONS	26,630	0	0	0	0	26,630
	Distribution Plant Subtotal	220,564,188	9,138,654	(623,961)	0	(5,861)	229,073,020

ACCOUNT SUMMARY BY FUNTIONAL CLASS
NW Natural

Period Beginning: Jan 2015
Period Ending: Dec 2015

Functional Class FERC Plant Account		Beginning Balance	Additions	Retirements	Transfers	Adjustments	Ending Balance
UTILITY							
General Plant							
389	LAND	0	1,585,854	0	0	0	1,585,854
390	STRUCTURES & IMPROVEMENTS	0	1,148,377	0	0	0	1,148,377
390.1	SOURCE CONTROL PLANT	667,064	0	0	0	0	667,064
391.1	OFFICE FURNITURE & EQUIPMEN	16,522	0	0	0	0	16,522
391.4	CUSTOMER INFORMATION SYSTEM	0	0	0	0	0	0
392	TRANSPORTATION EQUIPMENT	914,871	0	(68,546)	0	0	846,325
394	TOOLS - SHOP AND GARAGE EQUIPMENT	84,311	3,967	0	0	0	88,278
396	POWER OPERATED EQUIPMENT	269,425	0	(30,825)	0	0	238,600
397.3	TELEMETERING - OTHER	101,081	0	0	0	0	101,081
397.5	TELEPHONE EQUIPMENT	0	0	0	0	0	0
398.4	INSTALLED IN LEASED BUILDINGS	4,727	0	0	0	0	4,727
	General Plant Subtotal	2,058,001	2,738,199	(99,371)	0	0	4,696,829
	Washington Utility Property Grand Total	$225,483,253	$11,891,587	($723,332)	$0	($5,861)	$236,645,648

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Name of Respondent	This Report is:	Date of Report	Year of Report
	X An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	A Resubmission		Dec. 31, 2015

Washington State - Gas Plant Held for Future Use (Account 105)

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

Line No.	Description and Location of Property (a)	Date Originally Included in this account (b)	Date Expected to be Used In Utility Service (c)	Balance at End of Year (d)
1	N/A	N/A	N/A	N/A
2				
3				
4				
5	**NONE**			
6				
7				
8				
9				
10				
11				
12				
13				
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38				
39				
40				0

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Name of Respondent Northwest Natural Gas Company	This Report Is: X An Original A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 2015

Washington State - Construction Work in Progress-Gas (Account 107)

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

Line No.	Description of Project (a)	Construction Work in Progress-Gas (Account 107) (b)	Estimated Additional Cost of Project (c)
1	Mains and Service Jobs	109,781	254,960
2			
3			
4			
5			
6			
7			
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
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22			
23			
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25			
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30			
31			
32			
33			
34			
35			
36			
37			
38			
39			
40			
41			
42			
43			
44			
45	**Total**	109,781	254,960

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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

WASHINGTON STATE - GENERAL DESCRIPTION OF CONSTRUCTION OVERHEAD PROCEDURE

1. For each construction overhead explain: (a) the nature and extend of work, etc., the overhead charges are intended to cover, (b) the general procedure for determining the amount capitalized, (c) the method of distribution to construction jobs, (d) whether different rates area applied to different types of construction, (e) basis of differentiation in rates for different types of construction, and (f) whether the overhead is directly or indirectly assigned

2. Show below the computation of allowance for funds used during construction rates, in accordance with the provisions of Gas Plant Instructions 3(17) of the uniform system of Accounts.

3. Where a net-of-tax rate for borrowed funds is used, show the appropriate tax affect adjustment to the computations below in a manner that clearly indicates the amount of reduction in the gross rate for tax credits.

COMPUTATION OF ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION RATES

For Line (5), column (d) below, enter the rate granted in the last rate proceeding. If not available, use he average rate earned during the preceding 3 years.

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

Line No.	Title (a)		Amount (b)	Capitalization Ration (percent) (c)		Cost Rate Percentage (d)
	(1) Average Short-Term Debt	S	193,802,000			
	(2) Short-Term Interest				s	0.41
	(3) Long-Term Debt	D	601,700,000	-	d	6.152
	(4) Preferred Stock	P	-	-	p	-
	(5) Common Equity	C	780,972,535	-	c	9.5
	(6) Total Capitalization		-	100.00		
	(7) Average Construction Work in Progress	W	43,942,410			

2.	Gross Rates for Borrowed Funds s(S/W)+d[(D/(D+P+C))(1-(S/W)]	7.36
3.	Rate for Other Funds [1-(S/W)][p(P/(D+P+C))+c(C/(D+P+C))]	18.30
4.	Weighted Average Rate Actually Used for the Year	
	a. Rate for Borrowed Funds -	0.41
	b. Rate for Other Funds -	-

GENERAL DESCRIPTION OF CONSTRUCTION OVERHEAD PROCEDURE

1. a) Engineering Department overhead covers transmission and distribution system planning, design work, drafting and platting of construction work.

Distribution Department overhead covers transmission and distribution system work scheduling, field supervision and processing of work completed.

Administrative work: overhead includes Purchasing, Accounting and general office expense

General Services Department: overhead covers planning and supervision of general plant improvements and facilities.

b) Charges during the year are segregated into overhead accounts based on the proportion of activity devoted to construction work

c) Construction Overheads are being charged to individual work orders based upon overhead rates for different types of projects. Rates are determined by type of project using the annual capital budget and annual construction overhead budget.

d) Different rates are applied to different types of construction based on the annual capital budget for each type of plant.

e) Actual construction overhead rates applied to types of work in 2015

a. Production , Storage, Transmission and Distribution plant
b. Meters 59%
c. General Plant 67%
d. Non – Utility Property 27%
1%

f) Direct assignment of construction overhead capitalized during 2015:
$ 42,198,987

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (AFUDC)

AFUDC is applied to previous month's ending balance plus half of current month's expenditures of Construction Work in Progress (CWIP).

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS
NW Natural

Period Beginning: Jan 2015
Period Ending: Dec 2015

Functional Class FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve
UTILITY									
Intangible Plant									
301	ORGANIZATION	$0	$0	$0	$0	$0	$0	$0	$0
302	FRANCHISES & CONSENTS	0	0	0	0	0	0	0	0
303.1	COMPUTER SOFTWARE	3,144	0	0	0	0	0	0	3,144
303.2	CUSTOMER INFORMATION SYSTEM	1,863,073	0	0	0	0	0	0	1,863,073
303.3	INDUSTRIAL & COMMERCIAL BIL	0	0	0	0	0	0	0	0
303.4	CRMS	0	0	0	0	0	0	0	0
303.5	POWERPLANT SOFTWARE	0	0	0	0	0	0	0	0
	Intangible Plant Subtotal	1,866,216	0	0	0	0	0	0	1,866,216
Transmission Plant									
367	MAINS	83,895	20,734	0	0	0	0	0	104,629
	Transmission Plant Subtotal	83,895	20,734	0	0	0	0	0	104,629
Distribution Plant									
374.1	LAND	0	0	0	0	0	0	0	0
374.2	LAND RIGHTS	16,332	2,076	0	0	0	0	0	18,407
375	STRUCTURES & IMPROVEMENTS	30,845	0	0	0	0	0	0	30,845
376.11	MAINS < 4"	32,256,101	1,805,001	(22,029)	(71,194)	0	(1,618)	0	33,966,262
376.12	MAINS 4" & >	22,551,039	1,691,814	(105,881)	(291,128)	0	1,445	0	23,847,289
378	MEASURING & REG EQUIP - GENER	750,647	39,909	0	0	0	0	0	790,556
379	MEASURING & REG EQUIP - GATE	620,311	33,807	0	0	0	0	0	654,118
380	SERVICES	28,604,704	1,615,988	(51,883)	(194,241)	0	0	0	29,974,567
381	METERS	2,230,433	225,838	(39,955)	0	0	0	0	2,416,316
381.2	ERT (ENCODER RECEIVER TRANS	3,149,672	431,963	(71,268)	0	0	0	0	3,510,367
382	METER INSTALLATIONS	1,459,423	139,745	(324,717)	0	0	0	0	1,274,451
382.2	ERT INSTALLATION (ENCODER	498,272	63,231	(8,227)	0	0	0	0	553,276
383	HOUSE REGULATORS	5,873	1,045	0	0	0	0	0	6,917
386	OTHER PROPERTY ON CUSTOMERS P	0	0	0	0	0	0	0	0
387.2	CALORIMETERS @ GATE STATIONS	26,630	0	0	0	0	0	0	26,630
	Distribution Plant Subtotal	92,200,282	6,050,417	(623,961)	(556,563)	0	(173)	0	97,070,002

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS
NW Natural

Period Beginning: Jan 2015
Period Ending: Dec 2015

Functional Class FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve
UTILITY									
General Plant									
389	LAND	0	0	0	0	0	0	0	0
390	STRUCTURES & IMPROVEMENTS	0	926	0	0	0	0	0	926
390.1	SOURCE CONTROL PLANT	24,806	35,021	0	0	0	0	0	59,827
391.1	OFFICE FURNITURE & EQUIPMEN	17,958	1,317	0	0	0	0	0	19,275
391.4	CUSTOMER INFORMATION SYSTEM	0	0	0	0	0	0	0	0
392	TRANSPORTATION EQUIPMENT	599,029	50,883	(68,546)	0	0	0	0	581,367
394	TOOLS AND EQUIPMENT	15,658	6,159	0	0	0	0	0	21,818
396	POWER OPERATED EQUIPMENT	139,054	7,048	(30,825)	0	0	0	0	115,277
397.3	TELEMETERING - OTHER	16,142	71	0	0	0	0	0	16,213
397.5	TELEPHONE EQUIPMENT	0	0	0	0	0	0	0	0
398.4	INSTALLED IN LEASED BUILDINGS	4,727	0	0	0	0	0	0	4,727
	General Plant Subtotal	817,375	101,424	(99,371)	0	0	0	0	819,429
	Washington Utility Property Grand Total	$94,967,768	$6,172,575	($723,332)	($556,563)	$0	($173)	$0	$99,860,276

TOTAL SUMMARY WASHINGTON UTILITY DEPRECIATION RESERVES 12/31/2015

WASHINGTON			
108010		($984,240)	
108011		70,838,449	
108012		569,064	
108013		(12,303)	
108014		-	
108015		115,277	
108100		-	
108102		29,334,029	
	SUBTOTAL		$99,860,276
ADD:			
108001	**REMOVAL WORK IN PROCESS**		(1,111,729)
TOTAL WASHINGTON UTILITY DEPRECIATION			$98,748,547

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

WASHINGTON STATE - GAS STORED (ACCOUNTS 117.1, 117.2, 117.3, 117.4, 164.1, 164.2, AND 164.3)

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

Line No.	Description (a)	(Account 117.1) (b)	(Account 117.2) (c)	Noncurrent (Account 117.3) (d)	(Account 117.4) (e)	Current (Account 164.1) (f)	LNG (Account 164.2) (g)	LNG (Account 164.3) (h)	Total (i)
1	Balance at Beginning of Year								
2	Gas Delivered to Storage			See FERC Annual Report page 220					
3	Gas Withdrawn from Storage								
4	Other Debits and Credits								
5	Balance at End of Year								
6	Dekatherms								
7	Amount Per Dekatherm								

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WASHINGTON STATE - DEPRECIATION, DEPLETION, AND AMORTIZATION OF GAS PLANT							
Factors Used in Estimating Depreciation Charges							
Line Number	Account Number (a)	Depreciable Plant Base (Thousands) (b)	Estimated Average Service Life (c)	Net Salvage (percent) (d)	Applied Depreciation Rates (percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
1	303.1*	29,159	10.00	0.00	4.31	SQ	7.4
2	303.2*	29,830	15.00	0.00	6.96	SQ	6.7
3	303.3*	4,147	10.00	0.00	17.11	SQ	3.1
4	303.4*	1,323	5.00	0.00	22.64	SQ	2.9
5	303.5*	1,131	10.00	0.00	10.63	SQ	8.5
6	305.5*	13	5.00	0.00	0.00	-	0.0
7	311.7*	4	5.00	0.00	0.00	-	0.0
8	311.8*	4	5.00	0.00	0.00	-	0.0
9	305.11*	8	5.00	0.00	0.00	-	0.0
10	305.17*	47	5.00	0.00	0.00	-	0.0
11	318.3*	145	5.00	0.00	0.00	-	0.0
12	318.5*	244	5.00	0.00	0.00	-	0.0
13	319*	185	5.00	0.00	0.00	-	0.0
14	350.2*	51	65.00	0.00	1.62	R4	50.0
15	351*	6,223	55.00	0.00	1.71	R3	45.2
16	352*	26,944	45.00	0.00	2.07	S3	36.3
17	352.1*	3,539	50.00	0.00	1.95	S2	39.0
18	352.2*	10,833	50.00	0.00	2.01	S2.5	45.4
19	352.3*	6,441	50.00	0.00	1.88	S2.5	36.4
20	353*	7,513	55.00	(15.00)	2.06	S2.5	45.5
21	354*	41,812	40.00	(10.00)	2.66	R3	32.8
22	355*	9,362	45.00	(10.00)	2.17	R2.5	37.7
23	356*	297	35.00	0.00	2.48	S3	21.8
24	357*	703	25.00	0.00	2.28	R4	17.6
25	361.11*	745	50.00	(5.00)	5.82	R3	13.1
26	361.12*	3,109	50.00	(5.00)	3.32	R3	19.5
27	361.2*	27	55.00	(5.00)	1.87	S2	43.1
28	362.11*	1,839	50.00	(20.00)	2.35	R4	11.6
29	362.12*	5,791	50.00	(20.00)	2.72	R4	18.4
30	362.2*	2	50.00	(20.00)	1.31	R4	47.1
31	363.11*	2,528	50.00	(5.00)	2.88	R1.5	13.0
32	363.12*	6,837	50.00	(5.00)	0.82	R1.5	19.8
33	363.21*	2,308	40.00	(5.00)	1.40	R3	12.7
34	363.22*	2,481	40.00	(5.00)	0.09	R3	21.0
35	363.31*	128	20.00	(5.00)	7.10	R2	5.1
36	363.32*	216	20.00	(5.00)	4.71	R2	16.3
37	363.41*	541	45.00	(5.00)	0.04	R2.5	13.2
38	363.42*	113	45.00	(5.00)	0.73	R2.5	19.6
39	363.5*	1,828	25.00	0.00	1.04	R3	16.4
40	363.6*	739	40.00	0.00	0.00	R2	0.0
41	365.2*	4,827	65.00	0.00	1.89	R4	46.5
42	366.3*	1,042	50.00	0.00	1.95	S3	46.5
43	367*	12,030	55.00	(40.00)	3.08	R3	24.8
44	367.21*	1,514	55.00	(40.00)	2.51	R3	39.3
45	367.22*	14,949	55.00	(40.00)	2.46	R3	39.2
46	367.23*	33,960	55.00	(40.00)	2.67	R3	48.7
47	367.24*	17,466	55.00	(40.00)	2.59	R3	52.5
48	367.25*	18,410	55.00	(40.00)	2.61	R3	52.9
49	367.26*	38,300	55.00	(40.00)	2.60	R3	53.0
50	369*	3,524	40.00	(10.00)	2.68	R2.5	37.9

WASHINGTON STATE - DEPRECIATION, DEPLETION, AND AMORTIZATION OF GAS PLANT (Cont.

Factors Used in Estimating Depreciation Charges

Line Number	Account Number (a)	Depreciable Plant Base (Thousands) (b)	Estimated Average Service Life (c)	Net Salvage (percent) (d)	Applied Depreciation Rates (percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
51	374.2*	1,593	65.00	0.00	7.50	R3	11.6
52	375*	80	30.00	0.00	0.44	R1	19.5
53	376.11*	425,097	60.00	(60.00)	2.51	R2.5	46.9
54	376.12*	333,875	60.00	(50.00)	2.42	R2.5	48.7
55	376.21*	466	40.00	(60.00)	0.73	R0.5	32.9
56	376.22*	2,929	40.00	(65.00)	0.77	R0.5	32.2
57	377*	818	35.00	0.00	2.33	S2	32.5
58	378*	15,304	50.00	(20.00)	2.12	R2	39.6
59	379*	1,498	35.00	(20.00)	4.34	R2	15.3
60	380*	501,366	49.00	(60.00)	2.71	R0.5	42.5
61	381*	45,705	40.00	1.00	2.31	R2.5	29.6
62	381.1*	507	15.00	0.00	20.00	R3	0.0
63	381.2**	1,552	15.00	0.00	6.60	-	0.0
64	382*	68,668	38.00	(2.00)	2.47	R2.5	27.8
65	382.1*	398	15.00	(2.00)	0.05	R3	13.6
66	382.2**	333	15.00	0.00	6.60	-	0.0
67	383*	166	35.00	0.00	2.92	S2	34.2
68	387.1*	139	25.00	0.00	0.55	S2	18.7
69	387.2*	96	20.00	0.00	0.00	S1	0.0
70	387.3*	73	20.00	0.00	0.00	S4	0.0
71	390*	20,204	50.00	(5.00)	1.97	R2.5	37.4
72	390.1***	20,942	19.00	0.00	5.25	-	0.0
73	391.1*	8,107	20.00	0.00	7.97	SQ	8.1
74	391.2*	7,431	5.00	0.00	16.62	SQ	2.6
75	391.3*	939	5.00	0.00	-	SQ	0.0
76	391.4*	1,388	7.00	0.00	20.00	SQ	1.0
77	392*	23,107	12.00	15.00	5.04	L1.5	8.2
78	393*	119	25.00	0.00	1.10	SQ	2.8
79	394*	11,882	25.00	0.00	6.99	SQ	11.3
80	395*	68	20.00	0.00	3.65	SQ	6.7
81	396*	6,059	15.00	15.00	2.00	S0.5	13.9
82	397*	31	15.00	0.00	7.41	SQ	13.5
83	397.1*	1,053	10.00	0.00	0.68	SQ	8.0
84	397.2*	1,760	15.00	0.00	4.28	SQ	10.5
85	397.3*	2,961	15.00	0.00	0.07	SQ	14.5
86	397.4*	1,786	15.00	0.00	1.04	SQ	13.6
87	397.5*	1,810	10.00	0.00	16.25	SQ	1.7
88	398.1*	79	15.00	0.00	0.00	SQ	0.0
89	398.2*	53	15.00	0.00	0.00	SQ	0.0
90	398.3*	15	20.00	0.00	0.00	SQ	0.0
91	398.4*	10	20.00	0.00	5.94	SQ	1.0
92	398.5*	67	20.00	0.00	0.81	SQ	7.0

* Depreciable balance through 2005.
** Depreciable balance through 2008.
*** Depreciable balance through 2013.

(Next page is 261)

Name of Respondent Northwest Natural Gas Company	This Report is: X An Original A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 2015

Washington State - Reconciliation of Reported Net Income with Taxable Income for Federal Income Taxes

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

Line No.	Details (a)	Amount (b)
1	Net Income for the Year (Page 116)	
2	Reconciling items for the year	
3		
4	Taxable Income Not Reported on Books	
5	Contributions in Aid of Construction	
6	Revenue & Cost Adjustments	
7		
8	TOTAL	
9	Deductions Recorded on Books Not Deducted for Return	
10	Federal Tax Provision	
11	State Tax Provision	
12	Other	
13	TOTAL	
14	Income Recorded on Books not Included in Return	
15	Company Owned Life Insurance	
16		
17		
18	TOTAL	
19	Deductions Recorded on Books Not Charged Against Book Income	
20	State Tax Current	
21	Tax Depreciation in Excess of Book Depreciation	
22	Removal Costs	
23	Property Taxes	
24	Pension Costs	
25	Other	
26	TOTAL	
27	Federal Tax Net Income	
28	Show Computation of Tax:	
29	Federal Income Tax at Statutory Rate	
30	Less: Federal Tax Credits	
31	Federal Tax Provision - 2006 Earnings	
32	Less: Deferred taxes	
33	Less: Deferred Investment Tax Credits	
34	Plus: Prior Year Accrual Adjustment	
35	Total Federal Tax Provision	
	SEE FERC ANNUAL REPORT PAGE 261	

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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

WASHINGTON STATE - ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 282

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to property not subject to accelerated amortization.
2. For Other, include deferrals relating to other income and deductions.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric			
3	Gas			
4	Other			
4.01				
4.02				
4.03				
4.04				
4.05				
5	Total (Enter Total of Lines 2 Thru 4.05)			
6	Other (Specify)			
6.01				
6.02				
6.03				
6.04				
6.05				
7	TOTAL (Acct 282) (Total of lines 5 thru 6.05)			
8	Classification of TOTAL			
9	Federal Income Tax			
10	State Income Tax			
11	Local Income Tax			

SEE FERC ANNUAL REPORT PAGES 274-275

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

WASHINGTON STATE - ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 282)

3. Add rows as necessary to report all data. When rows are added, the additional row numbers should follow in sequence, 4.01, 4.02 and 6.01, 6.02, etc. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Acct. No.	Amount	Acct. No.	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
							3
							4
							4.01
							4.02
							4.03
							4.04
							4.05
							5
							6
							6.01
							6.02
							6.03
							6.04
							6.05
							7
							8
							9
							10
							11

SEE FERC ANNUAL REPORT PAGES 274-275

Name of Respondent Northwest Natural Gas Company	This Report is: X An Original A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 2015

WASHINGTON STATE - ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283

1. Report the information called for below concerning respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For Other (Specify), included deferrals related to other

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Gas			
3.01	Deferred Income Taxes - FAS 109			
3.02	Revenues & Cost of Gas Adjustments			
3.03	Deferred Depreciation - Federal			
3.04	Deferred Income Taxes - Other			
3.05	Deferred Depreciation - State			
4	Other - Reclassification between Utility & Non-utility			
5	Total (Total of Lines 2 Thru 4)			
6	Other (Specify) Non - Utility			
6.01	Other Comprehensive Income - Federal			
6.02	Other Comprehensive Income - State			
7	TOTAL (Acct 283) (Total of lines 5 thru 6.)			
8	Classification of TOTAL			
9	Federal Income Tax			
10	State Income Tax			
11	Local Income Tax			

SEE FERC ANNUAL REPORT PAGES 276-277

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

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

income and deductions.
3. Provide in the space below explanations for page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Acct. No.	Amount	Acct. No.	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
							3
							3.01
							3.02
							3.03
							3.04
							3.05
							4
							5
							6
							6.01
							6.02
							7
							8
							9
							10
							11

SEE FERC ANNUAL REPORT PAGES 276-277

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Name of Respondent	This Report is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

WASHINGTON STATE - GAS OPERATING REVENUES (Account 400)

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

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

Name of Respondent Northwest Natural Gas Company	This Report Is: X An Original A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 2015

WASHINGTON STATE - GAS OPERATING REVENUES (Continued)

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

OTHER REVENUES		TOTAL OPERATING REVENUES		DEKATHERM OF NATURAL GAS		
Amount for Current Year (f)	Amount for Previous Year (g)	Amount for Current Year (h)	Amount for Previous Year (i)	Amount for Current Year (j)	Amount for Previous Year (k)	Line No.
$ 65,993,735	$ 72,158,667	$ 65,993,735	$ 72,158,667	6,263,293	6,814,061	1
-	-	-	-			2
94,295	104,427	94,295	104,427			3
112,168	131,658	112,168	131,658			4
-	-	-	-	-	-	5
-	-	-	-	-	-	6
2,051,574	1,892,887	2,051,574	1,892,887	1,920,021	1,869,759	7
-	-	-	-			8
-	-	-	-			9
-	-	-	-			10
-	-	-	-			11
20,003	18,160	20,003	18,160			12
-	-	-	-			13
(1,370,619)	(2,738,015)	(1,370,619)	(2,738,015)			14
66,901,156	71,567,784	66,901,156	71,567,784			15
-	-	-	-			16
$ 66,901,156	$ 71,567,784	$ 66,901,156	$ 71,567,784			17

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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
NORTHWEST NATURAL GAS COMPANY	X An Original A Resubmission		Dec. 31, 2015

WASHINGTON STATE - OTHER GAS REVENUES (ACCOUNT 495)

1. For transactions with annual revenues of $250,000 or more, describe, for each transaction, commissions on sales of distributions of gas of others, compensation for minor or incidental services provided for others, penalties, profit or loss on sales of material and supplies, sales of steam, water, or electricity, miscellaneous royalties, revenues from dehydration, other processing of gas of others, and gains on settlements of imbalance receivables. Separately report revenues from cash-out penalties.

Line No.	Description of Transaction (a)	Revenues (in dollars) (b)
1		
2	Washington Amortizations	$ (1,190,422)
3	Washington GREAT Program	(300,227)
4	Other Miscellaneous Items	120,030
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25	TOTAL	(1,370,619)

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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

WASHINGTON STATE - GAS OPERATION AND MAINTENANCE EXPENSES

1. Report operation and maintenance expenses. If the amount for previous year is not derived from previously reported figures, explain in footnotes.
2. Provide in footnotes the source of the index used to determine the price for gas supplied by shippers as reflected on line 74.

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

INFORMATION NOT AVAILABLE
SEE FERC ANNUAL REPORT PAGES 317-325

Name of Respondent Northwest Natural Gas Company	This Report is: X An Original A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 2015

WASHINGTON STATE - GAS OPERATION AND MAINTENANCE EXPENSES (Continued)

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

INFORMATION NOT AVAILABLE
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Name of Respondent Northwest Natural Gas Company	This Report is: X An Original A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 2015

WASHINGTON STATE - GAS OPERATION AND MAINTENANCE EXPENSES (Continued

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
59	C. Exploration and Development		
60	Operation		
61	795 Delay Rentals		
62	796 Nonproductive Well Drilling		
63	797 Abandoned Leases		
64	798 Other Exploration		
65	TOTAL Exploration and Development (Total of lines 61 thru 64)		
66	D. Other Gas Supply Expenses		
67	Operation		
68	800 Natural Gas Well Head Purchases		
69	800.1 Natural Gas Well Head Purchases, Intracompany Transfers		
70	801 Natural Gas Field Line Purchases		
71	802 Natural Gas Gasoline Plant Outlet Purchases		
72	803 Natural Gas Transmission Line Purchases		
73	804 Natural Gas City Gate Purchases		
74	804.1 Liquefied Natural Gas Purchases		
75	805 Other Gas Purchases		
76	805.1 Purchases Gas Cost Adjustments		
77	TOTAL Purchased Gas (Total of Lines 68 thru 76)		
78	806 Exchange Gas		
79	Purchased Gas Expense		
80	807.1 Well Expense-Purchased Gas		
81	807.2 Operation of Purchased Gas Measuring Stations		
82	807.3 Maintenance of Purchased Gas Measuring Stations		
83	807.4 Purchased Gas Calculations Expense		
84	807.5 Other Purchased Gas Expenses		
85	TOTAL Purchased Gas Expense (Total of lines 80 thru 84)		

INFORMATION NOT AVAILABLE
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Name of Respondent Northwest Natural Gas Company	This Report is: X An Original A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 2015

WASHINGTON STATE - GAS OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
86	808.1 Gas Withdrawn from Storage-Debit		
87	808.2 Gas Delivered to Storage-Credit		
88	809.1 Withdrawals of Liquefied Natural Gas for Processing-Debit		
89	809.2 Deliveries of Natural Gas for Processing-Credit		
90	Gas used in Utility Operation-Credit		
91	810 Gas Used for Compressor Station Fuel-Credit		
92	811 Gas Used for Products Extraction-Credit		
93	812 Gas Used for Other Utility Operations-Credit		
94	TOTAL Gas Used in Utility Operations-Credit (Total of lines 91 thru 93)		
95	813 Other Gas Supply Expenses		
96	TOTAL Other Gas Supply Exp. (Total of lines 77, 78, 85, 86 thru 89, 94, 95)		
97	TOTAL Production Expenses (Total of lines 3, 30, 58, 65, and 96)		
98	2. NATURAL GAS STORAGE, TERMINALING AND PROCESSING EXPENSES		
99	A. Underground Storage Expenses		
100	Operation		
101	814 Operation Supervision and Engineering		
102	815 Maps and Records		
103	816 Well Expenses		
104	817 Lines Expenses		
105	818 Compressor Station Fuel and Power		
106	819 Compressor Station Fuel and Power		
107	820 Measuring and Regulating Station Expenses		
108	821 Purification Expenses		
109	822 Exploration and Development		
110	823 Gas Losses		
111	824 Other Expenses		
112	825 Storage Well Royalties		
113	826 Rents		
114	TOTAL Operation (Total of lines of 101 thru 113)		

INFORMATION NOT AVAILABLE
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Name of Respondent Northwest Natural Gas Company	This Report is: X An Original A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 2015

WASHINGTON STATE - GAS OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
115	Maintenance		
116	830 Maintenance Supervision and Engineering		
117	831 Maintenance of Structures and Improvements		
118	832 Maintenance of Reservoirs and Wells		
119	833 Maintenance of Lines		
120	834 Maintenance of Compressor Station Equipment		
121	835 Maintenance of Measuring and Regulating Station Equipment		
122	836 Maintenance of Purification Equipment		
123	837 Maintenance of Other Equipment		
124	TOTAL Maintenance (Total of lines 116 thru 123)		
125	TOTAL Underground Storage Expenses (Total of lines 114 and 124)		
126	B. Other Storage Expenses		
127	Operation		
128	840 Operation supervision and Engineering		
129	841 Operation Labor and Expenses		
130	842 Rents		
131	842.1 Fuel		
132	842.2 Power		
133	842.3 Gas Losses		
134	TOTAL Operation (Total of lines 128 thru 133)		
135	Maintenance		
136	843.1 Maintenance Supervision and Engineering		
137	843.2 Maintenance of Structures and Improvements		
138	843.3 Maintenance of Gas Holders		
139	843.4 Maintenance of Purification Equipment		
140	843.5 Maintenance of Liquefaction Equipment		
141	843.6 Maintenance of Vaporizing Equipment		
142	843.7 Maintenance of Compressor Equipment		
143	843.8 Maintenance of Measuring and Regulating Equipment		
144	843.9 Maintenance of Other Equipment		
145	TOTAL Maintenance (Total of lines 136 thru 144)		
146	TOTAL Other Storage Expenses (Total of lines 134 and 145)		

INFORMATION NOT AVAILABLE
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Name of Respondent	This Report is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

WASHINGTON STATE - GAS OPERATION AND MAINTENANCE EXPENSES (Continued)

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

INFORMATION NOT AVAILABLE
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Name of Respondent Northwest Natural Gas Company	This Report is: X An Original A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 2015

WASHINGTON STATE - GAS OPERATION AND MAINTENANCE EXPENSES (Continued)

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

INFORMATION NOT AVAILABLE
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Name of Respondent Northwest Natural Gas Company	This Report is: X An Original A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 2015

WASHINGTON STATE - GAS OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
208	874 Mains and Services Expenses		
209	875 Measuring and Regulating Station Expenses-General		
210	876 Measuring and Regulating Station Expenses-Industrial		
211	877 Measuring and Regulating Station Expenses-City Gas Check Station		
212	878 Meter and House Regulator Expenses		
213	879 Customer Installations Expenses		
214	880 Other Expenses		
215	881 Rents		
216	TOTAL Operations (Total of lines 204 thru 215)		
217	Maintenance		
218	885 Maintenance Supervision and Engineering		
219	886 Maintenance of Structures and Improvements		
220	887 Maintenance of Mains		
221	888 Maintenance of Compressor Station Equipment		
222	889 Maintenance of Measuring & Regulating Station Equipment-General		
223	890 Maintenance of Meas. and Reg. Station Equipment-Industrial		
224	891 Maintenance of Meas & Reg Station Equip-City Gate Check Station		
225	892 Maintenance of Services		
226	893 Maintenance of Meters and House Regulators		
227	894 Maintenance of Other Equipment		
228	TOTAL Maintenance (Total of lines 218 thru 227)		
229	TOTAL Distribution Expenses (Total of lines 216 and 228)		
230	5. CUSTOMER ACCOUNTS EXPENSES		
231	Operation		
232	901 Supervision		
233	902 Meter Reading Expenses		
234	903 Customer Records and Collection Expenses		

INFORMATION NOT AVAILABLE
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Name of Respondent Northwest Natural Gas Company	This Report is: X An Original A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 2015

WASHINGTON STATE - GAS OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
235	904 Uncollectible Accounts		
236	905 Miscellaneous Customer Accounts Expenses		
237	TOTAL Customer Accounts Expenses (Total of lines 232 thru 236)		
238	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSE		
239	Operation		
240	907 Supervision		
241	908 Customer Assistance Expense		
242	909 Informational and Instructional Expenses		
243	910 Miscellaneous Customer Service and Informational Expenses		
244	TOTAL Customer Service & Information Expenses (Total of lines 240 thru 243)		
245	7. SALES EXPENSES		
246	Operation		
247	911 Supervision		
248	912 Demonstration and Selling Expenses		
249	913 Advertising Expenses		
250	916 Miscellaneous Sales Expenses		
251	TOTAL Sales Expenses (Total of lines 247 thru 250)		
252	8. ADMINISTRATIVE AND GENERAL EXPENSES		
253	Operation		
254	920 Administrative and General Salaries		
255	921 Office Supplies and Expenses		
256	922 Administrative Expenses Transferred - Credit		
257	923 Outside Services Employed		
258	924 Property Insurance		
259	925 Injuries and Damages		
260	926 Employee Pensions and Benefits		
261	927 Franchise Requirements		
262	928 Regulatory Commission Expenses		
263	929 Duplicate Charges - Credit		
264	930.1 General Advertising Expenses		
265	930.2 Miscellaneous General Expenses		
266	931 Rents		
267	TOTAL Operation (Total of lines 254 thru 266)		
268	Maintenance		
269	935 Maintenance of General Plant		
270	TOTAL Administrative and General Expenses (Total of lines 267 and 269)		
271	TOTAL Gas O & M Expenses (Total of lines 97,177,201,229,237,244,251,and 270)		

INFORMATION NOT AVAILABLE
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Name of Respondent	This Report Is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

Washington State - Gas Used in Utility Operations

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

Line No.	Purpose for Which Gas Was Used (a)	Account Charged (b)	Natural Gas: Gas Used (Dth) (c)	Natural Gas: Amount of Credit (in dollars) (d)	Manufactured Gas: Gas Used (Dth) (d)	Manufactured Gas: Amount of Credit (in dollars) (d)
1	810 Gas Used for Compressor Station Fuel - Credit					
2	811 Gas Used for Products Extraction - Credit					
3	Gas Shrinkage and Other Usage in Respondent's Own Processing					
4	Gas Shrinkage, etc. for Respondent's Gas Processed by Others					
5	812 Gas Used for Other Utility Operations - Credit (Report separately for each principal use. Group minor uses.)					
6						
7						
8						
9						
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12						
13						
14						
15	**NONE**					
16						
17						
18						
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44						
45	**Total**					

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Name of Respondent	This Report Is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

WASHINGTON STATE - MISCELLANEOUS GENERAL EXPENSE (Account 930.2)

1. Provide the information requested below on miscellaneous general expenses
2. For Other Expenses, show the (a) purpose, (b) recipient and (c) amount of such items. List separately amounts of $250,000 or more however, amounts less than $250,000 may be grouped if the number of items so grouped is shown.

Line No.	Description (a)	Amount (in dollars) (b)
1	Industry association dues	
2	Experimental and general research expenses	
	a. Gas Research Institute (GRI)	
	b. Other	
3	Publishing and distributing information and reports to stockholders; trustee, registrar, and transfer agent fees and expenses, and other expenses of servicing outstanding securities of the responden	
4	Other expenses	
5		
6	Director's Fees and Expenses	
7		
8	Corporate Information - Annual Report	
9		
10	Annual Meeting	
11		
12	Market Expansion	
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40	TOTAL	

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS
NW Natural

Period Beginning: Jan 2015
Period Ending: Dec 2015

Functional Class / FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve
UTILITY									
Intangible Plant									
301	ORGANIZATION	$0	$0	$0	$0	$0	$0	$0	$0
302	FRANCHISES & CONSENTS	0	0	0	0	0	0	0	0
303.1	COMPUTER SOFTWARE	3,144	0	0	0	0	0	0	3,144
303.2	CUSTOMER INFORMATION SYSTEM	1,863,073	0	0	0	0	0	0	1,863,073
303.3	INDUSTRIAL & COMMERCIAL BIL	0	0	0	0	0	0	0	0
303.4	CRMS	0	0	0	0	0	0	0	0
303.5	POWERPLANT SOFTWARE	0	0	0	0	0	0	0	0
	Intangible Plant Subtotal	1,866,216	0	0	0	0	0	0	1,866,216
Transmission Plant									
367	MAINS	83,895	20,734	0	0	0	0	0	104,629
	Transmission Plant Subtotal	83,895	20,734	0	0	0	0	0	104,629
Distribution Plant									
374.1	LAND	0	0	0	0	0	0	0	0
374.2	LAND RIGHTS	16,332	2,076	0	0	0	0	0	18,407
375	STRUCTURES & IMPROVEMENTS	30,845	0	0	0	0	0	0	30,845
376.11	MAINS < 4"	32,256,101	1,805,001	(22,029)	(71,194)	0	(1,618)	0	33,966,262
376.12	MAINS 4" & >	22,551,039	1,691,814	(105,881)	(291,128)	0	1,445	0	23,847,289
378	MEASURING & REG EQUIP - GENER	750,647	39,909	0	0	0	0	0	790,556
379	MEASURING & REG EQUIP - GATE	620,311	33,807	0	0	0	0	0	654,118
380	SERVICES	28,604,704	1,615,988	(51,883)	(194,241)	0	0	0	29,974,567
381	METERS	2,230,433	225,838	(39,955)	0	0	0	0	2,416,316
381.2	ERT (ENCODER RECEIVER TRANS	3,149,672	431,963	(71,268)	0	0	0	0	3,510,367
382	METER INSTALLATIONS	1,459,423	139,745	(324,717)	0	0	0	0	1,274,451
382.2	ERT INSTALLATION (ENCODER	498,272	63,231	(8,227)	0	0	0	0	553,276
383	HOUSE REGULATORS	5,873	1,045	0	0	0	0	0	6,917
386	OTHER PROPERTY ON CUSTOMERS P	0	0	0	0	0	0	0	0
387.2	CALORIMETERS @ GATE STATIONS	26,630	0	0	0	0	0	0	26,630
	Distribution Plant Subtotal	92,200,282	6,050,417	(623,961)	(556,563)	0	(173)	0	97,070,002

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS
NW Natural

Period Beginning: Jan 2015
Period Ending: Dec 2015

Functional Class / FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve
UTILITY									
General Plant									
389	LAND	0	0	0	0	0	0	0	0
390	STRUCTURES & IMPROVEMENTS	0	926	0	0	0	0	0	926
390.1	SOURCE CONTROL PLANT	24,806	35,021	0	0	0	0	0	59,827
391.1	OFFICE FURNITURE & EQUIPMEN	17,958	1,317	0	0	0	0	0	19,275
391.4	CUSTOMER INFORMATION SYSTEM	0	0	0	0	0	0	0	0
392	TRANSPORTATION EQUIPMENT	599,029	50,883	(68,546)	0	0	0	0	581,367
394	TOOLS AND EQUIPMENT	15,658	6,159	0	0	0	0	0	21,818
396	POWER OPERATED EQUIPMENT	139,054	7,048	(30,825)	0	0	0	0	115,277
397.3	TELEMETERING - OTHER	16,142	71	0	0	0	0	0	16,213
397.5	TELEPHONE EQUIPMENT	0	0	0	0	0	0	0	0
398.4	INSTALLED IN LEASED BUILDINGS	4,727	0	0	0	0	0	0	4,727
	General Plant Subtotal	817,375	101,424	(99,371)	0	0	0	0	819,429
	Washington Utility Property Grand Total	$94,967,768	$6,172,575	($723,332)	($556,563)	$0	($173)	$0	$99,860,276

TOTAL SUMMARY WASHINGTON UTILITY DEPRECIATION RESERVES 12/31/2015

WASHINGTON		
108010	($984,240)	
108011	70,838,449	
108012	569,064	
108013	(12,303)	
108014	-	
108015	115,277	
108100	-	
108102	29,334,029	
SUBTOTAL		$99,860,276
ADD:		
108001 REMOVAL WORK IN PROCESS		(1,111,729)
TOTAL WASHINGTON UTILITY DEPRECIATION		$98,748,547

Name of Respondent	This Report is:	Date of Report	Year of Report
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WASHINGTON STATE - DEPRECIATION, DEPLETION, AND AMORTIZATION OF GAS PLANT (Accts 403, 404.1, 404.2, 404.3, 405)

(Except Amortization of Acquisition Adjustments) (continued)

4. Add rows as necessary to completely report all data. Number the additionalrows in sequence as 2.10, 3.10, 3.02, etc.

Section B. Factors Used in Estimating Depreciation Charges

Line No.	Functional Classification (a)	Plant Bases (In thousands) (b)	Applied Depreciation or Amortization Rates (percent) (c)
1			
2			
2.01			
2.02			
2.03			
3			
3.01			
3.02			
3.03			
3.04			
4			
4.01			
4.02			
4.03			
5			
6			
6.01			
6.02			
6.03			
7			
7.01			
7.02			
7.03			
7.04			
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8.01			
8.02			
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NONE

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Name of Respondent	This Report Is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

WASHINGTON STATE - PARTICULARS CONCERNING CERTAIN INCOME DEDUCTIONS AND INTEREST CHARGES ACCOUNTS

Report the information specified below, in the order given, for the respective income deduction and interest charges accounts.

(a) **Miscellaneous Amortization** (Account 425) - Describe the nature of items included in this account, the contra account charged, the total of amortization charges for the year, and the period of amortization.

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

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

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

Line No.	Item (a)	Amount (b)
1	Account 425 Miscellaneous Amortization	
2	Account 426.1 Donations	
3	Account 426.2 Insurance Benefits	
4	Account 426.3 Penalties - Internal Revenue	
5	Account 426.4 Civic, Political and Related Activities (426.31-426.33 & 426.41-426.45)	
6	Account 426.5 Other Deductions (426.05, 426.50-426.52)	
7	Account 426.6 Diversification (426.60)	
8		
9	Total Account 425 & 426	
10		
11	Account 430 Interest on Debt to Associated Companies	
12	Account 431 Other Interest Expense	
13	Notes Payable (431.1)	
14	Miscellaneous (431.2-431.5)	
15		
16	Total Account 430 & 431	
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Name of Respondent	This Report Is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

WASHINGTON STATE - REGULATORY COMMISSION EXPENSES (Account 928)

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

Line No.	Description (Furnish name of regulatory commission or body, the docket or case number, and a description of the case.) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expenses to Date (d)	Deferred in Account 186 at Beginning of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					

SEE FERC ANNUAL REPORT PAGES 350-351

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

WASHINGTON STATE - REGULATORY COMMISSION EXPENSES (Continued)

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

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CHARGED CURRENTLY TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 186 (i)	Contra Account (j)	Amount (k)	Deferred in Account 186, End of Year (l)	Line No.
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used. When reporting detail of other accounts, enter as many rows as necessary numbered sequentially starting with 74.01, 74.02, etc.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production			
4	Transmission			
5	Distribution			
6	Customer Accounts			
7	Customer Service and Informational			
8	Sales			
9	Administrative and General			
10	TOTAL Operation (Total of lines 3 thru 9)			
11	Maintenance			
12	Production			
13	Transmission			
14	Distribution			
15	Administrative and General			
16	TOTAL Maint. (Total of lines 12 thru 15)			
17	Total Operation and Maintenance			
18	Production (Total of lines 3 and 12)			
19	Transmission (Total of lines 4 and 13)			
20	Distribution (Total of lines 5 and 14)			
21	Customer Accounts (Line 6)			
22	Customer Service and Informational (Line 7)			
23	Sales (Line 8)			
24	Administrative and General (Total of lines 9 and 15)			
25	TOTAL Oper. and Maint. (Total of lines 18 thru 24)			
26	Gas			
27	Operation			
28	Production - Manufactured Gas			
29	Production - Nat. Gas (Including Expl. and Dev.)			
30	Other Gas Supply			
31	Storage, LNG Terminaling and Processing			
32	Transmission			
33	Distribution			
34	Customer Accounts			
35	Customer Service and Informational			
36	Sales			
37	Administrative and General			
38	TOTAL Operation (Total of lines 28 thru 37)			
39	Maintenance			
40	Production - Manufactured Gas			
41	Production - Natural Gas			
42	Other Gas Supply			
43	Storage, LNG Terminaling and Processing			
44	Transmission			
45	Distribution			
46	Administrative and General			

SEE FERC ANNUAL REPORT PAGE 354

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

WASHINGTON STATE - DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
47				
48	Gas (Continued)			
49	Total Operation and Maintenance			
50	Production - Manufactured Gas (Lines 28 and 40)			
51	Production - Nat. Gas (Including Expl. and Dev.) (Lines 29 and 41)			
52	Other Gas Supply (Lines 30 and 42)			
53	Storage, LNG Terminaling and Processing (Lines 31 and 43)			
54	Transmission (Total of lines 32 and 44)			
55	Distribution (Total of lines 33 and 45)			
56	Customer Accounts (Total of line 34)			
57	Customer Service and Informational (Total of line 35)			
58	Sales (Total of line 36)			
59	Administrative and General (Total of lines 37 and 46)			
60	Other Utility Departments			
61	Operation and Maintenance			
62	TOTAL All Utility Dept. (Total of lines 50 thru 61)			
63	Utility Plant			
64	Construction (By Utility Departments)			
65	Electric Plant			
66	Gas Plant			
67	Other			
68	TOTAL Construction (Total of lines 65 thru 67)			
69	Plant Removal (By Utility Departments)			
70	Electric Plant			
71	Gas Plant			
72	Other			
73	TOTAL Plant Removal (Total of lines 70 thru 72)			
74	Other Accounts (Specify):			
74.01	Merchandising			
74.02	Governmental			
74.03	NNG Financial Corporation			
74.04	Non Utility Construction Work in Progess 121107			
74.05	Construction Claims			
74.06	Storage Business			
74.07	Accounts Receivable			
74.08				
74.09				
74.10				
74.11				
74.12				
74.13				
74.14				
74.15				
75				
76	TOTAL Other Accounts			
77	TOTAL SALARIES AND WAGES			

SEE FERC ANNUAL REPORT PAGE 355

(Next Page is 357)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

WASHINGTON STATE - CHARGES FOR OUTSIDE PROFESSIONAL AND OTHER CONSULTATIVE SERVICES

1. Report the information specified below for all charges made during the year included in any account (including plant accounts) for outside consultative and other professional services. These services include rate, management, construction, engineering, research, financial, valuation, legal, accounting, purchasing, advertising, labor relations, and public relations, rendered for the respondent under written or oral arrangement, for which aggregate payments were made during the year to any corporation, partnership, organization of any kind, or individual (other than for services as an employee or for payments made for medical and related services) amounting to more than $250,000, including payments for legislative services, except those which should be reported in Account 426.4 Expenditures for Certain Civic, Political and Related Activities.
   (a) Name of person or organization rendering services.
   (c) Total charges for the year.
2. Designate associated companies with an asterisk in column (b).

Line No.	Description (a)	* (b)	Amount (in dollars) (c)
1			
2			
3			
4			
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39			

SEE FERC ANNUAL REPORT PAGE 357

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Name of Respondent Northwest Natural Gas Company	This Report is: X An Original A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 2015

WASHINGTON STATE - COMPRESSOR STATIONS

1. Report below details concerning compressor stations. Use the following subheading; field compressor stations, products extraction compressor stations, underground storage compressor stations, transmission compressor stations, distribution compressor stations, and other compressor stations.
2. For column (a), indicate the production areas where such stations are used. Group relatively small field compressor stations by production areas. Show the number of stations grouped. Identify any station held under a title other than full ownership. State in a footnote the name of owner or co-owner, the nature of respondent's title, and percent of ownership if jointly owned

Line No.	Name of station and location (a)	Number of Units at Station (b)	Certified Horsepower for Each Station (c)	Plant Cost (d)
1				
2				
3	**NONE**			
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
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24				
25				

Name of Respondent Northwest Natural Gas Company	This Report is: X An Original A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 2015

COMPRESSOR STATION

Designate any station that was not operated during the past year. Station in a footnote whether the book cost of such station has been retired in the books of account, or what disposition of the station and its book cost are contemplated. Designate any compressor units in transmission, compressor stations installed and put into operation during the year, and show in a footnote each unit's size and date the unit unit was placed in operation. For Column (e), include the type of fuel or power, in other than natural gas. If two types of fuel or power are used, show separate entries for natural gas and the other fuel or power.

Line No.	Expenses (Except depreciation and taxes)		Operation Data			
	Fuel or Power (e)	Other (f)	Gas for Compressor Fuel in Dth (g)	Total Compressor Hours of Operation During the Year (h)	Number of Compressors Operated at Time of Station Peak (i)	Date of Station Peak (j)
1						
2						
3	**NONE**					
4						
5						
6						
7						
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9						
10						
11						
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TRANSMISSION MAINS
SHOW PARTICULARS CALLED FOR CONCERNING TRANSMISSION MAINS *
WASHINGTON SUPPLEMENT

SYSTEM

LINE NUMBER	KIND OF MATERIAL (A)	DIAMETER OF PIPE, INCHES (B)	TOTAL LENGTH IN USE BEGINNING OF YEAR, FEET (C)	LAID DURING YEAR, FEET (D)	TAKEN UP OR ABANDONED DURING YEAR, FEET (E)	TOTAL IN USE END OF YEAR, FEET (F)
1	High Pressure	4"	12,842	171		13,013
2	High Pressure	6"	373,475		944	372,531
3	High Pressure	8"	306,956		296	306,660
4	High Pressure	10"	499,181		260	498,921
5	High Pressure	12"	1,160,732	3,546		1,164,278
6	High Pressure	16"	558,396		87	558,309
7	High Pressure	20"	71,725	6		71,731
8	High Pressure	24"	464,750		10	464,740
9						
10						
11						
12						
13						
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15						
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20						
21						
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27						
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31						
32						
33						
34						
	TOTALS		3,448,057	3,723	1,597	3,450,183

* Show separately and identify lines held under a title other than full ownership.

TRANSMISSION MAINS
SHOW PARTICULARS CALLED FOR CONCERNING TRANSMISSION MAINS *
WASHINGTON SUPPLEMENT

WASHINGTON

LINE NUMBER	KIND OF MATERIAL (A)	DIAMETER OF PIPE, INCHES (B)	TOTAL LENGTH IN USE BEGINNING OF YEAR, FEET (C)	LAID DURING YEAR, FEET (D)	TAKEN UP OR ABANDONED DURING YEAR, FEET (E)	TOTAL IN USE END OF YEAR, FEET (F)
1	High Pressure	4"	5	0	0	5
2	High Pressure	6"	100	0	0	100
3	High Pressure	8"	17,938	0	0	17,938
4						
5						
6						
7						
8						
9						
10						
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24						
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33						
34						
	TOTALS		18,043	0	0	18,043

* Show separately and identify lines held under a title other than full ownership.

DISTRIBUTION MAINS
SHOW PARTICULARS CALLED FOR CONCERNING DISTRIBUTION MAINS
WASHINGTON SUPPLEMENT

SYSTEM

LINE NUMBER	KIND OF MATERIAL (A)	DIAMETER OF PIPE, INCHES (B)	TOTAL LENGTH IN USE BEGINNING OF YEAR, FEET (C)	LAID DURING YEAR, FEET (D)	TAKEN UP OR ABANDONED DURING YEAR, FEET (E)	TOTAL IN USE END OF YEAR, FEET (F)
1	Low Pressure	2"	0			0
2	Low Pressure	3"	0			0
3	Low Pressure	4"	0			0
4	Low Pressure	6"	0			0
5	Low Pressure	Over 6"	0			0
6	High Pressure	Under 2"	18,524,646	16,330	20,720	18,520,256
7	High Pressure	2"	38,377,465	445,551	33,128	38,789,888
8	High Pressure	3"	160,222	46	0	160,268
9	High Pressure	4"	9,849,606	48,094	23,884	9,873,816
10	High Pressure	6"	2,886,617	25,931	7,245	2,905,303
11	High Pressure	Over 6"	1,483,062	12,282	2,170	1,493,174
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
	TOTALS		71,281,618	548,234	87,147	71,742,705

DISTRIBUTION MAINS
SHOW PARTICULARS CALLED FOR CONCERNING DISTRIBUTION MAINS
WASHINGTON SUPPLEMENT

WASHINGTON

LINE NUMBER	KIND OF MATERIAL (A)	DIAMETER OF PIPE, INCHES (B)	TOTAL LENGTH IN USE BEGINNING OF YEAR, FEET (C)	LAID DURING YEAR, FEET (D)	TAKEN UP OR ABANDONED DURING YEAR, FEET (E)	TOTAL IN USE END OF YEAR, FEET (F)
1	High Pressure	Under 2"	1,013,704	3,013	2,008	1,014,709
2	High Pressure	2"	6,163,797	102,416	2,881	6,263,332
3	High Pressure	3"	44,302	14	0	44,316
4	High Pressure	4"	1,432,063	12,921	1,917	1,443,067
5	High Pressure	6"	422,197	2,049	10	424,236
6	High Pressure	Over 6"	142,164	11,984	200	153,948
7						
8						
9						
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31						
32						
33						
34						
	TOTALS		9,218,227	132,397	7,016	9,343,608

SERVICE PIPES - GAS
SHOW PARTICULARS CALLED FOR CONCERNING THE LINE SERVICE PIPE
WASHINGTON SUPPLEMENT

SYSTEM

LINE NUMBER	KIND OF MATERIAL (A)	DIAMETER OF PIPE, INCHES (B)	NUMBER AT BEGINNING OF YEAR (C)	NUMBER ADDED DURING YEAR (D)	NUMBER REMOVED OR ABANDONED DURING YEAR (E)	NUMBER AT CLOSE OF YEAR (F)	AVERAGE LENGTH IN FEET (G)
1	HP, LP	Under 1"	641,313	7,191	1,722	646,782	-
2	HP, LP	1"	54,487	1,219	205	55,501	-
3	HP, LP	1 1/4"	5,240	0	11	5,229	-
4	HP, LP	2"	4,262	35	47	4,250	-
5	HP, LP	3"	49	0	0	49	-
6	HP, LP	4"	468	3	12	459	-
7	HP, LP	6"	16	0	3	13	-
8	HP, LP	Over 6"	13	0	1	12	-
9							
10							
11							
12							
13							
14							
15							
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32							
33							
34							
	TOTALS		705,848	8,448	2,001	712,295	

SERVICE PIPES - GAS
SHOW PARTICULARS CALLED FOR CONCERNING THE LINE SERVICE PIPE
WASHINGTON SUPPLEMENT

WASHINGTON

LINE NUMBER	KIND OF MATERIAL (A)	DIAMETER OF PIPE, INCHES (B)	NUMBER AT BEGINNING OF YEAR (C)	NUMBER ADDED DURING YEAR (D)	NUMBER REMOVED OR ABANDONED DURING YEAR (E)	NUMBER AT CLOSE OF YEAR (F)	AVERAGE LENGTH IN FEET (G)
1	HP	Under 1"	63,255	1,360	50	64,565	-
2	HP	1"	5,233	265	20	5,478	-
3	HP	1 1/4"	10	0	1	9	-
4	HP	2"	256	2	2	256	-
5	HP	4"	26	0	0	26	-
6	HP, LP	6"	8	0	0	8	-
7	HP, LP	Over 6"	0	0	0	0	-
8							
9							
10							
11							
12							
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33							
34							
	TOTALS		68,788	1,627	73	70,342	

NORTHWEST NATURAL GAS COMPANY
CUSTOMER METERS
SYSTEM 2015

Perf. #	Size	Type	Make	Capacity Cubic Ft.	In Service Begin. of Year	Add.	Retire-ments	In Service End of Year
0	Various	Orifice	Daniel	Various	372			372
2	RWR3	Rotary	Rockwell	3,000	1			1
7	RM5M	Rotary	Romet	5,000	1			1
9	RM11	Rotary	Romet	11,000	2			2
10	A5BT	Diaphragm	American	175	8			8
13	RS8C	Rotary	Roots	800	30			30
20	10BT	Diaphragm	American	250	1			1
22	1.5M	Rotary	Roots	1,500	12			12
23	1.5M TC	Rotary	Roots	1,500	17		2	15
24	1.5M ID	Rotary	Roots	1,500	51	1	1	51
26	R2M9	Rotary	Roots	2,000	1			1
32	3M125	Rotary	Roots	3,000	14			14
33	RS3M TC	Rotary	Roots	3,000	7			7
34	RS3M ID	Rotary	Roots	3,000	20		1	19
35	RS3M TC ID	Rotary	Roots	3,000	60			60
36	R3.7	Rotary	Roots	3,600	2			2
42	5M125	Rotary	Roots	5,000	10	1		11
43	RS5M TC	Rotary	Roots	5,000	20		1	19
44	RS5M ID	Rotary	Roots	5,000	66		2	64
52	7M125	Rotary	Roots	7,000	8			8
53	RS7M TC	Rotary	Roots	7,000	27		1	26
54	RS7M ID	Rotary	Roots	7,000	34		1	33
64	RS11 ID	Rotary	Roots	11,000	65		2	63
65	RS11 TC ID	Rotary	Roots	11,000	1			1
73	RS16 ID	Rotary	Roots	16,000	7			7
83	RS23 ID	Rotary	Roots	23,000	25			25
93	RS38 ID	Rotary	Roots	38,000	17			17
95	RS56 ID	Rotary	Roots	56,000	3			3
120	R175	Diaphragm	Rockwell	175	52,535	3	757	51,781
125	R200	Diaphragm	Rockwell	200	21,071	2	254	20,819
130	A175	Diaphragm	American	175	84,833	7	1,364	83,476
140	S175	Diaphragm	Sprague	175	23,407	2	389	23,020
260	Misc.	Various	Various	Various	0		1	(1)
270	1000A	Diaphragm	Schlemberger	1,000	168	1	13	156
272	1000A	Diaphragm	Actaris	1,000	22			22
300	1600 ID	Diaphragm	Rockwell	800	3		1	2
305	1600 TC ID	Diaphragm	Rockwell	800	7		1	6
310	RW3M ID	Diaphragm	Rockwell	1,450	48			48
315	RW3M TC ID	Diaphragm	Rockwell	1,450	29		1	28
320	RW5M ID	Diaphragm	Rockwell	2,500	35		2	33
325	RW5M TC ID	Diaphragm	Rockwell	2,500	45			45
390	1400 ID	Diaphragm	American	1,400	157		9	148
395	1400 TC ID	Diaphragm	American	1,400	6			6
400	2300 ID	Diaphragm	American	2,300	127		3	124
410	AL5M	Diaphragm	American	5,000	63	1	1	63
411	DU5M	Diaphragm	American	5,000	1			1
415	AL5M	Diaphragm	American	5,000	9			9
450	400A	Diaphragm	Schlemberger	400	1,448	1	47	1,402
452	400A	Diaphragm	Actaris	400	663		26	637
470	A425	Diaphragm	American	425	2,247	2	59	2,190
471	AL425	Diaphragm	American	425	2,758	1	66	2,693
472	A425	Diaphragm	American	425	2,680	1	86	2,595
475	AL-630	Diaphragm	American	630	10,528	1,329	168	11,689
480	A800 ID	Diaphragm	American	800	783		86	697
485	A800 TC ID	Diaphragm	American	800	845	1	55	791
486	A800	Diaphragm	American	800	7		1	6
490	S305	Diaphragm	Sprague	305	4			4
500	AL1M ID	Diaphragm	American	1,000	403		26	377
502	AL 1000	Diaphragm	American	1,000	339		53	286
505	AL1M TC ID	Diaphragm	American	1,000	490		4	486
507	AL 1000	Diaphragm	American	1,000	4,532	390	104	4,818
510	R310	Diaphragm	Rockwell	310	3,293	3	175	3,121
515	R315	Diaphragm	Rockwell	315	157		5	152
520	R415	Diaphragm	Rockwell	415	4,057	2	140	3,919
530	RW1M ID	Diaphragm	Rockwell	1,000	13		1	12
535	RW1M TC ID	Diaphragm	Rockwell	1,000	9			9

NORTHWEST NATURAL GAS COMPANY
CUSTOMER METERS
SYSTEM 2015

Perf. #	Size	Type	Make	Capacity Cubic Ft.	In Service Begin. of Year	Add.	Retire-ments	In Service End of Year
540	R750 ID	Diaphragm	Rockwell	750	486		91	395
545	R750 TC ID	Diaphragm	Rockwell	750	60		2	58
555	A310	Diaphragm	American	310	1,258	3	105	1,156
560	A250	Diaphragm	American	250	146,913	14	2,380	144,547
561	AC250	Diaphragm	American	250	150,431	18,151	3,465	165,117
565	RX250	Diaphragm	American	250	1,128		1	1,127
570	R275	Diaphragm	Rockwell	275	102,601	3	457	102,147
572	275	Diaphragm	Invensys	275	49,069	7	279	48,797
575	G2	Diaphragm	Westinghouse	200	18			18
580	SPRM	D+Reg	Sprague	175	485			485
585	S250	Diaphragm	Sprague	250	26,768	2	163	26,607
590	S250	Diaphragm	Lancaster	250	22,586	3	202	22,387
595	METRIS 250	Diaphragm	Schlemberger	250	11,815		175	11,640
613	8C	Rotary	Roots	800	44			44
616	8C175TQM	Rotary	Roots	800	29			29
617	8C175TQM	Rotary	Dresser/Roots	800	62	3		65
620	1M1480B3-HPC	Rotary	Dresser/Roots	1,000	4			4
621	1M300TQM-CD	Rotary	Dresser/Roots	1,000	1			1
622	1.5M	Rotary	Roots	1,500	218		12	206
623	1.5M	Rotary	Roots	1,500	23		1	22
625	15C175TQM	Rotary	Dresser/Roots	1,500	240	2	1	241
626	15CTQM	Rotary	Roots	1,500	604	7	3	608
632	3M	Rotary	Roots	3,000	363	6	3	366
633	RS3M	Rotary	Roots	3,000	137		2	135
636	5M175TQM	Rotary	Roots	3,000	1,079	19		1,098
637	3M175TQM	Rotary	Dresser/Roots	3,000	687	8		695
638	3M1480B3-HPC	Rotary	Dresser/Roots	3,000	4			4
642	5M	Rotary	Roots	5,000	245	12	3	254
643	RS5M TC	Rotary	Roots	5,000	129		4	125
644	5M175	Rotary	Roots	5,000	14			14
645	5M125	Rotary	Roots	5,000	2			2
646	5M175TQM	Rotary	Roots	5,000	718	17	6	729
647	5M175TQM	Rotary	Dresser/Roots	5,000	394	14	2	406
652	7M	Rotary	Roots	7,000	133	1	1	133
653	RS7M	Rotary	Roots	7,000	59			59
654	7M175	Rotary	Roots	7,000	34			34
655	7M175TQM	Rotary	Dresser/Roots	7,000	163	2		165
656	7M175TQM	Rotary	Roots	7,000	257	5		262
657	7M175TQM	Rotary	Roots	7,000	90	1		91
662	11M	Rotary	Roots	11,000	8			8
663	RS11	Rotary	Roots	11,000	44			44
664	RS11 ID	Rotary	Roots	11,000	41		1	40
665	RS11	Rotary	Roots	11,000	16			16
666	11M175TQM	Rotary	Roots	11,000	359	5	1	363
667	11M175TQM	Rotary	Roots	11,000	5			5
668	11M175TQM	Rotary	Dresser/Roots	11,000	1			1
672	16M	Rotary	Roots	16,000	2	1		3
673	16M175	Rotary	Roots	16,000	52			52
674	RS16 TC ID	Rotary	Roots	16,000	20			20
675	RS16 TC	Rotary	Roots	16,000	45			45
676	16M175TQM	Rotary	Roots	16,000	204	3		207
686	23M125TQM	Rotary	Roots	23,000	15	1		16
690	23M232TQM	Rotary	Dresser/Roots	23,000	44		2	42
696	38M125TQM	Rotary	Roots	23,000	24	2		26
698	56M175TQM	Rotary	Dresser/Roots	56,000	1			1
702	RT18	Turbine	Rockwell	38,000	1			1
703	RT18	Turbine	Rockwell	18,000	31			31
708	RT60	Turbine	Rockwell	30,000	18			18
709	RT60	Turbine	Rockwell	60,000	5			5
711	T140	Turbine	Rockwell	60,000	1			1
713	T140	Turbine	Rockwell	60,000	1			1
714	T140	Turbine	Rockwell	140,000	0			0
731	A4GT	Turbine	American	18,000	1			1
732	A6GT	Turbine	American	30,000	1			1
734	A8GT	Turbine	American	60,000	1			1

NORTHWEST NATURAL GAS COMPANY
CUSTOMER METERS
SYSTEM 2015

Perf. #	Size	Type	Make	Capacity Cubic Ft.	In Service Begin. of Year	Add.	Retire-ments	In Service End of Year
736	12GT	Turbine	American	150,000	2			2
751	AAT-18	Turbine	Invensys	18,000	2			2
756	AAT-27	Turbine	Invensys	27,000	1			1
760	AAT-35/45	Turbine	Sensus	35,000	2			2
766	AAT-57	Turbine	Invensys	57,000	3			3
770	AAT-60/45	Turbine	Sensus	60,000	1			1
771	AAT-60	Turbine	Invensys	60,000	1			1
776	AAT-90	Turbine	Invensys	90,000	2			2
791	AAT-140/45	Turbine	Sensus	140,000	2			2
792	AAT-140/45	Turbine	Sensus	140,000	2			2
803	3M125e	Rotary	Dresser/Roots	3,000	9	2		11
804	5M125e	Rotary	Dresser/Roots	5,000	8	2		10
805	7M125e	Rotary	Dresser/Roots	7,000	4			4
806	11M125e	Rotary	Dresser/Roots	11,000	4		1	3
813	3M175e	Rotary	Dresser/Roots	3,000	25	4	1	28
814	5M175e	Rotary	Dresser/Roots	5,000	12	6		18
815	7M175e	Rotary	Dresser/Roots	7,000	12	3		15
816	11M175e	Rotary	Dresser/Roots	11,000	6	1		7
817	16M175e	Rotary	Dresser/Roots	16,000	1	1	1	1
821	8c175TQMe	Rotary	Dresser/Roots	800	0	1		1
822	15c175TQMe	Rotary	Dresser/Roots	1,500	105	33	1	137
823	3M175TQMe	Rotary	Dresser/Roots	3,000	211	72		283
824	5M175TQMe	Rotary	Dresser/Roots	5,000	113	22		135
825	7M175TQMe	Rotary	Dresser/Roots	7,000	90	42		132
826	11M175TQMe	Rotary	Dresser/Roots	11,000	91	23		114
827	16M175TQMe	Rotary	Dresser/Roots	16,000	30	7		37
830	38M175TQMe	Rotary	Dresser/Roots	38,000	1			1
901	TURB	Turbine	Unkown	0	1			1
904	SDIA	Diaphragm	Unkown	500	54,068			54,068
	TOTALS				793,805	20,259	11,276	802,788

NORTHWEST NATURAL GAS COMPANY
CUSTOMER METERS
WASHINGTON 2015

Perf. #	Size	Type	Make	Capacity Cubic Ft.	In Service Begin. of Year	Add.	Retire-ments	In Service End of Year
0	Various	Orifice	Daniel	Various	1			1
7	RM5M	Rotary	Romet	5,000	1			1
13	RS8C 125	Rotary	Roots	800	7			7
24	1.5M ID	Rotary	Roots	1,500	5			5
33	RS3M TC	Rotary	Roots	3,000	3			3
34	RS3M ID	Rotary	Roots	3,000	5			5
36	R3.7	Rotary	Roots	3,600	1			1
42	5M125	Rotary	Roots	5,000	1			1
43	RS5M TC	Rotary	Roots	5,000	1			1
44	RS5M ID	Rotary	Roots	5,000	6			6
52	7M125	Rotary	Roots	3,000	4			4
54	RS7M ID	Rotary	Roots	7,000	2			2
64	RS11 ID	Rotary	Roots	11,000	4			4
83	RS23 ID	Rotary	Roots	23,000	3			3
93	RS38 ID	Rotary	Roots	38,000	1			1
120	R175	Diaphragm	Rockwell	175	2,941		38	2,903
125	R200	Diaphragm	Rockwell	200	714		5	709
130	A175	Diaphragm	American	175	3,606		71	3,535
140	S175	Diaphragm	Sprague	175	1,087		16	1,071
260	Misc.	Various	Various	Various	1			1
270	1000A	Diaphragm	Schlumberger	1,000	8		2	6
272	1000A	Diaphragm	Actaris	1,000	0			0
300	1600 ID	Diaphragm	Rockwell	800	1		1	0
310	RW3M ID	Diaphragm	Rockwell	1,450	0			0
320	RW5M ID	Diaphragm	Rockwell	2,500	9			9
325	RW5M TC ID	Diaphragm	Rockwell	2,500	2			2
390	1400 ID	Diaphragm	American	1,400	18			18
400	2300 ID	Diaphragm	American	2,300	10			10
410	AL5M	Diaphragm	American	5,000	9		1	8
450	400A	Diaphragm	Schlumberger	400	139		3	136
452	400A	Diaphragm	Actaris	400	70		1	69
470	A425	Diaphragm	American	425	120		2	118
471	AL425	Diaphragm	American	425	254		2	252
472	A425	Diaphragm	American	425	161		2	159
475	AL-630	Diaphragm	American	630	913	30	3	940
480	A800 ID	Diaphragm	American	800	65		5	60
485	A800 TC ID	Diaphragm	American	800	38	1	5	34
486	A800	Diaphragm	American	800	3			3
500	AL1M ID	Diaphragm	American	1,000	34		1	33
502	AL 1000	Diaphragm	American	1,000	24		10	14
505	AL1M TC ID	Diaphragm	American	1,000	17			17
507	AL 1000	Diaphragm	American	1,000	441	11	6	446
510	R310	Diaphragm	Rockwell	310	126		3	123
515	R315	Diaphragm	Rockwell	315	4			4
520	R415	Diaphragm	Rockwell	415	228		4	224
530	RW1M ID	Diaphragm	Rockwell	1,000	2			2
535	RW1M TC ID	Diaphragm	Rockwell	1,000	2			2
540	R750 ID	Diaphragm	Rockwell	750	38		5	33
545	R750 TC ID	Diaphragm	Rockwell	750	3			3
555	AL 310	Diaphragm	American	310	84		7	77
560	A250	Diaphragm	American	250	16,920	2	310	16,612
561	AC250	Diaphragm	American	250	18,718	1,644	488	19,874

NORTHWEST NATURAL GAS COMPANY
CUSTOMER METERS
WASHINGTON 2015

Perf. #	Size	Type	Make	Capacity Cubic Ft.	In Service Begin. of Year	Add.	Retire-ments	In Service End of Year
565	RX250	Diaphragm	American	250	150			150
570	R275	Diaphragm	Rockwell	275	14,471		40	14,431
572	275	Diaphragm	Invensys	275	7,122	2	17	7,107
580	SPRM	D+Reg	Sprague	175	8			8
585	S250	Diaphragm	Sprague	250	3,701		20	3,681
590	S250	Diaphragm	Lancaster	250	2,804	1	14	2,791
595	METRIS 250	Diaphragm	Schlumberger	250	1,748		15	1,733
613	8C	Rotary	Roots	800	1			1
616	8C175TQM	Rotory	Dresser/Roots	800	5			5
617	8C175TQM	Rotary	Dresser/Roots	800	9			9
622	1.5M	Rotary	Roots	1,500	13			13
623	1.5M	Rotary	Roots	1,500	1			1
625	15C175TQM	Rotary	Dresser/Roots	1,500	20			20
626	15CTQM	Rotary	Roots	1,500	57			57
632	3M	Rotary	Roots	3,000	35	1	1	35
633	RS3M	Rotary	Roots	3,000	11		1	10
636	5M175TQM	Rotary	Roots	3,000	100	1		101
637	3M175TQM	Rotary	Dresser/Roots	3,000	68			68
642	5M	Rotary	Roots	5,000	28			28
643	RS5M TC	Rotary	Roots	5,000	11			11
644	3M175TQS	Rotary	Roots	5,000	13			13
646	5M175TQM	Rotary	Roots	5,000	69			69
647	5M175TQM	Rotary	Dresser/Roots	5,000	48		1	47
652	7M	Rotary	Roots	7,000	14			14
653	RS7M	Rotary	Roots	7,000	5			5
654	7M175	Rotary	Roots	7,000	4			4
655	7M175TQM	Rotary	Dresser/Roots	7,000	16			16
656	7M175TQM	Rotary	Roots	7,000	29			29
657	7M175TQM	Rotary	Roots	7,000	12			12
663	RS11	Rotary	Roots	11,000	1			1
664	RS11 ID	Rotary	Roots	11,000	3			3
665	RS11	Rotary	Roots	11,000	1			1
666	11M175TQM	Rotary	Roots	11,000	19			19
667	11M175TQM	Rotary	Roots	11,000	1			1
672	16M	Rotary	Roots	16,000	1			1
674	RS16 TC ID	Rotary	Roots	16,000	2			2
675	RS16 TC	Rotary	Roots	16,000	2			2
676	16M175TQM	Rotary	Roots	16,000	30			30
696	38M125TQM	Rotary	Roots	38,000	8			8
803	3M125e	Rotary	Dresser/Roots	3,000	1	1		2
805	7M125e	Rotary	Dresser/Roots	7,000	1			1
813	3M175e	Rotary	Dresser/Roots	5,000	3	1		4
814	5M175e	Rotary	Dresser/Roots	5,000	1			1
822	15c175TQMe	Rotary	Dresser/Roots	1,500	13	1		14
823	3M175TQMe	Rotary	Dresser/Roots	3,000	18	1		19
824	5M175TQMe	Rotary	Dresser/Roots	5,000	9			9
825	7M175TQMe	Rotary	Dresser/Roots	7,000	11	1		12
826	11M175TQMe	Rotary	Dresser/Roots	11,000	5			5
827	16M175TQMe	Rotary	Dresser/Roots	16,000	1			1
	TOTALS				77,559	1,698	1,100	78,157

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A resubmission		Dec. 31, 2015

WASHINGTON STATE - 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 Dth as reported in the schedules indicated for the items of receipts and deliveries.
4. Indicate in a footnote the quantities of bundled sales and transportation gas and specify the line on which such quantities are listed.
5. If the respondent operates two or more systems which are not interconnected, submit separate pages for this purpose. Use copies of pages 520.
6. Also 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 of that were not transported through any interstate portion of the reporting pipeline.
7. Also 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.
8. 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 rows as necessary to report all data, numbered 14.01, 14.02, etc.

Line No.	Item	Ref. Page No.	Amount of Dth
	(a)	(b)	(c)
1	Name of System		
2	**GAS RECEIVED**		
3	Gas Purchases (Accounts 800-805)		-
4	Gas of Others Received for Gathering (Account 489.1)		8,171,489
5	Gas of Others Received for Transmission (Account 489.2)	305	N/A
6	Gas of Others Received for Distribution (Account 489.3) Transportation	301	1,920,021
7	Gas of Others Received for Contract Storage (Account 489.4)	307	N/A
8	Exchanged Gas Received from Others (Account 806)	328	N/A
9	Gas Received as Imbalances (Account 806)	328	N/A
10	Receipts of Respondent's Gas Transported by Others (Account 858)	332	N/A
11	Other Gas Withdrawn from Storage (Explain)		-
12	Gas Received from Shippers as Compressor Station Fuel		-
13	Gas Received from Shippers as Lost and Unaccounted for		-
14	Other Receipts (Specify)		-
15	Total Receipts (Total of lines 3 thru 14.?)		10,091,510
16	**GAS DELIVERED**		
17	Gas Sales (Accounts 480-484)		6,180,310
18	Deliveries of Gas Gathered for Others (Account 489.1)	303	N/A
19	Deliveries of Gas Transported for Others (Account 489.2)	305	N/A
20	Deliveries of Gas Distributed for Others (Account 489.3)	301	1,920,021
21	Deliveries of Contract Storage Gas (Account 489.4)	307	N/A
22	Exchange Gas Delivered to Others (Account 806)	328	N/A
23	Gas Delivered as Imbalances (Account 806)	328	N/A
24	Deliveries of Gas to Others for Transportation (Account 858)	332	N/A
25	Other Gas Delivered to Storage (Explain)		-
26	Gas Used for Compressor Station Fuel	509	N/A
27	Other Deliveries (Specify): Unbilled		82,983
28	Total Deliveries (Total of lines 17 thru 27)		8,183,314
29	**GAS UNACCOUNTED FOR**		
30	Production System Losses		-
31	Gathering System Losses		-
32	Transmission System Losses		-
33	Distribution System Losses		1,908,196
34	Storage System Losses		-
35	Other Losses (Specify)		-
36	Total Unaccounted for (Total of lines 30 thru 35)		1,908,196
37	Total Deliveries & Unaccounted for (Total of lines 28 and 36)		10,091,510

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A resubmission		Dec. 31, 2015

WASHINGTON STATE - EXECUTIVE SALARY SUPPLEMENTAL DETAILS

1. Report below the name, title and salary for each executive officer. An "executive officer" of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.

2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent and the date the change in incumbency was made.

Line No.	Name of Officer (a)	Salary for Year [1] (b)	Account Number (c)	Amount Assigned to WA (d)	Percent Increase Over Prior Year	Reason for Increase (f)
1	Gregg S. Kantor	549,333	921.1	N/A	3%	Market Adj. + Perf
2	David H. Anderson	418,083	921.1	N/A	5%	Market Adj. + Perf
3	Stephen P. Feltz [2]	158,833	921.1	N/A	-48%	Market Adj. + Perf
4	Gregory C. Hazelton [2]	149,863	921.1	N/A	N/A	N/A
5	Margaret D. Kirkpatrick	312,500	921.1	N/A	3%	Market Adj. + Perf
6	Lea Anne Doolittle	282,667	921.1	N/A	3%	Market Adj. + Perf
7	MardiLyn Saathoff	304,000	921.1	N/A	26%	Market Adj. + Perf
8	David A. Weber	263,750	921.1	N/A	3%	Market Adj. + Perf
9	David R. Williams	241,833	921.1	N/A	3%	Market Adj. + Perf
10	Grant M. Yoshihara	241,833	921.1	N/A	3%	Market Adj. + Perf
11	Shawn M. Filippi	210,000	921.1	N/A	N/A	N/A
12	C. Alex Miller	223,000	921.1	N/A	3%	Market Adj. + Perf
13	Thomas J.M. Imeson	242,667	921.1	N/A	36%	Market Adj. + Perf
14	Kimberly A. Heiting	205,000	921.1	N/A	N/A	N/A
15	Brody J. Wilson	211,333	921.1	N/A	14%	Market Adj. + Perf

(1) Salary amounts do not include bonuses paid to executives

(2) Effective June 30, 2015, Stephen P. Feltz retired and Gregory C. Hazelton became Senior Vice President and Chief Financial Officer.

EXECUTIVE COUNT BY CLASS AND TOTAL SALARIES BY CLASS

1. Pursuant to RCW 80.04.080, report below the number of employees by class (per company definition to be provided), and the total amount of salaries and wages paid each class.

	Employee Class (a)	Number of Employees (b)	Total Salaries and Wages Paid Each Class (c) [2]
10	Officers & Exempt	463	45,896,212
11	Bargaining Unit	598	41,602,879
13	Total	1,061	87,499,091

(2) Salaries and wages do not include bonuses paid

NORTHWEST NATURAL GAS COMPANY

Oregon Supplement to FERC Form 2

December 31, 2015

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

INDEX

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

STATE OF OREGON - STATEMENT OF INCOME FOR THE YEAR

1. Report amounts for accounts 412 and 413, Revenue and Expenses from Utility Plant Leased to Others, in another utility column (i, j) in a similar manner to a utility department. Spread the amount(s) over lines 2 thru 24 as appropriate. Include these amounts in columns (c) and (d) totals.
2. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
3. Report data for lines 7, 9, and 10 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1, and 407.2.

Line No.	ACCOUNT (a)	(REF) PAGE NO. (b)	GAS UTILITY CURRENT YEAR (c)	GAS UTILITY PREVIOUS YEAR (d)
1	**UTILITY OPERATING INCOME**			
2	Operating Revenues (400)	2		
3	Operating Expenses			
4	Operation Expenses (401)	4-9		
5	Maintenance Expenses (402)	4-9		
6	Depreciation Expense (403)	10		
7	Amort. & Depl. of Utility Plant (404-405)	10		
8	Amort. of Utility Plant Acq. Adj. (406)	10		
9	Amort of Property Losses, Unrecovered Plant and Regulatory Study Costs (407)			
10	Amort. of Conversion Expenses (407)			
11	Taxes Other Than Income Taxes (408.1)	11		
12	Income Taxes - Federal (409.1)	12		
13	- Other (409.1)	13		
14	Provision for Deferred Income Taxes (410.1)	14-21		
15	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	14-21		
16	Investment Tax Credit Adj. - Net (411.4)	22		
17	(Less) Gains from Disp. of Utility Plant (411.6)			
18	Losses from Disp. of Utility Plant (411.7)			
19	TOTAL Utility Operating Expenses (Total of lines 4 thru 18)			
20	Net Utility Operating income (Enter Total of line 2 less 19)			

SEE FERC ANNUAL REPORT PAGES 114-116

Name of Respondent	**This Report is:**	**Date of Report**	**Year of Report**
Northwest Natural Gas Company	(1) X An Original (2) A Resubmission	**(Mo, Da, Yr)**	Dec. 31, 2015

STATE OF OREGON - GAS OPERATING REVENUES (Account 400)

1. Report below natural gas operating revenues for each prescribed account, and manufactured gas revenues in total.
2. Natural gas means either natural gas unmixed or any mixture of natural and manufactured gas.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
4. Report quantities of natural gas sold in Dth.
5. If increases or decreases from previous year (columns (c) (e) and (g), are not derived from previously reported figures,

Line No.	Title of Account (a)	OPERATING REVENUES Amount for Current Year (b)	 Amount for Previous Year (c)
1	GAS SERVICE REVENUES		
2	480 Residential Sales	369,307,365	392,035,459
3	481 Commercial and Industrial Sales	-	-
4	Small (or Comm.) (See Instr. 6)	195,857,802	205,702,104
5	Large (or Ind.) (See instr. 6)	51,118,005	54,127,383
6	482 Other Sales to Public Authorities	-	-
7	484 Interdepartmental Sales	-	-
8	TOTAL Sales to Ultimate Consumers	616,283,172	651,864,946
9	483 Sales for Resale	-	-
10	TOTAL Nat. Gas Service Revenues	616,283,172	651,864,946
11	Revenues from Manufactured Gas	-	-
12	TOTAL Gas Service Revenues	616,283,172	651,864,946
13	OTHER OPERATING REVENUES		
14	485 Intercompany Transfers	-	-
15	487 Late Payment Charge	2,009,419	2,132,472
16	488 Misc. Service Revenues	1,117,488	1,231,435
17	489 Rev. From Trans. of Gas of Others	15,707,735	15,252,791
18	490 Sales of Prod. Ext. from Natural Gas	-	-
19	491 Rev. from Nat. Gas Proc. by Others	-	-
20	492 Incidental Gasoline and Oil Sales	-	-
21	493 Rent from Gas Property	271,564	257,781
22	494 Interdepartmental Rents	-	-
23	495 Other Gas Revenues	17,953,807	8,108,694
24	TOTAL Other Operating Revenues	37,060,013	26,983,173
25	TOTAL Gas Operating Revenues	653,343,185	678,848,119
26	(Less) 496 Provision for Rate Refunds	-	-
27	TOTAL Gas Operating Revenues Net of Provision for refund	653,343,185	678,848,119
28	Dist. Type Sales by State (Incl. Main Line Sales to Resid. and Comm. Custrs.)	565,165,167	597,737,563
29	Main Line Industrial Sales (Incl. Main Line Sales to Pub. Authorities)	51,118,005	54,127,383
30	Sales for Resale	-	-
31	Other Sales to Pub. Auth. (Local Dist. Only)	-	-
32	Interdepartmental Sales	-	-
33	TOTAL (Same as Line 10, Columns (b) and (d))	616,283,172	651,864,946

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	(1) X An Original (2) A Resubmission		Dec. 31, 2015

STATE OF OREGON - GAS OPERATING REVENUES (Account 400) (Continued)

explain any inconsistencies in a footnote.

6. Commercial and Industrial Sales, Account 481, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 2000, Mcf per year or approximately 800 Mcf per day of normal requirements. (See Account 481 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See page 108, Important Changes During Year, for important new territory added and important rate increases or decreases.

DTHS OF GAS SOLD		AVG. NO. OF NAT. GAS CUSTOMERS PER MO.		
Quantity for Year (d)	Quantity for Previous Year (e)	Number for Year (f)	Number for Previous Year (g)	Line No.
				1
31,039,607	33,769,735	571,534	565,155	2
				3
20,166,208	21,931,212	59,636	59,546	4
8,571,497	9,128,688	975	926	5
-	-	-	-	6
-	-	-	-	7
59,777,312	64,829,635	632,145	625,627	8
-	-	-	-	9
59,777,312	64,829,635	632,145	625,627	10
				11
				12
				13
				14
				15
				16
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				26
59,777,312				27
-				28
-				29
-				30
-				31
-				32
59,777,312				33

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

STATE OF OREGON - INTERDEPARTMENTAL SALES - NATURAL GAS (Account 484)
Report particulars concerning sales of natural gas included in Account 484

LINE NO.	DEPARTMENT AND BASIS OF CHARGES (a)	POINT OF DELIVERY (b)	MCF (14.73 psia at 60° F) (c)	REVENUE (d)
	NOT APPLICABLE			

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

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

Line No.	NAME OF LESSEE OR DEPARTMENT (Designate associated companies) (a)	DESCRIPTION OF PROPERTY (b)	AMOUNT OF REVENUE FOR YEAR: NATURAL GAS PROPERTY (c)	AMOUNT OF REVENUE FOR YEAR: MANUFACTURED GAS PROPERTY (d)
	ACCOUNT 493 - RENT FROM GAS PROPERTY			
	1. Koppers Co. Inc.	Facilities, equip., gasco plant		172,655
	2. Other	Communication	98,910	
		Totals	98,910	172,655

Name of Respondent	This Report is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

STATE OF OREGON - ALLOCATED GAS OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Current Year (b)	Previous Year (c)
1	1. PRODUCTION EXPENSES		
2	A. Manufactured Gas Production		
3	Manufactured Gas Production (Submit Supplemental Statement)		
4	B. Natural Gas Production		
5	B1. Natural Gas Production and Gathering		
6	Operation		
7	750 Operation Supervision and Engineering		
8	751 Production Maps and Records		
9	752 Gas Wells Expenses		
10	753 Field Lines Expenses		
11	754 Field Compressor Station Expenses		
12	755 Field Compressor Station Fuel and Power		
13	756 Field Measuring and Regulating Station Expenses		
14	757 Purification Expenses	**INFORMATION NOT AVAILABLE**	
15	758 Gas Well Royalties	**SEE FERC ANNUAL REPORT PAGES 317-325**	
16	759 Other Expenses		
17	760 Rents		
18	TOTAL Operation (Total of lines 7 thru 17)		
19	Maintenance		
20	761 Maintenance Supervision and Engineering		
21	762 Maintenance of Structures and Improvements		
22	763 Maintenance of Producing Gas Wells		
23	764 Maintenance of Field Lines		
24	765 Maintenance of Field Compressor Station Equipment		
25	766 Maintenance of Field Meas. and Reg. Station Equipment		
26	767 Maintenance of Purification Equipment		
27	768 Maintenance of Drilling and Cleaning Equipment		
28	769 Maintenance of Other Equipment		
29	TOTAL Maintenance (Total of lines 20 thru 28)		
30	TOTAL Natural Gas Production and Gathering (Total of lines 18 and 29)		
31	B2. Products Extraction		
32	Operation		
33	770 Operation Supervision and Engineering		
34	771 Operation Labor		
35	772 Gas Shrinkage		
36	773 Fuel		
37	774 Power		
38	775 Materials		
39	776 Operation Supplies and expenses		
40	777 Gas Processed by Others		
41	778 Royalties on Products Extracted		
42	779 Marketing expenses		
43	780 Products Purchased for Resale		
44	781 Variation in Products Inventory		
45	(Less) 782 Extracted Products Used by the Utility-Credit		
46	783 Rents		
47	TOTAL Operation (Total of Lines 33 thru 46)		

Name of Respondent	This Report is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

STATE OF OREGON - ALLOCATED GAS OPERATION AND MAINTENANCE EXPENSES

Line No.	Account (a)	Current Year (b)	Previous Year (c)
1	A. Manufactured Gas Production Detail		
2			
3			
4			
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7			
8			
9	**INFORMATION NOT AVAILABLE**		
10	**SEE FERC ANNUAL REPORT PAGES 317-325**		
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Name of Respondent Northwest Natural Gas Company	This Report is: X An Original A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 2015

STATE OF OREGON - ALLOCATED GAS OPERATION AND MAINTENANCE EXPENSES

Line No.	Account (a)	Current Year (b)	Previous Year (c)
31	B2. Products Extraction (Con't)		
32	Operation		
48	Maintenance		
49	784 Maintenance Supervision and Engineering		
50	785 Maintenance of Structures and Improvements		
51	786 Maintenance of Extraction and Refining Equipment		
52	787 Maintenance of Pipe Lines		
53	788 Maintenance of Extracted Products Storage Equipment		
54	789 Maintenance of Compressor Equipment		
55	790 Maintenance of Gas Measuring and Regulating Equipment		
56	791 Maintenance of Other Equipment		
57	TOTAL Maintenance (Total of lines 49 thru 56)		
58	TOTAL Products Extraction (Total of lines 47 and 57)		
59	C. Exploration and Development		
60	Operation		
61	795 Delay Rentals		
62	796 Nonproductive Well Drilling		
63	797 Abandoned Leases		
64	798 Other Exploration	**INFORMATION NOT AVAILABLE**	
65	TOTAL Exploration and Development (Total of lines 61 thru 64)	**SEE FERC ANNUAL REPORT PAGES 317-325**	
	D. Other Gas Supply Expenses		
66	Operation		
67	800 Natural Gas Well Head Purchases		
68	800.1 Natural Gas Well Head Purchases, Intracompany Transfers		
69	801 Natural Gas Field Line Purchases		
70	802 Natural Gas Gasoline Plant Outlet Purchases		
71	803 Natural Gas Transmission Line Purchases		
72	804 Natural Gas City Gate Purchases		
73	804.1 Liquefied Natural Gas Purchases		
74	805 Other Gas Purchases		
75	(Less) 805.1 Purchase Gas Cost Adjustments		
76	805.2 Incremental Gas Cost Adjustments		
77	TOTAL Purchased Gas (Total of Lines 67 thru 76)		
78	806 Exchange Gas		
79	Purchased Gas Expense		
80	807.1 Well Expense-Purchased Gas		
81	807.2 Operation of Purchased Gas Measuring Stations		
82	807.3 Maintenance of Purchased Gas Measuring Stations		
83	807.4 Purchased Gas Calculations Expense		
84	807.5 Other Purchased Gas Expenses		
85	TOTAL Purchased Gas Expense (Total of lines 80 thru 84)		
86	808.1 Gas Withdrawn from Storage-Debit		
87	(Less) 808.2 Gas Delivered to Storage-Credit		
88	809.1 Withdrawals of Liquefied Natural Gas for Processing-Debit		
89	(Less) 809.2 Deliveries of Natural Gas for Processing-Credit		
90	(Less)Gas used in Utility Operation-Credit		
91	810 Gas Used for Compressor Station Fuel-Credit		
92	811 Gas Used for Products Extraction-Credit		
93	812 Gas Used for Other Utility Operations-Credit		
94	TOTAL Gas Used in Utility Operations-Credit (Total of lines 91 thru 93)		
95	813 Other Gas Supply Expenses		
96	TOTAL Other Gas Supply Exp. (Total of lines 77, 78, 85, 86 thru 89, 94, 95)		
97	TOTAL Production Expenses (Total of lines 3, 30, 58, 65, and 96)		

Name of Respondent	This Report is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

STATE OF OREGON - ALLOCATED GAS OPERATION AND MAINTENANCE EXPENSES

Line No.	Account (a)	Current Year (b)	Previous Year (c)
98	2. NATURAL GAS STORAGE, TERMINALING AND PROCESSING EXPENSES		
99	A. Underground Storage Expenses		
100	Operation		
101	814 Operation Supervision and Engineering		
102	815 Maps and Records		
103	816 Well Expenses		
104	817 Lines Expenses		
105	818 Compressor Station Fuel and Power		
106	819 Compressor Station Fuel and Power		
107	820 Measuring and Regulating Station Expenses		
108	821 Purification Expenses		
109	822 Exploration and Development		
110	823 Gas Losses		
111	824 Other Expenses		
112	825 Storage Well Royalties		
113	826 Rents		
114	TOTAL Operation (Total of lines of 101 thru 113)		
115	Maintenance		
116	830 Maintenance Supervision and Engineering		
117	831 Maintenance of Structures and Improvements	**INFORMATION NOT AVAILABLE**	
118	832 Maintenance of Reservoirs and Wells	**SEE FERC ANNUAL REPORT PAGES 317-325**	
119	833 Maintenance of Lines		
120	834 Maintenance of Compressor Station Equipment		
121	835 Maintenance of Measuring and Regulating Station Equipment		
122	836 Maintenance of Purification Equipment		
123	837 Maintenance of Other Equipment		
124	TOTAL Maintenance (Total of lines 116 thru 123)		
125	TOTAL Underground Storage Expenses (Total of lines 114 and 124)		
126	B. Other Storage Expenses		
127	Operation		
128	840 Operation Supervision and Engineering		
129	841 Operation Labor and Expenses		
130	842 Rents		
131	842.1 Fuel		
132	842.2 Power		
133	842.3 Gas Losses		
134	TOTAL Operation (Total of lines 128 thru 133)		
135	Maintenance		
136	843.1 Maintenance Supervision and Engineering		
137	843.2 Maintenance of Structures and Improvements		
138	843.3 Maintenance of Gas Holders		
139	843.4 Maintenance of Purification Equipment		
140	843.5 Maintenance of Liquefaction Equipment		
141	843.6 Maintenance of Vaporizing Equipment		
142	843.7 Maintenance of Compressor Equipment		
143	843.8 Maintenance of Measuring and Regulating Equipment		
144	843.9 Maintenance of Other Equipment		
145	TOTAL Maintenance (Total of lines 136 thru 144)		
146	TOTAL Other Storage Expenses (Total of lines 134 and 145)		

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

STATE OF OREGON - ALLOCATED GAS OPERATION AND MAINTENANCE EXPENSES

Line No.	Account (a)	Current Year (b)	Previous Year (c)
147	C. Liquefied Natural Gas Terminaling and Processing Expenses		
148	Operation		
149	844.1 Operation Supervision and Engineering		
150	844.2 LNG Processing Terminal Labor and Expenses		
151	844.3 Liquefaction Processing Labor and Expenses		
152	844.4 Liquefaction Transportation Labor and Expenses		
153	844.5 Measuring and Regulating Labor and Expenses		
154	844.6 Compressor Station Labor and Expenses		
155	844.7 Communication system Expenses		
156	844.8 System Control and Load Dispatching		
157	845.1 Fuel		
158	845.2 Power		
159	845.3 Rents		
160	(Less) 845.4 Demurrage Charges		
161	845.5 Wharfage Receipts-Credit		
162	845.6 Processing Liquefied of Vaporized Gas by Others		
163	846.1 Gas Losses		
164	846.2 Other Expenses		
165	TOTAL Operation (Total of lines 149 thru 164)		
166	Maintenance		
167	847.1 Maintenance Supervision and Engineering	INFORMATION NOT AVAILABLE	
168	847.2 Maintenance of Structures and Improvements	SEE FERC ANNUAL REPORT PAGES 317-325	
169	847.3 Maintenance of LNG Processing Terminal Equipment		
170	847.4 Maintenance of LNG Transportation Equipment		
171	847.5 Maintenance of Measuring and Regulating Equipment		
172	847.6 Maintenance of Compressor Station Equipment		
173	847.7 Maintenance of Communication Equipment		
174	847.8 Maintenance of Other Equipment		
175	TOTAL Maintenance (Total of lines 167 thru 174)		
176	TOTAL Liquefied Nat Gas Terminaling and Proc Exp (Total of lines 165 & 175)		
177	TOTAL Natural Gas Storage (Total of lines 125, 146, and 176)		
178	3. TRANSMISSION EXPENSES		
179	Operation		
180	850 Operation Supervision and Engineering		
181	851 System Control and Load Dispatching		
182	852 Communication system Expenses		
183	853 Compressor Station Labor and Expenses		
184	854 Gas for Compressor Station Fuel		
185	855 Other Fuel and Power for Compressor Stations		
186	856 Mains Expenses		
187	857 Measuring and Regulating Station Expenses		
188	858 Transmission and Compression of Gas by Others		
189	859 Other Expenses		
190	860 Rents		
191	TOTAL Operations (Total of lines 180 thru 190)		
192	Maintenance		
193	861 Maintenance Supervision and Engineering		
194	862 Maintenance of Structures and Improvements		
195	863 Maintenance of Mains		
196	864 Maintenance of Compressor Station Equipment		
197	865 Maintenance of Measuring and Regulating Station Equipment		
198	866 Maintenance of Communication Equipment		
199	867 Maintenance of Other Equipment		
200	TOTAL Maintenance (Total of lines 193 thru 199)		
201	TOTAL Transmission Expenses (Total of lines 191 and 200)		

Name of Respondent	This Report is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

STATE OF OREGON - ALLOCATED GAS OPERATION AND MAINTENANCE EXPENSES

Line No.	Account (a)	Current Year (b)	Previous Year (c)
202	4. DISTRIBUTION EXPENSES		
203	Operation		
204	870 Operation Supervision and Engineering		
205	871 Distribution Load Dispatching		
206	872 Compressor Station Labor and Expenses		
207	873 Compressor Station Fuel and Power		
208	874 Mains and Services Expenses		
209	875 Measuring and Regulating Station Expenses-General		
210	876 Measuring and Regulating Station Expenses-Industrial		
211	877 Measuring and Regulating Station Expenses-City Gas Check Station		
212	878 Meter and House Regulator Expenses		
213	879 Customer Installations Expenses		
214	880 Other Expenses		
215	881 Rents		
216	TOTAL Operations (Total of lines 204 thru 215)		
217	Maintenance		
218	885 Maintenance Supervision and Engineering		
219	886 Maintenance of Structures and Improvements		
220	887 Maintenance of Mains	**INFORMATION NOT AVAILABLE**	
221	888 Maintenance of Compressor Station Equipment	**SEE FERC ANNUAL REPORT PAGES 317-325**	
222	889 Maintenance of Measuring & Regulating Station Equipment-General		
223	890 Maintenance of Meas. and Reg. Station Equipment-Industrial		
224	891 Maintenance of Meas & Reg Station Equip-City Gate Check Station		
225	892 Maintenance of Services		
226	893 Maintenance of Meters and House Regulators		
227	894 Maintenance of Other Equipment		
228	TOTAL Maintenance (Total of lines 218 thru 227)		
229	TOTAL Distribution Expenses (Total of lines 216 and 228)		
230	5. CUSTOMER ACCOUNTS EXPENSES		
231	Operation		
232	901 Supervision		
233	902 Meter Reading Expenses		
234	903 Customer Records and Collection Expenses		
235	904 Uncollectible Accounts		
236	905 Miscellaneous Customer Accounts Expenses		
237	TOTAL Customer Accounts Expenses (Total of lines 232 thru 236)		
238	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSE		
239	Operation		
240	907 Supervision		
241	908 Customer Assistance Expense		
242	909 Informational and Instructional Expenses		
243	910 Miscellaneous Customer Service and Informational Expenses		
244	TOTAL Customer Service & Information Expenses (Total of lines 240 thru 243)		
245	7. SALES EXPENSES		
246	Operation		
247	911 Supervision		
248	912 Demonstration and Selling Expenses		
249	913 Advertising Expenses		
250	916 Miscellaneous Sales Expenses		
251	TOTAL Sales Expenses (Total of lines 247 thru 250)		

Name of Respondent Northwest Natural Gas Company	This Report is: X An Original A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 2015

STATE OF OREGON - ALLOCATED GAS OPERATION AND MAINTENANCE EXPENSES

Line No.	Account (a)	Current Year (b)	Previous Year (c)
252	8. ADMINISTRATIVE AND GENERAL EXPENSES		
253	Operation		
254	920 Administrative and General Salaries		
255	921 Office Supplies and Expenses	**INFORMATION NOT AVAILABLE**	
256	(Less) 922 Administrative Expenses Transferred - Credit	**SEE FERC ANNUAL REPORT PAGES 317-325**	
257	923 Outside Services Employed		
258	924 Property Insurance		
259	925 Injuries and Damages		
260	926 Employee Pensions and Benefits		
261	927 Franchise Requirements		
262	928 Regulatory Commission Expenses		
263	(Less) 929 Duplicate Charges - Credit		
264	930.1 General Advertising Expenses		
265	930.2 Miscellaneous General Expenses		
266	931 Rents		
267	TOTAL Operation (Total of lines 254 thru 266)		
268	Maintenance		
269	935 Maintenance of General Plant		
270	TOTAL Administrative and General Expenses (Total of lines 267 and 269)		
271	TOTAL Gas O & M Expenses (Total of lines 97,177,201,229,237,244,251,and 270)		

STATE OF OREGON - ALLOCATED GAS OPERATION AND MAINTENANCE EXPENSES

LINE NO.	FUNCTIONAL CLASSIFICATIONS (a)	OPERATION (b)	MAINTENANCE (c)	TOTAL (d)
272	Production			
273	Manufactured Gas			
274	Natural gas:			
275	Production and Gathering			
276	Products Extraction			
277	Exploration and Dev.			
278	TOTAL Natural Gas			
279	Other Gas Supply Expenses			
280	TOTAL Production		**INFORMATION NOT AVAILABLE**	
281	Underground Storage		**SEE FERC ANNUAL REPORT PAGES 317-325**	
282	Other Storage			
283	LNG Terminaling and Processing			
284	Transmission Expenses			
285	Distribution Expenses			
286	Customer Accounts Expenses			
287	Customer Service and Informational Expenses			
288	Sales Expenses			
289	Adm. and General Expenses			
290	TOTAL Gas O. & M. Expenses			

Name of Respondent	This Report is:	Date of Report	Year of Report
Northwest Natural Gas Company	(1) X An Original (2) A Resubmission	(Mo, Day, Yr)	Dec. 31, 2015

STATE OF OREGON

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

Line No.	FUNCTIONAL CLASSIFICATION (a)	DEPRECIATION EXPENSE (ACCOUNT 403) (b)	AMORTIZATION & DEPLETION OF PRODUCING NATURAL GAS LAND & LAND RIGHTS (ACCOUNT 404.1) (c)	AMORTIZATION OF UNDERGROUND STORAGE LAND & LAND RIGHTS (ACCOUNT 404.2) (d)	AMORTIZATION OF OTHER LIMITED-TERM GAS PLANT (ACCOUNT 404.3) (e)	AMORTIZATION OF OTHER GAS PLANT (ACCOUNT 405) (f)	TOTAL (g)
1	Intangible Plant						
2	Production Plant, Manufactured Gas						
3	Production and Gathering Plant, Natural Gas						
4	Products Extraction Plant						
5	Underground Gas Storage Plant						
6	Other Storage Plant						
7	Base Load LNG Terminaling and Processing Plant						
8	Transmission Plant	**INFORMATION NOT AVAILABLE**					
9	Distribution Plant						
10	General Plant						
11	Common Plant - Gas						
12							
13							
14							
15							
16							
17							
18							
19	TOTAL						

Name of Respondent Northwest Natural Gas Company	This Report is: X An Original A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 2015

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

Line No.	KIND OF TAX (a)	AMOUNT (b)
	SEE FERC ANNUAL REPORT **PAGES 262 - 263** **PAGES 262A - 263A** **PAGES 262C - 263C** **PAGES 262E - 263E**	
	TOTAL (Must agree with page 1, line 11)	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

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

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

Line No.	PARTICULARS (Details) (a)	AMOUNT (b)
1	Gas Operating Revenues	
2	Operations and Maintenance Expenses	
3	Taxes, Other than Income	
4	State Income (Excise) Tax	
5	Interest	
6	Federal Income Tax Depreciation	
7	Other Additions (Subtractions) to Derive Taxable Income	
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15		
16		
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26		
27	Federal Tax Net Income	
28	Show Computation of Tax: **SEE FERC ANNUAL REPORT** **PAGE 261 A-1 and 261 B-2**	

Name of Respondent	This Report is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

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

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

Line No.	PARTICULARS (Details) (a)	AMOUNT (b)
1	Gas Operating Revenues	
2	Operations and Maintenance Expenses	
3	Taxes, Other than Income	
4	Interest	
5	State Income (Excise) Tax Depreciation	
6	Other Additions (Subtractions) to Derive Taxable Income	
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13		
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16		
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26		
27	State Tax Net Income	
28	Show Computation of Tax:	
	SEE FERC ANNUAL REPORT **PAGE 262-C**	

Name of Respondent Northwest Natural Gas Company	This Report is: X An Original A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 2015

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

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

Line No.	ACCOUNT SUBDIVISIONS (a)	BALANCE BEGINNING OF YEAR (b)	CHANGES DURING YEAR AMOUNTS DEBITED ACCOUNT 410.1 (c)	CHANGES DURING YEAR AMOUNTS CREDITED ACCOUNT 411.1 (d)
1	Electric			
2				
3				
4				
5				
6				
7	Other			
8	TOTAL ELECTRIC			
9	Gas			
10				
11				
12				
13				
14				
15	Other			
16	TOTAL GAS			
17	Other (Specify)			
18	TOTAL (ACCOUNT 190)			
19	Classification of Totals			
20	Federal Income Tax			
21	State Income Tax			
22	Local Income Tax			

NOT APPLICABLE

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

STATE OF OREGON - ALLOCATED ACCUMULATED DEFERRED INCOME TAXES (Account 190) (Con't)

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

CHANGES DURING YEAR		ADJUSTMENTS					
		DEBITS		CREDITS			
AMOUNTS DEBITED ACCOUNT 410.2 (e)	AMOUNTS CREDITED ACCOUNT 411.2 (f)	ACCT. NO. (g)	AMOUNT (h)	ACCT. NO. (i)	AMOUNT (j)	BALANCE END OF YEAR (k)	Line No.
							1
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NOT APPLICABLE

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

STATE OF OREGON - ALLOCATED ACCUMULATED DEFERRED INCOME TAXES (Account 281)

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

Line No.	ACCOUNT (a)	BALANCE BEGINNING OF YEAR (b)	CHANGES DURING YEAR AMOUNTS DEBITED ACCOUNT 410.1 (c)	CHANGES DURING YEAR AMOUNTS CREDITED ACCOUNT 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities			
5	Other			
6				
7				
8	TOTAL Electric *(Total of lines 3 thru 7)*			
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other			
13				
14				
15	TOTAL Gas *(Total of lines 10 thru 14)*			
16	Gas (Specify)			
17	TOTAL (Acct 281) *Total of 8, 15 & 16)*			
18	Classification of TOTAL			
19	Federal Income Tax			
20	State Income Tax			
21	Local Income Tax			

NOT APPLICABLE

Name of Respondent	This Report is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

STATE OF OREGON - ALLOCATED ACCELERATED AMORTIZATION PROPERTY (Account 281) (Con't)

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

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

CHANGES DURING YEAR		ADJUSTMENTS					
		DEBITS		CREDITS			
AMOUNTS DEBITED ACCOUNT 410.2 (e)	AMOUNTS CREDITED ACCOUNT 411.2 (f)	ACCT. NO. (g)	AMOUNT (h)	ACCT. NO. (i)	AMOUNT (j)	BALANCE END OF YEAR (k)	Line No.
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
							15
							16
							17
							18
							19
							20
							21

NOT APPLICABLE

Name of Respondent	This Report is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

STATE OF OREGON - ALLOCATED ACCUMULATED DEFERRED INCOME TAXES (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to property not subject to accelerated amortization.
2. In the space provided furnish explanations, including the following in columnar order:
   (a) State the general method or methods of liberalized depreciation being used (sum-of-year digits, declining balance, etc.)
   (b) Estimated lives (i.e. useful life, guideline life, guideline class life, etc.)
   (c) Classes of plant to which each method is being applied and date method was adopted.

Line No.	ACCOUNT SUBDIVISIONS (a)	BALANCE BEGINNING OF YEAR (b)	CHANGES DURING YEAR AMOUNTS DEBITED ACCOUNT 410.1 (c)	CHANGES DURING YEAR AMOUNTS CREDITED ACCOUNT 411.1 (d)
1	Account 282			
2	Electric			
3	Gas			
4	Other			
5	TOTAL (*Total of lines 2 thru4)*			
6	Other (Specify)			
7				
8				
9	TOTAL (Acct 282) *(Total of 5 thru 8)*			
10	Classification of TOTAL			
11	Federal Income Tax			
12	State Income Tax			
13	Local Income Tax			

NOT APPLICABLE

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

STATE OF OREGON - ALLOCATED OTHER PROPERTY (Account 282) (Con't)

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

CHANGES DURING YEAR		ADJUSTMENTS					
AMOUNTS DEBITED ACCOUNT 410.2	AMOUNTS CREDITED ACCOUNT 411.2	DEBITS		CREDITS		BALANCE END OF YEAR	Line No.
		ACCT. NO.	AMOUNT	ACCT. NO.	AMOUNT		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13

NOT APPLICABLE

Name of Respondent	This Report is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

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

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. In the space provided below include amounts relating to insignificant items under Other.

Line No.	ACCOUNT SUBDIVISIONS (a)	BALANCE BEGINNING OF YEAR (b)	CHANGES DURING YEAR AMOUNTS DEBITED ACCOUNT 410.1 (c)	CHANGES DURING YEAR AMOUNTS CREDITED ACCOUNT 411.1 (d)
1	Account 283			
2	Electric			
3				
4				
5				
6				
7				
8	Other			
9	TOTAL Electric *(Total of 2 thru 8)*			
10	Gas			
11				
12				
13				
14				
15				
16	Other			
17	TOTAL Gas (*Total of lines 10 thru 16)*			
18	Other (Specify)			
19	TOTAL *(Acct 283) (Total of 9, 17, & 18)*			
20	Classification of TOTAL			
21	Federal Income Tax			
22	State Income Tax			
23	Local Income Tax			

SEE FERC ANNUAL REPORT PAGE 276

Name of Respondent Northwest Natural Gas Company	This Report is: X An Original A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 2015

STATE OF OREGON - ALLOCATED ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Con't)

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

CHANGES DURING YEAR		ADJUSTMENTS					
		DEBITS		CREDITS			
AMOUNTS DEBITED ACCOUNT 410.2 (e)	AMOUNTS CREDITED ACCOUNT 411.2 (f)	ACCT. NO. (g)	AMOUNT (h)	ACCT. NO. (i)	AMOUNT (j)	BALANCE END OF YEAR (k)	Line No.
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
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							14
							15
							16
							17
							18
							19
							20
							21
							22
							23

SEE FERC ANNUAL REPORT
PAGE 277

Name of Respondent	This Report is:	Date of Report	Year of Report
Northwest Natural Gas Company	(1) X An Original (2) A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

STATE OF OREGON - ALLOCATED ACCUMULATED DEFERED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Explain by footnote any correction to the account balance shown in column (g). Include in column (l) the average period over which the tax credits are amortized.

Line No.	ACCOUNT	BALANCE AT BEGINNING OF YEAR	DEFERRED FOR YEAR		ALLOCATION TO CURRENT YEAR'S INCOME			
			ACCOUNT NO.	AMOUNT	ACCOUNT NO.	AMOUNT	ADJUSTMENTS	BALANCE AT END OF YEAR
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13	**INFORMATION NOT AVAILABLE**							
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	(1) X An Original (2) A Resubmission		Dec. 31, 2015

STATE OF OREGON - ALLOCATED ACCUMULATED DEFERED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	ACCOUNT	BALANCE AT BEGINNING OF YEAR	DEFERRED FOR YEAR		ALLOCATION TO CURRENT YEAR'S INCOME			
			ACCOUNT NO.	AMOUNT	ACCOUNT NO.	AMOUNT	ADJUSTMENTS	BALANCE AT END OF YEAR
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Gas Utility							
2	3%							
3	4%							
4	7%							
5	10%							
6	TOTAL							
7	Other (List separately and show							
8	3%, 4%, 7% , 10% and TOTAL							
9								
10								
11								
12								
13				**INFORMATION NOT AVAILABLE**				
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								

Name of Respondent	This Report is:	Date of Report	Year of Report
Northwest Natural Gas Company	(1) X An Original (2) A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

STATE OF OREGON - SITUS UTILITY PLANT

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

Line No.	Item (a)	Total (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Common (g)
1	**UTILITY PLANT**						
2	In Service						
3	Plant in Service (Classified)	2,325,059,345		2,325,059,345			
4	Property Under Capital Leases	-		-			
5	Plant Purchased or Sold	-		-			
6	Completed Construction not Classified	168,708,763		168,708,763			
7	Experimental Plant Unclassified	-		-			
8	TOTAL (Enter total of lines 3 thru 7)	2,493,768,108		2,493,768,108			
9	Leased to Others	-		-			
10	Held for Future Use	923,155		923,155			
11	Construction Work in Progress	39,178,406		39,178,406			
12	Acquisition Adjustments	-		-			
13	TOTAL Utility Plant (Enter total of lines 8 thru 12)	2,533,869,669		2,533,869,669			
14	Accum. Prov. for Depr., Amort., & Depl.	1,094,562,367		1,094,562,367			
15	Net Utility Plant (Line 13 less 14)	1,439,307,302		1,439,307,302			
16	**DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION**						
17	In Service:						
18	Depreciation	1,045,167,026		1,045,167,026			
19	Amort. and Depl. of Producing Natural Gas Land and Land Rights	-		-			
20	Amort. of Underground Storage Land and Land Rights	25,143		25,143			
21	Amort. of Other Utility Plant	70,493,046		70,493,046			
21.01	Salvage Work In Progress	-		-			
21.02	Less Removal Work in Progress	21,122,848		21,122,848			
22	TOTAL in Service (Lines 18 thru 21)	1,094,562,367		1,094,562,367			
23	Leased to Others						
24	Depreciation	-		-			
25	Amortization and Depletion	-		-			
26	TOTAL Leased to Others (Lines 24 and 25)	-		-			
27	Held for Future Use						
28	Depreciation	-		-			
29	Amortization	-		-			
30	TOTAL Held for Future Use (Lines 28 and 29)	-		-			
31	Abandonment of Leases (Natural Gas)	-		-			
32	Amort. of Plant Acquisition Adjustment	-		-			
33	TOTAL Accumulated Provisions (Should agree with line 14 above) (Lines 22, 26, 30, 31, and 32)	1,094,562,367		1,094,562,367			

ACCOUNT SUMMARY BY FUNTIONAL CLASS
NW Natural

Period Beginning: Jan 2015
Period Ending: Dec 2015

Functional Class / FERC Plant Account		Beginning Balance	Additions	Retirements	Transfers	Adjustments	Ending Balance
UTILITY							
Intangible Plant							
301	ORGANIZATION	$852	$0	$0	$0	$0	$852
302	FRANCHISES & CONSENTS	83,496	0	0	0	0	83,496
303.1	COMPUTER SOFTWARE	53,335,387	5,129,339	(1,073,332)	0	(443,935)	56,947,460
303.2	CUSTOMER INFORMATION SYSTEM	30,488,305	0	0	0	0	30,488,305
303.3	INDUSTRIAL & COMMERCIAL BIL	4,146,951	0	0	0	0	4,146,951
303.4	CRMS	682,893	0	0	0	0	682,893
303.5	POWERPLANT SOFTWARE	0	0	0	0	0	0
	Intangible Plant Subtotal	88,737,884	5,129,339	(1,073,332)	0	(443,935)	92,349,956
Production Plant - Oil Gas			0	0	0	0	
304.1	LAND	24,998	0	0	0	0	24,998
305.2	P P O G STRU & IMPR-SEWER S	0	0	0	0	0	0
305.5	P P O G STRU & IMPR-OTHER Y	13,156	0	0	0	0	13,156
312.3	P P O G FUEL HANDLING AND S	0	0	0	0	0	0
318.3	P P O G LIGHT OIL REFINING	144,896	0	0	0	0	144,896
318.5	P P O G TAR PROCESSING	243,551	0	0	0	0	243,551
325	NATURAL GAS PROD AND GATHER	0	0	0	0	0	0
327	NATURAL GAS PROD & GATHERIN	0	0	0	0	0	0
328	NATURAL GAS PROD AND GATHER	0	0	0	0	0	0
331	NATURAL GAS PROD & GATHERIN	0	0	0	0	0	0
332	NATURAL GAS PROD & GATHERIN	0	0	0	0	0	0
333	NATURAL GAS PROD & GATHERIN	0	0	0	0	0	0
334	NATURAL GAS PROD & GATHERIN	0	0	0	0	0	0
	Production Plant - Oil Gas Subtotal	426,601	0	0	0	0	426,601
Production Plant - Other							
305.11	GAS PRODUCTION - COTTAGE G	8,320	0	0	0	0	8,320
305.17	STRUCTURES MIXING STATION	46,587	0	0	0	0	46,587
311	P P OTHER-LIQUEFIED PETROLE	0	0	0	0	0	0
311.4	P P OTHER-L P G GRANGER	0	0	0	0	0	0
311.7	LIQUIFIED GAS EQUIPMENT COO	4,033	0	0	0	0	4,033
311.8	LIQUIFIED GAS EQUIPMENT LIN	4,209	0	0	0	0	4,209
319	GAS MIXING EQUIPMENT GASCO	185,448	0	0	0	0	185,448
	Production Plant - Other Subtotal	248,597	0	0	0	0	248,597

ACCOUNT SUMMARY BY FUNTIONAL CLASS
NW Natural

Period Beginning: Jan 2015
Period Ending: Dec 2015

Functional Class / FERC Plant Account		Beginning Balance	Additions	Retirements	Transfers	Adjustments	Ending Balance
UTILITY							
Natural Gas Underground Storage							
350.1	LAND	106,549	0	0	0	0	106,549
350.2	RIGHTS-OF-WAY	109,625	0	0	0	0	109,625
351	STRUCTURES AND IMPROVEMENTS	7,139,428	68,816	0	0	0	7,208,244
352	WELLS	20,047,076	0	0	0	0	20,047,076
352.1	STORAGE LEASEHOLD & RIGHTS	3,938,491	0	0	0	0	3,938,491
352.2	RESERVOIRS	5,844,618	0	0	0	1,427,935	7,272,553
352.3	NON-RECOVERABLE NATURAL GAS	6,440,890	0	0	0	0	6,440,890
353	LINES	6,552,220	0	0	0	0	6,552,220
354	COMPRESSOR STATION EQUIPMENT	29,528,531	85,727	0	0	1,737,553	31,351,812
355	MEASURING / REGULATING EQUIPM	6,700,892	0	0	0	458,515	7,159,407
356	PURIFICATION EQUIPMENT	297,363	0	0	0	0	297,363
357	OTHER EQUIPMENT	1,331,924	105	0	0	0	1,332,029
	Natural Gas Underground Storage Subtotal	88,037,608	154,648	0	0	3,624,002	91,816,259
Local Storage Plant							
360.11	LAND - LNG LINNTON	83,598	0	0	0	0	83,598
360.12	LAND - LNG NEWPORT	536,675	0	0	0	0	536,675
360.2	LAND - OTHER	106,557	0	0	0	0	106,557
361.11	STRUCTURES & IMPROVEMENTS	4,540,966	53,825	0	0	0	4,594,791
361.12	STRUCTURES & IMPROVEMENTS	4,659,407	(2,668)	0	0	0	4,656,739
361.2	STRUCTURES & IMPROVEMENTS -	26,757	0	0	0	0	26,757
362.11	GAS HOLDERS - LNG LINNTON	2,690,579	53,825	0	0	0	2,744,404
362.12	GAS HOLDERS - LNG NEWPORT	5,791,956	0	0	0	0	5,791,956
362.2	GAS HOLDERS - LNG OTHER	1,600	0	0	0	0	1,600
363.11	LIQUEFACTION EQUIP. - LINN	2,921,686	53,825	0	0	0	2,975,511
363.12	LIQUEFACTION EQUIP - NEWPO	7,308,111	0	0	0	0	7,308,111
363.21	VAPORIZING EQUIP - LINNTON	2,629,836	53,824	0	0	0	2,683,660
363.22	VAPORIZING EQUIP - NEWPORT	3,594,015	70,347	0	0	0	3,664,362
363.31	COMPRESSOR EQUIP - LINNTON	180,903	0	0	0	0	180,903
363.32	COMPRESSOR EQUIPMENT - NE	1,390,926	0	0	0	0	1,390,926
363.41	MEASURING & REGULATING EQU	1,091,077	5,026	0	0	151,562	1,247,665
363.42	MEASURING & REGULATING EQU	113,414	0	0	0	0	113,414
363.5	CNG REFUELING FACILITIES	3,051,295	0	0	0	0	3,051,295
363.6	LNG REFUELING FACILITIES	739,473	0	0	0	0	739,473
	Local Storage Plant Subtotal	41,458,832	288,003	0	0	151,562	41,898,397

ACCOUNT SUMMARY BY FUNTIONAL CLASS
NW Natural

Period Beginning: Jan 2015
Period Ending: Dec 2015

Functional Class / FERC Plant Account		Beginning Balance	Additions	Retirements	Transfers	Adjustments	Ending Balance
UTILITY							
Transmission Plant							
365.1	LAND	89,772	0	0	0	0	89,772
365.2	LAND RIGHTS	6,455,177	0	0	0	0	6,455,177
366.3	STRUCTURES & IMPROVEMENTS -	1,041,984	0	0	0	0	1,041,984
367	MAINS	140,349,960	5,075,186	0	0	(102,846)	145,322,300
367.21	NORTH MIST TRANSMISSION LI	1,994,582	0	0	0	0	1,994,582
367.22	SOUTH MIST TRANSMISSION LI	14,949,264	0	0	0	0	14,949,264
367.23	SOUTH MIST TRANSMISSION LI	34,881,341	0	0	0	0	34,881,341
367.24	11.7M S MIST TRANS LINE	17,466,182	0	0	0	0	17,466,182
367.25	12M NORTH S MIST TRANS	18,613,651	0	0	0	0	18,613,651
367.26	38M NORTH S MIST TRANS	68,232,676	0	0	0	0	68,232,676
368	TRANSMISSION COMPRESSOR	0	0	0	0	0	0
369	MEASURING & REGULATE STATION	3,969,549	0	0	0	0	3,969,549
370	COMMUNICATION EQUIPMENT	0	0	0	0	0	0
	Transmission Plant Subtotal	308,044,138	5,075,186	0	0	(102,846)	313,016,479
Distribution Plant							
374.1	LAND	76,386	0	0	0	0	76,386
374.2	LAND RIGHTS	1,856,083	0	0	0	0	1,856,083
375	STRUCTURES & IMPROVEMENTS	49,372	0	0	0	0	49,372
376.11	MAINS < 4"	464,906,167	14,832,797	(286,752)	0	(160,126)	479,292,086
376.12	MAINS 4" & >	420,957,204	15,209,615	(425,131)	0	268,832	436,010,520
377	COMPRESSOR STATION EQUIPMENT	969,942	0	0	0	(151,562)	818,380
378	MEASURING & REG EQUIP - GENER	28,997,225	837,505	0	0	0	29,834,730
379	MEASURING & REG EQUIP - GATE	4,073,081	865,758	0	0	(303)	4,938,536
380	SERVICES	624,298,119	24,431,667	(1,241,545)	0	0	647,488,241
381	METERS	71,083,083	3,653,681	(1,086,754)	0	0	73,650,010
381.1	METERS (ELECTRONIC)	1,464,473	77,201	0	0	0	1,541,674
381.2	ERT (ENCODER RECEIVER TRANS	32,458,063	1,985,436	(535,915)	0	504	33,908,088
382	METER INSTALLATIONS	54,749,773	2,207,536	(3,113,604)	0	(200)	53,843,505
382.1	METER INSTALLATIONS (ELECTR	481,020	0	0	0	0	481,020
382.2	ERT INSTALLATION (ENCODER	8,632,976	0	(105,487)	0	0	8,527,489
383	HOUSE REGULATORS	1,243,208	205,693	0	0	0	1,448,901
386	OTHER PROPERTY ON CUSTOMERS P	0	0	0	0	0	0
387.1	CATHODIC PROTECTION TESTING	173,859	0	0	0	0	173,859

ACCOUNT SUMMARY BY FUNTIONAL CLASS
NW Natural

Period Beginning: Jan 2015
Period Ending: Dec 2015

Functional Class / FERC Plant Account		Beginning Balance	Additions	Retirements	Transfers	Adjustments	Ending Balance
UTILITY							
387.2	CALORIMETERS @ GATE STATIONS	69,794	0	0	0	0	69,794
387.3	METER TESTING EQUIPMENT	72,671	0	0	0	0	72,671
	Distribution Plant Subtotal	1,716,612,499	64,306,888	(6,795,188)	0	(42,855)	1,774,081,344
General Plant							
389	LAND	9,609,258	0	0	0	0	9,609,258
390	STRUCTURES & IMPROVEMENTS	54,853,432	2,377,091	0	0	0	57,230,523
390.1	SOURCE CONTROL FACILITY	17,923,231	0	0	0	0	17,923,231
391.1	OFFICE FURNITURE & EQUIPMEN	9,856,553	554,813	0	0	0	10,411,366
391.2	COMPUTERS	22,897,389	2,862,978	(10,029,192)	0	443,935	16,175,110
391.3	ON SITE BILLING	0	0	0	0	0	0
391.4	CUSTOMER INFORMATION SYSTEM	0	0	0	0	0	0
392	TRANSPORTATION EQUIPMENT	28,886,714	6,088,187	(1,322,375)	0	0	33,652,526
393	STORES EQUIPMENT	119,406	0	0	0	0	119,406
394	TOOLS - SHOP & GARAGE EQUIPUI	16,220,907	424,267	0	0	0	16,645,174
395	LABORATORY EQUIPMENT	68,293	0	0	0	0	68,293
396	POWER OPERATED EQUIPMENT	8,356,164	1,126,133	(550,579)	0	0	8,931,718
397	GEN PLANT-COMMUNICATION EQU	88,322	0	0	0	0	88,322
397.1	MOBILE	475,621	0	0	0	0	475,621
397.2	OTHER THAN MOBILE & TELEMET	1,690,854	0	0	0	0	1,690,854
397.3	TELEMETERING - OTHER	4,617,676	(29,206)	0	0	0	4,588,470
397.4	TELEMETERING - MICROWAVE	1,522,718	124,078	0	0	0	1,646,796
397.5	TELEPHONE EQUIPMENT	394,587	96,155	0	0	0	490,742
398	GEN PLANT-MISCELLANEOUS EQU	0	0	0	0	0	0
398.1	PRINT SHOP	83,249	0	0	0	0	83,249
398.2	KITCHEN EQUIPMENT	12,812	0	0	0	0	12,812
398.3	JANITORIAL EQUIPMENT	14,873	0	0	0	0	14,873
398.4	INSTALLED IN LEASED BUILDINGS	5,393	0	0	0	0	5,393
398.5	OTHER MISCELLANEOUS EQUIPMENT	66,739	0	0	0	0	66,739
	General Plant Subtotal	177,764,191	13,624,495	(11,902,146)	0	443,935	179,930,475
	Oregon Utility Property Grand Total	$2,421,330,350	$88,578,560	($19,770,666)	$0	$3,629,863	$2,493,768,108

ACCOUNT SUMMARY BY FUNTIONAL CLASS
NW Natural

Period Beginning: Jan 2015
Period Ending: Dec 2015

Functional Class / FERC Plant Account		Beginning Balance	Additions	Retirements	Transfers	Adjustments	Ending Balance
NON-UTILITY							
Intangible Plant							
303.1	COMPUTER SOFTWARE	$163,357	$0	$0	$0	$0	$163,357
303.2	CUSTOMER INFORMATION SYSTEM	61,429	0	0	0	0	61,429
Non Utility	Intangible Plant Subtotal	224,786	0	0	0	0	224,786
Natural Gas Underground Storage							
352	WELLS	16,940,451	0	0	0	0	16,940,451
352.1	STORAGE LEASEHOLD & RIGHTS	1,020	0	0	0	0	1,020
352.2	RESERVOIRS	4,989,436	0	0	0	(1,427,935)	3,561,501
353	LINES	1,649,744	0	0	0	0	1,649,744
354	COMPRESSOR STATION EQUIPMENT	14,676,125	171,575	0	0	(1,737,553)	13,110,147
355	MEASURING / REGULATING EQUIPM	9,267,567	(588)	0	0	(458,515)	8,808,465
357	OTHER EQUIPMENT	63,256	0	0	0	0	63,256
Non Utility	Natural Gas Underground Storage Subtotal	47,587,600	170,987	0	0	(3,624,002)	44,134,585
Transmission Plant							
368	TRANSMISSION COMPRESSOR	7,723,454	0	0	0	0	7,723,454
Non Utility	Transmission Plant Subtotal	7,723,454	0	0	0	0	7,723,454
Distribution Plant							
376.12	MAINS 4" & >	878,618	0	0	0	0	878,618
Non Utility	Distribution Plant Subtotal	878,618	0	0	0	0	878,618
General Plant							
389	LAND	438,739	0	0	0	0	438,739
390	STRUCTURES & IMPROVEMENTS	218,156	407	0	0	0	218,563
Non Utility	General Plant Subtotal	656,895	407	0	0	0	657,302
Non Utility Other							
121.1	NON-UTIL PROP-DOCK	1,946,033	0	0	0	0	1,946,033
121.2	NON-UTIL PROP-LAND	125,102	0	0	0	0	125,102
121.3	NON-UTIL PROP-OIL ST	2,616,313	0	0	0	0	2,616,313

ACCOUNT SUMMARY BY FUNTIONAL CLASS

NW Natural

Period Beginning: Jan 2015
Period Ending: Dec 2015

Functional Class FERC Plant Account	Beginning Balance	Additions	Retirements	Transfers	Adjustments	Ending Balance
NON-UTILITY						
121.7 NON-UTIL PROP-APPL CENTER	61,113	0	0	0	0	61,113
121.8 NON-UTIL PROP-STORAGE	288,112	0	(192,074)	0	0	96,038
Non Utility Other	5,036,673	0	(192,074)	0	0	4,844,599
Oregon Non Utility Property Grand Total	$62,108,025	$171,394	($192,074)	$0	($3,624,002)	$58,463,343

Name of Respondent Northwest Natural Gas Company	This Report is: X An Original A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 2015

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

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

Line No.	DESCRIPTION AND LOCATION OF PROPERTY (a)	DATE ORIGINALLY INCLUDED IN THIS ACCOUNT (b)	DATE EXPECTED TO BE USED IN UTILITY SERVICE (c)	BALANCE END OF YEAR (d)
1				
2				
3	Underground Storage	07/2009	Undetermined	127,921
4	Easement	11/2011	Undetermined	136,720
5	Willamette Valley Crossing - Engineering Costs	05/2015	Undetermined	658,514
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40	TOTALS			923,155

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

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

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

Line No.	Description of Project (a)	Construction Work in Progress-Gas (Account 107) (b)	Estimated Additional Cost of Project (c)
1	North Mist	14,470,563	110,529,437
2	Mains and Service Jobs	7,826,993	2,294,637
3	Misc IS Projects	6,595,773	1,508,538
4	Newport LNG Readiness	6,391,150	2,697,758
5	Other	1,564,637	370,073
6	Portland LNG Readiness	1,430,317	609,525
7	Misc Facilities Projects	898,973	527,245
8			
9			
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45	**Total**	39,178,406	118,537,213

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS

NW Natural

Period Beginning: Jan 2015
Period Ending: Dec 2015

Functional Class / FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve
UTILITY									
Intangible Plant									
301	ORGANIZATION	$0	$0	$0	$0	$0	$0	$0	$0
302	FRANCHISES & CONSENTS	0	0	0	0	0	0	0	0
303.1	COMPUTER SOFTWARE	19,450,318	2,366,005	(1,073,332)	0	0	(12,941)	0	20,730,050
303.2	CUSTOMER INFORMATION SYSTEM	30,485,095	0	0	0	0	0	0	30,485,095
303.3	INDUSTRIAL & COMMERCIAL BIL	4,146,951	0	0	0	0	0	0	4,146,951
303.4	CRMS	374,476	154,607	0	0	0	0	0	529,083
303.5	POWERPLANT SOFTWARE	0	0		0	0	0	0	0
	Intangible Plant Subtotal	54,456,839	2,520,612	(1,073,332)	0	0	(12,941)	0	55,891,178
Production Plant - Oil Gas									
304.1	LAND	0	0	0	0	0	0	0	0
305.2	P P O G STRU & IMPR-SEWER S	0	0	0	0	0	0	0	0
305.5	P P O G STRU & IMPR-OTHER Y	13,814	0	0	0	0	0	0	13,814
312.3	P P O G FUEL HANDLING AND S	0	0	0	0	0	0	0	0
318.3	P P O G LIGHT OIL REFINING	152,141	0	0	0	0	0	0	152,141
318.5	P P O G TAR PROCESSING	255,729	0	0	0	0	0	0	255,729
325	NATURAL GAS PROD AND GATHER	0	0	0	0	0	0	0	0
327	NATURAL GAS PROD & GATHERIN	0	0	0	0	0	0	0	0
328	NATURAL GAS PROD AND GATHER	0	0	0	0	0	0	0	0
331	NATURAL GAS PROD & GATHERIN	0	0	0	0	0	0	0	0
332	NATURAL GAS PROD & GATHERIN	0	0	0	0	0	0	0	0
333	NATURAL GAS PROD & GATHERIN	0	0	0	0	0	0	0	0
334	NATURAL GAS PROD & GATHERIN	0	0	0	0	0	0	0	0
	Production Plant - Oil Gas Subtotal	421,683	0	0	0	0	0	0	421,683
Production Plant - Other									
305.11	GAS PRODUCTION - COTTAGE G	8,736	0	0	0	0	0	0	8,736
305.17	STRUCTURES MIXING STATION	51,246	0	0	0	0	0	0	51,246
311	P P OTHER-LIQUEFIED PETROLE	(0)	(0)	0	0	0	0	0	(0)
311.4	P P OTHER-L P G GRANGER	0	0	0	0	0	0	0	0
311.7	LIQUIFIED GAS EQUIPMENT COO	8,066	0	0	0	0	0	0	8,066
311.8	LIQUIFIED GAS EQUIPMENT LIN	6,585	0	0	0	0	0	0	6,585
319	GAS MIXING EQUIPMENT GASCO	194,720	0	0	0	0	0	0	194,720
	Production Plant - Other Subtotal	269,353	(0)	0	0	0	0	0	269,353

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS
NW Natural

Period Beginning: Jan 2015
Period Ending: Dec 2015

Functional Class / FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve
UTILITY									
Natural Gas Underground Storage									
350.1	LAND	0	0	0	0	0	0	0	0
350.2	RIGHTS-OF-WAY	23,367	1,776	0	0	0	0	0	25,143
351	STRUCTURES AND IMPROVEMENTS	2,420,511	122,144	0	0	0	0	0	2,542,655
352	WELLS	10,560,588	414,974	0	0	0	0	0	10,975,563
352.1	STORAGE LEASEHOLD & RIGHTS	1,440,015	76,801	0	0	0	0	0	1,516,816
352.2	RESERVOIRS	1,721,701	136,611	0	0	0	380,287	0	2,238,598
352.3	NON-RECOVERABLE NATURAL GAS	3,077,618	121,089	0	0	0	0	0	3,198,707
353	LINES	2,771,168	134,976	0	0	0	0	0	2,906,144
354	COMPRESSOR STATION EQUIPMENT	15,525,294	818,342	0	0	0	688,663	0	17,032,299
355	MEASURING / REGULATING EQUIPM	3,952,667	152,044	0	0	0	163,412	0	4,268,124
356	PURIFICATION EQUIPMENT	210,321	7,375	0	0	0	0	0	217,696
357	OTHER EQUIPMENT	766,647	30,368	0	0	0	0	0	797,015
	Natural Gas Underground Storage Subtotal	42,469,899	2,016,501	0	0	0	1,232,361	0	45,718,760
Local Storage Plant									
360.11	LAND - LNG LINNTON	0	0	0	0	0	0	0	0
360.12	LAND - LNG NEWPORT	0	0	0	0	0	0	0	0
360.2	LAND - OTHER	0	0	0	0	0	0	0	0
361.11	STRUCTURES & IMPROVEMENTS	1,683,223	246,695	0	0	0	0	0	1,929,917
361.12	STRUCTURES & IMPROVEMENTS	2,251,279	142,547	0	0	0	0	0	2,393,826
361.2	STRUCTURES & IMPROVEMENTS -	10,028	466	0	0	0	0	0	10,493
362.11	GAS HOLDERS - LNG LINNTON	2,199,125	63,281	0	0	0	0	0	2,262,406
362.12	GAS HOLDERS - LNG NEWPORT	5,281,034	157,541	0	0	0	0	0	5,438,576
362.2	GAS HOLDERS - LNG OTHER	1,151	21	0	0	0	0	0	1,172
363.11	LIQUEFACTION EQUIP. - LINN	2,465,662	84,207	0	0	0	0	0	2,549,869
363.12	LIQUEFACTION EQUIP - NEWPO	7,067,748	59,929	0	0	0	0	0	7,127,677
363.21	VAPORIZING EQUIP - LINNTON	2,587,862	36,849	0	0	0	0	0	2,624,712
363.22	VAPORIZING EQUIP - NEWPORT	2,609,196	3,195	0	0	0	0	0	2,612,390
363.31	COMPRESSOR EQUIP - LINNTON	197,047	9,850	0	0	0	0	0	206,897
363.32	COMPRESSOR EQUIPMENT - NE	247,128	65,513	0	0	0	0	0	312,641
363.41	MEASURING & REGULATING EQU	597,923	491	0	0	0	5,849	0	604,263
363.42	MEASURING & REGULATING EQU	116,630	839	0	0	0	0	0	117,469
363.5	CNG REFUELING FACILITIES	1,297,064	31,733	0	0	0	0	0	1,328,797
363.6	LNG REFUELING FACILITIES	739,473	0	0	0	0	0	0	739,473
	Local Storage Plant Subtotal	29,351,573	903,157	0	0	0	5,849	0	30,260,579

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS
NW Natural

Period Beginning: Jan 2015
Period Ending: Dec 2015

Functional Class FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve
UTILITY									
Transmission Plant									
365.1	LAND	0	0	0	0	0	0	0	0
365.2	LAND RIGHTS	1,642,326	122,003	0	0	0	0	0	1,764,329
366.3	STRUCTURES & IMPROVEMENTS -	256,648	20,319	0	0	0	0	0	276,966
367	MAINS	18,902,681	4,350,871	0	0	0	(6,219)	0	23,247,332
367.21	NORTH MIST TRANSMISSION LI	979,770	50,061	0	0	0	0	0	1,029,831
367.22	SOUTH MIST TRANSMISSION LI	9,565,979	367,724	0	0	0	0	0	9,933,703
367.23	SOUTH MIST TRANSMISSION LI	10,895,030	931,269	0	0	0	0	0	11,826,299
367.24	11.7M S MIST TRANS LINE	4,367,353	452,342	0	0	0	0	0	4,819,695
367.25	12M NORTH S MIST TRANS	4,335,890	485,782	0	0	0	0	0	4,821,672
367.26	38M NORTH S MIST TRANS	16,100,013	1,773,923	0	0	0	0	0	17,873,935
368	TRANSMISSION COMPRESSOR	(9)	0	0	0	0	0	0	(9)
369	MEASURING & REGULATE STATION	1,232,219	106,384	0	0	0	0	0	1,338,604
370	COMMUNICATION EQUIPMENT	0	0	0	0	0	0	0	0
	Transmission Plant Subtotal	68,277,899	8,660,678	0	0	0	(6,219)	0	76,932,358
Distribution Plant									
374.1	LAND	0	0	0	0	0	0	0	0
374.2	LAND RIGHTS	1,121,443	139,206	0	0	0	0	0	1,260,649
375	STRUCTURES & IMPROVEMENTS	49,323	200	0	0	0	0	0	49,523
376.11	MAINS < 4"	254,908,879	11,777,692	(286,752)	(1,104,201)	9,810	(3,010)	0	265,302,418
376.12	MAINS 4" & >	168,275,971	10,274,367	(425,131)	(1,378,332)	10,734	9,402	0	176,767,010
377	COMPRESSOR STATION EQUIPMENT	597,668	19,510	0	0	0	(5,849)	0	611,329
378	MEASURING & REG EQUIP - GENER	9,407,457	629,054	0	0	0	0	0	10,036,511
379	MEASURING & REG EQUIP - GATE	941,528	189,193	0	0	0	(1)	0	1,130,720
380	SERVICES	332,935,655	17,229,951	(1,241,545)	(2,383,422)	0	0	0	346,540,640
381	METERS	18,186,616	1,649,923	(1,086,754)	0	0	0	0	18,749,785
381.1	METERS (ELECTRONIC)	681,747	302,521	0	0	0	0	0	984,267
381.2	ERT (ENCODER RECEIVER TRANS	11,391,969	2,204,936	(535,915)	0	0	14	0	13,061,004
382	METER INSTALLATIONS	9,388,195	1,280,414	(3,113,604)	0	0	(13)	0	7,554,993
382.1	METER INSTALLATIONS (ELECTR	29,044	11,490	0	0	0	0	0	40,534
382.2	ERT INSTALLATION (ENCODER	3,378,948	571,077	(105,487)	0	0	0	0	3,844,538
383	HOUSE REGULATORS	124,229	38,872	0	0	0	0	0	163,101
386	OTHER PROPERTY ON CUSTOMERS P	0	0	0	0	0	0	0	0
387.1	CATHODIC PROTECTION TESTING	139,519	956	0	0	0	0	0	140,475
387.2	CALORIMETERS @ GATE STATIONS	69,794	0	0	0	0	0	0	69,794
387.3	METER TESTING EQUIPMENT	72,671	0	0	0	0	0	0	72,671
	Distribution Plant Subtotal	811,700,657	46,319,364	(6,795,188)	(4,865,955)	20,543	543	0	846,379,964

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS
NW Natural

Period Beginning: Jan 2015
Period Ending: Dec 2015

Functional Class FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve
UTILITY									
General Plant									
389	LAND	437,351	0	0	0	0	0	0	437,351
390	STRUCTURES & IMPROVEMENTS	7,227,695	1,078,327	0	0	0	0	0	8,306,022
390.1	SOURCE CONTROL FACILITY	1,290,207	940,970	0	0	0	0	0	2,231,176
391.1	OFFICE FURNITURE & EQUIPMEN	5,659,684	798,327	0	0	0	0	0	6,458,011
391.2	COMPUTERS	19,598,592	3,758,878	(10,029,192)	0	0	12,941	0	13,341,218
391.3	ON SITE BILLING	0	0	0	0	0	0	0	0
391.4	CUSTOMER INFORMATION SYSTEM	0	0	0	0	0	0	0	0
392	TRANSPORTATION EQUIPMENT	8,594,290	1,511,374	(1,322,375)	0	234,987	0	0	9,018,277
393	STORES EQUIPMENT	119,406	0	0	0	0	0	0	119,406
394	TOOLS - SHOP & GARAGE EQUIPUI	9,143,686	1,144,528	0	0	4,301	0	0	10,292,515
395	LABORATORY EQUIPMENT	68,293	0	0	0	0	0	0	68,293
396	POWER OPERATED EQUIPMENT	3,387,461	174,990	(550,579)	0	150,376	0	0	3,162,248
397	GEN PLANT-COMMUNICATION EQU	20,565	6,545	0	0	0	0	0	27,110
397.1	MOBILE	401,156	3,234	0	0	0	0	0	404,390
397.2	OTHER THAN MOBILE & TELEMET	1,690,854	0	0	0	0	0	0	1,690,854
397.3	TELEMETERING - OTHER	2,971,990	3,250	0	0	0	0	0	2,975,239
397.4	TELEMETERING - MICROWAVE	917,244	15,889	0	0	0	0	0	933,133
397.5	TELEPHONE EQUIPMENT	93,501	78,997	0	0	0	0	0	172,497
398	GEN PLANT-MISCELLANEOUS EQU	0	0	0	0	0	0	0	0
398.1	PRINT SHOP	83,249	0	0	0	0	0	0	83,249
398.2	KITCHEN EQUIPMENT	2,561	525	0	0	0	0	0	3,086
398.3	JANITORIAL EQUIPMENT	14,873	0	0	0	0	0	0	14,873
398.4	INSTALLED IN LEASED BUILDINGS	5,393	0	0	0	0	0	0	5,393
398.5	OTHER MISCELLANEOUS EQUIPMENT	66,739	0	0	0	0	0	0	66,739
	General Plant Subtotal	61,794,788	9,515,834	(11,902,146)	0	389,664	12,941	0	59,811,080
	Utility Property Grand Total	$1,068,742,691	$69,936,146	($19,770,666)	($4,865,955)	$410,207	$1,232,534	$0	$1,115,684,955
NON UTILITY									
Intangible Plant									
303.1	COMPUTER SOFWARE	$31,211	$7,041	$0	$0	$0	$0	$0	$38,252
303.2	CUSTOMER INFORMATION SYSTEM	33,677	4,275	0	0	0	0	0	37,952
Non Utility	Intangible Plant Subtotal	64,888	11,316	0	0	0	0	0	76,204

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS
NW Natural

Period Beginning: Jan 2015
Period Ending: Dec 2015

Functional Class / FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve
NON-UTILITY									
Natural Gas Underground Storage									
352	WELLS	2,897,870	350,667	0	0	0	0	0	3,248,538
352.1	STORAGE LEASEHOLD & RIGHTS	161	20	0	0	0	0	0	181
352.2	RESERVOIRS	1,039,144	78,731	0	0	0	(380,287)	0	737,589
353	LINES	286,345	33,985	0	0	0	0	0	320,330
354	COMPRESSOR STATION EQUIPMENT	4,026,791	363,726	0	0	0	(688,663)	0	3,701,854
355	MEASURING / REGULATING EQUIPM	1,696,887	194,466	0	0	0	(163,412)	0	1,727,941
357	OTHER EQUIPMENT	7,271	1,442	0	0	0	0	0	8,714
Non Utility	Natural Gas Underground Storage Subtotal	9,954,470	1,023,037	0	0	0	(1,232,361)	0	9,745,146
Transmission Plant									
368	TRANSMISSION COMPRESSOR	1,609,866	238,655	0	0	0	0	0	1,848,520
Non Utility	Transmission Plant Subtotal	1,609,866	238,655	0	0	0	0	0	1,848,520
Distribution Plant									
376.12	MAINS 4" & >	171,959	21,319	0	0	0	0	0	193,278
Non Utility	Distribution Plant Subtotal	171,959	21,319	0	0	0	0	0	193,278
General Plant									
389	LAND	0	0	0	0	0	0	0	0
390	STRUCTURES & IMPROVEMENTS	21,946	3,974	0	0	0	0	0	25,920
Non Utility	General Plant Subtotal	21,946	3,974	0	0	0	0	0	25,920
Non Utility Other									
121.1	NON-UTIL PROP-DOCK	1,951,925	(4,858)	0	0	0	0	0	1,947,067
121.2	NON-UTIL PROP-LAND	0	0	0	0	0	0	0	0
121.3	NON-UTIL PROP-OIL ST	2,211,494	3,360	0	0	0	0	0	2,214,854
121.7	NON-UTIL PROP-APPL CENTER	25,823	4,219	0	0	0	0	0	30,042
121.8	NON-UTIL PROP-STORAGE	(1)	0	0	0	0	0	0	(1)
Non Utility	Other	4,189,241	2,721	0	0	0	0	0	4,191,962
	Non Utility Property Grand Total	$16,012,369	$1,301,022	$0	$0	$0	($1,232,361)	$0	$16,081,031

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS
NW Natural

Period Beginning: Jan 2015
Period Ending: Dec 2015

Functional Class FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve
TOTAL SUMMARY ALL UTILITY DEPRECIATION RESERVES 12/31/2015									
OREGON									
108010	($31,823,751)								
108011	844,496,119								
108012	11,756,897								
108013	(2,695,451)								
108014	(395,452)								
108015	3,256,811								
108100	0								
108102	296,599,619								
108002	(5,791,902)								
108003	(25,992)								
108004	308,317								
108666	0								
SUBTOTAL		1,115,685,215							
ADD:									
108001 REMOVAL WORK IN PROCESS		(21,122,848)							
TOTAL OREGON UTILITY DEPRECIATION		1,094,562,367							
TOTAL SUMMARY ALL NON-UTILITY RESERVES DEPRECIATION									
NON UTILITY									
122027	$1,034								
122028	4,293,054								
122100	11,276,832								
122002	(531,316)								
122029	0								
122026	1,113,338								
	(71,969)								
TOTAL NON UTILITY DEPRECIATION		$16,080,973							

Name of Respondent	This Report is:	Date of Report	Year of Report
Northwest Natural Gas Company	(1) X An Original (2) A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

STATE OF OREGON - ALLOCATED

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

Line No.	ITEM (a)	TOTAL (b)	ELECTRIC (c)	GAS (d)	OTHER (SPECIFY) ___ (e)	OTHER (SPECIFY) ___ (f)	COMMON (g)
1	UTILITY PLANT						
2	In Service						
3	Plant in Service (Classified)						
4	Property Under Capital Leases						
5	Plant Purchased or Sold						
6	Completed Construction not Classified						
7	Experimental Plant Unclassified						
8	TOTAL *(Enter Total of lines 3 thru 7)*				**INFORMATION NOT AVAILABLE**		
9	Leased to Others						
10	Held for Future Use						
11	Construction Work in Progress						
12	Acquisition Adjustments						
13	TOTAL Utility Plant *(Lines 8 thru 12)*						
14	Accum. Prov. For Depr., Amort., & Depl.						
15	Net Utility Plant (line 13 less 14)						
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION & DEPLETION						
17	In Service:						
18	Depreciation						
19	Amort. & Depl: Of Producing Natural Gas Land & Land Rights						
20	Amort. Of Underground Storage Land & Land Rights						
21	Amort. Of Other Utility Plant						
22	TOTAL In Service *(Lines 18 thru 21)*						
23	Leased to Others						
24	Depreciation						
25	Amortization and Depletion						
26	TOTAL Leased to Others (Lines 24 and 25)						
27	Held for Future Use						
28	Depreciation						
29	Amortization						
30	TOTAL held for Future Use *(Lines 28 and 29)*						
31	Abandonment of Leases (Natural Gas)						
32	Amort. Of Plant Acquisition Adj.						
33	TOTAL Accumulated Provisions (should agree with line 14) *(Lines 22, 26, 30, 31 & 32)*						

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	(1) X An Original (2) A Resubmission		Dec. 31, 2015

STATE OF OREGON - ALLOCATED GAS PLANT IN SERVICE

1. Report below the original cost of gas plant in service
2. In addition to Account 101, *Gas Plant In Service (Classified)*, this page and the next include Account 102, *Gas Plant Purchased or Sold,* Account 103, *Completed Construction Not Classified - Gas.*
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
5. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions or prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on Estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) reversals of tentative distributions of prior year unclassified retirements. Attach supplemental statement showing the account distributions of these tentative classifications in column (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at the end of the year. (**Continued on page 33**)

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
1	1. Intangible Plant						
2	301 Organization						
3	302 Franchises and Consents						
4	303 Miscellaneous Intangible Plant						
5	TOTAL Intangible Plant						
6	2. Production Plant						
7	Natural Gas Production & Gathering Plant						
8	325.1 Producing Lands			**INFORMATION NOT AVAILABLE**			
9	325.2 Producing Leaseholds						
10	325.3 Gas Rights						
11	325.4 Rights-of-Way						
12	325.5 Other Land and Land Rights						
13	326 Gas Well Structures						
14	327 Field Compressor Station Structures						
15	328 Field Meas. And Reg. Sta. Structures						
16	329 Other Structures						
17	330 Producing Gas Wells - Well Construction						
18	331 Producing Gas Wells - Well Equipment						
19	332 Field Lines						
20	333 Field Compressor Station Equipment						
21	334 Field Mess. And Reg. Sta. Equipment						
22	335 Drilling and Cleaning Equipment						
23	336 Purification Equipment						
24	337 Other Equipment						
25	338 Unsuccessful Explor. & Devel. Costs						
26	TOTAL Production & Gathering Plant						
27	Products Extraction Plant						
28	340 Land and Land Rights						
29	341 Structures and Improvements						
30	342 Extraction and Refining Equipment						
31	343 Pipe lines						
32	344 Extracted Products Storage Equipment						

Name of Respondent	This Report is:	Date of Report	Year of Report
Northwest Natural Gas Company	(1) X An Original (2) A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

STATE OF OREGON - ALLOCATED GAS PLANT IN SERVICE (CONT'D)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
	2. Production Plant (Con't) Products Extraction Plant (Con't)						
33	345 Compressor Equipment						
34	345 Gas Meas. And Reg. Equipment						
35	347 Other Equipment						
36	TOTAL Products Extraction Plant						
37	TOTAL Nat. Gas Production Plant						
38	Mfd. Gas Prod. Plant (*Submit Suppl. Stmt*)						
39	TOTAL Production Plant						
40	3. Natural Gas Storage & Proc. Plant						
41	Underground Storage Plant						
42	350.1 Land						
43	350.2 Rights-of-Way				**INFORMATION NOT AVAILABLE**		
44	351 Structures & Improvements						
45	352 Wells						
46	352.1 Storage Leaseholds & Rights						
47	352.2 Reservoirs						
48	352.3 Non-recoverable Natural Gas						
49	353 Lines						
50	354 Compressor Station Equipment						
51	355 Measuring & Reg. Equipment						
52	356 Purification Equipment						
53	357 Other Equipment						
54	TOTAL Underground Storage Plant						
55	Other Storage Plant						
56	360 Land and Land Rights						
57	361 Structures and Improvements						
58	362 Gas Holders						
59	363 Purification Equipment						
60	363.1 Liquefaction Equipment						
61	363.2 Vaporizing Equipment						
62	363.3 Compressor Equipment						
63	363.4 Meas. And Reg. Equipment						
64	363.5 Other Equipment						
65	TOTAL Other Storage Plant						

Name of Respondent	This Report is:	Date of Report	Year of Report
Northwest Natural Gas Company	(1) X An Original (2) A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

STATE OF OREGON - ALLOCATED GAS PLANT IN SERVICE (CONT'D)

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
66	Base Load Liquefied Natural Gas Terminaling and Processing Plant						
67	364.1 Land and Land Rights						
68	364.2 Structures and Improvements						
69	364.3 LNG Processing Terminal Equipment						
70	364.4 LNG Transportation Equipment						
71	364.5 Measuring and Regulating Equipment						
72	364.6 Compressor Station Equipment						
73	364.7 Communications Equipment						
74	364.8 Other Equipment						
75	TOTAL Base Load Liquefied Natural						
76	Gas, Terminaling, & Processing Plant				INFORMATION NOT AVAILABLE		
77	TOTAL Nat. Gas Storage & Proc. Plant						
78	4. Transmission Plant						
79	365.1 Land and Land Rights						
80	365.2 Rights-of-Way						
81	366 Structures and Improvements						
82	367 Mains						
83	368 Compressor Station Equipment						
84	369 Measuring and Reg. Sta. Equipment						
85	370 Communication Equipment						
86	371 Other Equipment						
87	TOTAL Transmission Plant						
88	5. Distribution Plant						
89	374 Land and Land Rights						
90	375 Structures and Improvements						
91	376 Mains						
92	377 Compressor Station Equipment						
93	378 Meas. And Reg. Sta. Equip. - General						
94	379 Meas. And Reg. Sta. Equip. - City Gate						
95	380 Services						
96	381 Meters						
97	382 Meter Installations						
98	383 House Regulators						
99	384 House Reg. installations						
100	385 Industrial Meas. & Reg. Sta. Equip						
101	386 Other Prop. On Customers' premises						
102	387 Other Equipment						
103	TOTAL Distribution Plant						

Name of Respondent Northwest Natural Gas Company	This Report is: (1) X An Original (2) A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 2015

STATE OF OREGON - ALLOCATED GAS PLANT IN SERVICE (CONT'D)

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
104	6. General Plant						
105	389 Land and Land Rights						
106	390 Structures and Improvements						
107	391 Office Furniture and Equipment						
108	392 Transportation Equipment						
109	393 Store Equipment			INFORMATION NOT AVAILABLE			
110	394 Tools, Shop, and Garage Equipment						
111	395 Laboratory Equipment						
112	396 Power Operated Equipment						
113	397 Communication Equipment						
114	398 Miscellaneous Equipment						
115	Subtotal						
116	399 Other Intangible Property						
117	TOTAL General Plant						
118	TOTAL (Accounts 101 and 106)						
119	Gas Plant Purchased (*See Instr. 8*)						
120	(Less) Gas Plant Sold (*See Instr. 8*)						
121	Experimental Gas Plant Unclassified						
122	TOTAL Gas Plant In Service						

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

STATE OF OREGON - ALLOCATED GAS PLANT HELD FOR FURTURE USE (Account 105)

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

Line No.	Description and Location of Property (a)	Date Originally Included in this account (b)	Date Expected to be Used In Utility Service (c)	Balance at End of Year (d)
1				
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12	**INFORMATION NOT AVAILABLE**			
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50	TOTALS			

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

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

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

Line No.	Description of Project (a)	Construction Work in Progress (Account 107) (b)	Estimated Additional Cost of Project (c)
1			$
2			
3			
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11	**INFORMATION NOT AVAILABLE**		
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41			
42			
43			
44	TOTALS		

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

STATE OF OREGON - ALLOCATED ACCUMULATED PROVISION FOR DEPRECIATION OF GAS UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustements during the year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, line 11, column (c), and that reported for gas plant in service, pages 32-35, column (d) excluding retirements of non-depreciable property.
3. The provisions of Account 108 of the Uniform System of Accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year-end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund of similar method of depreciation accounting.

Section A. Balances and Changes During Year

	ITEM (a)	TOTAL (c+d+e) (b)	GAS PLANT IN SERVICE (c)	GAS PLANT HELD FOR FUTURE USE (d)	GAS PLANT LEASED TO OTHERS (e)
1	Balance Beginning of Year				
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense				
4	(413) Exp. Of Gas Plt. Lease to Others				
5	Transportation Expenses - Clearing				
6	Other Clearing Accounts				
7	Other Accounts (Specify):				
8					
9	Total Deprec. Prov. For Year *(Enter total of lines 3-8)*		**INFORMATION NOT AVAILABLE**		
10	Net Charges for Plant Retired:				
11	Book Cost of Plant Retired				
12	Cost of Removal				
13	Salvage (Credit)				
14	TOTAL Net Charges for Plant Ret. *(Enter Total of lines 11-13)*				
15	Other Debit or Credit Items (Describe):				
16					
17	Balance End of Year *(Enter Total of Lines 1,9, 14, 15,& 16)*				

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

	ITEM (a)	TOTAL (c+d+e) (b)	GAS PLANT IN SERVICE (c)	GAS PLANT HELD FOR FUTURE USE (d)	GAS PLANT LEASED TO OTHERS (e)
18	Production - Manufactured Gas				
19	Prod. And Gathering - Natural Gas				
20	Products Extraction - Natural Gas				
21	Underground Gas Storage				
22	Other Storage Plant				
23	Base Load LNG Term and Proc. Plt.				
24	Transmission				
25	Distribution				
26	General				
27	TOTAL *(Total of Lines 18 thru 26)*				

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

STATE OF OREGON - GAS STORED (Account 117, 164.1, 164.2 and 164.3)

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

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

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

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

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

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

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

Line No.	Description	NONCURRENT (ACCOUNT 117) (a)	CURRENT (ACCOUNT 164.1) (b)	LNG (ACCOUNT 164.2) (c)	LNG (ACCOUNT 164.3) (d)	Total (e)
1	Balance, beginning of year					
2	Gas delivered to storage					
3	(Contra Account)		**SEE FERC ANNUAL REPORT**			
4	Gas withdrawn from storage		**PAGE 220**			
5	(Contra Account)					
6	Other debits or credits					
7	(Explain)					
8						
9						
10						
11						
12	Balance, end of year					
13	MCF					
14	Amount per Mcf					

Line No.		
15	State basis of segregation of inventory between current and noncurrent portions.	
16		
17	Gas delivered to storage:	
18	Mcf	
19	Amount per Mcf	
20	Cost basis of gas delivered to storage:	
21	Specify: Own production (give production area, see	
22	uniform system of accounts); average system purchases	
23	specific purchases (state which purchases).	
24	Does cost of gas delivered to storage include any expenses	
25	for use of respondent's transmission, storage, or other	
26	facilities? If so, give particulars and date of Commission	
27	approval of the accounting.	
28		
29	Gas withdrawn from storage:	
30	Mcf	
31	Amount per Mcf	
32	Cost basis of withdrawals:	
33	Specify: average cost, lifo, fifo. (Explain any change in	
34	inventory basis during year and give date of Commission;	
35	approval of the change or approval of an inventory basis	
36	different from that referred to in uniform system of accounts)	
37		
38		
39		

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

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

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

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

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

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

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

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

5. Column instructions are as follows:

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

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

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

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

<u>Column (g)</u> - List the assigned commission rate schedule number or small producer certificate docket number. Use the designation "NF" in Column (g) to indicate non-jurisdictional purchases.

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

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

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

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

<u>Colum (l)</u> - State the dollar amount (omit cents) paid and previously paid for the volumes of gas shown in Column (k).

<u>Column (m)</u> - State the average cost per MCF to the nearest hundredth of a cent. (Column (l) divided by Column (k) multiplied by 100).

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Name of Respondent	This Report Is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

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

Line No.	NAME OF SELLER (DESIGNATE ASSOCIATED COMPANIES) (a)	NAME OF PRODUCING FIELD OR GASOLINE PLANT (b)	NET RATE EFFECTIVE DECEMBER 31 (c)
1			
2			
3			
4			
5			
6			
7			
8			
9			
10	**SEE FERC ANNUAL REPORT PAGE 520**		
11			
12			
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Name of Respondent Northwest Natural Gas Company	This Report Is: X An Original A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 2015

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

Seller Code (d)	State Code (e)	County Code (f)	Rate Schedule No. (g)	Rate Schedule Suffix (h)	Date of Contract (i)	Approx BTU Per CU Ft. (j)	Gas Purchased - MCF (14.73 PSIA 60°F) (k)	Cost of Gas (l)	Cost Per MCF (Cents) (m)	Line No.
										1
										2
										3
										4
										5
										6
										7
			SEE FERC ANNUAL REPORT PAGE 520							8
										9
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Name of Respondent	This Report Is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

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

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

Line No.	PURPOSE FOR WHICH GAS WAS USED (a)	ACCOUNT CHARGED (b)	NATURAL GAS: Dth OF GAS USED (14.73 PSIA AT 60° F) (c)	NATURAL GAS: AMOUNT OF CREDIT (d)	NATURAL GAS: AMOUNT PER Dth (CENTS) (e)	MANUFACTURED GAS: MCF OF GAS USED (14.73 PSIA AT 60° F) (f)	MANUFACTURED GAS: AMOUNT OF CREDIT (g)
1	810 Gas used for Compressor Station Fuel - Credit						
2	811 Gas used for Products Extraction - Credit						
3	(a) Gas shrinkage & other usage in respondent's own processing						
4	(b) Gas shrinkage, etc. for respondent's gas processed by others						
5	812 Gas used for Other Utility Operations - Credit						
6	(Report separately for each principal use, Group minor uses.)						
7							
8	Portland and District Centers		102,499	223,813			
9	Storage Plants		164,976	Included in the Cost of Inventory			
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25	TOTAL		267,475	223,813	0.84		

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northwest Natural Gas Company	(1) X An Original (2) A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

STATE OF OREGON - GAS ACCOUNT - NATURAL GAS

1. The purpose of this schedule is to account for the quantity of natural gas received and delivered by the respondent, taking into consideration differences in pressure bases used in measuring Mcf of natural gas received and delivered.
2. Natural gas means either natural gas unmixed or any mixture of natural and manufactured gas.
3. Enter in column (c) the Dth as reported in the schedules indicated for the items of receipts and deliveries.
4. In a footnote report the volumes of gas from respondent's own production delivered to respondent's transmission system and included in natural gas sales.
5. If the respondent operates two or more systems which are not interconnected, separate schedules should be submitted. Insert pages for this purpose.

Line No.	Item (a)	Ref. Page No. (b)	Amount of Dth (c)
1	**GAS RECEIVED**		
2	Natural Gas Produced		-
3	LPG Gas Produced and Mixed with Natural Gas		-
4	Manufactured Gas Produced and Mixed with Natural Gas		-
5	Purchased Gas		
6	(a.) Wellhead		-
7	(b.) Field Lines		577,324
8	(c.) Gasoline Plants		-
9	(d.) Transmission Line		-
10	(e.) City Gate Under FERC Rate Schedules		57,943,849
11	(f.) LNG		-
12	(g.) Other		-
13	TOTAL, Gas Purchased (Enter Total of lines 7 thru 13)		58,521,173
14	Gas of Others Received for Transportation		34,900,668
15	Receipts of Respondents' Gas Transported or Compressed by Others		-
16	Exchange Gas Received		-
17	Gas Withdrawn from Underground Storage	*	1,480,537
18	Gas Received from LNG Storage		330,089
19	Gas Received from LNG Processing		-
20	Other Receipts (Specify): Off System Storage Withdrawal		3,093,652
21	TOTAL Receipts (Enter Total of lines 2 thru 5, 13, and 14 thru 20)		98,326,119

Note: * This amount does not tie to system page 512 as it only includes Oregon storage sites.

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northwest Natural Gas Company	(1) X An Original (2) A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

STATE OF OREGON - GAS ACCOUNT - NATURAL GAS (Continued)

01 NAME OF SYSTEM OREGON

Line No.	Item (a)	Ref. Page No. (b)	Amount of Dth (c)
	GAS DELIVERED		
22	Natural Gas Sales		
23	Field Sales		
24 25	(i) To Interstate Pipeline Companies for Resale Pursuant to FERC Rate Schedules		-
26	(ii) Retail Industrial Sales		-
27	(iii) Other Field Sales		-
28	TOTAL, Field Sales (Enter Total of lines 26 thru 28)		-
29	Transmission System Sales		
30	(i) To Interstate Pipeline Co. for Resale Under FERC Rate Schedules		-
31 32	(ii) To Interstate Pipeline Co. and Gas Utilities for Resale Under FERC Rate Schedules		-
33	(iii) Mainline Industrial Sales Under FERC Certification		-
34	(iv) Other Mainline Industrial Sales		-
35	(v) Other Transmission System Sales		-
36	TOTAL, Transmission System Sales (Enter Total of lines 31 thru 35)		-
37	Local Distribution by Respondent		
38	(i) Retail Industrial Sales		8,569,382
39	(ii) Other Distribution System Sales		50,506,784
40	TOTAL, Distribution System Sales (Lines 38 + 39)		59,076,166
41	Unbilled Therms		701,145
42	TOTAL SALES (Enter Total of lines 29, 36, 40, and 41)		59,777,311
43			
44	Deliveries of Gas Transported or Compressed for:		
45	(a.) Other Interstate Pipeline Companies		-
46	(b.) Others - Transportation		34,900,667
47	TOTAL, Gas Transported or Compressed for Others (Enter Total of lines 44 and 45)		34,900,667
48	Deliveries of Respondent's Gas for Trans. or Compression by Others		-
49	Exchange Gas Delivered		-
50	Natural Gas Used by Respondent		267,475
51	Natural Gas Delivered to Underground Storage	*	2,500,438
52	Natural Gas Delivered to LNG Storage		155,242
53	Natural Gas Delivered to LNG Processing	331	-
54	Natural Gas for Franchise Requirements		-
55	Other Deliveries (Specify): FIK		-
56	TOTAL SALES & OTHER DELIVERIES (Lines 42, 47, 48 thru 55)		97,601,133
	UNACCOUNTED FOR		
57	Production System Losses		-
58	Storage Losses: Mist Gas Loss		-
59	Transmission System Losses		-
60	Distribution System Losses		724,986
61	Other Losses (Leakage)		-
62	TOTAL Unaccounted for (Enter Total of lines 57 thru 61)		724,986
63	TOTAL SALES, OTHER DELIVERIES, AND UNACCOUNTED FOR (Enter Total of lines 55 and 62)		98,326,119

Note: * This amount does not tie to system page 512 as it only includes Oregon storage sites.

Name of Respondent Northwest Natural Gas Company	This Report is: X An Original A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 2015

STATE OF OREGON - MISCELLANEOUS GENERAL EXPENSES (Account 930.2)

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

LINE NO.	ITEMS (a)	TOTAL (b)	AMOUNT APPLICABLE TO STATE OF OREGON (c)	AMOUNT APPLICABLE TO OTHER STATES (d)
	SEE FERC ANNUAL REPORT PAGE 335			

Name of Respondent	This Report is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

STATE OF OREGON - POLITICAL ADVERTISING

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

Line No.	DESCRIPTION (a)	ACCOUNT CHARGED (b)	AMOUNT (c)
	NONE		

Name of Respondent	This Report is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

STATE OF OREGON - POLITICAL CONTRIBUTIONS

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

Line No.	Description of Investment (a)	Account Charged (b)	Amount (c)
1	INTERNAL LOBBY AND INTERNAL RESOURCES	426-04935	134,568
2	NATURAL GAS POLITICAL	426-04935	100,000
3	GROW OREGON NOW	426-04935	20,000
4	GROW OREGON	426-04935	16,700
5	CM3 LLC	426-04935	1,226
6	CITIZENS FOR SAFE REYNOLDS SCHOOLS	426-04935	1,000
7	OTHER < $1,000	426-04935	9,716
8	Total 426-04935	Total	283,210
9			
10			
11	NATURAL GAS POLITICAL COMMITTEE	426-04955	260,000
12	Total 426-04955	Total	260,000
13			
14			
15	INTERNAL LOBBY AND INTERNAL RESOURCES	426-04950	306,043
16	OTHER < $1,000	426-04950	1,643
17	Total 426-04950	Total	307,686
18			
19			
20		Total	850,896

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

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

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

Line No.	Description (a)	Account Number (b)	Total Amount (c)	Amount assigned to Oregon (d)
1	All expenditures shown below are reflected in the Statement of Income of			
2	Northwest Natural Gas for the year ended December 31, 2015			
3	All expenditures are based upon the accrual method of accounting.			
4				
5	**Name of Affiliated Party: Gill Ranch Storage, LLC**			
6	Relationship: Wholly Owned Subsidiary of NW Natural Gas Storage, LLC			
7	Shared Services Agreement - see FERC Form 2 p. 358	Various	706,798	N/A
8	Corporate income taxes accrued and charged on behalf of affiliated party			
9	Federal income tax expense (benefit) - see FERC Form 2 p. 263B	409-43075	(4,498,340)	N/A
10	State income tax expense (benefit) - see FERC Form 2 p. 263C	409-43145	(2,285,365)	N/A
11	**Total of transactions with affiliated party**		(6,076,907)	
12				
13				
14	**Name of Affiliated Party: Northwest Natural Energy, LLC**			
15	Relationship: Wholly Owned Subsidiary of Northwest Natural Gas Company			
16	NW Energy LLC Investment	123.1	165,634,862	N/A
17	Shared Services Agreement - see FERC Form 2 p. 358	Various	161,463	N/A
18	Corporate income taxes accrued and charged on behalf of affiliated party			
19	Federal income tax expense (benefit) - see FERC Form 2 p. 263B	409-49001	(76,655)	N/A
20	State income tax expense (benefit) - see FERC Form 2 p. 263C	409-49002	(18,676)	N/A
21	**Total of transactions with affiliated party**		165,700,994	
22				
23	**Name of Affiliated Party: NW Natural Gas Storage LLC**			
24	Relationship: Wholly Owned Subsidiary of NW Energy LLC			
25	Shared Services Agreement - see FERC Form 2 p. 358	Various	518,248	N/A
26	Corporate income taxes accrued and charged on behalf of affiliated party			
27	Federal income tax expense (benefit) - see FERC Form 2 p. 263B	409-44001	(210,523)	N/A
28	State income tax expense (benefit) - see FERC Form 2 p. 263C	409-44002	(112,001)	N/A
29	**Total of transactions with affiliated party**		195,724	
30				
31	**Name of Affiliated Party: NNG Financial Corporation**			
32	Relationship: Wholly Owned Subsidiary of Northwest Natural Gas Company			
33	Pipeline capacity charges (KB Pipeline)	804-02910	224,258	N/A
34	NNG Financial Corporation Investment	123.1	368,660	N/A
35	Corporate income taxes accrued and charged on behalf of affiliated party			
36	Federal income tax expense (benefit) - see FERC Form 2 p. 263B	409-23075	(24,125)	N/A
37	State income tax expense (benefit) - see FERC Form 2 p. 263C	409-23145	(5,259)	N/A
38	**Total of transactions with affiliated party**		563,534	
39				
40	**Name of Affiliated Party: Northwest Biogas, LLC**			
41	NW Biogas LLC Investment	123.1	30,401	N/A
42	**Total of transactions with affiliated party**		30,401	
43				
44	**Name of Affiliated Party: Northwest Energy Corporation**			
45	Northwest Energy Corp Investment	123.1	140,167,402	N/A
46	**Total of transactions with affiliated party**		140,167,402	
47				
48	**Name of Affiliated Party: NWN Gas Reserves, LLC**			
49	Relationship: Wholly Owned Subsidiary of Northwest Energy Corporation			
50	Federal income tax expense (benefit) - see FERC Form 2 p. 263B	409-33080	(10,120,520)	N/A
51	**Total of transactions with affiliated party**		(10,120,520)	
52				
53	**Total of transactions with all affiliated parties**		290,460,628	N/A

NORTHWEST NATURAL
DONATIONS FOR THE YEAR ENDED DECEMBER 31, 2015

DESCRIPTION	AMOUNT ASSIGNED TO OREGON	AMOUNT ASSIGNED TO WASHINGTON
FRIENDS OF THE CHILDREN - PORTLAND	$ 120,300	$ 30,000
UNITED WAY	93,200	45,000
CASA FOR CHILDREN	75,000	
FOREST PARK CONSERVANCY	70,000	
OREGON COMMUNITY FOUNDATION	54,940	18,000
AMERICAN RED CROSS CASCADES REGION	50,000	20,000
OREGON STATE UNIVERSITY FOUNDATION	25,000	
UNIVERSITY OF OREGON FOUNDATION	24,298	
ENVIRONMENTAL FEDERATION OF OREGON	20,000	
REGIONAL ARTS & CULTURE COUNCIL	18,000	
PORTLAND STATE	15,750	
PORTLAND CENTER STAGE	15,000	
THE OREGON ZOO FOUNDATION	15,000	
OHSU FOUNDATION	14,000	
UNITED WAY OF LINN COUNTY	11,200	
MERCY CORPS	11,000	
OREGON ALLIANCE OF INDEPENDENT	11,000	
BIG BROTHERS BIG SISTERS NORTHWEST	10,500	2,000
BLACK UNITED FUND OF OREGON	10,500	
LITERARY ARTS INC	10,000	
OREGON HISTORICAL SOCIETY	10,000	
PORTLAND COMMUNITY COLLEGE	10,000	
SCHOOLHOUSE SUPPLIES INC	10,000	
SMART	10,000	
THE LIBRARY FOUNDATION	10,000	
URBAN LEAGUE OF PORTLAND	10,000	
VERNONIA EDUCATION FOUNDATION	10,000	
PORTLAND CLASSICAL CHINESE GARDEN	9,500	
UNITED WAY OF COLUMBIA COUNTY	8,500	
DOERNBECHER CHILDREN'S	7,500	
LIFEWORKS NORTHWEST	7,500	2,000
STAND FOR CHILDREN	7,500	
YWCA CLARK COUNTY		7,200
ALL HANDS RAISED	7,000	
COMMUNITY WAREHOUSE	6,450	
OREGON FOOD BANK INC	6,150	
CENTRAL CITY CONCERN INC	6,000	
AMERICAN CANCER SOCIETY	5,500	
SUNSHINE DIVISION INC	5,400	
FRIENDS OF TREES	5,000	2,500
BEAVERTON EDUCATION FOUNDATION	5,000	
BOYS AND GIRLS CLUBS	5,000	
BRIDGE MEADOWS	5,000	
CAMP FIRE USA	5,000	
CAMPBELL INSTITUTE	5,000	
CASA OF MARION COUNTY INC	5,000	
CLACKAMAS WOMEN'S SERVICES	5,000	
COMMUNITY TRANSITIONAL SCHOOL	5,000	
DRESS FOR SUCCESS OF OREGON INC	5,000	

NORTHWEST NATURAL
DONATIONS FOR THE YEAR ENDED DECEMBER 31, 2015

DESCRIPTION	AMOUNT ASSIGNED TO OREGON	AMOUNT ASSIGNED TO WASHINGTON
FRIENDS OF OUTDOOR SCHOOL	5,000	
GUIDE DOGS FOR THE BLIND INC	5,000	
I HAVE A DREAM FOUNDATION OREGON	5,000	
LINN-BENTON COMMUNITY COLLEGE	5,000	
OPEN MEADOW ALTERNATIVE SCHOOLS INC	5,000	
OREGON MUSEUM OF	5,000	
OREGON SYMPHONY ASSOCIATION	5,000	
PORTLAND ART MUSEUM	5,000	
PORTLAND CHILDREN'S MUSEUM	5,000	
PORTLAND IMPACT INC	5,000	
PORTLAND OPERA ASSOCIATION INC	5,000	
SOLV	5,000	
THE BLACK PARENT INITIATIVE	5,000	
THE CHILDREN'S CENTER OF CLACKAMAS	5,000	
THE FRESHWATER TRUST	5,000	
THE INTERTWINE ALLIANCE FOUNDATION	5,000	
THE NATURE CONSERVANCY	5,000	
TUALATIN RIVERKEEPERS	5,000	
WILLAMETTE WEST	5,000	
CHESS FOR SUCCESS	4,500	
JUNIOR ACHIEVEMENT	4,400	
NORTHWEST NATURAL GAS CO	4,240	
INSTITUTE FOR YOUTH SUCCESS	4,000	
CLASSROOM LAW PROJECT	3,500	
DE LA SALLE	3,500	
CATHOLIC CHARITIES	3,000	
OREGON BALLET THEATRE	3,000	
UNITED WAY OF LANE COUNTY	3,000	
WIND & OAR BOAT SCHOOL	2,000	1,000
FENCES FOR FIDO	2,850	
AMERICAN HEART ASSOCIATION	2,500	
BASIC RIGHTS EDUCATION FUND	2,500	
BRADLEY-ANGLE HOUSE	2,500	
CASH OREGON	2,500	
CHILDREN'S TRUST FUND	2,500	
COMMUNITY ACTION ORGANIZATION	2,500	
CONCORDIA UNIVERSITY	2,500	
EMANUEL MEDICAL CENTER FOUNDATION	2,500	
FREE CLINIC OF SOUTHWEST WASHINGTON	2,500	
FRIENDS OF THE RIDGEFIELD		2,500
KAIROSPDX	2,500	
MACDONALD CENTER	2,500	
MT HOOD COMMUNITY	2,500	
MUSLIM EDUCATIONAL TRUST	2,500	
OREGON BUSINESS COUNCIL (OBC)	2,500	
P:EAR	2,500	
PORTLAND FESTIVAL SYMPHONY	2,500	
PORTLAND INSTITUTE FOR CONTEMPORARY	2,500	
SATURDAY ACADEMY	2,500	

NORTHWEST NATURAL
DONATIONS FOR THE YEAR ENDED DECEMBER 31, 2015

DESCRIPTION	AMOUNT ASSIGNED TO OREGON	AMOUNT ASSIGNED TO WASHINGTON
THE DOUGY CENTER INC	2,500	
UNITED WAY OF THE COLUMBIA GORGE	2,500	
VIRGINIA GARCIA	2,500	
VOLUNTEERS OF AMERICA OREGON	2,500	
FRIENDS OF THE COLUMBIA GORGE	2,000	
HISPANIC METROPOLITAN CHAMBER	2,000	
JOIN	2,000	
LIBERTY RESTORATION INC	2,000	
LINN COUNTY CHILD VICTIM ASSMNT CTR	2,000	
METROPOLITAN YOUTH SYMPHONY	2,000	
NEIGHBORHOOD HOUSE	2,000	
PORTLAND PLAYHOUSE	2,000	
SHARE		2,000
UNITED WAY OF CLATSOP COUNTY	2,000	
UNITED WAY OF SOUTHWESTERN OREGON	2,000	
HARPER'S PLAYGROUND	1,900	
OREGON CHILDREN'S FOUNDATION	1,650	
FOOD SHARE OF LINCOLN COUNTY	1,500	
REAP INC	1,500	
THE PIECE	1,500	
WILLAMETTE PARTNERSHIP	1,500	
LOWER COLUMBIA RIVER	1,250	1,250
ASIAN AMERICAN YOUTH	1,000	
ASSISTANCE LEAGUE OF GREATER PORTLA	1,000	
BLANCHET HOUSE OF HOSPITALITY	1,000	
CASA OF LINCOLN COUNTY	1,000	
CENTRAL OREGON COAST NOW FOUNDATION	1,000	
FRIENDLY HOUSE INC	1,000	
INNOVATIVE SERVICES NW		1,000
MULTNOMAH COUNTY SCHOOL DISTRICT 51	1,000	
MY LITTLE WAITING ROOM c/o PROVIDEN	1,000	
NORTHWEST FAMILY SERVICES	1,000	
OREGON NIKKEI ENDOWMENT INC	1,000	
PHAME ACADEMY	1,000	
SERENDIPITY CENTER INC	1,000	
THE COMMUNITY FOUNDATION	1,000	
Internal Resources	4,531	
Less than $1k	42,884	1,450
Grand Total	1,150,892	135,900
Total of Donations > $1,000	1,108,008	134,450
Various Charities < $1,000	42,884	1,450
Total Donations	1,150,892	135,900

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

State of Oregon - Officers' Salaries

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration, or finance), and any other person who performs similar policy-making functions.

2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent and date change in incumbency was made.

3. Utilities which are required to file similar data with the Securities and Exchange Commission, may substitute a copy of Item 4, Regulation S-K, identified as this schedule page. The substituted page(s) should be conformed to the size of this page.

Line No.	Title (a)	Name of Officer (b)	Salary for Year Total (c)	Salary for Year Oregon (d)
1	Chief Executive Officer	Gregg S. Kantor	549,333	549,333
2	President and Chief Operating Officer	David H. Anderson	418,083	418,083
3	Senior Vice President and Chief Financial Officer	Stephen P. Feltz	158,833	158,833
4	Senior Vice President and Chief Financial Officer	Gregory C. Hazelton	149,863	149,863
5	Senior Vice President and General Counsel	Margaret D. Kirkpatrick	312,500	312,500
6	Senior Vice President and Chief Administrative Officer	Lea Anne Doolittle	282,667	282,667
7	Senior Vice President and General Counsel	MardiLyn Saathoff	304,000	304,000
8	President Gas Storage LLC	David A. Weber	263,750	263,750
9	Vice President Utility Services	David R. Williams	241,833	241,833
10	Vice President Utility Operations	Grant M. Yoshihara	241,833	241,833
11	Vice President and Corporate Secretary	Shawn M. Filippi	210,000	210,000
12	Vice President and Treasurer	C. Alex Miller	223,000	223,000
13	Vice President Public Affairs	Thomas J.M. Imeson	242,667	242,667
14	Vice President Communications and Chief Marketing Officer	Kimberly A. Heiting	205,000	205,000
15	Controller	Brody J. Wilson	211,333	211,333

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission	(Mo, Da, Yr)	Dec. 31, 2015

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

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

Line No.	NAME OF RECIPENT (a)	NATURE OF SERVICE (b)	AMOUNT OF PAYMENT (c)
	SEE FERC ANNUAL REPORT PAGE 357		

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2015

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

Oregon Production Statistics (Therms)		
Gas Produced		
Gas Purchased		647,726,420
Total Receipts		647,726,420
Gas Sales		590,761,660
Gas Used by Company		2,674,750
Gas Delivered to LNG and Storage - Net		8,450,529
Losses & billing Delay		45,839,481
Total Disbursements		647,726,420
Oregon Revenue by Service Class		
Residential	$	369,101,737
Commercial & Industrial		
Firm		217,983,094
Interruptible		29,198,713
Transportation		15,707,735
Total	$	631,991,279
Gas Sold in Therms (Oregon)		
Residential		310,396,065
Commercial & Industrial		
Firm		231,333,733
Interruptible		56,043,318
Transportation		349,006,678
Total		946,779,794
Average Number of Oregon Customers		
Residential		571,534
Commercial & Industrial		
Firm		60,183
Interruptible		135
Transportation		293
Total		632,145

BUILDING
WITH FORESIGHT

NW Natural®

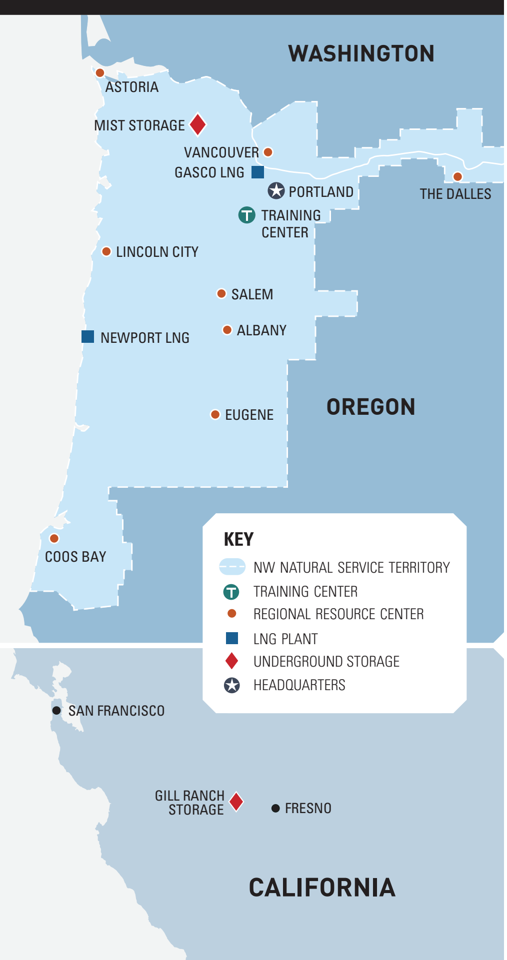
2015 ANNUAL REPORT

CORPORATE **PROFILE**

NW Natural (NYSE: NWN) is a 157-year-old natural gas distribution company headquartered in Portland, Oregon.

NW Natural serves more than 714,000 utility customers in Oregon and Southwest Washington and provides natural gas storage to customers on the West Coast. In keeping with its steady growth strategy, the company has increased dividends paid to shareholders for 60 consecutive years.

SERVICE TERRITORY AND STORAGE FACILITIES



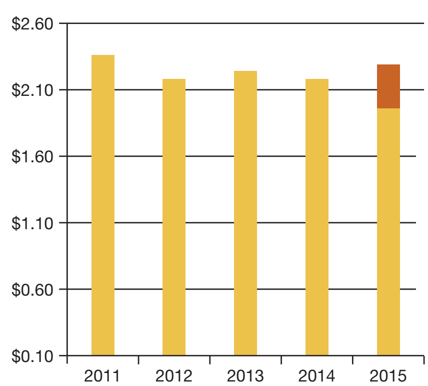
FINANCIAL OVERVIEW	2015	2014	INCREASE (DECREASE)
EARNINGS			
Financial facts ($000):			
Operating revenues	723,791	754,037	(4)%
Utility margin	371,392	366,088	1
Net income	53,703	58,692	(9)
Adjusted net income*	62,778	58,692	7
Financial ratios (%):			
Return on average common equity	6.9	7.7	(80) bps
Adjusted return on average common equity*	8.1	7.7	40
Capital structure** at year-end:			
Long-term debt	42.5	44.8	(230) bps
Common stock equity	57.5	55.2	230

**Excluding short-term debt and current long-term maturities.

COMMON STOCK			
Shareholder data (000):			
Average shares outstanding – diluted	27,417	27,223	1%
Year-end shares outstanding	27,427	27,284	1
Per share data ($):			
Diluted earnings	1.96	2.16	(9)%
Adjusted diluted earnings*	2.29	2.16	6
Dividends paid	1.86	1.85	1
Book value at year-end	28.47	28.12	1
Market value at year-end	50.61	49.90	1
UTILITY OPERATING HIGHLIGHTS			
Gas sales and transportation deliveries (000 therms)	1,028,612	1,092,990	(6)%
Degree days	3,458	3,792	(9)
Customers at year-end	714,428	704,644	1
Employees at year-end	1,061	1,084	(2)

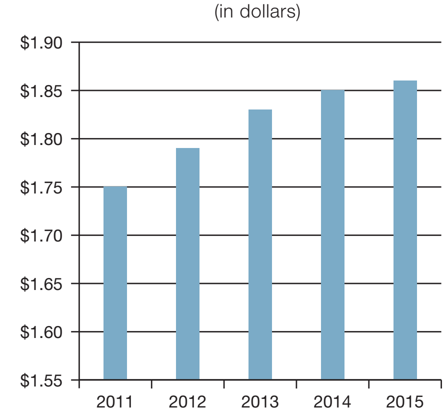
DIVIDENDS PAID ON COMMON STOCK (per share)		
PAYMENT DATE		
February 15	$ 0.4650	$ 0.460
May 15	0.4650	0.460
August 15	0.4650	0.460
November 15	0.4675	0.465
Total dividends paid	$ 1.8625	$ 1.845

DILUTED EARNINGS PER SHARE
(in dollars)



Diluted earnings per share were $1.96 or $2.29 adjusted for the regulatory disallowance in 2015.*

DIVIDENDS PAID PER SHARE
(in dollars)



Annual dividends paid per share in 2015 increased for the 60th consecutive year. The current indicated annual dividend is $1.87 per share.

*Indicates non-GAAP measures based on the $15 million pre-tax or $9.1 million after-tax charge from the 2015 environmental order. After-tax amounts calculated using statutory tax rate of 39.5% and EPS uses 27.4 million diluted shares.

Left: Gregg Kantor, CEO
Right: David Anderson, President and COO

NW Natural has a long record of thinking ahead, of careful planning and disciplined execution. These attributes served us well in 2015.

This past year we completed the removal of our bare steel pipe – making NW Natural's distribution system one of the most modern in the nation. A milestone made possible due to pipe replacement cost trackers established three decades ago.

We successfully navigated the financial impacts of a record-warm winter as a result of effective cost management and our weather normalization mechanism (WARM) put in place in 2003.

We advanced a proposal to expand our storage assets in Oregon, first identified in 1979, to serve gas-fired electric generation that will back up recently built wind resources.

And we began collecting revenues in November through our new environmental cost recovery mechanism. The Site Remediation and Recovery Mechanism (SRRM) allows us to recover prudently incurred environmental cleanup costs allocated to Oregon, associated with legacy manufactured gas plants that operated until 1957. While that docket required a $15 million write-down in 2015 due to over-earning in years past, the recovery mechanism aligns our company and customers around a responsible cleanup of these legacy assets.

Acting with foresight is no accident. It is part of our culture and key to a successful business in the Pacific Northwest. At NW Natural, we are proud of our ability to anticipate the needs of our customers, find innovative solutions, and successfully respond to challenges. Evidence of this can be seen in our 2015 performance:

2015 HIGHLIGHTS

- Reported net income of $53.7 million or $1.96 per share. Excluding the environmental charge, net income was $62.8 million or $2.29 per share, an increase of 13 cents per share compared to 2014 results.*
- Continued to add new customers at an annual growth rate of 1.4 percent, bringing our customer base to more than 714,000.
- Reduced residential customer rates by approximately 7 percent in Oregon and 14 percent in Washington, as a result of the lowest natural gas commodity prices in 15 years.
- Earned the highest customer satisfaction score among large utilities in the West in the 2015 J.D. Power Gas Utility Residential Customer Satisfaction Study.
- Invested $129 million in capital expenditures for customer growth and system improvements.
- Received key regulatory decisions from the Public Utility Commission of Oregon that resulted in cost recovery for prudently incurred environmental expenses and Jonah Field investments.
- Increased common dividends paid for the 60th consecutive year, one of the longest dividend increase records of any company on the NYSE.

System Safety and Preparedness

Removing the last few miles of all identified bare steel pipe in our system last year was a major accomplishment, but it was just one of many initiatives we're working on to ensure our systems' safety and reliability.

In 2015, we moved forward on a five-year, $25 million infrastructure investment plan in Clark County, WA. The system upgrades planned for Clark County will include new high-pressure distribution lines and extensions to better serve customers in our service territory's fastest-growing community.

We also began to make additional improvements to our Newport LNG facility, built in 1977. Upgrades planned for this natural gas storage facility on the Oregon Coast include tank refurbishments, turbine modernization, and control room enhancements at an estimated cost of $25 million.

Customer and system safety remains at the core of our operational priorities. In 2015, we once again reached our emergency response goals of answering 90 percent of emergency calls within 10 seconds, and responding on-site to damage and odor calls within 30 minutes on average.

We also continued to prepare for a large-scale emergency event, such as a severe earthquake. Should our Portland headquarters be rendered unsafe, we can now transfer gas control and emergency dispatch operations to our new Business Continuity Center in Sherwood, Oregon. The facility was built to the highest structural standards for earthquake preparedness and has been outfitted to host employees crucial to core business functions during the first phases of a natural disaster.

But today system safety doesn't stop at state-of-the art pipelines and facilities. Utilities must also anticipate and mitigate cybersecurity threats. In 2015, our Information Technology team made significant strides to increase our cyber resiliency, deploying new cybersecurity technology, employee education and training on new policies and emergency response protocols company-wide.

SYSTEM SAFETY

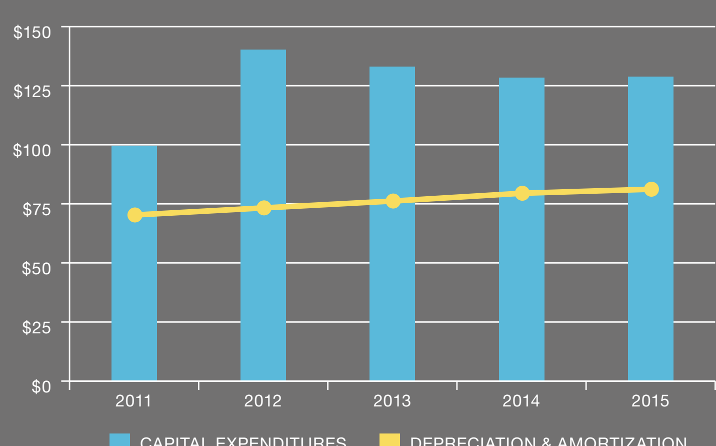
COMPLETED THE REMOVAL OF BARE STEEL AND CAST IRON PIPES

Regulatory Progress

Last year, we continued to manage several important regulatory dockets at the Public Utility Commission of Oregon (OPUC).

Early in 2015, we received the commission's decision on our environmental cost recovery proceeding. In its order, the OPUC found that $114 million of environmental remediation expenses and carrying costs incurred through March of 2014 were prudent, as were the insurance settlements we executed totaling approximately $150 million. However, the OPUC disallowed recovery of $15 million of environmental costs based on the application of an earnings test for past years when the company earned above its authorized rate of return. As a result, we took an after-tax charge of $9.1 million to net income in 2015.

CAPITAL EXPENDITURES WITH DEPRECIATION & AMORTIZATION
(in millions)



Total investment in capital expenditures during 2015 was $129 million, of which nearly $100 million was related to system integrity, maintenance and customer growth.

Andrea Kuehnel and Scott Burg were part of the team that worked to remove the last known bare steel from NW Natural's system.

WE REDUCED RESIDENTIAL CUSTOMER RATES

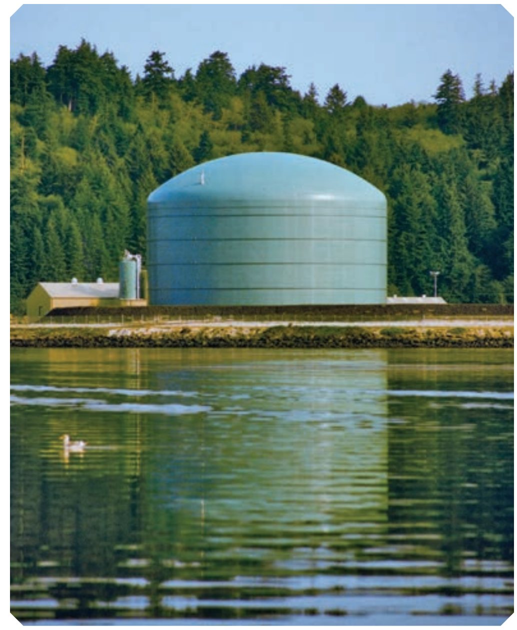
APPROXIMATELY
7 PERCENT
IN OREGON AND

14 PERCENT
IN WASHINGTON

In January 2016, the commission reviewed our compliance filing under their 2015 order and confirmed the company's recovery of environmental costs allocated to Oregon rate payers under the mechanism. However, they disallowed interest earned on the original $15 million disallowance, which resulted in the company recognizing a $2 million after-tax charge in 2016. Although the charges were disappointing, this was a complex docket, and we believe the mechanism provides a good path forward for all stakeholders.

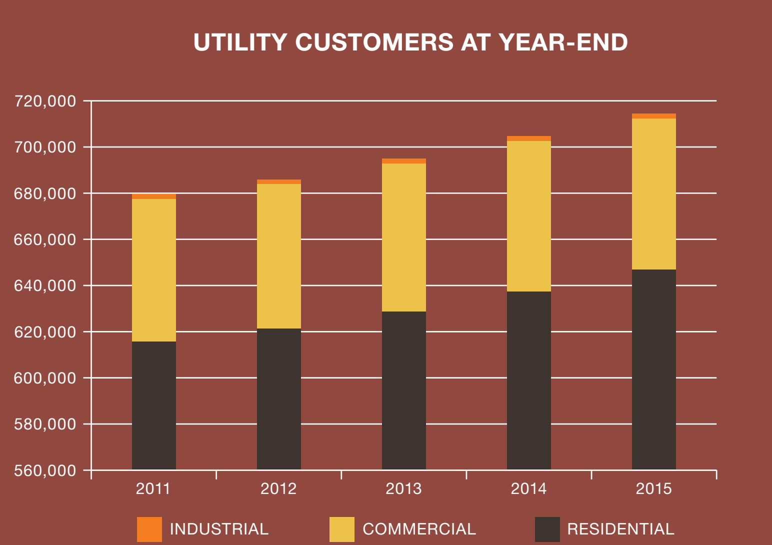
In September of last year, the OPUC also adopted an all-party settlement that determined how we would recover costs associated with seven wells we drilled under our amended gas reserves agreement. This $10 million additional investment provides long-term price protection for Oregon utility customers. We were pleased with this collaborative settlement and the positive conclusion to the docket.

In 2016, we will be working with the commission and other utilities in Oregon on a policy docket to explore commodity hedging, including what role gas reserves could play in a balanced natural gas supply portfolio. It's our view that today's low prices, coupled with the expected increase in demand for natural gas to serve power generation, make long-term hedging opportunities like gas reserves an important option to help ensure future price stability for our customers.



Utility and Storage Operations

In November, we reduced residential customer rates approximately 7 percent in Oregon and 14 percent in Washington. With that reduction, our customers are paying less for their natural gas now than they did 15 years ago. This price decline helps our customers and improves the company's competitive position, as consumers in our service area can save about 50 percent by switching from an electric or oil furnace to natural gas.



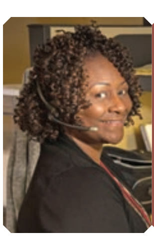
We added 9,784 new customers in 2015, and now serve 714,428 customers.

Our engineering team created a streamlined piping and metering design that reduces developer costs. As a result, this 10-story "Block 75" project in Portland will now include gas amenities in all 75 apartments, when it opens later in 2016.

We were pleased to pair these lower rates with another year of outstanding service from our employees. For the sixth time in nine years, NW Natural ranked first in the annual J.D. Power Residential Customer Satisfaction Study for natural gas utilities in the West. This also marked the eighth time in nine years of posting among the top two highest satisfaction scores in the nation.

Also in 2015, operations at our underground storage facility near Mist, Oregon performed well, providing valuable services to our core utility customers and profitably serving storage customers in the Northwest. However, our California Gill Ranch storage facility continued to operate in challenging market conditions.

Excess natural gas storage capacity and limited gas price volatility have kept storage values low in California over the last several years. But new legislation recently signed by the Governor is likely to change the state's energy landscape in substantial ways. California's new Renewable Portfolio Standard (RPS) requires 50 percent of its power generation be produced from renewables by 2030, which we believe provides a strategic opportunity for the flexible energy resources Gill Ranch can deliver. As the impacts of those RPS requirements unfold, our priority is to pursue higher value service contracts and tap into new market opportunities.



NW NATURAL
RANKED FIRST
in the J.D. Power Residential Customer Satisfaction Study in the West

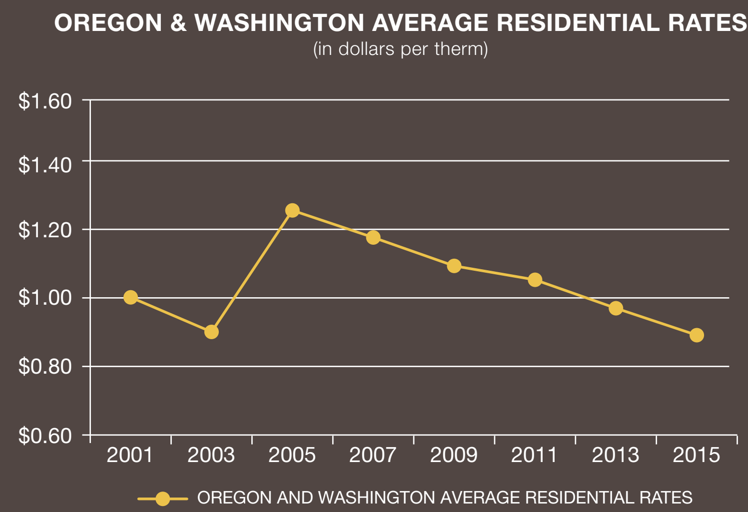
Competing for the Future

Our region is attracting young, college educated households considered vital for both economic development and longer-term growth. More people were employed in 2015, with the average monthly employment in the Portland and Vancouver Metro area increasing by about 35,000 new jobs for an annual employment growth rate of 3.2 percent. This is more than one percentage point above the national average. In that same time period, the unemployment rate fell 100 basis points to 5.3 percent. Oregon's average wage today is the highest it has been in a generation. We are also seeing strong housing growth in the Portland area with a 25 percent increase in single-family building permits in the last 12 months. NW Natural leveraged these economic improvements last year to sign up nearly 9,800 new customers, an annual growth rate of 1.4 percent.

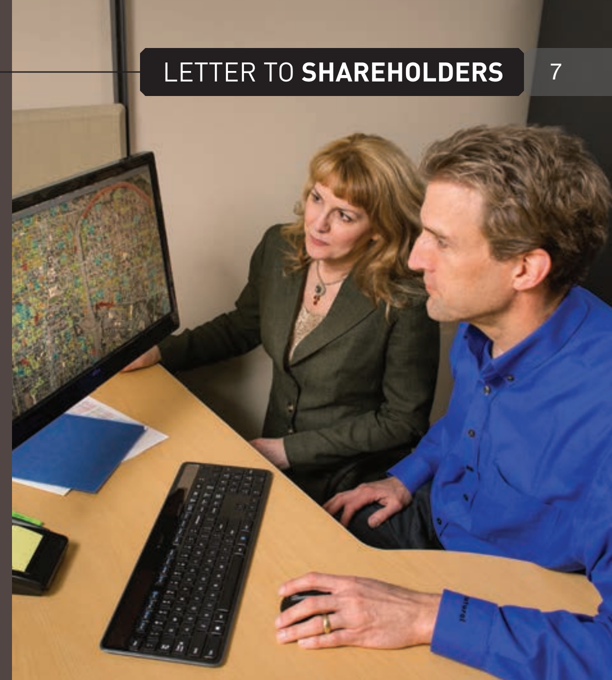
PORTLAND AREA RENTERS
prefer natural gas amenities

Nationally, single-family new construction has yet to rebound to pre-recession levels – and the Northwest is no exception. But there has been an upturn in the housing sector locally, particularly in multifamily apartments. Seeing this trend emerge, we created a cross-functional team to evaluate every aspect of the apartment rental market – a market typically underserved with natural gas in the Northwest and across the U.S.

One of the first steps we took to assess our opportunity was to conduct renter preference research. A recent study showed 80 percent of Portland area renters paying average rent prices or above prefer gas amenities such



Today's residential rates are lower than they were 15 years ago.



The portal team is now working on new enhancements to leverage web analytics and cost data to identify main extension opportunities.

as cooktops, water heating and fireplaces – demonstrating a clear gap between what renters' desire and what's available.

Armed with this data, we created a comprehensive marketing program to target apartment developers. While still early, we've been pleased with the level of interest from project owners. We view rental apartments as an untapped growth opportunity and a priority segment for us moving forward.

Competing for growth today requires making it easier and faster to connect to gas. In 2015, the use of our industry-leading online portal grew, as consumers searched for gas availability in their area with the click of a mouse or a tap on the screen. In fact, almost 30 percent of our conversion sales used this web tool and more than 1,500 online orders were submitted by builders and contractors last year. Strong adoption of the portal's functionality helps us operate more efficiently. But, as important, portal analytics allow us to strategically target new areas for growth and create customized marketing programs in 2016 and beyond.

30
PERCENT
of conversions used the portal

Leading with Solutions

Policy makers in the Pacific Northwest are committed to shutting down coal-fired electric generation and substantially increasing the use of renewables to meet our region's power needs. Natural gas and its supporting infrastructure are critical to helping achieve this goal. One way is by helping to back-up intermittent wind resources at a local electric utility's gas-fired generating plants.

In 2015, we submitted an application to the Oregon Energy Facility Siting Council for an amendment to our existing Mist Site Certificate to allow us to provide on-demand storage services to these gas-fired generating plants. Last year, we also held an open house with the local community, obtained required permits and property rights, and worked with local agencies on the details of the project. In early 2016, the Department of Energy published a proposed order as part of the permitting process. If there are no challenges to that order, we could receive approval from the Oregon Energy Facility Siting Council for our permit later this spring. Concurrently, we are in the process of rebidding the engineering, procurement, and construction portion of the project. Following the approval of the permit and the rebidding process, we expect to receive a notice to proceed from the project sponsor later this year.

Another way NW Natural is striving to support our region's environmental goals is through a new Combined Heat and Power (CHP) program. The CHP program is the first proposal submitted by the company under Senate Bill 844 – the Oregon legislation designed to incent natural gas utilities to invest in projects that reduce carbon emissions. As submitted, the CHP program would provide financial incentives to customers in our service territory that invest in and install CHP at their facilities. We submitted the program in June 2015, and expect a decision from the Commission in the spring of 2016. That decision will also help determine how we proceed with other potential carbon reduction programs under this legislation.

Leadership for the Future

Over many years, NW Natural has demonstrated the careful planning essential to finding and retaining the talent necessary to drive future success. Detailed succession plans are an integral part of the company's business activities, and this past year, the benefits of that work were visible.

In July of 2015, the board of directors elected David H. Anderson as President, adding to his responsibilities as Chief Operating Officer. Then in December, we announced my retirement at the end of 2016 and that David would begin serving as Chief Executive Officer effective Aug. 1 this year. To help with the transition, I will be staying on as an advisor to the board until the end of December.

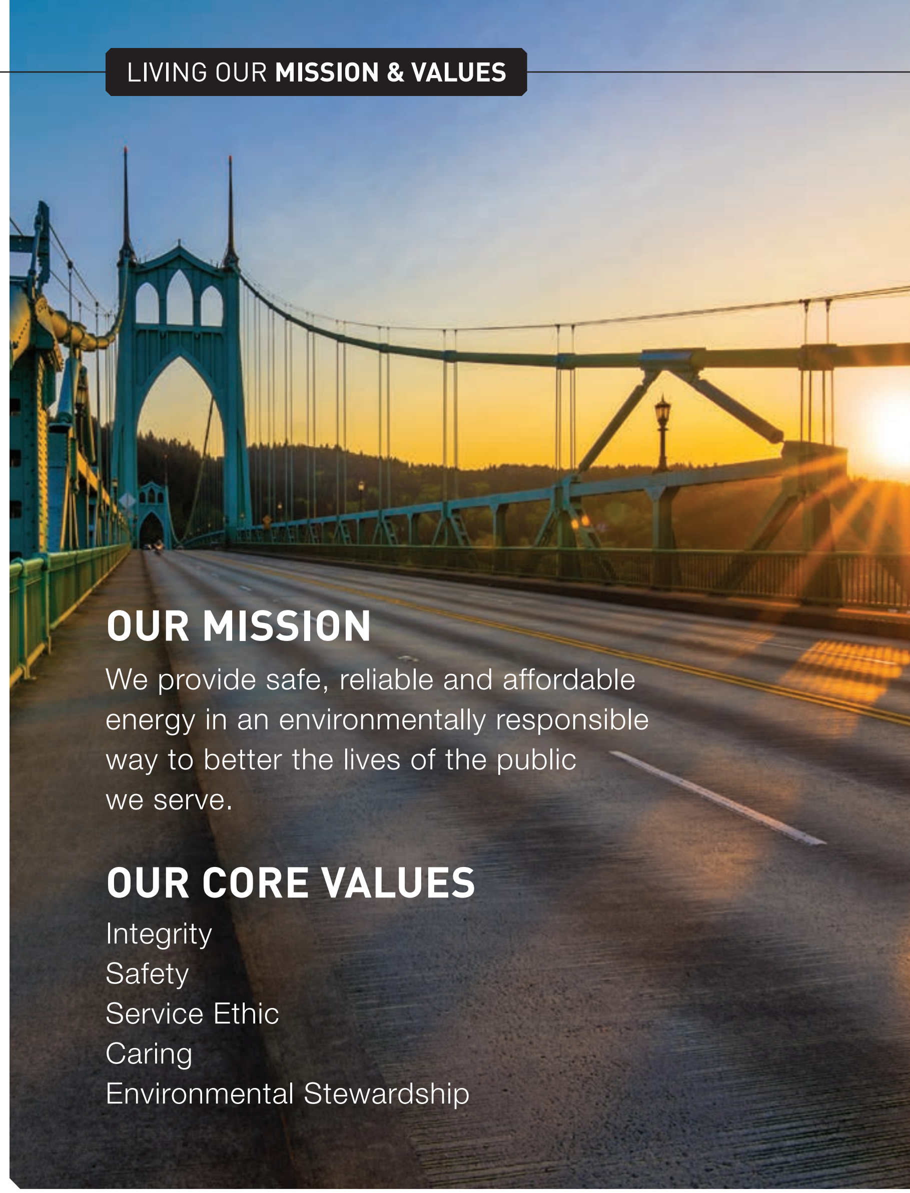
A smooth transition at the top is critical, but as important is developing the talent for succession in key positions across the organization. That has been a long-held commitment at NW Natural, one that in my opinion is the true mark of a company with foresight.

In today's complex and rapidly changing energy landscape, foresight has never been more important. In 2016, NW Natural will remain focused on meeting today's expectations while keeping an eye on the horizon.

We will continue to safely provide our product with great customer service; provide a solid financial value to our customers and to you, our shareholders; and look toward the future – ensuring we have the expertise to drive growth and provide innovative solutions that fuel our long-term success.

As I complete my last year at the company, I would like you to know it has been a great privilege to work with the talented men and women who make up NW Natural and to lead this great company on your behalf. And finally, as we continue into our 157th year, from all of us at NW Natural, we thank you for your investment and support.

Gregg S. Kantor
CEO



OUR MISSION

We provide safe, reliable and affordable energy in an environmentally responsible way to better the lives of the public we serve.

OUR CORE VALUES

Integrity
Safety
Service Ethic
Caring
Environmental Stewardship

Produced by NW Natural's
Corporate Communications

PHOTO CREDITS

Bruce Forster - Cover: Tilikum Crossing;
Page 3: Gregg Kantor and David Anderson

Dale Headrick - Page 4: Andrea Kuehnel and Scott Burg;
Page 5: Newport storage facility; Page 6: D.G. Graham,
Block 75 project

Robbie McClaran - Page 9: Board of Directors

Corky Miller - Page 4: Bare steel removal, Page 6: Customer
Service Rep; Page 7: Kristen Brown and Walter Cahall;
Inside back cover: Nikki Sparley, Chu Lee and backpack event;
Page 8: Corporate Officers

PRINTING

RR Donnelley

NW Natural®

Front to back – left to right

LEA ANNE DOOLITTLE
Senior Vice President and
Chief Administrative Officer

MARDILYN SAATHOFF
Senior Vice President
and General Counsel

GREGG S. KANTOR
Chief Executive Officer

DAVID H. ANDERSON
President and
Chief Operating Officer

DAVID R. WILLIAMS
Vice President
Utility Services

KIMBERLY HEITING
Vice President
Communications and
Chief Marketing Officer

SHAWN M. FILIPPI
Vice President and
Corporate Secretary

C. ALEX MILLER
Vice President Regulation
and Treasurer

TOM IMESON
Vice President
Public Affairs

GREGORY C. HAZELTON
Senior Vice President and
Chief Financial Officer

GRANT M. YOSHIHARA
Vice President
Utility Operations

BRODY J. WILSON
Controller and Chief
Accounting Officer

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Chief Executive Officer
Columbia Sportswear
Company

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Cori Investment
Advisors, LLC

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of the Board
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Industries, Inc.

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Executive Officer
NW Natural

C. SCOTT GIBSON
President
Gibson Enterprises

TOD R. HAMACHEK
Chairman of the Board
NW Natural

GREGG S. KANTOR
Chief Executive Officer
NW Natural

JANE L. PEVERETT
Former President and
Chief Executive Officer
British Columbia Trans-
mission Corporation

KENNETH THRASHER
Chairman
of the Board
Compli Corporation

MALIA WASSON
Former Executive
Vice President of
Commercial Banking,
U.S. Bank

Notice of Annual Meeting

The 2016 Annual Meeting will be held at 2 p.m., Thursday, May 26, at the company's headquarters, One Pacific Square, 220 NW 2nd Ave., 4th floor, Portland, Oregon 97209. A meeting notice and proxy statement will be sent to all shareholders in April. If you plan to attend the annual meeting, you will need to detach and retain the admission ticket attached to your proxy card mailed to you with the notice of the annual meeting and the proxy statement. As space is limited, you may bring only one guest to the meeting. If you hold your stock through a broker, bank or other nominee, please bring a legal proxy or other evidence to the meeting showing that you owned NW Natural Common Stock as of the record date, April 7, 2016, and we will provide you with an admission ticket. A form of government-issued photograph identification will be required for both you and your guest to enter the meeting.

Dividend reinvestment and direct stock purchase plan

Participants may make an initial investment in company stock and common shareholders of record may reinvest all or part of their dividends in additional shares under the company's plan. Cash purchases may also be made. Participants in the plan bear the cost of brokerage fees and commissions for shares purchased on the open market to fulfill purchases under the plan. A prospectus will be sent upon request.

Scheduled dividend payment dates

Subject to Board approval, the following dates are scheduled for dividend payment:

February 12, 2016
May 13, 2016
August 15, 2016
November 15, 2016

Certifications

The Chief Executive Officer certified to the NYSE on June 25, 2015, that, as of that date, he was not aware of any violation by the company of NYSE's corporate governance listing standards, and the company had filed with the Securities and Exchange Commission (SEC), as exhibits 31.1 and 31.2 to its Annual Report on Form 10-K for the year ended December 31, 2014, the certificates of the Chief Executive Officer and the Chief Financial Officer of the company certifying the quality of the company's public disclosure. For the year ended December 31, 2015, the certificates of the Chief Executive Officer and Chief Financial Officer are attached as exhibits 31.1 and 31.2 to the Form 10-K included in this Annual Report.

Contact the NW Natural Board

Concerns may be directed to the nonmanagement directors by writing to NW Natural Board of Directors, c/o Corporate Secretary.

Forward-looking statements

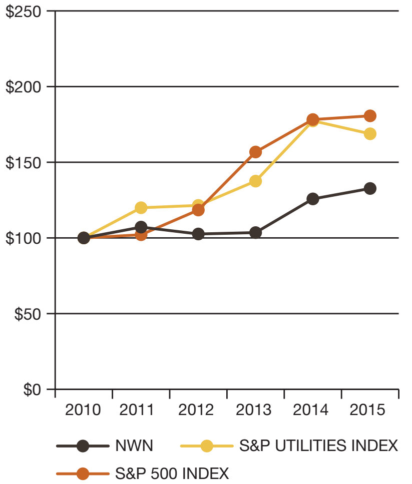
The statements made in this Annual Report that are not purely historical, including statements regarding strategy, growth and marketing initiatives, dividends, earnings, financial value, future demand for gas, commodity costs and competitiveness, revenues, customer growth, gas supplies and reserves, hedge efficacy, capital expenditures, pipeline and storage infrastructure investments, system expansion, Mist storage expansion project, including but not limited to cost and timelines, growth initiatives including SB844 projects, emergency preparedness, cyber resiliency and preparedness, system reliability, storage performance values, governmental policy and legislation and the effects thereof, regulatory cost recovery mechanisms, including, but not limited to, the SRRM, regulatory prudence reviews including, but not limited to, commodity hedging, regulatory proceedings and actions, economic recovery factors, customer savings, market trends and the competitive environment, and coal-fired and renewable energy resources, are forward-looking statements within the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995. NW Natural's actual results could differ materially from those anticipated in these forward-looking statements as a result of risks and uncertainties, including those described in the attached report on Form 10-K.

For a more complete description of these risks and uncertainties, please refer to our filings with the SEC on Forms 10-K and 10-Q.

Request for publications

The following publications may be obtained without charge by contacting the Corporate Secretary at NW Natural's address: Annual Report; Form 10-K; Form 10-Q; Corporate Governance Standards; Director Independence Standards; Code of Ethics; and Board Committee Charters. These publications, as well as other filings made with the SEC, are also available on our website at nwnatural.com. Our SEC filings are also available by request through the SEC by mail at U.S. Securities and Exchange Commission, Office of FOIA/PA Operations, 100 F Street, N.E., Washington, D.C. 20549, or online at sec.gov. You can obtain information about access to the Public Reference Room and how to access or request records by calling the SEC at 1-800-SEC-0330.

COMPARISON OF FIVE-YEAR CUMULATIVE TOTAL RETURN
(Based on $100 invested on 12/31/2010)



Total shareholder return (annualized) over the five years ending December 31, 2015 for NW Natural was 5.9%, compared to Standard & Poor's (S&P) Utilities Index return of 11%, and the S&P 500 Index return of 12.5%.

Form 10-K

Annual Report

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2015

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from ___________ to ____________

Commission file number 1-15973

NW Natural

NORTHWEST NATURAL GAS COMPANY
(Exact name of registrant as specified in its charter)

Oregon	**93-0256722**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

220 N.W. Second Avenue, Portland, Oregon 97209

(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code: **(503) 226-4211**

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock	New York Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes [X] No [ ]

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Yes [ ] No [X]

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes [X] No [ ]

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes [X] No [ ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.
[X]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer [X]	Accelerated Filer [ ]
Non-accelerated Filer [ ]	Smaller Reporting Company [ ]

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

As of June 30, 2015, the registrant had 27,355,642 shares of its Common Stock outstanding, of which 26,973,861 shares were held by non-affiliates. The aggregate market value of the shares of Common Stock (based upon the closing price of these shares on the New York Stock Exchange on that date) held by non-affiliates was $1,137,757,457.

At February 19, 2016, 27,435,906 shares of the registrant's Common Stock (the only class of Common Stock) were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement of the registrant, to be filed in connection with the 2016 Annual Meeting of Shareholders, are incorporated by reference in Part III.

NORTHWEST NATURAL GAS COMPANY

Annual Report to Securities and Exchange Commission on Form 10-K
For the Fiscal Year Ended December 31, 2015

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AFUDC	Allowance for Funds Used During Construction
AOCI / AOCL	Accumulated Other Comprehensive Income (Loss)
ASC	Accounting Standards Codification
ASU	Accounting Standards Update as issued by the FASB
Average Weather	The 25-year average heating degree days based on temperatures established in our last Oregon general rate case
Bcf	Billion cubic feet, a volumetric measure of natural gas, where one Bcf is roughly equal to 10 million therms
Btu	British thermal unit, a basic unit of thermal energy measurement; one Btu equals the energy required to raise one pound of water one degree Fahrenheit at an atmospheric pressure of one and 60 degrees Fahrenheit. One hundred thousand Btu's equal one therm
CAP	Compliance Assurance Process with the Internal Revenue Service
CNG	Compressed Natural Gas
CO_2	Carbon Dioxide
Core Utility Customers	Residential, commercial and industrial customers receiving firm service from the utility
Cost of Gas	The delivered cost of natural gas sold to customers, including the cost of gas purchased or withdrawn/produced from storage inventory or reserves, gains and losses from gas commodity hedges, pipeline demand costs, seasonal demand cost balancing adjustments, regulatory gas cost deferrals and Company gas use
CPUC	California Public Utilities Commission, the entity that regulates our California gas storage business at our Gill Ranch facility with respect to rates and terms of service, among other matters
Decoupling	A billing rate mechanism, also referred to as our conservation tariff, which is designed to break the link between utility earnings and the quantity of natural gas sold to customers; the design is intended to allow the utility to encourage industrial and small commercial customers to conserve energy while not adversely affecting its earnings due to reductions in sales volumes
Demand Cost	A component in core utility customer rates representing the cost of securing firm pipeline capacity, whether the capacity is used or not
Dth	Dekatherm (also decatherm) is equal to 10 therms or one million British thermal units (Btu)
EBITDA	Earnings before interest, taxes, depreciation and amortization, a non-GAAP financial measure
EE/CA	Engineering Evaluation / Cost Analysis
Encana	Encana Oil & Gas (USA) Inc.
Energy Corp	Northwest Energy Corporation, a wholly-owned subsidiary of NW Natural
EPA	Environmental Protection Agency
EPS	Earnings per share
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission; the entity regulating interstate storage services offered by our Mist gas storage facility as part of our gas storage segment
Firm Service	Natural gas service offered to customers under contracts or rate schedules that will not be disrupted to meet the needs of other customers
FMBs	First Mortgage Bonds
GAAP	Accounting principles generally accepted in the United States of America
General Rate Case	A periodic filing with state or federal regulators to establish billing rates for utility customers
GHG	Greenhouse gases
Gill Ranch	Gill Ranch Storage, LLC, a wholly-owned subsidiary of NWN Gas Storage
Gill Ranch Facility	Underground natural gas storage facility near Fresno, California, with 75% owned by Gill Ranch and 25% owned by PG&E

GTN	Gas Transmission Northwest, which owns a transmission pipeline serving California and the Pacific Northwest
Heating Degree Days	Units of measure reflecting temperature-sensitive consumption of natural gas, calculated by subtracting the average of a day’s high and low temperatures from 65 degrees Fahrenheit
HATFA	Highway and Transportation Funding Act of 2014
Interruptible Service	Natural gas service offered to customers (usually large commercial or industrial users) under contracts or rate schedules that allow for interruptions when necessary to meet the needs of firm service customers
IRP	Integrated Resource Plan
IRS	United States Internal Revenue Service
KB	Kelso-Beaver Pipeline, of which 10% is owned by K-B Pipeline Company, a subsidiary of NNG Financial
LIBOR	London Interbank Offered Rate
LNG	Liquefied Natural Gas, the cryogenic liquid form of natural gas. To reach a liquid form at atmospheric pressure, natural gas must be cooled to approximately negative 260 degrees Fahrenheit
LWG	Lower Willamette Group
MAP-21	A federal pension plan funding law called the Moving Ahead for Progress in the 21st Century Act, July 2012
Moody's	Moody's Investors Service, Inc. is a credit rating agency
NAV	Net Asset Value
NNG Financial	NNG Financial Corporation, a wholly-owned subsidiary of NW Natural
NOL	Net Operating Loss
NRD	Natural Resource Damages
NWN Energy	NW Natural Energy, LLC, a wholly-owned subsidiary of NW Natural
NWN Gas Reserves	NW Natural Gas Reserves, LLC, a wholly-owned subsidiary of Northwest Energy Corporation
NWN Gas Storage	NW Natural Gas Storage, LLC, a wholly-owned subsidiary of NWN Energy
ODEQ	Department of Environmental Quality
OPEIU	Office and Professional Employees International Union Local No. 11, AFL-CIO, which is also referred to as the Union representing NW Natural's bargaining unit employees
OPUC	Public Utility Commission of Oregon; the entity that regulates our Oregon utility business with respect to rates and terms of service, among other matters; the OPUC also regulates our Mist gas storage facility's intrastate storage services
PBGC	Pension Benefit Guaranty Corporation
PG&E	Pacific Gas & Electric Company; is a 25% owner of the Gill Ranch Facility
PGA	Purchased Gas Adjustment, a regulatory mechanism which adjusts customer rates to reflect changes in the forecasted cost of gas and differences between forecasted and actual gas costs from the prior year
PGE	Portland General Electric
PHMSA	U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration
PRP	Potentially Responsible Parties
RI/FS	Remedial Investigation / Feasibility Study
ROD	Record of Decision
ROE	Return on Equity, a measure of corporate profitability, calculated as net income divided by average common stock equity. Authorized ROE refers to the equity rate approved by a regulatory agency for use in determining utility revenue requirements
ROR	Rate of Return
S&P	Standard & Poor's, a division of The McGraw-Hill Companies, Inc., is a credit rating agency
Sales Service	Service provided whereby a customer purchases both natural gas commodity supply and transportation from the utility
SEC	U.S. Securities and Exchange Commission

SIP	System Integrity Program, an Oregon billing rate mechanism that provides cost recovery of pipeline system integrity programs, which are required under various safety standards prescribed by both state and federal regulators
SRRM	Site Remediation and Recovery Mechanism, an Oregon billing rate mechanism for recovering prudently incurred environmental site remediation costs through customer billings, subject to an earnings test
TAIL	TransCanada American Investments, Ltd., a 50% owner of TWH
Therm	The basic unit of natural gas measurement, equal to one hundred thousand Btu's
TWH	Trail West Holdings, LLC is 50% owned by NWN Energy
TWP	Trail West Pipeline, LLC, a subsidiary of TWH
TransCanada	TransCanada Pipelines Limited, owner of TAIL and GTN
Transportation Service	Service provided whereby a customer purchases natural gas directly from a supplier but pays the utility to transport the gas over its distribution system to the customer's facility
Utility Margin	A financial measure consisting of utility operating revenues less the associated cost of gas, franchise tax and environmental recoveries
VIE	Variable Interest Entity
Weather Normalization	An Oregon billing rate mechanism applied to residential and commercial customers to adjust for temperature variances from average weather; rates decrease when the weather is colder than average, and rates increase when the weather is warmer than average; the mechanism is applied to customer bills from December through mid-May of each heating season
WUTC	Washington Utilities and Transportation Commission, the entity that regulates our Washington utility business with respect to rates and terms of service, among other matters

FORWARD-LOOKING STATEMENTS

This report contains forward-looking statements within the meaning of the U.S. Private Securities Litigation Reform Act of 1995. Forward-looking statements can be identified by words such as anticipates, assumes, intends, plans, seeks, believes, estimates, expects, and similar references to future periods. Examples of forward-looking statements include, but are not limited to, statements regarding the following:

- plans, projections and predictions;
- objectives;
- goals;
- strategies;
- assumptions and estimates;
- future events or performance;
- trends;
- risks;
- timing and cyclicality;
- earnings and dividends;
- capital expenditures and allocation;
- capital structure;
- growth;
- customer rates;
- workforce succession;
- commodity costs;
- gas reserves;
- operational performance and costs;
- energy policy and preferences;
- efficacy of derivatives and hedges;
- liquidity and financial positions;
- project and program development, expansion, or investment;
- competition;
- procurement and development of gas supplies;
- estimated expenditures;
- costs of compliance;
- credit exposures;
- potential efficiencies;
- rate or regulatory outcomes, recovery or refunds;
- impacts of laws, rules and regulations;
- tax liabilities or refunds;
- levels and pricing of gas storage contracts and gas storage markets;
- outcomes and effects of potential claims, litigation, regulatory actions, and other administrative matters;
- projected obligations under retirement plans;
- availability, adequacy, and shift in mix, of gas supplies;
- effects of new or anticipated changes in critical accounting policies;
- approval and adequacy of regulatory deferrals;
- effects and efficacy of regulatory mechanisms; and
- environmental, regulatory, litigation and insurance costs and recoveries, and timing thereof.

Forward-looking statements are based on our current expectations and assumptions regarding our business, the economy and other future conditions. Because forward-looking statements relate to the future, they are subject to inherent uncertainties, risks and changes in circumstances that are difficult to predict. Our actual results may differ materially from those contemplated by the forward-looking statements. We therefore caution you against relying on any of these forward-looking statements. They are neither statements of historical fact nor guarantees or assurances of future performance. Important factors that could cause actual results to differ materially from those in the forward-looking statements are discussed at Item 1A., "Risk Factors" of Part I and Item 7. and Item 7A., "Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Quantitative and Qualitative Disclosures About Market Risk", respectively, of Part II of this report.

Any forward-looking statement made by us in this report speaks only as of the date on which it is made. Factors or events that could cause our actual results to differ may emerge from time to time, and it is not possible for us to predict all of them. We undertake no obligation to publicly update any forward-looking statement, whether as a result of new information, future developments or otherwise, except as may be required by law.

NORTHWEST NATURAL GAS COMPANY
PART I

ITEM 1. BUSINESS

OVERVIEW

Northwest Natural Gas Company (NW Natural or the Company) was incorporated under the laws of Oregon in 1910. Our Company and its predecessors have supplied gas service to the public since 1859, and we have been doing business as NW Natural since 1997. We maintain operations in Oregon, Washington, and California and conduct business through NW Natural and its subsidiaries. References in this discussion to "Notes" are to the Notes to the Consolidated Financial Statements in Item 8 of this report.

We have two core businesses: our regulated local gas distribution business, referred to as the utility segment, which serves residential, commercial, and industrial customers in Oregon and southwest Washington; and our gas storage businesses, referred to as the gas storage segment, which provides storage services for utilities, gas marketers, electric generators, and large industrial users from storage facilities located in Oregon and California. In addition, we have investments and other non-utility activities we aggregate and report as other. See Note 4 to the Consolidated Financial Statements for further information on total assets and results of operations for our segments for the years ended December 31, 2013, 2014 and 2015.

The utility business is our largest segment, while our gas storage businesses account for the majority of our remaining net income. The following table reflects the percentage allocation between segments and other as of December 31, 2015:

		Non-Utility(1)		
	Utility	Gas Storage(2)	Other	Total
Assets	91.0%	8.5%	0.5%	100.0%
Net Income	99.4%	0.3%	0.3%	100.0%

(1) We refer to our gas storage segment and other as non-utility as they are not included in our regulated gas distribution business; however, certain aspects of the gas storage segment and other may be regulated by the OPUC, WUTC, CPUC, or FERC.

(2) Gas Storage segment includes asset management services for both the utility and non-utility portion of our Mist gas storage facility.

LOCAL GAS DISTRIBUTION "UTILITY"

The utility is principally engaged in the regulated distribution of natural gas in Oregon and southwest Washington to over 714,000 customers with approximately 89% of our customers located in Oregon and 11% located in Washington. In total, we provide natural gas service to over 100 cities in 18 counties with an estimated population of 3.5 million in our service territory.

We have been allocated an exclusive service territory by the OPUC and WUTC, which includes a major portion of western Oregon, including the Portland metropolitan area, most of the Willamette Valley, the Coastal area from Astoria to Coos Bay, and portions of Washington along the Columbia River. Portland serves as one of the largest international ports on the West Coast and is a key distribution center due to its comprehensive transportation system of ocean and river shipping, transcontinental railways and highways, and an international airport. Major businesses located in our service territory include retail, manufacturing, and high-technology industries.

Natural gas provides a clean, low-carbon, and affordable energy source, and supply in the United States is at an all-time high. We are committed to environmental stewardship and furthering the usage of natural gas to fuel heat, electric generation, and transportation systems in our communities. To this end, we filed our first proposal in 2015 with state regulators under a Carbon Solutions Program incentivizing industrial users to install combined heat and power systems using natural gas. See Part II, Item 7, "Results of Operations—*Regulatory Matters*". We also have an approved CNG tariff in place to provide customers with high-pressured gas service. Further, we have partnered with local agencies on environmental programs, and are able to allow residential and commercial customers to offset their carbon emissions by supporting carbon-reduction projects at dairies and other farms. Energy conservation is another key component of our environmental focus and competitive advantage, and we were among the first utilities in the nation to break the link between utility earnings and the quantity of natural gas sold to customers with our decoupling mechanism or conservation tariff. The decoupling mechanism is intended to allow the utility to encourage industrial and small commercial customers to conserve energy while not adversely affecting its earnings due to reductions in sales volumes. We will continue to further the role of natural gas in our region and country as it is an affordable, energy efficient fuel source.

Customers

We serve residential, commercial and industrial customers with no individual customer or industry accounting for more than 10% of our utility revenues. On an annual basis, residential and commercial customers typically account for around 60% of our utility's total volumes delivered and 90% of our utility's margin. Industrial customers largely account for the remaining volumes and utility margin. The following table presents summary customer information as of December 31, 2015:

	Number of Customers	% of Volumes	% of Utility Margin (1)
Residential	646,841	34%	63%
Commercial	66,584	21%	27%
Industrial	1,003	45%	8%
Other(1)	N/A	N/A	2%
Total	714,428	100%	100%

(1) Utility margin is also affected by other items, including miscellaneous services, gains or losses from our incentive gas cost sharing mechanism, and other service fees.

Generally residential and commercial customers purchase both their natural gas commodity (gas sales) and natural gas delivery services (transportation services) from the utility. Industrial customers also purchase transportation services from the utility, but may buy the gas commodity either from the utility or directly from a third-party gas marketer or supplier. Our gas commodity cost is primarily a pass-through cost to customers; therefore, our profit margins are not materially affected by an industrial customer's decision to purchase gas from us or from third parties. Industrial and large commercial customers may also select between firm and interruptible service levels, with firm services generally providing higher profit margins compared to interruptible services.

To help manage gas supplies, our industrial tariffs are designed to provide some certainty regarding industrial customers' volumes by requiring an annual service election, special charges for changes between elections, and in some cases, a minimum or maximum volume requirement before changing options.

Customer growth rates for natural gas utilities in the Pacific Northwest historically have been among the highest in the nation due to lower market saturation as natural gas became widely available as a residential heating source after other fuel options. We estimate natural gas is currently in approximately 60% of residential single-family dwellings in our service territory. Customer growth in our region comes from the following main sources, in both new construction and conversions: single-family housing, both new construction and conversions; multifamily housing construction; and commercial buildings, both new construction and conversions. Single family new construction has consistently been our strongest performing source of growth. We have added increasing numbers of customers in our service territory for the last four years as the economy has recovered. Continued customer growth is closely tied to the comparative pricing of natural gas to electricity and fuel oil and the health of the Portland, Oregon and Vancouver, Washington economies. We believe there is potential for continued growth as natural gas is affordable, reliable, a clean fuel choice, and a preferred energy source in our service territory. See Note 4 for information on the utility's assets and results of operations.

Competitive Conditions

In our service areas, we have no direct competition from other natural gas distributors, but we compete with other forms of energy supply in each customer class. This competition among energy suppliers is based on price, efficiency, reliability, performance, market conditions, technology, federal and state energy policy, and environmental impacts.

For residential and small to mid-size commercial customers, we compete primarily with electricity, fuel oil, propane, and renewable energy providers.

In the industrial and large commercial markets, we compete with all forms of energy, including competition from wholesale natural gas marketers. In addition, large industrial customers could bypass our local gas distribution system by installing their own direct pipeline connection to the interstate pipeline system. We have designed custom transportation service agreements with several of our largest industrial customers to provide transportation service rates that are competitive with the customer’s costs of installing their own pipeline; these agreements generally prohibit bypass. Due to the cost pressures confronting a number of our largest customers competing in global markets, bypass continues to be a competitive threat. Although we do not expect a significant number of our large customers to bypass our system in the foreseeable future, we could experience deterioration of utility margin if customers bypass or switch over to custom contracts with lower profit margins.

Seasonality of Business

Our utility business is seasonal in nature due to higher gas usage by residential and commercial customers during the cold winter heating months.

Regulation and Rates

The utility is subject to regulation by the OPUC, WUTC, and FERC. These regulatory agencies authorize rates and allow recovery mechanisms to provide our utility the opportunity to recover prudently incurred capital and operating costs from customers, while also earning a reasonable return on investment for investors. In addition, the OPUC and WUTC also regulate the system of accounts and issuance of securities by our utility.

We file general rate cases and rate tariff requests periodically with the commissions to establish approved rates, an authorized ROE, an overall rate of return on rate base (ROR), an authorized utility capital structure, and other revenue/cost deferral and recovery mechanisms.

In addition, under our Mist interstate storage certificate with FERC, the utility is required to file either a petition for rate approval or a cost and revenue study every five years to change or justify maintaining the existing rates for the interstate storage service. We filed a rate petition in 2013 and received approval in 2014 for new maximum cost-based rates effective January 1, 2014.

The utility's most recent general rate case in Oregon was effective November 1, 2012, and the latest Washington rate case was effective January 1, 2009. Our current approved rates and recovery mechanisms for each service area include:

	Oregon	Washington
Authorized Rate Structure:		
ROE	9.5%	10.1%
ROR	7.8%	8.4%
Debt/Equity Ratio	50%/50%	49%/51%
Key Regulatory Mechanisms:		
PGA	X	X
Incentive Sharing	X	
Weather Normalization Tariff	X	
Decoupling	X	
SIP[(1)]	X	
Pension Balancing	X	
Environmental Cost Deferral	X	X
SRRM	X	

(1) Regulatory authority for SIP expired October 31, 2014, although the bare steel replacement portion of the mechanism remained in place until the end of 2015.

In general, these rates and regulatory mechanisms do not allow the utility to earn a profit or incur a loss on our gas commodity purchases. This means gas commodity purchase costs are primarily a pass-through cost in customer rates, with the exception of our gas reserves investments and incentive cost sharing mechanism in Oregon. Under this mechanism, we can either increase or decrease margin revenues based on higher or lower actual gas purchase costs compared to gas purchase costs embedded in the PGA.

For a complete discussion of regulatory matters, open dockets, current regulatory activities, and additional details on each rate mechanism, see Part II, Item 7, "Results of Operations—*Regulatory Matters*" and "*Gas Storage*".

Gas Supply

The utility strives to secure sufficient, reliable supplies of natural gas to meet the needs of customers at the lowest reasonable cost, while maintaining price stability and managing gas purchase costs prudently. This is accomplished through a comprehensive strategy focused on the following items:

- **Diverse Supply** - providing diversity of supply sources;
- **Diverse Contracts** - maintaining a variety of contract durations and types;
- **Reliability** - ensuring gas resource portfolios are sufficient to satisfy customer requirements under extreme cold weather conditions; and
- **Cost Management and Recovery** - employing prudent gas cost management strategies.

Diversity of Supply Sources

We purchase our gas supplies primarily from the Alberta and British Columbia areas of Canada and multiple receipt points in the U.S. Rocky Mountains to protect against regional supply disruptions and to take advantage of price differentials. For 2015, 62% of our gas supply came from Canada, with the balance primarily coming from the U.S. Rocky Mountain region. We believe gas supplies available in the western United States and Canada are adequate to serve our core utility requirements for the foreseeable future. We continue to evaluate the long-term supply mix based on projections of gas production and pricing in the U.S. Rocky Mountain region as well as other regions in North America; however, we believe the cost of natural gas coming from western Canada and the U.S. Rocky Mountain region will continue to track with broader U.S. market pricing. Additionally, the extraction of shale gas has increased the availability of gas supplies throughout North America for the foreseeable future.

We supplement our firm gas supply purchases with gas withdrawals from gas storage facilities, including underground reservoirs and LNG storage facilities. Storage facilities are generally injected with natural gas during the off-peak months in the spring and summer and the gas is withdrawn for use during peak demand months in the winter.

The following table presents the storage facilities available for our utility supply:

	Maximum Daily Deliverability *(therms in millions)*	Capacity *(Bcf)*
Gas Storage Facilities:		
Owned Facility:		
Mist, Oregon[(1)]	3.1	10.6
Contracted Facilities:		
Jackson Prairie, Washington[(2)]	0.5	1.1
Alberta, Canada[(3)]	0.7	4.4
LNG Facilities:		
Owned Facilities:		
Newport, Oregon	0.6	0.9
Portland, Oregon	1.2	0.6
Total	6.1	17.6

(1) The Mist gas storage facility has a total maximum daily deliverability of 5.2 million therms and a total working gas capacity of about 16 Bcf, of which 3.1 million therms of daily deliverability and 10.6 Bcf of storage capacity are reserved for core utility customers.

(2) The storage facility is located near Chehalis, Washington and is contracted from Northwest Pipeline, a subsidiary of The Williams Companies.

(3) This resource does not add to our total peak day capacity, but mitigates price risks as it displaces equivalent volumes of heating season spot purchases.

The Mist facility is used for both utility and non-utility purposes. Under our regulatory agreements with the OPUC and WUTC, non-utility gas storage at Mist can be developed in advance of core utility customer needs but is subject to recall by the utility when needed to serve utility customers as their demand increases. In May 2015, the utility recalled 0.3 million therms per day of deliverability and 0.7 Bcf of associated storage capacity from the non-utility business to serve core utility customer needs.

In addition, we have the ability to recall pipeline capacity and supply resources from certain customers if needed to meet high demand requirements.

Diverse Contract Durations and Types

We have a diverse portfolio of short-, medium-, and long-term firm gas supply contracts and a variety of contract types including firm and interruptible supplies plus supplemental supplies from gas storage facilities.

Our portfolio of firm gas supply contracts typically includes the following gas purchase contracts: year-round and winter-only baseload supplies; seasonal supply with an option to call on additional daily supplies during the winter heating season; and daily or monthly spot purchases.

During 2015, we purchased a total of 669 million therms under contracts with durations outlined in the chart below:

Contract Duration (primary term)	Percent of Purchases
Long-term (one year or longer)	33%
Short-term (more than one month, less than one year)	30
Spot	37
Total	100%

We renew or replace gas supply contracts as they expire. Aside from the gas supplies provided by an independent energy marketing company as part of asset management services, no individual supplier provided over 10% of our gas supply requirements in 2015.

Reliability

The effectiveness of our gas distribution system ultimately rests on whether we provide reliable service to our core utility customers. To ensure our effectiveness, we develop a composite design year, including a seven day design peak event based on the most severe cold weather experienced during the last 30 years in our service territory.

Our projected maximum design day firm utility customer sendout totals are approximately 9.5 million therms. Of this total, we are currently capable of meeting about 50% of our maximum design day requirements with gas from storage located within or adjacent to our service territory, while the remaining supply requirements would come from gas purchases under firm gas purchase contracts and recall agreements.

To supplement near-term natural gas supplies, we planned to segment transportation capacity during the 2014-2015 and 2015-2016 heating seasons for approximately 0.4 million therms per day if needed. Pipeline segmentation is a natural gas transportation mechanism under which a shipper can leverage its firm pipeline transportation capacity by separating it into multiple segments with alternate delivery routes. The reliability of service on these alternate routes will vary depending on the constraints of the pipeline system. For those segments with acceptable reliability, segmentation provides a shipper with increased flexibility and potential cost savings compared to traditional pipeline service.

Specifically, we could segment pipeline capacity that flows from Stanfield, Oregon with additional gas expected from the Sumas, Washington trading hub. This segmented capacity is considered reliable as the pipeline has not experienced constraints from Sumas in recent years.

We believe our gas supplies would be sufficient to meet existing firm customer demand if we were to experience maximum design day weather conditions. We will continue to evaluate and update our forecasted requirements and incorporate changes in our IRP process.

The following table shows the sources of supply projected to be used to satisfy the design day sendout for the 2015-2016 winter heating season:

Therms in millions	Therms	Percent
Sources of utility supply:		
Firm supply purchases	3.3	34%
Mist underground storage (utility only)	3.1	32
Company-owned LNG storage	1.8	19
Off-system storage contract	0.5	5
Pipeline segmentation capacity	0.4	4
Recall agreements	0.4	4
Peak day citygate deliveries(1)	0.2	2
Total	9.7	100%

(1) These citygate deliveries are contracted from December 2015 to February 2016 with this resource being evaluated for future heating seasons after the current winter.

The OPUC and WUTC have IRP processes in which utilities define different growth scenarios and corresponding resource acquisition strategies in an effort to evaluate supply and demand resource requirements, consider uncertainties in the planning process and the need for flexibility to respond to changes, and establish a plan for providing reliable service at the least cost.

In general, the IRP is filed biannually with both the OPUC and the WUTC. An update is filed in Oregon in the off year. The OPUC acknowledges receipt of the IRP; whereas the WUTC provides notice our IRP met the requirements of the Washington Administrative Code. OPUC acknowledgment of the IRP does not constitute ratemaking approval of any specific resource acquisition strategy or expenditure. However, the Commissioners generally indicate they would give considerable weight in prudence reviews to utility actions consistent with acknowledged plans. The WUTC has indicated the IRP process is one factor it will consider in a prudence review. We filed our 2014 IRP in both Oregon and Washington in August 2014 and received acknowledgment from the OPUC in February 2015, and notice from the WUTC in March 2015. We plan to file an IRP with both Commissions in 2016.

Gas Cost Management Strategy

The cost of gas sold to utility customers primarily consists of the following items, which are included in annual PGA rates: purchase price paid to suppliers; charges paid to pipeline companies to transport gas to our distribution system; costs paid to store gas; our gas reserves contracts; and gains or losses related to gas commodity derivative contracts.

We employ a number of strategies to mitigate the cost of gas sold to utility customers. Our primary strategies for managing gas commodity price risk include:

- negotiating fixed prices directly with gas suppliers;
- negotiating financial derivative contracts that: (1) effectively convert floating index prices in physical gas supply contracts to fixed prices (referred to as commodity price swaps); or (2) effectively set a ceiling or floor price, or both, on floating index priced physical supply contracts (referred to as commodity price options such as calls, puts, and collars). See Part II, Item 7A, "Quantitative and Qualitative Disclosures About Market Risk—Credit Risk—*Credit Exposure to Financial Derivative Counterparties"*;
- buying physical gas supplies at a set price and injecting the gas into storage for price stability and to minimize pipeline capacity demand costs; and
- investing in gas reserves for longer term price stability. See Note 11 for additional information about our gas reserves.

We also contract with an independent energy marketing company to capture opportunities regarding our storage and pipeline capacity when those assets are not serving the needs of our core utility customers. Our asset management activities provide cost savings that reduce our utility customer's cost of gas and opportunities to generate incremental revenues for our shareholders from a regulatory incentive-sharing mechanism, which are included in our gas storage segment.

<u>Cost Recovery</u>
Mechanisms for gas cost recovery are designed to be fair and reasonable, with an appropriate balance between the interests of our customers and shareholders. In general, utility rates are designed to recover the costs of, but not to earn a return on, the gas commodity sold. We minimize risks associated with gas cost recovery by resetting customer rates annually through the PGA and aligning customer and shareholder interests through the use of sharing, weather normalization, and conservation mechanisms in Oregon. See Part II, Item 7, "Results of Operations—Regulatory Matters—*Rate Mechanisms"* and "Results of Operations—Business Segments—Local Gas Distribution Utility Operations—*Cost of Gas*."

<u>Transportation of Gas Supplies</u>
Our local gas distribution system is reliant on a single, bi-directional interstate transmission pipeline to bring gas supplies into our distribution system. Although we are dependent on a single pipeline, the pipeline's gas flows into the Portland metropolitan market from two directions: (1) the north, which brings supplies from the British Columbia and Alberta supply basins; and (2) the east, which brings supplies from Alberta as well as the U.S. Rocky Mountain supply basins.

We incur monthly demand charges related to our firm pipeline transportation contracts. Our largest pipeline agreements are with Northwest Pipeline. These contracts are multi-year contracts with expirations ranging from 2016 to 2044. We actively work with Northwest Pipeline and others to renew contracts in advance of expiration to ensure gas transportation capacity is sufficient to meet our utility needs.

Rates for interstate pipeline transportation services are established by FERC within the U.S. and by Canadian authorities for services on Canadian pipelines.

As mentioned above, our service territory is dependent on a single pipeline for its natural gas supply. Although supply has not been disrupted in the recent past, pipeline replacement projects and long-term projected natural gas demand in our region underscore the need for pipeline transportation diversity. In addition, there are several potential industrial projects in the region, which could increase the demand for natural gas and the need for additional pipeline capacity and pipeline diversity.

Several interstate pipeline projects currently proposed could meet the region's and our projected demand. The pipeline location is dependent on the location of the committed industrial project. We will evaluate and closely monitor the currently prospected projects to determine the best option for ratepayers. The Company also has an equity investment in Trail West Holdings, LLC (TWH) that is developing plans to build the Trail West pipeline. This pipeline would connect TransCanada Pipelines Limited's (TransCanada) Gas Transmission Northwest (GTN) interstate transmission line to our local gas distribution system. If constructed, this pipeline would provide another transportation path for gas purchases from Alberta and the U.S. Rocky Mountains in addition to the one that currently moves gas through the Northwest Pipeline system. See Part II, Item 7, *"2016 Outlook"*.

<u>Gas Distribution</u>
The primary goals of our gas distribution operations are safety and reliability of our system, which entails building and maintaining a safe pipeline distribution system.

Safety and the protection of our employees, our customers, and the public at large are, and will remain, our top priorities. We construct, operate and maintain our pipeline distribution system and storage operations with the goal of ensuring natural gas is delivered and stored safely, reliably, and efficiently.

NW Natural has one of the most modern distribution systems in the country with no identified cast iron pipe or bare steel main. We removed the final three miles of known bare steel from our system in 2015 and completed our cast iron pipe removal in 2000. Since the 1980s, we have taken a proactive approach to replacement programs and partnered with our Commissions on progressive regulation to further safety and reliability efforts for our distribution system. In the past, we had a cost recovery program in Oregon that encompassed the Company's programs for bare steel replacement, transmission pipeline integrity management, and distribution pipeline integrity management. Currently, we are working with the OPUC and other Oregon natural gas utilities to evaluate guidelines for potential future safety cost-recovery tracking programs. See Part II, Item 7, "Results of Operations-Regulatory Matters-*System Integrity Program*".

Natural gas distribution businesses are likely to be subject to even greater federal and state regulation in the future due to pipeline incidents involving other companies. Additional regulations from the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) are currently under development with final regulations expected in 2016 and effective dates beginning in 2017. We will continue to work diligently with industry associations as well as federal and state regulators to ensure the safety of our system and compliance with new laws and regulations. We expect the costs associated with compliance of federal, state, and local rules would be recoverable in rates.

GAS STORAGE

Our gas storage segment includes the following:

- the non-utility portion of the Mist gas storage facility near Mist, Oregon;
- our Gill Ranch gas storage facility near Fresno, California; and
- asset management services provided by an independent energy marketing company.

In general, the supply of natural gas remains relatively stable over the course of a year, while the demand for natural gas typically fluctuates seasonally. Storage facilities allow customers to purchase and inject natural gas supplies during periods of low demand and withdraw these supplies for use or resale during periods of higher demand. These facilities allow us to capitalize on the imbalance of supply and demand and price volatility for natural gas.

See Note 4 for more information on gas storage assets and results of operations and "Financial Condition—*Liquidity and Capital Resources*".

Gas Storage Facilities

The following table provides information concerning the Company's non-utility gas storage facilities:

		Maximum	
	Designed Storage Capacity (Bcf)	Deliverability (Therms in millions/day[3]	Injection (Therms in millions/day)[3]
Mist Storage[1]	5.4	2.1	0.8
Gill Ranch Storage[2]	15.0	4.9	2.4

(1) Approximately 5.4 Bcf of a total 16 Bcf at Mist is currently available to our gas storage segment. The remaining 10.6 Bcf is used to provide gas storage for our local distribution business and its utility customers. All storage capacity and daily deliverability currently developed for the gas storage segment at Mist is available for recall by the utility. In May 2015, the utility recalled approximately 0.3 million therms per day of deliverability and 0.7 Bcf of capacity for core utility customer use.

(2) Our share of the Gill Ranch facility is currently 15 Bcf out of a total capacity of 20 Bcf.

(3) Our share of the expected daily maximum injection and deliverability rates.

Mist Storage Facility

The Mist storage facility began operations in 1989 and currently consists of seven depleted natural gas reservoirs, 22 injection and withdrawal wells, a compressor station, dehydration and control equipment, gathering lines and other related facilities.

SERVICES. Mist provides multi-cycle gas storage services to customers in the interstate and intrastate markets from the facility located in Columbia County, Oregon, near the town of Mist. The Mist field was initially converted to storage operations for our utility customers. Since 2001, gas storage capacity at Mist has also been made available to interstate customers by developing new incremental capacity in advance of core utility customer requirements to meet the demands for interstate storage service. These interstate storage services are offered under a limited jurisdiction blanket certificate issued by FERC. In addition, since 2005 we have offered intrastate firm storage services in Oregon under an OPUC-approved rate schedule as an optional service to eligible non-residential utility customers.

CUSTOMERS. For Mist storage services, firm service agreements with customers are entered into with terms typically ranging from 2 to 10 years. Currently, our gas storage revenues from Mist are derived primarily from firm service customers who provide energy related services, including natural gas distribution, electric generation, and energy marketing. Three storage customers currently account for all of our existing contracted non-utility gas storage capacity at Mist, with the largest customer accounting for about half of the total capacity. These three customers have contracts expiring at various dates through 2019.

COMPETITIVE CONDITIONS. Our Mist gas storage facility benefits from limited competition from other Pacific Northwest storage facilities primarily because of its geographic location. However, competition from other storage providers in Washington and Canada, as well as competition for interstate pipeline capacity, does exist. In the future, we could face increased competition from new or expanded gas storage facilities as well as from new natural gas pipelines, marketers, and alternative energy sources.

SEASONALITY. Mist gas storage revenues generally do not follow seasonal patterns similar to those experienced by the utility because most of the storage capacity is contracted with customers for firm service, which are primarily in the form of fixed monthly reservation charges and are not affected by customer usage. However, there is seasonal variation with Mist storage capacity related to utility customers' lower demand during the spring and summer months. This surplus storage capacity and related transportation capacity can be optimized under regulatory sharing agreements with the OPUC and WUTC. See *"Asset Management"* below.

REGULATION. Our Mist facility is subject to regulation by the OPUC and WUTC. In addition, FERC has approved maximum cost-based rates under our Mist interstate storage certificate. We are required to file either a petition for rate approval or a cost and revenue study with FERC at least every five years to change or justify maintaining the existing rates for the interstate storage service. See Part II, Item 7, "Results of Operations—*Regulatory Matters"*.

EXPANSION OPPORTUNITIES. The need for new, flexible gas-fired electricity generation has been identified in the Pacific Northwest region to integrate intermittent wind resources into the power system, thereby increasing the associated need for gas storage. To address this need, we are planning a potential expansion of our Mist storage facility. If completed, this expansion would be supported by a long-term contract with Portland General Electric (PGE) to serve gas-fired electric power generation facilities at Port Westward, Oregon, which is located approximately 15 miles from Mist.

The project would include a new reservoir providing up to 2.5 Bcf of available storage, an additional compressor station with design capacity of 1.2 million therms of gas per day, innovative no-notice service with uninterrupted turn capability, and a 13-mile pipeline to connect to PGE's gas plants at Port Westward. The current estimated cost of the expansion is approximately $125 million with a targeted in-service date in winter of 2018-19, depending on the permitting process and construction schedule.

In early 2015, we received authorization from PGE to begin permitting and land acquisition work, and a new rate schedule was approved in October 2014 under which we will provide no-notice gas storage service associated with the expansion. This expansion project is subject to PGE's final approval of project costs and a notice to proceed, as well as the receipt of permits, certain land rights, and other conditions.

Gill Ranch Storage Facility

Gill Ranch Storage, LLC (Gill Ranch), our subsidiary, has a joint project agreement with Pacific Gas and Electric Company (PG&E) to develop and own the Gill Ranch underground natural gas storage facility near Fresno, California. Currently, Gill Ranch is the sole operator of the facility. The facility began operations in 2010 and consists of three depleted natural gas reservoirs, 12 injection and withdrawal wells, a compressor station, dehydration and control equipment, gathering lines, an electric substation, a natural gas transmission pipeline extending 27 miles from the storage field to an interconnection with the PG&E transmission system, and other related facilities. Gill Ranch owns the rights to 75% of the available storage capacity at the facility. Gill Ranch's share of the facility currently provides 15 Bcf of working gas capacity.

California has been impacted by challenging market conditions for gas storage, with contract prices in the region near historic lows and a greater number of competitors in the area compared to the Pacific Northwest region. Prices for the 2015-16 gas year showed improvement, however prices remained low relative to the pricing in our original long-term contracts which ended primarily in the 2013-14 gas storage year. In the future, we may see an improvement in gas storage values and an increase in the demand for natural gas driven by a number of factors, including changes in electric generation triggered by California's renewable portfolio standards, an increase in use of alternative fuels to meet carbon reduction targets, improvement of the California economy, growth of domestic industrial manufacturing, potential exports of liquefied natural gas from the west coast, and other favorable storage market conditions in and around California. These factors, if they occur, may contribute to higher summer/winter natural gas price spreads, gas price volatility, and gas storage values. We are continuing to explore opportunities to increase revenues through enhanced services for storage customers and capitalizing on opportunities that fit our business-risk profile.

SERVICES. Gill Ranch provides intrastate, multi-cycle storage services in California at market-based rates under a CPUC-approved tariff that includes firm storage service, interruptible storage service, and park and loan storage services. Our Gill Ranch facility is not currently authorized to provide interstate gas storage services.

CUSTOMERS. Customer contracts for firm storage capacity at Gill Ranch are as long as 27 years in duration; however, the majority of the contracted capacity is shorter term in nature due to market conditions. In the near-term, we expect Gill Ranch to contract for terms ranging from one to five years. For the 2015-16 gas storage year, Gill Ranch has several storage customers, with the largest single contract accounting for approximately 13% of our storage capacity. In the near term, we continue to expect shorter contract lengths reflecting current market prices and trends.

The California market served by Gill Ranch is larger, and has a greater diversity of prospective customers, than the Pacific Northwest market served by Mist. Therefore, we expect less sensitivity to any single customer or group of customers at Gill Ranch. Current Gill Ranch customers provide energy related services, including natural gas production, marketing, and electric generation.

COMPETITIVE CONDITIONS. The Gill Ranch storage facility competes with a number of other storage providers, including local integrated gas companies and other independent storage operators in the northern California market. The Gill Ranch storage facility currently competes with a number of other storage providers, including local integrated gas companies and other independent storage providers (ISPs) in the northern California market. There are currently four ISPs authorized by the CPUC to provide storage services in California, with the Gill Ranch storage facility comprising approximately 12% of the storage capacity held by ISPs. A recent proposed acquisition, which is pending CPUC approval, will consolidate approximately 80% of the storage capacity authorized by the CPUC to ISPs in California. The effect of this dominant market share on the Gill Ranch storage facility pricing and contracting levels remains unknown and cannot be predicted at this time.

In addition, in October 2015 a significant natural gas leak occurred at a southern California gas storage facility that persisted in 2016. During this time-frame, short-term storage spreads for the region improved. At this time, we do not know the long-term effects of this incident on gas storage prices. Regulatory proceedings at both the national and California state level have been opened in response to the incident, and it is likely additional regulations will result and increase short-term costs for all storage providers. The implications of the regulatory proceeding are unknown and cannot be predicted at this time until the rules are finalized.

SEASONALITY. While the majority of our Gill Ranch revenues are not subject to seasonality, and although we expect much of the storage revenue at Gill Ranch to be in the form of fixed monthly demand charges, cash flows can fluctuate due to timing of asset management and other revenues. In addition, a significant portion of operating costs at Gill Ranch are subject to fluctuations based on periods when storage customers elect to inject or withdraw.

REGULATION. Gill Ranch has a tariff on file with the CPUC authorizing it to charge market-based rates for the storage services offered. See Part II, Item 7, "Results of Operations–*Regulatory Matters"*.

EXPANSION OPPORTUNITIES. Subject to market demand, project execution, available financing, receipt of future permits, and other rights, the Gill Ranch storage facility can be expanded beyond the current combined permitted capacity of 20 Bcf without further expansion of the takeaway pipeline system. Taking these considerations into account and with certain infrastructure modifications, we currently estimate the Gill Ranch storage facility could support an additional 25 Bcf of storage capacity, bringing the total storage capacity to approximately 45 Bcf, of which our current rights would give us up to an additional 7.5 Bcf or ownership of a total of approximately 22.5 Bcf.

Asset Management

We contract with an independent energy marketing company to provide asset management services, primarily through the use of commodity and pipeline capacity release transactions. The results are included in the gas storage segment, except for amounts allocated to our utility pursuant to regulatory sharing agreements involving the use of utility assets. Utility pre-tax income from third-party asset management services is subject to revenue sharing with core utility customers. See Part II, Item 7, "Results of Operations—*Business Segments—Gas Storage"*.

OTHER

We have non-utility investments and other business activities which are aggregated and reported as other. Other primarily consists of:

- an equity method investment in a joint venture to build and operate a gas transmission pipeline in Oregon. TWH is owned 50% by NWN Energy, a wholly-owned subsidiary of NW Natural, and 50% by TransCanada American Investments Ltd., an indirect wholly-owned subsidiary of TransCanada Corporation. See Part II, Item 7, "*2016 Outlook"*;
- a minority interest in Kelso-Beaver Pipeline held by our wholly-owned subsidiary NNG Financial Corporation (NNG Financial); and
- other operating and non-operating income and expenses of the parent company that are not included in utility or gas storage operations.

The pipelines referred to above are regulated by FERC. Less than 1% of our consolidated assets and consolidated net income are related to activities in other. See Note 4 for summary information for these assets and results of operations.

ENVIRONMENTAL ISSUES

Properties and Facilities

We own, or previously owned, properties and facilities that are currently being investigated that may require environmental remediation and are subject to federal, state and local laws and regulations related to environmental matters. These laws and regulations may require expenditures over a long timeframe to address certain environmental impacts. Estimates of liabilities for environmental costs are difficult to determine with precision because of the various factors that can affect their ultimate disposition. These factors include, but are not limited to, the following:

- the complexity of the site;
- changes in environmental laws and regulations at the federal, state and local levels;
- the number of regulatory agencies or other parties involved;
- new technology that renders previous technology obsolete, or experience with existing technology that proves ineffective;
- the ultimate selection of a particular technology;
- the level of remediation required;
- variations between the estimated and actual period of time that must be dedicated to respond to an environmentally-contaminated site; and
- the application of environmental laws that impose joint and several liabilities on all potentially responsible parties.

We seek recovery of environmental costs through received insurance proceeds and customer rates, and we believe recovery of these costs is probable. In Oregon, we have a mechanism to recover expenses, subject to an earnings test and allocation rules. See Part II, Item 7, "Results of Operations—Rate Matters—Rate Mechanisms—*Environmental Costs*", Note 2, Note 15, and Note 16.

Greenhouse Gas Issues

We recognize our businesses are likely to be impacted by future requirements to address greenhouse gas emissions. Future federal and/or state requirements may seek to limit future emissions of greenhouse gases, including both carbon dioxide (CO_2) and methane. These future laws and regulations may require certain activities to reduce emissions and/or increase the price paid for energy based on its carbon content.

Current federal rules require the reporting of greenhouse gas emissions. In September 2009, the EPA issued a final rule requiring the annual reporting of greenhouse gas emissions from certain industries, specified large greenhouse gas emission sources, and facilities that emit 25,000 metric tons or more of CO_2 equivalents per year. We began reporting emission information in 2011. Under this reporting rule, local gas distribution companies like NW Natural are required to report system throughput to the EPA on an annual basis. The EPA also issued additional greenhouse gas reporting regulations requiring the annual reporting of fugitive emissions from our operations.

The outcome of federal and state policy development in the area of climate change cannot be determined at this time, but these initiatives could produce a number of results including new regulations, legal actions, additional charges to fund energy efficiency activities, or other regulatory actions. The adoption and implementation of any regulations limiting emissions of greenhouse gas from our operations could require us to incur costs to reduce emissions of greenhouse gases associated with our operations, which could result in an increase in the prices we charge our customers or a decline in the demand for natural gas. On the other hand, because natural gas is a fossil fuel with relatively low carbon content, it is also possible future carbon constraints could create additional demand for natural gas for electric generation, direct use of natural gas in homes and businesses, and as a reliable and relatively low-emission back-up fuel source for alternative energy sources. Requirements to reduce greenhouse gas emissions from the transportation sector, such as those in Oregon's clean fuel standard, could also result in additional demand for natural gas for use in vehicles.

We continue to take steps to address future greenhouse gas emission issues, including actively participating in policy development through participation on various Oregon taskforces and, at the federal level, within the American Gas Association. We engage in policy development and in identifying ways to reduce greenhouse gas emissions associated with our operations and our customers' gas use, including offering the Smart Energy program, which allows customers to voluntarily contribute funds to projects such as biodigesters on dairy farms that offset the greenhouse gases produced from their natural gas use.

EMPLOYEES

At December 31, 2015, the utility workforce consisted of 598 members of the Office and Professional Employees International Union (OPEIU) Local No. 11, AFL-CIO, and 463 non-union employees. Our labor agreement with members of OPEIU covers wages, benefits and working conditions. On May 22, 2014, our union employees ratified a new labor agreement (Joint Accord) that extends to November 30, 2019, and thereafter from year to year unless either party serves notice of its intent to negotiate modifications to the collective bargaining agreement.

At December 31, 2015, our subsidiaries had a combined workforce of 15 non-union employees. Our subsidiaries receive certain services from centralized operations at the utility, and the utility is reimbursed for those services pursuant to a Shared Services Agreement.

ADDITIONS TO INFRASTRUCTURE

We make capital expenditures in order to maintain and enhance the safety and integrity of our pipelines, gate stations, storage facilities and related assets, to expand the reach or capacity of those assets, or improve the efficiency of our operations. We expect to make a significant level of capital expenditures for additions to utility and gas storage infrastructure over the next five years, reflecting continued investments in customer growth, technology, and distribution system improvements. For the five-year period ending in 2020, capital expenditures for the utility are estimated to be between $850 and $950 million, including the Company's proposed investment in an expansion of our Mist gas storage facility and excluding any potential future gas reserves investments. In addition, we are evaluating the impact of the five-year extension of bonus depreciation resulting from the enactment of the Federal Protecting Americans From Tax Hikes Act of 2016 on the mix and profile of our investments. We expect cash tax savings from bonus depreciation and are evaluating how to best take advantage of these savings during the period in which they are in effect. Our current capital expenditure range does not consider any additional capital that may be available as a result of this legislation.

In 2016, utility capital expenditures are estimated to be between $155 and $175 million, and non-utility capital investments are estimated to be less than $5 million. Additional spend for gas storage and other investments during and after 2016 will depend largely on future decisions about potential expansion opportunities in gas storage projects.

EXECUTIVE OFFICERS OF THE REGISTRANT

For information concerning our executive officers, see Part III, Item 10.

AVAILABLE INFORMATION

We file annual, quarterly and special reports and other information with the Securities and Exchange Commission (SEC). Reports, proxy statements and other information filed by us can be read and requested through the SEC by mail at U.S. Securities and Exchange Commission, Office of FOIA/PA Operations, 100 F Street, N.E., Washington, D.C. 20549, by facsimile at (202) 772-9337, or online at its website (http://www.sec.gov). You can obtain information about access to the Public Reference Room and how to access or request records by calling the SEC at 1-800-SEC-0330. The SEC website contains reports, proxy and information statements and other information we file electronically. In addition, we make available on our website (http://www.nwnatural.com), our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) and proxy materials filed under Section 14 of the Securities Exchange Act of 1934, as amended (Exchange Act), as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

We have adopted a Code of Ethics for all employees and officers that is available on our website. We intend to disclose amendments to, and any waivers from the Code of Ethics on our website. Our Corporate Governance Standards, Director Independence Standards, charters of each of the committees of the Board of Directors and additional information about the Company are also available at the website. Copies of these documents may be requested, at no cost, by writing or calling Shareholder Services, NW Natural, One Pacific Square, 220 N.W. Second Avenue, Portland, Oregon 97209, telephone 503-226-4211 ext. 2402.

ITEM 1A. RISK FACTORS

Our business and financial results are subject to a number of risks and uncertainties, many of which are not within our control. When considering any investment in our securities, investors should carefully consider the following information, as well as information contained in the caption "Forward-Looking Statements", Item 7A, and other documents we file with the SEC. This list is not exhaustive and the order of presentation does not reflect management's determination of priority or likelihood. Additionally, our listing of risk factors that primarily affects one of our business segments does not mean that such risk factor is inapplicable to our other business segments.

Risks Related to our Business Generally

REGULATORY RISK. *Regulation of our businesses, including changes in the regulatory environment, failure of regulatory authorities to approve rates which provide for timely recovery of our costs and an adequate return on invested capital, or an unfavorable outcome in regulatory proceedings may adversely impact our financial condition and results of operations.*

The OPUC and WUTC have general regulatory authority over our utility business in Oregon and Washington, respectively, including the rates charged to customers, authorized rates of return on rate base, including ROE, the amounts and types of securities we may issue, services we provide and the manner in which we provide them, the nature of investments we make, actions investors may take with respect to our company, and deferral and recovery of various expenses, including, but not limited to, pipeline replacement, environmental remediation costs, commodity hedging expense, transactions with affiliated interests, weather adjustment mechanisms and other matters. Similarly, in our gas storage businesses FERC has regulatory authority over interstate storage services, the CPUC has regulatory authority over our Gill Ranch storage operations, and the WUTC and OPUC have regulatory authority over our Mist storage operations.

The prices the OPUC and WUTC allow us to charge for retail service, and the maximum FERC-approved rates FERC authorizes us to charge for interstate storage and related transportation services, are the most significant factors affecting our financial position, results of operations and liquidity. The OPUC and WUTC have the authority to disallow recovery of costs they find imprudently incurred or otherwise disallow. For example, in February 2015 the OPUC issued an Order to the Company regarding implementation of our SRRM that disallowed from rate recovery approximately $15 million of approximately $95 million of our total environmental expenditures made from 2003 to 2012, due to the OPUC's application of a recently formulated earnings test. The OPUC issued a subsequent Order in January 2016 that, among other things, disallowed interest on the $15 million disallowance after 2012 and found only 96.68% of prudently incurred environmental remediation costs to be allowable to Oregon. Additionally, the rates allowed by the FERC may be insufficient for recovery of costs incurred. We expect to continue to make expenditures to expand, improve and operate our utility distribution and gas storage systems. Regulators can find such expansions or improvements of expenditures were not prudently incurred, and deny recovery. Additionally, while the OPUC and WUTC have established an authorized rate of return for our utility through the ratemaking process, the regulatory process does not provide assurance that we will be able to achieve the earnings level authorized.

Moreover, in the normal course of business we may place assets in service or incur higher than expected levels of operating expense before rate cases can be filed to recover those costs—this is commonly referred to as regulatory lag. The failure of any regulatory commission to approve requested rate increases on a timely basis to recover increased costs or to allow an adequate return could adversely impact our financial condition and results of operations.

As a regulated utility, we frequently have dockets open with our regulators. The regulatory proceedings for these dockets typically involve multiple parties, including governmental agencies, consumer advocacy groups, and other third parties. Each party has differing concerns, but all generally have the common objective of limiting amounts included in rates. We cannot predict the timing or outcome of these deferred proceedings or the effects of those outcomes on our results of operations and financial condition.

ENVIRONMENTAL LIABILITY RISK. *Certain of our properties and facilities may pose environmental risks requiring remediation, the costs of which are difficult to estimate and which could adversely affect our financial condition, results of operations, and cash flows.*

We own, or previously owned, properties that require environmental remediation or other action. We accrue all material loss contingencies relating to these properties. A regulatory asset at the utility has already been recorded for estimated costs pursuant to a deferral Order from the OPUC and WUTC. In addition to maintaining regulatory deferrals, we settled with most of our historical liability insurers for only a portion of the costs we have incurred to date and expect to incur in the future. To the extent amounts we recovered from insurance are inadequate or we are unable to recover these deferred costs in utility customer rates, we would be required to reduce our regulatory assets which would result in a charge to current year earnings. In addition, in our most recent Oregon general rate case, the OPUC approved the SRRM, which limits recovery of our deferred amounts to those amounts which satisfy an annual prudence review and a recently adopted earnings test that requires the Company to contribute additional amounts toward environmental remediation costs above approximately $10 million in years in which the Company earns above its authorized Return on Equity (ROE). To the extent the Company earns more than its authorized ROE in a year, the Company would be required to cover environmental expenses greater than the $10 million with those earnings that exceed its authorized ROE. In addition, the OPUC ordered a review of the SRRM in 2018 or when we obtain greater certainty of environmental costs, whichever occurs first. These ongoing prudence reviews, the earnings test, or the three-year review could reduce the amounts we are allowed to recover, and could adversely affect our financial condition, results of operations and cash flows.

Moreover, we may have disputes with regulators and other parties as to the severity of particular environmental matters and what remediation efforts are appropriate. We cannot predict with certainty the amount or timing of future expenditures related to environmental investigation, remediation or other action, the portions of these costs allocable to us, or disputes or litigation arising in relation thereto. Our liability estimates are based on current remediation technology, industry experience gained at similar sites, an assessment of the probable level of involvement, and the financial condition of other potentially responsible parties. However, it is difficult to estimate such costs due to uncertainties surrounding the course of environmental remediation, the preliminary nature of certain of our site investigations, and the application of environmental laws that impose joint and several liabilities on all potentially responsible parties. These uncertainties and disputes arising therefrom could lead to further adversarial administrative proceedings or litigation, with associated costs and uncertain outcomes, all of which could adversely affect our financial condition, results of operations and cash flows.

ENVIRONMENTAL REGULATION COMPLIANCE RISK. *We are subject to environmental regulations for our ongoing operations, compliance with which could adversely affect our operations or financial results.*

We are subject to laws, regulations and other legal requirements enacted or adopted by federal, state and local governmental authorities relating to protection of the environment, including those legal requirements that govern discharges of substances into the air and water, the management and disposal of hazardous substances and waste, groundwater quality and availability, plant and wildlife protection, and other aspects of environmental regulation. Current and additional environmental regulations could result in increased compliance costs or additional operating restrictions and could have an adverse effect on our financial condition and results of operations, particularly if those costs are not fully recoverable from insurance or through utility customer rates.

GLOBAL CLIMATE CHANGE RISK. *Future legislation to address global climate change may expose us to regulatory and financial risk. Additionally, our business may be subject to physical risks associated with climate change, all of which could adversely affect our financial condition, results of operations and cash flows.*

There are a number of international, federal and state legislative and regulatory initiatives being proposed and adopted in an attempt to measure, control or limit the effects of global warming and overall climate change, including greenhouse gas emissions such as carbon dioxide and methane. Such current or future legislation or regulation could impose on us operational requirements, additional charges to fund energy efficiency initiatives, or levy a tax based on carbon content. Such initiatives could result in us incurring additional costs to comply with the imposed restrictions, provide a cost advantage to energy sources other than natural gas, reduce demand for natural gas, impose costs or restrictions on end users of natural gas, impact the prices we charge our customers, impose increased costs on us associated with the adoption of new infrastructure and technology to respond to such requirements, and may impact cultural perception of our service or products negatively, diminishing the value of our brand, all of which could adversely affect our business practices, financial condition and results of operations. Climate change may cause physical risks, including an increase in sea level, intensified storms, water scarcity and changes in weather conditions, such as changes in precipitation, average temperatures and extreme wind or other climate conditions. A significant portion of the nation's gas infrastructure is located in areas susceptible to storm damage that could be aggravated by wetland and barrier island erosion, which could give rise to gas supply interruptions and price spikes.

These and other physical changes could result in disruptions to natural gas production and transportation systems potentially increasing the cost of gas beyond that assumed in our PGA and affecting our ability to procure gas to meet our customer demand. These changes could also affect our distribution systems resulting in increased maintenance and capital costs, disruption of service, regulatory actions and lower customer satisfaction. Additionally, to the extent that climate change adversely impacts the economic health or weather conditions of our service territory directly, it could adversely impact customer demand or our customers' ability to pay. Such physical risks could have an adverse effect on our financial condition, results of operations, and cash flows.

BUSINESS DEVELOPMENT RISK. *Our business development projects may encounter unanticipated obstacles, costs, changes or delays that could result in a project becoming impaired, which could negatively impact our financial condition, results of operations and cash flows.*

Business development projects involve many risks. We are currently engaged in several business development projects, including, but not limited to, the early planning and development stages for a regional pipeline in Oregon, and a potential expansion of our gas storage facility at Mist. We may also engage in other business development projects such as investment in additional long-term gas reserves or CNG refueling stations. These projects may not be successful. Additionally, we may not be able to obtain required governmental permits and approvals to complete our projects in a cost-efficient or timely manner potentially resulting in delays or abandonment of the projects. We could also experience startup and construction delays, construction cost overruns, inability to negotiate acceptable agreements such as rights-of-way, easements, construction, gas supply or other material contracts, changes in customer demand or commitment, public opposition to projects, changes in market prices, and operating cost increases. Additionally, we may be unable to finance our business development projects at acceptable interest rates or within a scheduled time frame necessary for completing the project. One or more of these events could result in the project becoming impaired, and such impairment could have an adverse effect on our financial condition and results of operations.

JOINT PARTNER RISK. *Investing in business development projects through partnerships, joint ventures or other business arrangements affects our ability to manage certain* *risks and could adversely impact our financial condition, results of operations and cash flows.*

We use joint ventures and other business arrangements to manage and diversify the risks of certain utility and non-utility development projects, including our Trail West pipeline, Gill Ranch storage and our gas reserves agreements. We may acquire or develop part-ownership interests in other similar projects in the future. Under these arrangements, we may not be able to fully direct the management and policies of the business relationships, and other participants in those relationships may take action contrary to our interests including making operational decisions that could affect our costs and liabilities. In addition, other participants may withdraw from the project, divest important assets, become financially distressed or bankrupt, or have economic or other business interests or goals that are inconsistent with ours.

For example, our gas reserves arrangements, which operate as a hedge backed by physical gas supplies, involve a number of risks. These risks include gas production that is significantly less than the expected volumes, or no gas volumes; operating costs that are higher than expected; changes in our consolidated tax position or tax laws that could affect our ability to take, or timing of, certain tax benefits that impact the financial outcome of this transaction; inherent risks of gas production, including disruption to operations or complete shut-in of the field; and a participant in one of these business arrangements acting contrary to our interests. In addition, while the cost of the original gas reserves venture is currently included in customer rates, the occurrence of one or more of these risks, could affect our ability to recover this hedge in rates. Further, any new gas reserves arrangements have not been approved for inclusion in rates, and our regulators may ultimately determine to not include all or a portion of future transactions in rates. The realization of any of these situations could adversely impact the project as well as our financial condition, results of operations and cash flows.

OPERATING RISK. *Transporting and storing natural gas involves numerous risks that may result in accidents and other operating risks and costs, some or all of which may not be fully covered by insurance, and which could adversely affect our financial condition, results of operations and cash flows.*

Our operations are subject to all of the risks and hazards inherent in the businesses of local gas distribution and storage, including:

- earthquakes, floods, storms, landslides and other adverse weather conditions and hazards;
- leaks or other losses of natural gas or other chemicals or compounds as a result of the malfunction of equipment or facilities;
- damages from third parties, including construction, farm and utility equipment or other surface users;
- operator errors;
- negative performance by our storage reservoirs that could cause us to fail to meet expected or forecasted operational levels or contractual commitments to our customers;
- problems maintaining, or the malfunction of, pipelines, wellbores and related equipment and facilities that form a part of the infrastructure that is critical to the operation of our gas distribution and storage facilities;
- collapse of underground storage caverns;
- operating costs that are substantially higher than expected;
- migration of natural gas through faults in the rock or to some area of the reservoir where existing wells cannot drain the gas effectively resulting in loss of the gas;
- blowouts (uncontrolled escapes of gas from a pipeline or well) or other accidents, fires and explosions; and
- risks and hazards inherent in the drilling operations associated with the development of the gas storage facilities and/or wells.

These risks could result in personal injury or loss of human life, damage to and destruction of property and equipment, pollution or other environmental damage, breaches of our contractual commitments, and may result in curtailment or suspension of our operations, which in turn could lead to significant costs and lost revenues. Further, because our pipeline, storage and distribution facilities are in or near populated areas, including residential areas, commercial business centers, and industrial sites, any loss of human life or adverse financial outcomes resulting from such events could be significant. Additionally, we may not be able to obtain the level or types of insurance we desire, and the insurance coverage we do obtain may contain large deductibles or fail to cover certain hazards or cover all potential losses. The occurrence of any operating risks not covered by insurance could adversely affect our financial condition, results of operations and cash flows.

BUSINESS CONTINUITY RISK. *We may be adversely impacted by local or national disasters, pandemic illness, terrorist activities, including cyber-attacks, and other extreme events to which we may not able to promptly respond.*

Local or national disasters, pandemic illness, terrorist activities, including cyber-attacks, and other extreme events are a threat to our assets and operations. Companies in our industry may face a heightened risk due to exposure to acts of terrorism, including physical and security breaches of our information technology infrastructure in the form of cyber-attacks. These attacks could target or impact our technology or mechanical systems that operate our natural gas distribution, transmission or storage facilities and result in a disruption in our operations, damage to our system and inability to meet customer requirements. In addition, the threat of terrorist activities could lead to increased economic instability and volatility in the price of natural gas that could affect our operations. Threatened or actual national disasters or terrorist activities may also disrupt capital markets and our ability to raise capital, or impact our suppliers or our customers directly. Local disaster or pandemic illness could result in part of our workforce being unable to operate or maintain our infrastructure or perform other tasks necessary to conduct our business. A slow or inadequate response to events may have an adverse impact on operations and earnings. We may not be able to obtain sufficient insurance to cover all risks associated with local and national disasters, pandemic illness, terrorist activities and other events. Additionally, large scale natural disasters or terrorist attacks could destabilize the insurance industry making insurance we do have unavailable, which could increase the risk that an event could adversely affect our operations or financial results.

EMPLOYEE BENEFIT RISK. *The cost of providing pension and postretirement healthcare benefits is subject to changes in pension assets and liabilities, changing employee demographics and changing actuarial assumptions, which may have an adverse effect on our financial condition, results of operations and cash flows.*

Until we closed the plans to new hires, which for non-union employees was in 2006 and for union employees was in 2009, we provided pension plans and postretirement healthcare benefits to eligible full-time utility employees and retirees. Most of our current utility employees were hired prior to these dates, and therefore remain eligible for these plans. Our cost of providing such benefits is subject to changes in the market value of our pension assets, changes in employee demographics including longer life expectancies, increases in healthcare costs, current and future legislative changes, and various actuarial calculations and assumptions. The actuarial assumptions used to calculate our future pension and postretirement healthcare expense may differ materially from actual results due to significant market fluctuations and changing withdrawal rates, wage rates, interest rates and other factors. These differences may result in an adverse impact on the amount of pension contributions, pension expense or other postretirement benefit costs recorded in future periods. Sustained declines in equity markets and reductions in bond rates may have a material adverse effect on the value of our pension fund assets and liabilities. In these circumstances, we may be required to recognize increased contributions and pension expense earlier than we had planned to the extent that the value of pension assets is less than the total anticipated liability under the plans, which could have a negative impact on financial condition, results of operations and cash flows.

WORKFORCE RISK. *Our business is heavily dependent on being able to attract and retain qualified employees and maintain a competitive cost structure with market-based salaries and employee benefits, and workforce disruptions could adversely affect our operations and results.*

Our ability to implement our business strategy and serve our customers is dependent upon our continuing ability to attract and retain talented professionals and a technically skilled workforce, and being able to transfer the knowledge and expertise of our workforce to new employees as our largely older workforce retires. We expect that a significant portion of our workforce will retire within the current decade, which will require that we attract, train and retain skilled workers to prevent loss of institutional knowledge or skills gap. Without an appropriately skilled workforce, our ability to provide quality service and meet our regulatory requirements will be challenged and this could negatively impact our earnings. Additionally, within our utility segment a majority of our workers are represented by the OPEIU Local No.11 AFL-CIO (the Union), and are covered by a collective bargaining agreement that extends to November 30, 2019. Disputes with the Union over terms and conditions of the agreement could result in instability in our labor relationship and work stoppages that could impact the timely delivery of gas and other services from our utility and Mist gas storage facility, which could strain relationships with customers and state regulators and cause a loss of revenues. Our collective bargaining agreement may also limit our flexibility in dealing with our workforce, and our ability to change work rules and practices and implement other efficiency-related improvements to successfully compete in today's challenging marketplace, which may negatively affect our financial condition and results of operations.

LEGISLATIVE, COMPLIANCE AND TAXING AUTHORITY RISK. *We are subject to governmental regulation, and compliance with local, state and federal requirements, including taxing requirements, and unforeseen changes in or interpretations of such requirements could affect our financial condition and results of operations.*

We are subject to regulation by federal, state and local governmental authorities. We are required to comply with a variety of laws and regulations and to obtain authorizations, permits, approvals and certificates from governmental agencies in various aspects of our business. We cannot predict with certainty the impact of any future revisions or changes in interpretations of existing regulations or the adoption of new laws and regulations applicable to them. Additionally, any failure to comply with existing or new laws and regulations could result in fines, penalties or injunctive measures that could affect operating assets. For example, under the Energy Policy Act of 2005, the FERC has civil authority under the Natural Gas Act to impose penalties for current violations of up to $1 million per day for each violation. In addition, as the regulatory environment for our industry increases in complexity, the risk of inadvertent noncompliance may also increase. Changes in regulations, the imposition of additional regulations, and the failure to comply with laws and regulations could negatively influence our operating environment and results of operations.

Additionally, changes in federal, state or local tax laws and their related regulations, or differing interpretations or enforcement of applicable law by a federal, state or local taxing authority, could result in substantial cost to us and negatively affect our results of operations. Tax law and its related regulations and case law are inherently complex and dynamic. Disputes over interpretations of tax laws may be settled with the taxing authority in examination, upon appeal or through litigation. Our judgments may include reserves for potential adverse outcomes regarding tax positions that have been taken that may be subject to challenge by taxing authorities. Changes in laws, regulations or adverse judgments may negatively affect our financial condition and results of operations.

SAFETY REGULATION RISK. *We may experience increased federal, state and local regulation of the safety of our systems and operations, which could adversely affect our operating costs and financial results.*

The safety and protection of the public, our customers and our employees is and will remain our top priority. We are committed to consistently monitoring and maintaining our distribution system and storage operations to ensure that natural gas is acquired, stored and delivered safely, reliably and efficiently. Given recent high-profile natural gas explosions, leaks and accidents in other parts of the country involving both distribution systems and storage facilities, we anticipate that the natural gas industry may be the subject of even greater federal, state and local regulatory oversight. We intend to work diligently with industry associations and federal and state regulators to ensure compliance with the new laws. We expect there to be increased costs associated with compliance, and those costs could be significant. If these costs are not recoverable in our customer rates, they could have a negative impact on our operating costs and financial results.

HEDGING RISK. *Our risk management policies and hedging activities cannot eliminate the risk of commodity price movements and other financial market risks, and our hedging activities may expose us to additional liabilities for which rate recovery may be disallowed, which could result in an adverse impact on our operating revenues, costs, derivative assets and liabilities and operating cash flows.*

Our gas purchasing requirements expose us to risks of commodity price movements, while our use of debt and equity financing exposes us to interest rate, liquidity and other financial market risks. In our Utility segment, we attempt to manage these exposures with both financial and physical hedging mechanisms, including our gas reserves transactions which are hedges backed by physical gas supplies. While we have risk management procedures for hedging in place, they may not always work as planned and cannot entirely eliminate the risks associated with hedging. Additionally, our hedging activities may cause us to incur additional expenses to obtain the hedge. We do not hedge our entire interest rate or commodity cost exposure, and the unhedged exposure will vary over time. Gains or losses experienced through hedging activities, including carrying costs, generally flow through the PGA mechanism or are recovered in future general rate cases. However, the hedge transactions we enter into for the utility are subject to a prudence review by the OPUC and WUTC, and, if found imprudent, those expenses may be, and have been previously, disallowed, which could have an adverse effect on our financial condition and results of operations.

In addition, our actual business requirements and available resources may vary from forecasts, which are used as the basis for our hedging decisions, and could cause our exposure to be more or less than we anticipated. Moreover, if our derivative instruments and hedging transactions do not qualify for hedge accounting under generally accepted accounting standards, our hedges may not be effective and our results of operations and financial condition could be adversely affected.

We also have credit-related exposure to derivative counterparties. In general, we require our counterparties to have an investment-grade credit rating at the time the derivative instrument is entered into, and we specify limits on the contract amount and duration based on each counterparty's credit rating. Nevertheless, counterparties owing us money or physical natural gas commodities could breach their obligations. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements to meet our normal business requirements. In that event, our financial results could be adversely affected. Additionally, under most of our hedging arrangements, any downgrade of our senior unsecured long-term debt credit rating could allow our counterparties to require us to post cash, a letter of credit or other form of collateral, which would expose us to additional costs and may trigger significant increases in borrowing from our credit facilities if the credit rating downgrade is below investment grade. Further, based on current interpretations, we are not considered a "swap dealer" or "major swap participant" in 2015, so we are exempt from certain requirements under the Dodd-Frank Act. If we are unable to claim this exemption, we could be subject to higher costs for our derivatives activities.

INABILITY TO ACCESS CAPITAL MARKET RISK. *Our inability to access capital, or significant increases in the cost of capital, could adversely affect our financial condition and results of operations.*

Our ability to obtain adequate and cost effective short-term and long-term financing depends on maintaining investment grade credit ratings as well as the existence of liquid and stable financial markets. Our businesses rely on access to capital markets, including commercial paper, bond and equity markets, to finance our operations, construction expenditures and other business requirements, and to refund maturing debt that cannot be funded entirely by internal cash flows. Disruptions in capital markets could adversely affect our ability to access short-term and long-term financing. Our access to funds under committed short-term credit facilities, which are currently provided by a number of banks, is dependent on the ability of the participating banks to meet their funding commitments. Those banks may not be able to meet their funding commitments if they experience shortages of capital and liquidity. Disruptions in the bank or capital financing markets as a result of economic uncertainty, changing or increased regulation of the financial sector, or failure of major financial institutions could adversely affect our access to capital and negatively impact our ability to run our business and make strategic investments.

A negative change in our current credit ratings, particularly below investment grade, could adversely affect our cost of borrowing and access to sources of liquidity and capital. Such a downgrade could further limit our access to borrowing under available credit lines. Additionally, downgrades in our current credit ratings below investment grade could cause additional delays in accessing the capital markets by the utility while we seek supplemental state regulatory approval, which could hamper our ability to access credit markets on a timely basis. A credit downgrade could also require additional support in the form of letters of credit, cash or other forms of collateral and otherwise adversely affect our financial condition and results of operations.

Risks Related Primarily to Our Local Utility Business

GAS PRICE RISK. *Higher natural gas commodity prices and volatility in the price of gas may adversely affect our results of operations and cash flows.*

The cost of natural gas is affected by a variety of factors, including weather, changes in demand, the level of production and availability of natural gas supplies, transportation constraints, availability and cost of pipeline capacity, federal and state energy and environmental regulation and legislation, natural disasters and other catastrophic events, national and worldwide economic and political conditions, and the price and availability of alternative fuels. In our utility segment, the cost we pay for natural gas is generally passed through to our customers through an annual PGA rate adjustment. If gas prices were to increase significantly, it would raise the cost of energy to our utility customers, potentially causing those customers to conserve or switch to alternate sources of energy. Significant price increases could also cause new home builders and commercial developers to select alternative fuel sources. Decreases in the volume of gas we sell could reduce our earnings, and a decline in customers could slow growth in our future earnings. Additionally, because a portion of any 10% or 20% difference between the estimated average PGA gas cost in rates and the actual average gas cost incurred is recognized as current income or expense, higher average gas costs than those assumed in setting rates can adversely affect our operating cash flows, liquidity and results of operations. Additionally, notwithstanding our current rate structure, higher gas costs could result in increased pressure on the OPUC or the WUTC to seek other means to reduce rates, which also could adversely affect our results of operations and cash flows.

Higher gas prices may also cause us to experience an increase in short-term debt and temporarily reduce liquidity because we pay suppliers for gas when it is purchased, which can be in advance of when these costs are recovered through rates. Significant increases in the price of gas can also slow our collection efforts as customers experience increased difficulty in paying their higher energy bills, leading to higher than normal delinquent accounts receivable resulting in greater expense associated with collection efforts and increased bad debt expense.

CUSTOMER GROWTH RISK. *Our utility margin, earnings and cash flow may be negatively affected if we are unable to sustain customer growth rates in our local gas distribution segment.*

Our utility margins and earnings growth have largely depended upon the sustained growth of our residential and commercial customer base due, in part, to the new construction housing market, conversions of customers to natural gas from other fuel sources and growing commercial use of natural gas. The recent recession slowed new construction. While construction has resumed, it has not returned to its original pace and has been heavily multi-family, which is a segment that has historically used natural gas less frequently. Insufficient growth in these markets, for economic, political or other reasons could result in an adverse long-term impact on our utility margin, earnings and cash flows.

RISK OF COMPETITION. *Our gas distribution business is subject to increased competition which could negatively affect our results of operations.*

In the residential and commercial markets, our gas distribution business competes primarily with suppliers of electricity, fuel oil, propane, and renewable energy. In the industrial market, we compete with suppliers of all forms of energy. Competition among these forms of energy is based on price, efficiency, reliability, performance, market conditions, technology, environmental impacts and public perception.

Technological improvements in other energy sources such as heat pumps, batteries or other alternative technologies could erode our competitive advantage. If natural gas prices rise relative to other energy sources, or if the cost, environmental impact or public perception of such other energy sources improves relative to natural gas, it may negatively affect our ability to attract new customers or retain our existing residential, commercial and industrial customers, which could have a negative impact on our customer growth rate and results of operations.

RELIANCE ON THIRD PARTIES TO SUPPLY NATURAL GAS RISK. *We rely on third parties to supply the natural gas in our distribution segment, and limitations on our ability to obtain supplies, or failure to receive expected supplies for which we have contracted, could have an adverse impact on our financial results.*

Our ability to secure natural gas for current and future sales depends upon our ability to purchase and receive delivery of supplies of natural gas from third parties. We, and in some cases, our suppliers of natural gas do not have control over the availability of natural gas supplies, competition for those supplies, disruptions in those supplies, priority allocations on transmission pipelines, or pricing of those supplies. Additionally, third parties on whom we rely may fail to deliver gas for which we have contracted. If we are unable to obtain, or are limited in our ability to obtain, natural gas from our current suppliers or new sources, we may not be able to meet our customers' gas requirements and would likely incur costs associated with actions necessary to mitigate services disruptions, both of which could significantly and negatively impact our results of operations.

SINGLE TRANSPORTATION PIPELINE RISK. *We rely on a single pipeline company for the transportation of gas to our service territory, a disruption of which could adversely impact our ability to meet our customers’ gas requirements.*

Our distribution system is directly connected to a single interstate pipeline, which is owned and operated by Northwest Pipeline. The pipeline’s gas flows are bi-directional, transporting gas into the Portland metropolitan market from two directions: (1) the north, which brings supplies from the British Columbia and Alberta supply basins; and (2) the east, which brings supplies from the Alberta and the U.S. Rocky Mountain supply basins. If there is a rupture or inadequate capacity in the pipeline, we may not be able to meet our customers’ gas requirements and we would likely incur costs associated with actions necessary to mitigate service disruptions, both of which could significantly and negatively impact our results of operations.

WEATHER RISK. *Warmer than average weather may have a negative impact on our revenues and results of operations.*

We are exposed to weather risk primarily in our utility segment. A majority of our volume is driven by gas sales to space heating residential and commercial customers during the winter heating season. Current utility rates are based on an assumption of average weather. Warmer than average weather typically results in lower gas sales. Colder weather typically results in higher gas sales. Although the effects of warmer or colder weather on utility margin in Oregon are expected to be mitigated through the operation of our weather normalization mechanism, weather variations from normal could adversely affect utility margin because we may be required to purchase more or less gas at spot rates, which may be higher or lower than the rates assumed in our PGA. Also, a portion of our Oregon residential and commercial customers (usually less than 10%) have opted out of the weather normalization mechanism, and 11% of our customers are located in Washington where we do not have a weather normalization mechanism. These effects could have an adverse effect on our financial condition, results of operations and cash flows.

CUSTOMER CONSERVATION RISK. *Customers' conservation efforts may have a negative impact on our revenues.*

An increasing national focus on energy conservation, including improved building practices and appliance efficiencies may result in increased energy conservation by customers. This can decrease our sales of natural gas and adversely affect our results of operations because revenues are collected mostly through volumetric rates, based on the amount of gas sold. In Oregon, we have a conservation tariff which is designed to recover lost utility margin due to declines in residential and small commercial customers' consumption. However, we do not have a conservation tariff in Washington that provides us this margin protection on sales to customers in that state.

RELIANCE ON TECHNOLOGY RISK. *Our efforts to integrate, consolidate and streamline our operations have resulted in increased reliance on technology, the failure or security breach of which could adversely affect our financial condition and results of operations.*

Over the last several years we have undertaken a variety of initiatives to integrate, standardize, centralize and streamline our operations. These efforts have resulted in greater reliance on technological tools such as: an enterprise resource planning system, an automated dispatch system, an automated meter reading system, a customer information system, a web-based ordering and tracking system, and other similar technological tools and initiatives. The failure of any of these or other similarly important technologies, or our inability to have these technologies supported, updated, expanded or integrated into other technologies, could adversely impact our operations. We take precautions to protect our systems, but there is no guarantee that the procedures we have implemented to protect against unauthorized access to secured data and systems are adequate to safeguard against all security breaches. Our utility could experience breaches of security pertaining to sensitive customer, employee and vendor information maintained by the utility in the normal course of business which could adversely affect the utility's reputation, diminish customer confidence, disrupt operations, materially increase the costs we incur to protect against these risks, and subject us to possible financial liability or increased regulation or litigation, any of which could adversely affect our financial condition and results of operations.

Furthermore, we rely on information technology systems in our operations of our distribution and storage operations. There are various risks associated with these systems, including, hardware and software failure, communications failure, data distortion or destruction, unauthorized access to data, misuse of proprietary or confidential data, unauthorized control through electronic means, programming mistakes and other inadvertent errors or deliberate human acts. In particular, cyber security attacks, terrorism or other malicious acts could damage, destroy or disrupt all of our business systems. Any failure of information technology systems could result in a loss of operating revenues, an increase in operating expenses and costs to repair or replace damaged assets. As these potential cyber security attacks become more common and sophisticated, we could be required to incur costs to strengthen our systems or obtain specific insurance coverage against potential losses.

Risks Related Primarily to Our Gas Storage Businesses

LONG-TERM LOW OR STABILIZATION OF GAS PRICE RISK. *Any significant stabilization of natural gas prices or long-term low gas prices could have a negative impact on the demand for our natural gas storage services, which could adversely affect our financial results.*

Storage businesses benefit from price volatility, which impacts the level of demand for services and the rates that can be charged for storage services. Largely due to the abundant supply of natural gas made available by hydraulic fracturing techniques, natural gas prices have dropped significantly to levels that are near historic lows. If prices and volatility remain low or decline further, then the demand for storage services, and the prices that we will be able to charge for those services, may decline or be depressed for a prolonged period of time. Prices below the costs to operate the storage facility could result in a decision to shut in all or a portion of the facility. A sustained decline in these prices or a shut-in of all or a portion of the facility could have an adverse impact on our financial condition, results of operations and cash flows.

NATURAL GAS STORAGE COMPETITION RISK. *Increasing competition in the natural gas storage business could reduce the demand for our storage services and drive prices down for storage, which could adversely affect our financial condition, results of operation and cash flows.*

Our natural gas storage segment competes primarily with other storage facilities and pipelines. Natural gas storage is an increasingly competitive business, with the ability to expand or build new storage capacity in California, the U.S. Rocky Mountains and elsewhere in the United States and Canada. Increased competition in the natural gas storage business could reduce the demand for our natural gas storage services, drive prices down for our storage business, and adversely affect our ability to renew or replace existing contracts at rates sufficient to maintain current revenues and cash flows, which could adversely affect our financial condition, results of operations and cash flows.

IMPAIRMENT OF LONG-LIVED ASSETS RISK. *If storage pricing does not improve, or higher value customers are not obtained, our Gill Ranch storage asset may be impaired, which could have a material effect on our financial condition, or results of operations.*

We review the carrying value of long-lived assets whenever events or changes in circumstances indicate the carrying amount of the assets might not be recoverable. The determination of recoverability is based on the undiscounted net cash flows expected to result from the operations of such assets. Projected cash flows depend on the future operating costs associated with the asset, storage pricing, the ability to contract with higher value customers, and the future market and price for gas storage over the remaining life of the asset. Sustained low gas storage prices, the failure to contract with higher value customers, or operating costs that are above revenues from the facility could result in an impairment of the carrying value of our Gill Ranch storage facility. Similarly, if we were to determine to sell the Gill Ranch storage facility, such determination may result in an impairment of the carrying value of the facility. Any impairment charge taken by the Company with respect to its long-lived assets, including Gill Ranch, could be material to the quarter that the charge is taken and could otherwise have a material effect on the Company's financial condition, and results of operations.

THIRD-PARTY PIPELINE RISK. *Our gas storage businesses depend on third-party pipelines that connect our storage facilities to interstate pipelines, the failure or unavailability of which could adversely affect our financial condition, results of operations and cash flows.*

Our gas storage facilities are reliant on the continued operation of a third-party pipeline and other facilities that provide delivery options to and from our storage facilities. Because we do not own all of these pipelines, their operations are not within our control. If the third-party pipeline to which we are connected were to become unavailable for current or future withdrawals or injections of natural gas due to repairs, damage to the infrastructure, lack of capacity or other reasons, our ability to operate efficiently and satisfy our customers' needs could be compromised, thereby potentially having an adverse impact on our financial condition, results of operations and cash flows.

ITEM 1B. UNRESOLVED STAFF COMMENTS

We have no unresolved comments.

ITEM 2. PROPERTIES

Utility Properties

Our natural gas pipeline system consists of approximately 14,000 miles of distribution and transmission mains located in our service territory in Oregon and Washington. In addition, the pipeline system includes service pipelines, meters and regulators, and gas regulating and metering stations. Pipeline mains are located in municipal streets or alleys pursuant to franchise or occupation ordinances, in county roads or state highways pursuant to agreements or permits granted pursuant to statute, or on lands of others pursuant to easements obtained from the owners of such lands. We also hold permits for the crossing of numerous navigable waterways and smaller tributaries throughout our entire service territory.

We own service building facilities in Portland, as well as various satellite service centers, garages, warehouses, and other buildings necessary and useful in the conduct of our business. We also lease office space in Portland for our corporate headquarters, which expires on May 31, 2020. Resource centers are maintained on owned or leased premises at convenient points in the distribution system to provide service within our utility service territory. We also own LNG storage facilities in Portland and near Newport, Oregon.

In order to reduce risks associated with gas leakage in older parts of our system, we undertook accelerated pipe replacement programs under which we removed and replaced 100% of our cast iron mains by the end of 2000, and under which we eliminated all remaining known bare steel mains and services by the end of 2015.

Gas Storage Properties

We hold leases and other property interests in approximately 12,000 net acres of underground natural gas storage in Oregon and approximately 5,000 net acres of underground natural gas storage in California, and easements and other property interests related to pipelines associated with those facilities. We own rights to depleted gas reservoirs near Mist, Oregon, that are continuing to be developed and operated as underground gas storage facilities. We also hold an option to purchase future storage rights in certain other areas of the Mist gas field in Oregon, as well as in California related to the Gill Ranch storage project.

We consider all of our properties currently used in our operations, both owned and leased, to be well maintained, in good operating condition, and, along with planned additions, adequate for our present and foreseeable future needs.

Our Mortgage and Deed of Trust (Mortgage) is a first mortgage lien on substantially all of the property constituting our utility plant.

ITEM 3. LEGAL PROCEEDINGS

Other than the proceedings disclosed in Note 15, we have only nonmaterial litigation in the ordinary course of business.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock is listed and trades on the New York Stock Exchange under the symbol NWN. The high and low trades for our common stock during the past two years were as follows:

	2015		2014	
Quarter Ended	High	Low	High	Low
March 31	$ 52.25	$ 43.35	$ 44.09	$ 40.05
June 30	49.77	41.32	47.32	43.06
September 30	46.74	42.00	47.50	41.81
December 31	51.85	45.03	52.57	42.29

The closing price for our common stock on December 31, 2015 and 2014 was $50.61 and $49.90, respectively.

As of February 19, 2016, there were 5,697 holders of record of our common stock.

We have paid quarterly dividends on our common stock in each year since the stock first was issued to the public in 1951. Annual common dividend payments per share, adjusted for stock splits, have increased each year since 1956. Dividends per share paid during the past two years were as follows:

Payment Date	2015	2014
February 15	$ 0.4650	$ 0.460
May 15	0.4650	0.460
August 15	0.4650	0.460
November 15	0.4675	0.465
Total per share	$ 1.8625	$ 1.845

The declaration and amount of future dividends depend upon our earnings, cash flows, financial condition, and other factors. The amount and timing of dividends payable on our common stock are within the sole discretion of our Board of Directors. Subject to Board approval, we expect to continue paying cash dividends on our common stock on a quarterly basis.

The following table provides information about purchases of our equity securities that are registered pursuant to Section 12 of the Securities Exchange Act of 1934 during the quarter ended December 31, 2015:

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased[(1)]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs[(2)]	Maximum Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs[(2)]
Balance forward			2,124,528	$ 16,732,648
10/01/15-10/31/15	3,279	$ 47.12	—	—
11/01/15-11/30/15	26,594	46.37	—	—
12/01/15-12/31/15	1,204	48.27	—	—
Total	31,077	46.52	2,124,528	$ 16,732,648

(1) During the quarter ended December 31, 2015, 26,529 shares of our common stock were purchased on the open market to meet the requirements of our Dividend Reinvestment and Direct Stock Purchase Plan. In addition, 4,548 shares of our common stock were purchased on the open market to meet the requirements of our share-based programs. During the quarter ended December 31, 2015, no shares of our common stock were accepted as payment for stock option exercises pursuant to our Restated Stock Option Plan.

(2) We have a common stock share repurchase program under which we purchase shares on the open market or through privately negotiated transactions. We currently have Board authorization through May 31, 2016 to repurchase up to an aggregate of 2.8 million shares or up to an aggregate of $100 million. During the quarter ended December 31, 2015, no shares of our common stock were repurchased pursuant to this program. Since the program's inception in 2000, we have repurchased approximately 2.1 million shares of common stock at a total cost of approximately $83.3 million.

ITEM 6. SELECTED FINANCIAL DATA

	For the year ended December 31,				
In thousands, except share data	2015	2014	2013	2012	2011
Operating revenues	$ 723,791	$ 754,037	$ 758,518	$ 730,607	$ 828,055
Net income	53,703	58,692	60,538	58,779	63,044
Earnings per share of common stock:					
Basic	$ 1.96	$ 2.16	$ 2.24	$ 2.19	$ 2.36
Diluted	1.96	2.16	2.24	2.18	2.36
Dividends paid per share of common stock	1.86	1.85	1.83	1.79	1.75
Total assets, end of period	$ 3,076,692	$ 3,064,945	$ 2,970,911	$ 2,813,120	$ 2,742,718
Total equity	780,972	767,321	751,872	729,627	712,158
Long-term debt	576,700	621,700	681,700	691,700	641,700

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following is management's assessment of Northwest Natural Gas Company's (NW Natural or the Company) financial condition, including the principal factors that affect results of operations. The discussion refers to our consolidated results for the years ended December 31, 2015, 2014, and 2013. References in this discussion to "Notes" are to the Notes to Consolidated Financial Statements in Item 8 of this report.

The consolidated financial statements include NW Natural and its direct and indirect wholly-owned subsidiaries including:

- NW Natural Energy, LLC (NWN Energy);
- NW Natural Gas Storage, LLC (NWN Gas Storage);
- Gill Ranch Storage, LLC (Gill Ranch);
- NNG Financial Corporation (NNG Financial);
- Northwest Energy Corporation (Energy Corp); and
- NW Natural Gas Reserves, LLC (NWN Gas Reserves).

We operate in two primary reportable business segments: local gas distribution and gas storage. We also have other investments and business activities not specifically related to one of these two reporting segments, which we aggregate and report as other. We refer to our local gas distribution business as the utility, and our gas storage segment and other as non-utility. Our utility segment includes our NW Natural local gas distribution business, NWN Gas Reserves, which is a wholly-owned subsidiary of Energy Corp, and the utility portion of our Mist underground storage facility in Oregon (Mist). Our gas storage segment includes NWN Gas Storage, which is a wholly-owned subsidiary of NWN Energy, Gill Ranch, which is a wholly-owned subsidiary of NWN Gas Storage, the non-utility portion of Mist, and asset management services. Other includes NWN Energy's equity investment in Trail West Holding, LLC (TWH), which is pursuing the development of a proposed natural gas pipeline through its wholly-owned subsidiary, Trail West Pipeline, LLC (TWP), and NNG Financial's equity investment in Kelso-Beaver Pipeline (KB Pipeline). For a further discussion of our business segments and other, see Note 4.

In addition to presenting the results of operations and earnings amounts in total, certain financial measures are expressed in cents per share or exclude the after-tax regulatory disallowance related to the OPUC's 2015 environmental order, which are non-GAAP financial measures. We present net income and earnings per share (EPS) excluding the regulatory disallowance along with the U.S. GAAP measures to illustrate the magnitude of this disallowance on ongoing business and operational results. Although the excluded amounts are properly included in the determination of net income and earnings per share under U.S. GAAP, we believe the amount and nature of such disallowance make period to period comparisons of operations difficult or potentially confusing. Financial measures are expressed in cents per share as these amounts reflect factors that directly impact earnings, including income taxes. All references in this section to EPS are on the basis of diluted shares (see Note 3). We use such non-GAAP financial measures to analyze our financial performance because we believe they provide useful information to our investors and creditors in evaluating our financial condition and results of operations.

We manage our business and strategic initiatives with a long-term view of providing natural gas service safely and reliably to customers, working with regulators on key policy initiatives, and remaining focused on growing our business. See *"2016 Outlook"* below for more information. Highlights for the year include:

- steady annual customer growth rate at the core utility of 1.4% at December 31, 2015;
- increased new meter sets installed to approximately 11,000, which is nearly 4% higher than the prior year;
- invested $118.3 million in our distribution system and facilities including $19.9 million on SIP, allowing us to complete our bare steel replacement;
- continued to make progress on our North Mist gas storage expansion project;
- decreased residential customer rates approximately 7% in Oregon and 14% in Washington with the 2015-16 PGA effective November 1, 2015;
- ranked first in residential customer satisfaction for large gas utilities in the West in the 2015 J.D. Power and Associates Study, making 2015 the 14th consecutive year of top three rankings; and
- increased our dividend, marking the 60th consecutive year of increases.

Key financial highlights include:

	2015		2014		2013	
In millions, except per share data	Amount	Per Share	Amount	Per Share	Amount	Per Share
Consolidated net income	$ 53.7	$ 1.96	$ 58.7	$ 2.16	$ 60.5	$ 2.24
Adjustments:						
Regulatory environmental disallowance, net of taxes $5.9[1]	9.1	0.33	—	—	—	—
Adjusted consolidated net income[1]	$ 62.8	$ 2.29	$ 58.7	$ 2.16	$ 60.5	$ 2.24
Utility margin	$ 371.4		$ 366.1		$ 353.9	
Gas storage operating revenues	21.4		22.2		31.1	
ROE	6.9%		7.7%		8.2%	
Adjusted ROE[1]	8.1%		7.7%		8.2%	

(1) Regulatory environmental disallowance of $15 million is recorded in utility operations and maintenance expense. Adjusted EPS, net income, and ROE are non-GAAP financial measures based on the after-tax disallowance. EPS is calculated using the combined federal and state statutory tax rate of 39.5% and 27.4 million diluted shares for the year ended December 31, 2015.

2015 COMPARED TO 2014. Overall, consolidated net income decreased $5.0 million. The decrease was primarily due to the $9.1 million after-tax charge related to the regulatory disallowance associated with a February 2015 OPUC Order in our SRRM docket. Under the Order, we were required to forego collection of $15 million, pre-tax, out of the approximate $95 million of environmental expenditures and associated carrying costs deferred through 2012. This charge is reflected in operations and maintenance expense. Excluding the charge, net income increased $4.1 million primarily due to the following factors:

- a $5.3 million increase in utility margin primarily due to customer growth and gas cost sharing, offset by the effects of warmer weather;
- a $0.9 million decrease in gas storage operating revenues as storage was negatively impacted by a decrease in storage prices between the 2013-14 and 2014-15 gas years;
- a $5.8 million increase in other income, net related to the recognition of equity earnings on deferred regulatory asset balances as a result of the OPUC SRRM Order;
- a $5.5 million increase in operations and maintenance expense mainly due to higher compensation and benefits expense; and
- a $1.7 million increase in depreciation and amortization expenses due to additional utility capital expenditures.

During 2015, management implemented temporary cost saving initiatives to mitigate the effects of warm weather and the $15 million regulatory disallowance. These initiatives resulted in approximately $5 million of operations and maintenance expense savings that are not expected to be repeated in the future.

2014 COMPARED TO 2013. Overall, consolidated net income decreased $1.8 million. Our net income is most significantly impacted by our utility business which had favorable results during the year, but increases at the utility were more than offset by declines from our gas storage segment. The primary factors were:

- a $12.2 million increase in utility margin primarily due to customer growth and the rate-base return on our gas reserves and other investments;
- a $8.9 million decrease in gas storage operating revenues as storage was negatively impacted by re-contracting certain expiring firm storage capacity at lower prices;
- a $3.3 million increase in depreciation and amortization expenses due to additional utility capital expenditures; and
- a $2.7 million decrease in other income, net due to lower interest income on net deferred regulatory balances.

2016 OUTLOOK

Our near-term outlook and long-term strategic goals for the business are aligned with delivering gas safely and reliably to our customers, investing for profitable growth in our core gas distribution and gas storage businesses, and creating new ideas to drive growth opportunities. Our 2016 strategy leverages our resources and our history of innovative solutions to continue meeting the needs of customers, regulators, and shareholders. We consider the following goals critical in achieving these long-term goals:

Deliver Gas	Grow Our Businesses
Ensure Safety and Reliability	Grow Utility Customers
Advance Regulatory Policies and Initiatives	Pursue Strategic Utility Investments
Promote Sustainable Energy Policies	Develop Non-utility Growth Initiatives

SAFETY AND RELIABILITY. Delivering natural gas safely and reliably to customers and providing employees with a safe work environment are our top priorities. During 2016, we will continue to ensure our pipeline system and facilities are well maintained, new facility improvements are planned and well executed, and business continuity requirements are met. Projects planned for 2016 include infrastructure investments in high-growth areas such as Clark County, Washington, refurbishing our LNG facilities, and continuing to prepare for large-scale emergency events such as an earthquake. In addition, we will remain proactive regarding investments in computer systems and cybersecurity infrastructure.

REGULATION. Constructive regulation supports customers receiving quality service at a reasonable cost and the Company receiving timely cost recovery and earning a reasonable return on shareholder investments. In 2016, we will be evaluating our future rate case needs in Oregon and Washington, progressing open dockets from 2015, and we will also update our Integrated Resource Plan focusing on investments needed to support the growth in our region. Finally, we will work with regulators to further our shared commitment to the environment with continued efforts around the carbon solutions programs and providing gas to rural communities.

ENERGY POLICIES. The Pacific Northwest is committed to energy conservation, environmental sustainability, and reducing carbon emissions. Natural gas is an important clean energy resource for our region and the country. In 2016, we will continue to play an active role in shaping energy policies and programs, which reflect the interests of our customers, including progressing CNG transportation initiatives and working on legislation that supports making natural gas available to rural communities. In addition, we are working hard with other potentially responsible parties to make progress with the EPA on a solution to ensure the Portland Harbor Superfund Site cleanup is done in a smart, cost effective, and responsible way.

UTILITY CUSTOMERS. We intend to capitalize on natural gas as a preferred energy choice in our service territory by creating a comprehensive marketing program for rental projects that further our penetration in the residential multi-family housing sector. In addition, we remain focused on supporting single-family and commercial markets to grow our customer base. Additional growth may also come with increased industrial load from new projects in the region and proposed legislation that favors lower carbon emissions and lower cost energy alternatives, such as natural gas.

KEY UTILITY INVESTMENTS. Investing in new infrastructure, operating efficiencies, and marketing opportunities position our core business for growth now and well into the future.

A growth investment for our storage business is the planned expansion at Mist to support a gas-fired plant built by Portland General Electric (PGE) at their nearby Port Westward facility. In early 2016, will be working closely with the Oregon Energy Siting Facilities Council to finalize the cost estimates and receive a notice to proceed. We expect construction to begin in 2016 with an in-service date in the winter of 2018-19.

NON-UTILITY INITIATIVES. We remain focused on creating value in our non-utility gas storage business, working to identify and contract with higher value customers and position ourselves for longer-term improvement in the California storage markets. We believe the state's renewable energy policies could strategically shift the value of gas storage in California in the future.

DIVIDENDS

Dividend highlights include:

Per common share	2015	2014	2013
Dividends paid	$ 1.86	$ 1.85	$ 1.83

The Board of Directors declared a quarterly dividend on our common stock of $0.4675 cents per share, payable on February 12, 2016, to shareholders of record on January 29, 2016, reflecting an indicated annual dividend rate of $1.87 per share.

RESULTS OF OPERATIONS

Regulatory Matters

Regulation and Rates

UTILITY. Our utility business is subject to regulation by the OPUC, WUTC, and FERC with respect to, among other matters, rates and terms of service. The OPUC and WUTC also regulate the system of accounts and issuance of securities by our utility. In 2015, approximately 89% of our utility gas volumes and revenues were derived from Oregon customers, with the remaining 11% from Washington customers. Earnings and cash flows from utility operations are largely determined by rates set in general rate cases and other proceedings in Oregon and Washington. They are also affected by the local economies in Oregon and Washington, the pace of customer growth in the residential, commercial, and industrial markets, and our ability to remain price competitive, control expenses, and obtain reasonable and timely regulatory recovery of our utility-related costs, including operating expenses and investment costs in utility plant and other regulatory assets. See "*Most Recent General Rate Cases"* below.

GAS STORAGE. Our gas storage business is subject to regulation by the OPUC, WUTC, CPUC, and FERC with respect to, among other matters, rates and terms of service. The OPUC and CPUC also regulate the issuance of securities and system of accounts. The OPUC and CPUC regulate intrastate storage services, and the FERC regulates interstate storage services. The OPUC and FERC use a maximum cost of service model which allows for gas storage prices to be set at or below the cost of service as approved by each agency in the last regulatory filing. The CPUC regulates Gill Ranch under a market-based rate model which allows for the price of storage services to be set by the marketplace. In 2015, approximately 72% of our storage revenues were derived from FERC, Oregon, and Washington regulated operations and approximately 28% from California operations.

Most Recent General Rate Cases

OREGON. Effective November 1, 2012, the OPUC authorized rates to customers based on an ROE of 9.5%, an overall rate of return of 7.78%, and a capital structure of 50% common equity and 50% long-term debt.

WASHINGTON. Effective January 1, 2009, the WUTC authorized rates to customers based on an ROE of 10.1% and an overall rate of return of 8.4% with a capital structure of 51% common equity, 5% short-term debt, and 44% long-term debt.

FERC. We are required under our Mist interstate storage certificate authority and rate approval orders to file every five years either a petition for rate approval or a cost and revenue study to change or justify maintaining the existing rates for our interstate storage services. In December 2013 we filed a rate petition, which was approved in 2014 and allows for the maximum cost-based rates for our interstate gas storage services. These rates were effective January 1, 2014, with the rate changes having no significant impact on our revenues.

Regulatory Proceeding Updates

During 2015, we were involved in the regulatory activity discussed below.

ENVIRONMENTAL COST DEFERRAL AND SITE REMEDIATION AND RECOVERY MECHANISM (SRRM). In February 2015, the OPUC issued an Order regarding the SRRM for recovering prudently incurred environmental site remediation costs through customer billings, subject to an earnings test. The OPUC Order found the following: (1) prudence of all but $33 thousand of costs incurred through March 31, 2014; (2) prudence of approximately $150 million of insurance settlement proceeds, with one-third of the proceeds applied to costs prior to December 31, 2012 and two-thirds to offset future environmental expenses over the next 20 years; (3) the disallowance of $15 million out of approximately $95 million of environmental remediation expenses we had deferred from 2003 to 2012 based on the OPUC's determination of how an earnings test should have applied during that period; which resulted in a non-cash $15 million before tax expense recognized in the first quarter 2015; (4) how the SRRM recovery mechanism would allow recovery of past and future environmental costs; and (5) an OPUC review of the SRRM following its third year of operation. This Order also required us to submit a compliance filing demonstrating how we would implement the Commission's determinations.

We submitted the required compliance filing demonstrating the proposed implementation of the Order and SRRM. In September 2015, the OPUC ordered we would not be required to establish a secure account for the insurance proceeds, rather we would defer proceeds to a regulatory liability account until utilized, and we would accrue interest to rate payers' benefit at a rate equal to the five-year treasury rate plus 100 basis points. See "Rate Mechanisms —*Environmental Cost Deferral and SRRM"*, Note 15 and Note 16.

On January 27, 2016, the OPUC issued an Order addressing the remaining outstanding issues in the compliance filing. See Note 16 regarding this subsequent event.

GAS RESERVES. We filed with the OPUC in February 2015 seeking cost recovery on additional investments in gas reserves. In September 2015, the OPUC adopted an all-party settlement. See "Rate Mechanisms—*Gas Reserves*" below and Note 11.

PREPAID PENSION ASSET. In August 2015, the OPUC issued the final Order related to this docket, which confirmed the use of accounting expense for recovery of pension costs, but denied the utilities' request to recover the financing costs associated with funding our pension plans in advance of expense recognition. Although we will not recover the financing costs associated with funding our plans, we will continue collecting pension expense based on the amounts set in our 2003 Oregon general rate case and will continue deferring the difference between actual pension expense and collected expense in our pension balancing account. See "Rate Mechanisms—*Pension Cost Deferral and Pension Balancing Account"* below.

SYSTEM INTEGRITY PROGRAM (SIP). We filed a request to extend the SIP program in the fourth quarter of 2014. The OPUC considered our renewal request at a public meeting in March 2015 and suspended our filing and ordered additional process, including involvement of other gas utilities in the state, before making a final decision. See "Rate Mechanisms—*System Integrity Program"* below.

HEDGING. In our most recent Integrated Resource Plan, we proposed to the OPUC that we engage in continued long-term gas hedging. The OPUC determined it wanted to consider long-term hedging along with a general review of overall hedging practices among all gas utilities in the state. The OPUC therefore opened a new docket to discuss broader gas hedging practices across gas utilities in Oregon. Our request for the OPUC to consider long-term hedging practices will be considered as part of this docket. The OPUC established that this docket will follow two phases. The first phase will be focused on an analytical review of hedging and hedging practices, followed by a second phase regarding potential hedging guidelines. After these phases, a status report will be submitted to the OPUC, and the remainder of the process will be determined at that time.

INTERSTATE STORAGE SHARING. We received an Order from the OPUC in March 2015 on their review of the current revenue sharing arrangement that allocates a portion of the net revenues generated from non-utility Mist storage services and third-party asset management services to utility customers. The Order requires a third-party cost study to be performed and the results of the cost study may initiate a new docket or the re-opening of the original docket.

CARBON SOLUTIONS PROGRAM. Oregon Senate Bill 844 (SB 844) required the OPUC to develop rules and programs to reduce carbon emissions in Oregon. In June 2015, we submitted our first project related to Combined Heat and Power (CHP) for OPUC approval. The submitted CHP program would pay owners of new commercial- and industrial-scale CHP systems for verified carbon emission reductions. A final decision regarding CHP is expected in the first half of 2016.

WEATHER NORMALIZATION MECHANISM (WARM). In Oregon, WARM is applied to residential and commercial customers' bills to adjust for temperature variances from average weather. In 2015, the OPUC initiated a review of the WARM mechanism as a result of customer complaints received this year related to surcharges applied under the WARM mechanism due to the record warm weather in our service territory during the 2014-15 winter. The OPUC review is focused on ensuring the calculations were done correctly, and to assess whether any modifications to the mechanism are necessary. Based on the scope of this proceeding established by the Commission, we do not expect this proceeding to significantly reduce the value WARM provides to us or our customers in mitigating the impact from variations in weather. Since its inception, WARM has resulted in a net benefit to customers, providing customer bill savings of approximately $9.9 million as of the end of the most recent heating season.

Rate Mechanisms

PURCHASED GAS ADJUSTMENT. Rate changes are established for the utility each year under PGA mechanisms in Oregon and Washington to reflect changes in the expected cost of natural gas commodity purchases. This includes gas prices under spot purchases as well as contract supplies, gas prices hedged with financial derivatives, gas prices from the withdrawal of storage inventories, the production of gas reserves, interstate pipeline demand costs, temporary rate adjustments, which amortize balances of deferred regulatory accounts, and the removal of temporary rate adjustments effective for the previous year.

Each year, we typically hedge gas prices on approximately 75% of our utility's annual sales requirement based on normal weather, including both physical and financial hedges. We entered the 2015-16 gas year (November 1, 2015 - October 31, 2016) hedged at 75% of our forecasted sales volumes, including 44% in financial swap and option contracts and 31% in physical gas supplies. For further discussion see "Regulatory Matters—Rate Mechanisms—*Purchased Gas Adjustment"* above.

In addition to the amount hedged for the current gas contract year, we are also hedged in future years at approximately 16% for the 2016-17 gas year and between 5% and 14% for annual requirements over the following five gas years as of December 31, 2015. Our hedge levels are subject to change based on actual load volumes, which depend to a certain extent on weather, economic conditions, and estimated gas reserve production. Also, our storage inventory levels may increase or decrease with storage expansion, changes in storage contracts with third parties, and/or storage recall by the utility.

Under the current PGA mechanism in Oregon, there is an incentive sharing provision whereby we are required to select each year either an 80% deferral or a 90% deferral of higher or lower actual gas costs compared to estimated PGA prices, such that the impact on current earnings from the incentive sharing is either 20% or 10% of the difference between actual and estimated gas costs, respectively. For the 2014-15 and 2015-16 gas years, we selected the 90% and 80% deferral option, respectively. Under the Washington PGA mechanism, we defer 100% of the higher or lower actual gas costs, and those gas cost differences are passed on to customers through the annual PGA rate adjustment.

We filed our PGA in September 2015 and received OPUC and WUTC approval in October 2015. PGA rate changes were effective November 1, 2015. The rate changes decreased the average monthly bills of residential customers by approximately 7% and 14% in Oregon and Washington, respectively. The decrease in Oregon reflected customers' portion of adjustments for changes in wholesale natural gas costs, offset by adjustments related to the decoupling mechanism, environmental costs, and additional annual adjustments based on ongoing orders with the OPUC. Washington rates reflected the full effect of changes in wholesale natural gas costs and some additional annual adjustments based on ongoing orders with the WUTC.

EARNINGS TEST REVIEW. We are subject to an annual earnings review in Oregon to determine if the utility is earning above its authorized ROE threshold. If utility earnings exceed a specific ROE level, then 33% of the amount above that level is required to be deferred or refunded to customers. Under this provision, if we select the 80% deferral gas cost option, then we retain all of our earnings up to 150 basis points above the currently authorized ROE. If we select the 90% deferral option, then we retain all of our earnings up to 100 basis points above the currently authorized ROE. We selected the 90% deferral option for the 2013-14 and 2014-15 PGA years, and we selected the 80% deferral option for the 2015-16 PGA year. The ROE threshold is subject to adjustment annually based on movements in long-term interest rates. For calendar years 2013, 2014, and 2015, the ROE threshold was 10.58%, 10.66%, and 10.60%, respectively. There were no refunds required for 2013 and 2014. We do not expect a refund for 2015 based on our results and anticipate filing the 2015 test in May 2016.

GAS RESERVES. In 2011 the OPUC approved the Encana gas reserves transaction to provide long-term gas price protection for our utility customers and determined our costs under the agreement would be recovered, on an ongoing basis through our annual PGA mechanism. Gas produced from our interests is sold at then prevailing market prices, and revenues from such sales, net of associated operating and production costs and amortization, are credited to our cost of gas. The cost of gas, including a carrying cost for the rate base investment, is included in our annual Oregon PGA filing, which allows us to recover these costs through customer rates. Our net investment under the original agreement earns a rate of return and provides long-term price protection for our utility customers.

In March 2014, we amended the original gas reserves agreement in response to Encana's sale of its interest in the Jonah field located in Wyoming to Jonah Energy. Under the amendment, we ended the drilling program with Encana, but increased our working interests in our assigned sections of the Jonah field and we retained the right to invest in new wells with Jonah Energy.

In 2014, we elected to participate in some of the additional wells drilled in the Jonah field under our amended gas reserves agreement with Jonah Energy and may have the opportunity to participate in more wells in the future. We filed an application requesting regulatory deferral in Oregon for these additional investments, which was granted in April 2015. In September 2015, the OPUC adopted an all-party settlement, under which volumes produced under the amended agreement are included in our Oregon PGA beginning November 1, 2015 at a fixed rate of $0.4725 per therm, which approximates the 10-year hedge rate plus financing costs at the inception of the investment.

DECOUPLING. In Oregon, we have a decoupling mechanism. Decoupling is intended to break the link between utility earnings and the quantity of gas consumed by customers, removing any financial incentive by the utility to discourage customers' efforts to conserve energy. The Oregon decoupling mechanism was reauthorized and the baseline expected usage per customer was set in the 2012 Oregon general rate case. This mechanism employs a use-per-customer decoupling calculation, which adjusts margin revenues to account for the difference between actual and expected customer volumes. The margin adjustment resulting from differences between actual and expected volumes under the decoupling component is recorded to a deferral account, which is included in the annual PGA filing. In Washington, customer use is not covered by such a tariff. See "Business Segments—*Local Gas Distribution Utility Operations"* below.

WEATHER NORMALIZATION TARIFF. In Oregon, we have an approved weather normalization mechanism, which is applied to residential and commercial customer bills. This mechanism is designed to help stabilize the collection of fixed costs by adjusting residential and commercial customer billings based on temperature variances from average weather, with rate decreases when the weather is colder than average and rate increases when the weather is warmer than average. The mechanism is applied to bills from December through May of each heating season. The mechanism adjusts the margin component of customers' rates to reflect average weather, which uses the 25-year average temperature for each day of the billing period. Daily average temperatures and 25-year average temperatures are based on a set point temperature of 59 degrees Fahrenheit for residential customers and 58 degrees Fahrenheit for commercial customers. This weather normalization mechanism was reauthorized in the 2012 Oregon general rate case without an expiration date. Residential and commercial customers in Oregon are allowed to opt out of the weather normalization mechanism, and as of December 31, 2015, 9% of total customers had opted out. We do not have a weather normalization mechanism approved for residential and commercial Washington customers, which account for about 11% of total customers. See "Business Segments—*Local Gas Distribution Utility Operations"* below.

INDUSTRIAL TARIFFS. The OPUC and WUTC have approved tariffs covering utility service to our major industrial customers, including terms, which are intended to give us certainty in the level of gas supplies we need to acquire to serve this customer group. The terms include, among other things, an annual election period, special pricing provisions for out-of-cycle changes, and a requirement that industrial customers complete the term of their service election under our annual PGA tariff.

SYSTEM INTEGRITY PROGRAM (SIP). In the past, we have had the approval of the OPUC for specific accounting treatment and cost recovery for our SIP, which is an integrated safety program that consolidates the bare steel replacement program, the transmission pipeline integrity management program, and the distribution integrity management program related to pipeline safety rules adopted by the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA). We recorded these costs as capital expenditures, accumulated the costs over each 12-month period, and recovered the revenue requirement associated with these costs, subject to audit, through rate changes effective with the Oregon annual PGA. Our SIP costs were tracked into rates annually, with the first $4 million of capital costs subject to regulatory lag and annual rate-base recovery capped at $12 million. Costs above the cap could also be approved with written consent of the OPUC staff and other interested parties and approval of the OPUC.

During 2013, the OPUC approved a temporary two-year extension, beginning in November 2012, of our capital expenditure tracking mechanism to recover capital costs related to SIP and authorized a total increase of $13.7 million above the cap during the extension period. Regulatory authority for SIP expired October 31, 2014, although the bare steel replacement portion of the mechanism remained in place until the end of 2015. We filed a request to extend the SIP program in the fourth quarter of 2014 and upon consideration of our request in March of 2015, the OPUC ordered an additional process and evaluation with other gas utilities in the state before making a final decision. In the interim, we will recover our remaining bare steel replacement costs through the 2015-16 PGA, and we expect system integrity capital costs not tracked through our SIP mechanism would be included in rate base in our next rate case.

ENVIRONMENTAL COST DEFERRAL AND SRRM. In Oregon, we have a SRRM through which we track and have the ability to recover prudently incurred past deferred and future environmental remediation costs allocable to Oregon, subject to an earnings test.

The SRRM defines three classes of deferred environmental remediation expense:

- Pre-review - This class of costs represents remediation spend that has not yet been deemed prudent by the OPUC. Carrying costs on these remediation expenses are recorded at our authorized cost of capital. We anticipate the prudence review for annual costs and approval of the earnings test prescribed by the OPUC to occur by the third quarter of the following year.
- Post-review - This class of costs represents remediation spend that has been deemed prudent and allowed after applying the earnings test, but is not yet included in amortization. We earn a carrying cost on these amounts at a rate equal to the five-year treasury rate plus 100 basis points.
- Amortization - This class of costs represents amounts included in current customer rates for collection and is generally calculated as one-fifth of the post-review deferred balance. We earn a carrying cost equal to the amortization rate determined annually by the OPUC, which approximates a short-term borrowing rate. We included $8.4 million of deferred remediation expense approved by the OPUC for collection during the 2015-2016 PGA year.

The earnings test is an annual review of our adjusted Utility ROE compared to our authorized Utility ROE, which is currently 9.5%. To apply the earnings test first we must determine what if any costs are subject to the test through the following calculation:

Annual spend
Less: $5 million base rate rider(1)
Prior year carry-over(2)
$5 million insurance + interest on insurance
Total deferred annual spend subject to earnings test
Less: over-earnings adjustment, if any
Add: deferred interest on annual spend(3)
Total amount transferred to post-review

(1) Base rate rider went into Oregon customer rates beginning November 1, 2015.
(2) Prior year carry-over results when the prior year amount transferred to post-review is negative. The negative amount is carried over to offset annual spend in the following year.
(3) Deferred interest is added to annual spend to the extent the spend is recoverable.

If the adjusted Utility ROE is greater than the authorized Utility ROE, then we could be required to expense up to the amount that results in the Utility earning its authorized ROE. For 2015, we have performed this test, which will be submitted to the OPUC in May 2016, and have concluded that there is no earnings test adjustment for 2015.

The WUTC has also previously authorized the deferral of environmental costs, if any, that are appropriately allocated to Washington customers. This Order was effective in January 2011 with cost recovery and a carrying charge to be determined in a future proceeding.

PENSION COST DEFERRAL AND PENSION BALANCING ACCOUNT. Effective January 1, 2011, the OPUC approved our request to defer annual pension expenses above the amount set in rates, with recovery of these deferred amounts through the implementation of a balancing account, which includes the expectation of higher and lower pension expenses in future years. Our recovery of these deferred balances includes accrued interest on the account balance at the utility's authorized rate of return, which is currently 7.78%. Future years' deferrals will depend on changes in plan assets and projected benefit liabilities based on a number of key assumptions, and our pension contributions. Pension expense deferrals, including interest, were $8.2 million, $4.6 million, and $9.1 million in 2015, 2014 and 2013, respectively. See "*Application of Critical Accounting Policies and Estimates*" below.

CUSTOMER CREDITS FOR GAS STORAGE SHARING. On an annual basis, we credit amounts to Oregon and Washington customers as part of our regulatory incentive sharing mechanism related to net revenues earned from Mist gas storage and asset management activities. Generally amounts are credited to Oregon customers in June, while credits are given to customers in Washington through reductions in rates through the annual PGA filing in November.

The following table presents the credits to customers:

In millions	2015	2014	2013
Oregon utility customer credit	$ 9.6	$ 11.4	$ 8.8
Washington utility customer credit	0.8	0.8	0.5

Business Segments - Local Gas Distribution Utility Operations

Utility margin results are primarily affected by customer growth, revenues from rate-base additions, and, to a certain extent, by changes in delivered volumes due to weather and customers' gas usage patterns because a significant portion of our utility margin is derived from natural gas sales to residential and commercial customers. In Oregon, we have a conservation tariff (also called the decoupling mechanism), which adjusts utility margin up or down each month through a deferred regulatory accounting adjustment designed to offset changes resulting from increases or decreases in average use by residential and commercial customers. We also have a weather normalization tariff in Oregon, which adjusts customer bills up or down to offset changes in utility margin resulting from above- or below-average temperatures during the winter heating season. Both mechanisms are designed to reduce the volatility of customer bills and our utility's earnings. See "Regulatory Matters—*Rate Mechanisms"* above.

Utility segment highlights include:

Dollars and therms in millions, except EPS data	2015	2014	2013
Utility net income	$ 53.4	$ 58.6	$ 54.9
EPS - utility segment	1.95	2.15	2.03
Gas sold and delivered (in therms)	1,029	1,093	1,146
Utility margin[(1)]	$ 371.4	$ 366.1	$ 353.9

(1) See Utility Margin Table below for a reconciliation and additional detail.

2015 COMPARED TO 2014. The primary factors contributing to the $5.2 million or $0.20 per share decrease in utility net income were as follows:

- the $15 million pre-tax charge, or $9.1 million after-tax charge, for the regulatory disallowance associated with the February 2015 OPUC Order on the recovery of past environmental cost deferrals. This charge is reflected in operations and maintenance expense;
- a $5.3 million increase in utility margin primarily due to:
    - a $4.4 million increase from customer growth;
    - a $5.3 million increase from gas cost incentive sharing resulting from lower gas prices than those estimated in the PGA; partially offset by
    - an approximate $4.0 million decrease due to lower customer usage from warmer weather, which impacts utility margins from our Washington customers where we do not have a weather normalization mechanism in place, and from our Oregon customers who opted out of weather normalization.
- a $6.6 million increase in other income, net, primarily due to the recognition of the equity earnings on deferred environmental expenditures as a result of the February order;
- a $7.2 million increase in operations and maintenance expense, excluding the environmental disallowance, primarily due to an increase in compensation and benefit expense; and
- a net $0.4 million increase in other expenses related to increased depreciation expense from additional capital investments and an increase in general taxes from higher Oregon property tax expense, offset by a decrease in interest expense due to debt redemptions made during the year.

Total utility volumes sold and delivered in 2015 decreased 6% over 2014 primarily due to the impact of warmer weather.

2014 COMPARED TO 2013. The primary factors contributing to the $3.7 million or $0.12 per share increase in net income were as follows:

- a $12.2 million net increase in utility margin primarily due to:
    - a $16.6 million increase from customer growth in residential and commercial customers, industrial margins, and added rate-base returns on certain investments, including gas reserves; partially offset by
    - a $2.1 million increase in loss from gas cost incentive sharing mainly resulting from higher gas prices and volumes than those estimated in the PGA; and
    - the remaining decrease was primarily due to warmer weather as measured by heating degree days, in Washington, which does not have a weather normalization mechanism in place, and the effect of warmer weather on margin for Oregon customers that opt out of weather normalization.
- a $3.2 million increase in depreciation expense due to additional capital expenditures;
- a $3.0 million decrease in operations and maintenance expense; and
- a $2.1 million decrease in other income, net primarily due to lower interest income on regulatory deferred account balances.

Total utility volumes sold and delivered in 2014 decreased 5% over 2013 primarily due to the impact of warmer weather on residential and commercial use.

UTILITY MARGIN TABLE. The following table summarizes the composition of utility gas volumes, revenues, and cost of sales:

In thousands, except degree day and customer data	2015	2014	2013	Favorable/(Unfavorable) 2015 vs. 2014	Favorable/(Unfavorable) 2014 vs. 2013
Utility volumes (therms):					
Residential and commercial sales	570,728	620,903	671,906	(50,175)	(51,003)
Industrial sales and transportation	457,884	472,087	474,525	(14,203)	(2,438)
Total utility volumes sold and delivered	1,028,612	1,092,990	1,146,431	(64,378)	(53,441)
Utility operating revenues:					
Residential and commercial sales	$ 644,835	$ 672,440	$ 673,250	$ (27,605)	$ (810)
Industrial sales and transportation	71,495	73,992	68,880	(2,497)	5,112
Other revenues	3,914	3,983	4,054	(69)	(71)
Less: Revenue taxes	18,034	18,837	19,002	(803)	(165)
Total utility operating revenues	702,210	731,578	727,182	(29,368)	4,396
Less: Cost of gas	327,305	365,490	373,298	38,185	7,808
Less: Environmental remediation expense	3,513	—	—	(3,513)	—
Utility margin	$ 371,392	$ 366,088	$ 353,884	$ 5,304	$ 12,204
Utility margin:[1]					
Residential and commercial sales	$ 334,134	$ 334,247	$ 321,608	$ (113)	$ 12,639
Industrial sales and transportation	30,081	29,982	28,335	99	1,647
Miscellaneous revenues	3,913	4,329	4,308	(416)	21
Gain (loss) from gas cost incentive sharing	3,182	(2,135)	(41)	5,317	(2,094)
Other margin adjustments	82	(335)	(326)	417	(9)
Utility margin	$ 371,392	$ 366,088	$ 353,884	$ 5,304	$ 12,204
Degree days					
Average[2]	4,240	4,240	4,240	—	—
Actual	3,458	3,792	4,379	(9)%	(13)%
Percent colder (warmer) than average weather[2]	(18)%	(11)%	3%		
Customers - end of period:					
Residential customers	646,841	637,411	628,634	9,430	8,777
Commercial customers	66,584	66,304	65,321	280	983
Industrial customers	1,003	929	918	74	11
Total number of customers	714,428	704,644	694,873	9,784	9,771
Customer growth:					
Residential customers	1.5 %	1.4 %			
Commercial customers	0.4 %	1.5 %			
Industrial customers	8.0 %	1.2 %			
Total customer growth	1.4 %	1.4 %			

(1) Amounts reported as margin for each category of customers are operating revenues, which are net of revenue taxes, less cost of gas and environmental remediation expense.
(2) Average weather represents the 25-year average degree days, as determined in our 2012 Oregon general rate case.

Residential and Commercial Sales

The primary factors that impact results of operations in the residential and commercial markets are customer growth, seasonal weather patterns, energy prices, competition from other energy sources, and economic conditions in our service areas. The impact of weather on margin is significantly reduced through our weather normalization mechanism in Oregon; approximately 80% of our total customers are covered under this mechanism. The remaining customers either opt out of the mechanism or are located in Washington, which does not have a similar mechanism in place. For more information on our weather mechanism, see "Regulatory Matters—Rate Mechanisms—*Weather Normalization Tariff*" above.

Residential and commercial sales highlights include:

In millions	2015	2014	2013
Volumes (therms):			
Residential sales	350.9	381.5	418.6
Commercial sales	219.8	239.4	253.3
Total volumes	570.7	620.9	671.9
Operating revenues:			
Residential sales	$ 424.6	$ 441.5	$ 447.4
Commercial sales	220.2	230.9	225.9
Total operating revenues	$ 644.8	$ 672.4	$ 673.3
Utility margin:			
Residential:			
Sales	$ 211.6	$ 223.6	$ 234.1
Weather normalization	14.0	5.1	(9.0)
Decoupling	7.2	4.0	2.6
Total residential utility margin	232.8	232.7	227.7
Commercial:			
Sales	84.8	91.6	92.1
Weather normalization	5.8	2.2	(4.0)
Decoupling	10.7	7.7	5.8
Total commercial utility margin	101.3	101.5	93.9
Total utility margin	$ 334.1	$ 334.2	$ 321.6

2015 COMPARED TO 2014. The primary factors contributing to changes in the residential and commercial markets were as follows:

- sales volumes decreased 50.2 million therms, or 8%, primarily reflecting 9% warmer weather, which was partially offset by customer growth;
- operating revenues decreased $27.6 million, due to the 8% decrease in sales volumes, as well as a 2% decrease in average gas rates over last year; and
- utility margin decreased $0.1 million, due to warmer weather, almost entirely offset by increases from commercial and residential customer growth.

2014 COMPARED TO 2013. The primary factors contributing to changes in the residential and commercial markets were as follows:

- sales volumes decreased 51.0 million therms, or 8%, primarily reflecting 13% warmer weather, which was partially offset by customer growth and a record February cold weather event;
- operating revenues decreased $0.8 million, due to the 8% decrease in sales volumes, which was partially offset by a 4% increase in average gas rates over last year; and
- utility margin increased $12.6 million, or 4%, primarily related to customer growth, added loads under higher commercial rate schedules, and added rate-base returns from our gas reserves and other investments, partially offset by the effect of warmer weather on our Washington customers and Oregon customers that opted out of the weather normalization mechanism.

Industrial Sales and Transportation

Industrial customers have the option of purchasing sales or transportation services from the utility. Under the sales service, the customer buys the gas commodity from the utility. Under the transportation service, the customer buys the gas commodity directly from a third-party gas marketer or supplier. Our gas commodity cost is primarily a pass-through cost to customers; therefore, our profit margins are not materially affected by an industrial customer's decision to purchase gas from us or from third parties. Industrial and large commercial customers may also select between firm and interruptible service options, with firm services generally providing higher profit margins compared to interruptible services. To help manage gas supplies, our industrial tariffs are designed to provide some certainty regarding industrial customers' volumes by requiring an annual service election on November 1, special charges for changes between elections, and in some cases, a minimum or maximum volume requirement before changing options.

Industrial sales and transportation highlights include:

In millions	2015	2014	2013
Volumes (therms):			
Industrial - firm sales	32.4	34.0	34.3
Industrial - firm transportation	144.0	153.6	144.5
Industrial - interruptible sales	70.2	76.4	59.5
Industrial - interruptible transportation	211.3	208.1	236.2
Total volumes	457.9	472.1	474.5
Utility margin:			
Industrial - sales and transportation	$ 30.1	$ 30.0	$ 28.3

2015 COMPARED TO 2014. The primary factors contributing to changes in the industrial sales and transportation markets were as follows:

- sales and transportation volumes decreased by 14.2 million therms due to lower usage from warmer weather and lower demand from a few large volume transportation customers on lower margin rate schedules;
- utility margin increased $0.1 million, primarily due to an increase in industrial customers under higher margin rate schedules partially offset by higher fee revenue in the prior year from increased usage during the cold weather event in February 2014.

2014 COMPARED TO 2013. The primary factors contributing to changes in the industrial sales and transportation markets were as follows:

- sales and transportation volumes decreased by 2.4 million therms due to lower usage by large volume interruptible transportation customers on lower margin rate schedules;
- utility margin increased $1.6 million, or 6% primarily due to volume growth under higher margin rate schedules and other customer charges stemming from the extreme cold weather event in February 2014.

Other Revenues

Other revenues include miscellaneous fee income as well as regulatory revenue adjustments, which reflect current period deferrals to and prior year amortizations from regulatory asset and liability accounts, except for gas cost deferrals which flow through cost of gas. Decoupling amortizations and other regulatory amortizations from prior year deferrals are included in revenues from residential, commercial and industrial firm customers.

Other revenue for 2015, 2014, and 2013 remained flat year-over-year as expected.

In millions	2015	2014	2013
Other revenues	$ 3.9	$ 4.0	$ 4.1

Cost of Gas

Cost of gas as reported by the utility includes gas purchases, gas withdrawn from storage inventory, gains and losses from commodity hedges, pipeline demand costs, seasonal demand cost balancing adjustments, regulatory gas cost deferrals, gas reserves costs, and company gas use. The OPUC and WUTC generally require natural gas commodity costs to be billed to customers at the actual cost incurred, or expected to be incurred, by the utility. Customer rates are set each year so that if cost estimates were met we would not earn a profit or incur a loss on gas commodity purchases; however, in Oregon we have an incentive sharing mechanism which has been described under "Regulatory Matters—Rate Mechanisms—*Purchased Gas Adjustment"* above. In addition to the PGA incentive sharing mechanism, gains and losses from hedge contracts entered into after annual PGA rates are effective for Oregon customers are also required to be shared and therefore may impact net income. Further, we also have a regulatory agreement whereby we earn a rate of return on our investment in the gas reserves acquired under the original agreement with Encana and include gas from our amended gas reserves agreement at a fixed rate of $0.4725 per therm, which are also reflected in utility margin. See "Application of Critical Accounting Policies and Estimates—*Accounting for Derivative Instruments and Hedging Activities"* below.

Cost of gas highlights include:

Dollars and therms in millions	2015	2014	2013
Cost of gas	$ 327.3	$ 365.5	$ 373.3
Volumes sold (therms)	660	716	766
Average cost of gas (cents per therm)	$ 0.50	$ 0.51	$ 0.49
Gain (loss) from gas cost incentive sharing	3.2	(2.1)	—

2015 COMPARED TO 2014. Cost of gas decreased $38.2 million, or 10% primarily due to an 8% decrease in sales volume reflecting warmer weather during the year as well as a 2% decrease in average cost of gas reflecting lower market prices for natural gas.

2014 COMPARED TO 2013. Cost of gas decreased $7.8 million, or 2% primarily due to a 7% decrease in sales volume reflecting warmer weather during the year, partially offset by a 4% increase in average cost of gas collected through rates.

During the extreme cold weather event in February 2014, we experienced a record sendout and consequently, the higher volumes of gas purchased at that time resulted in a margin loss of $2.1 million in 2014 compared to a margin gain of $3.2 million for 2015 as prices were lower due to the record warmer weather, particularly in the first quarter of 2015. The effect on net income from our gas cost incentive sharing mechanism for 2013 was a pre-tax loss in margin of less than $0.1 million. For a discussion of our gas cost incentive sharing mechanism, see "Regulatory Matters—Rate Mechanisms—*Purchased Gas Adjustment*" above.

Business Segments - Gas Storage

Our gas storage segment primarily consists of the non-utility portion of our Mist underground storage facility in Oregon and our 75% undivided ownership interest in the Gill Ranch underground storage facility in California.

At Mist, we provide gas storage services to customers in the interstate and intrastate markets primarily using storage capacity that has been developed in advance of core utility customers' requirements. We also contract with an independent energy marketing company to provide asset management services using our utility and non-utility storage and transportation capacity, the results of which are included in the gas storage businesses segment. Pre-tax income from gas storage at Mist and asset management services is subject to revenue sharing with core utility customers. Under this regulatory incentive sharing mechanism, we retain 80% of pre-tax income from Mist gas storage services and asset management services when the underlying costs of the capacity being used are not included in our utility rates, and 33% of pre-tax income from such storage and asset management services when the capacity being used is included in utility rates. The remaining 20% and 67%, respectively, are credited to a deferred regulatory account for credit to our core utility customers. See "Regulatory Matters—*Open Regulatory Proceedings*" above for information regarding an open docket related to this incentive sharing mechanism.

Our 75% undivided ownership interest in the Gill Ranch facility is held by our wholly-owned subsidiary Gill Ranch, LLC, which is also the operator of the facility. Our portion of the facility is 15 Bcf of gas storage capacity. Gill Ranch commenced operations at the end of 2010, with the first full storage injection season beginning on April 1, 2011. We also contract with an independent energy marketing company to provide asset management services at Gill Ranch. See also Note 4.

Gas storage segment highlights include:

In millions, except EPS data	2015	2014	2013
Gas storage net income (loss)	$ 0.2	$ (0.4)	$ 5.6
EPS - gas storage segment	0.01	(0.01)	0.21
Operating revenues	21.4	22.2	31.1
Operating expenses	16.3	18.2	16.4

2015 COMPARED TO 2014. Our gas storage segment net income increased $0.6 million primarily due to the following offsetting factors:

- a $0.9 million decrease in operating revenues, primarily due to a decrease in storage prices between the 2013-14 and 2014-15 gas storage years; and
- a $1.9 million decrease in operating expenses primarily due to lower repair and power costs at our Gill Ranch facility.

2014 COMPARED TO 2013. Our gas storage segment net income decreased $5.9 million primarily due to the following factors:

- an $8.9 million decrease in operating revenues, primarily reflecting recontracting expiring storage capacity at lower prices as the gas storage market prices remain at historic lows; and
- a $1.8 million increase in operating expenses primarily due to higher repair and power costs at our Gill Ranch facility.

Our Mist gas storage facility benefits from limited competition from other Pacific Northwest storage facilities primarily because of its geographic location.

Over the past few years, market prices for natural gas storage, particularly in California, were negatively affected by the abundant supply of natural gas, low volatility of natural gas prices, and surplus gas storage capacity. In addition, storage prices were further affected by extreme cold weather during the 2013-14 winter, which resulted in a significant decline in storage levels, a rise in spot gas prices, and lower storage values due to a flatter forward price curve for the 2014-15 gas storage year. We re-contracted certain expiring storage capacity for the 2014-15 gas storage year with shorter-term contracts at lower market prices than in previous years. These trends accounted for most of the decline in gas storage operating revenues.

Prices for the 2015-16 and 2016-17 gas years have shown improvement, however remain low relative to the pricing in our original long-term contracts, which ended primarily in the 2013-14 gas storage year. In the future, we may see an improvement in gas storage values and an increase in the demand for natural gas driven by a number of factors, including changes in electric generation triggered by California's renewable portfolio standards, an increase in use of alternative fuels to meet carbon reduction targets, recovery of the California economy, growth of domestic industrial manufacturing, potential exports of liquefied natural gas from the west coast, and other favorable storage market conditions in and around California. These factors, if they occur, may contribute to higher summer/winter natural gas price spreads, gas price volatility, and gas storage values. We are continuing to explore opportunities to increase revenues through enhanced services for storage customers and capitalizing on opportunities that fit our business-risk profile. Should storage values not improve in the future, this could have a negative impact on our future cash flows and could result in impairment of our Gill Ranch gas storage facility. Refer to Note 2 for more information regarding our accounting for impairment of long-lived assets.

Other

Other primarily consists of NNG Financial's equity investment in KB Pipeline, an equity investment in TWH, which has invested in the Trail West pipeline project, and other miscellaneous non-utility investments and business activities. There were no significant changes in our other activities in 2015. See Note 4 and Note 12 for further details on other activities and our investment in TWH.

Consolidated Operations

Operations and Maintenance

Operations and maintenance highlights include:

In millions	2015	2014	2013
Operations and maintenance	$ 157.5	$ 137.0	$ 136.6

2015 COMPARED TO 2014. Operations and maintenance expense increased $20.5 million, primarily due to the following factors:

- the $15 million pre-tax charge for the regulatory disallowance associated with the February 2015 OPUC Order on the recovery of past environmental cost deferrals. We also expensed an additional $1 million related to the Order; and
- a $5.5 million increase in compensation and benefit expense, including increased employee incentive expense, retirement expense, and health care costs, as well as higher wage rates under the new union labor contract, which became effective June 1, 2014; offset by
- a $1.9 million decrease primarily related to 2014 repair and power costs at our Gill Ranch gas storage facility.

During 2015, management implemented temporary cost saving initiatives to mitigate the effects of warm weather and the $15 million regulatory disallowance. These initiatives resulted in approximately $5 million of operations and maintenance expense savings that are not expected to be repeated in the future.

2014 COMPARED TO 2013. Operations and maintenance expense increased $0.4 million, primarily due to the following factors:

- a $2.4 million increase from additional repair and power costs at our Gill Ranch storage facility;
- a $1.5 million increase in professional service costs related to our ongoing growth initiatives;
- a $0.4 million increase in bad debt expense at the utility due to lower comparable amounts in 2013 driven by a decrease in our allowance for uncollectible accounts in the first quarter of 2013; and
- Partially offsetting the above factors was a $3.9 million decrease in utility payroll and other costs.

Delinquent customer receivable balances continue to remain at historically low levels. The utility's bad debt expense as a percent of revenues was 0.1% for 2015 and 2014.

In addition to fluctuations in operation and maintenance expense reported above, we have OPUC approval to defer certain utility pension costs in excess of what is currently recovered in customer rates. This pension cost deferral is recorded to a regulatory balancing account, which stabilizes the amount of operations and maintenance expense each year. For the years ended December 31, 2015, 2014 and 2013 we deferred pension expenses totaling $8.2 million, $4.6 million and $9.1 million, respectively. As a result, increased pension costs had a minimal effect on operations and maintenance expense in 2015 and 2014, with the increase principally related to the costs allocated to our Washington operations, which are not covered by the pension balancing account. For further explanation of the pension balancing account, see Note 8 and "Regulatory Matters—Rate Mechanisms—
Pension Cost Deferral and Prepaid Pension Assets," above for further explanation of the pension balancing account.

Depreciation and Amortization

Depreciation and amortization highlights include:

In millions	2015	2014	2013
Depreciation and amortization	$ 80.9	$ 79.2	$ 75.9

2015 COMPARED TO 2014. Depreciation and amortization expense increased by $1.7 million due to utility plant additions that included natural gas transmission and distribution system investments and computer software.

2014 COMPARED TO 2013. Depreciation and amortization expense increased by $3.3 million due to an increase in utility depreciation expense from system investments, resource center improvements, and gas storage facilities enhancements.

Other Income, Net

Other income, net highlights include:

In millions	2015	2014	2013
Gains from company-owned life insurance	$ 2.2	$ 2.0	$ 2.5
Interest income	0.1	0.1	0.1
Loss from equity investments	(0.1)	(0.2)	(0.1)
Net interest income on deferred regulatory accounts	8.2	2.4	4.5
Other non-operating	(2.7)	(2.4)	(2.3)
Total other income, net	$ 7.7	$ 1.9	$ 4.7

2015 COMPARED TO 2014. Other income, net, increased $5.8 million primarily due to the recognition of the equity component in interest income from our deferred environmental expenses. We realized the equity earnings of these deferred regulatory asset balances as a result of the OPUC SRRM Order we received in February 2015.

2014 COMPARED TO 2013. Other income, net, decreased $2.7 million primarily due to lower interest income on net deferred regulatory balances as a result of insurance proceeds credited to regulatory balances for environmental costs. Our regulatory environmental deferred cost account subject to interest accruals changed from a net regulatory asset balance of $56 million at December 31, 2013 to a net regulatory liability balance of approximately $30 million at December 31, 2014 due to insurance proceeds received in 2014 exceeding amounts spent.

Interest Expense, Net

Interest expense, net highlights include:

In millions	2015	2014	2013
Interest expense, net	$ 42.5	$ 44.6	$ 45.2

2015 COMPARED TO 2014. Interest expense, net of amounts capitalized, decreased $2.1 million primarily due to the redemption of $40 million of utility First Mortgage Bonds (FMBs) in June 2015, $60 million of utility FMBs in 2014, and the retirement of $20 million of Gill Ranch's debt in June 2014. This was partially offset by the early retirement of $20 million of Gill Ranch's debt in December 2015, which included a make whole interest provision.

2014 COMPARED TO 2013. Interest expense, net of amounts capitalized, decreased $0.6 million primarily due to the redemptions of debt in 2014 of $50 million of utility FMBs in July 2014 and $10 million in September 2014, and the retirement of $20 million of debt pursuant to Gill Ranch's amended loan agreement in June 2014.

Income Tax Expense
Income tax expense highlights include:

In millions	2015	2014	2013
Income tax expense	$ 35.8	$ 41.6	$ 41.7
Effective tax rate	40.0%	41.5%	40.8%

2015 COMPARED TO 2014. The decrease in the effective income tax rate reflects the benefits of depletion deductions from our gas reserves activity.

2014 COMPARED TO 2013. The increase in the effective income tax rate was primarily the result of a $0.6 million income tax charge in 2014 related to a higher statutory tax rate in Oregon, which required the revaluation of deferred tax balances.

FINANCIAL CONDITION

Capital Structure

One of our long-term goals is to maintain a strong consolidated capital structure, generally consisting of 45% to 50% common stock equity and 50% to 55% long-term and short-term debt, and with a target utility capital structure of 50% common stock and 50% long-term debt. When additional capital is required, debt or equity securities are issued depending on both the target capital structure and market conditions. These sources of capital are also used to fund long-term debt retirements and short-term commercial paper maturities. See "*Liquidity and Capital Resources"* below and Note 7.

Achieving the target capital structure and maintaining sufficient liquidity to meet operating requirements are necessary to maintain attractive credit ratings and provide access to capital markets at reasonable costs. Our consolidated capital structure was as follows:

	December 31,	
	2015	2014
Common stock equity	47.2%	46.1%
Long-term debt	34.9	37.4
Short-term debt, including current maturities of long-term debt	17.9	16.5
Total	100.0%	100.0%

Liquidity and Capital Resources

At December 31, 2015 we had $4.2 million of cash and cash equivalents compared to $9.5 million at December 31, 2014. We did not have restricted cash at December 31, 2015 compared to $3.0 million in restricted cash at December 31, 2014 held as collateral for the long-term debt outstanding at Gill Ranch, which we redeemed in December 2015. In order to maintain sufficient liquidity during periods when capital markets are volatile, we may elect to maintain higher cash balances and add short-term borrowing capacity. In addition, we may also pre-fund utility capital expenditures when long-term fixed rate environments are attractive. As a regulated entity, our issuance of equity securities and most forms of debt securities are subject to approval by the OPUC and WUTC. Our use of retained earnings is not subject to those same restrictions.

For the utility segment, the short-term borrowing requirements typically peak during colder winter months when the utility borrows money to cover the lag between natural gas purchases and bill collections from customers. Our short-term liquidity for the utility is primarily provided by cash balances, internal cash flow from operations, proceeds from the sale of commercial paper notes, as well as available cash from multi-year credit facilities, short-term credit facilities, company-owned life insurance policies, and the sale of long-term debt. Utility long-term debt proceeds are primarily used to finance utility capital expenditures, refinance maturing debt of the utility, and provide temporary funding for other general corporate purposes of the utility.

Based on our current debt ratings (see "*Credit Ratings"* below), we have been able to issue commercial paper and long-term debt at attractive rates and have not needed to borrow or issue letters of credit from our back-up credit facility. In the event we are not able to issue new debt due to adverse market conditions or other reasons, we expect our near-term liquidity needs can be met using internal cash flows or, for the utility segment, drawing upon our committed credit facility. We also have a universal shelf registration statement filed with the SEC for the issuance of secured and unsecured debt or equity securities, subject to market conditions and certain regulatory approvals. As of December 31, 2015, we have Board authorization to issue up to $325 million of additional FMBs. We also have OPUC approval to issue up to $325 million of additional long-term debt for approved purposes.

In the event our senior unsecured long-term debt ratings are downgraded, or our outstanding derivative position exceeds a certain credit threshold, our counterparties under derivative contracts could require us to post cash, a letter of credit, or other forms of collateral, which could expose us to additional cash requirements and may trigger increases in short-term borrowings while we were in a net loss position. We were not near the threshold for posting collateral at December 31, 2015. However, if the credit risk-related contingent features underlying these contracts were triggered on December 31, 2015, assuming our long-term debt ratings dropped to non-investment grade levels, we could have been required to post $21.2 million of collateral to our counterparties. See "*Credit Ratings*" below and Note 13.

Other items that may have a significant impact on our liquidity and capital resources include pension contribution requirements, expiration of bonus tax depreciation, environmental expenditures and insurance recoveries.

PENSION CONTRIBUTIONS. We expect to make significant contributions to our company-sponsored defined benefit plan, which is closed to new employees, over the next several years until we are fully funded under the Pension Protection Act rules, including the new rules issued under the Moving Ahead for Progress in the 21st Century Act (MAP-21) and the Highway and Transportation Funding Act of 2014 (HATFA). See "Application of Critical Accounting Policies—*Accounting for Pensions and Postretirement Benefits*" below.

BONUS DEPRECIATION. Regarding income tax, 50 percent bonus depreciation was available for a large portion of our capital expenditures in 2013, 2014 and 2015 for both federal and Oregon. This generated an income tax net operating loss (NOL) in 2013, and reduced taxable income in 2014 and 2015, providing cash flow benefits. The Federal Protecting Americans From Tax Hikes Act of 2015 became law on December 17, 2015 and extended federal bonus depreciation through 2019.

ENVIRONMENTAL EXPENDITURES. Concerning environmental expenditures, we expect to continue using cash resources to fund our environmental liabilities. In 2015, we received an Order from the OPUC regarding our SRRM and began recovering amounts through utility rates in November 2015. These expenditures are uncertain as to the amount and timing. See Note 15, Note 16, and "Results of Operations—Regulatory Matters—*Environmental Costs*" above.

GAS STORAGE. Short-term liquidity for the gas storage segment is supported by cash balances, internal cash flow from operations, external financing, and equity contributions from its parent company.

The amount and timing of our Gill Ranch facility's cash flows from year to year are uncertain, as the majority of these storage contracts are currently short-term. We have seen slightly higher contract prices for the 2015-16 and 2016-17 storage years, but overall prices are still lower than the long-term contracts that expired at the end of the 2013-14 storage year. While we expect continuing challenges for Gill Ranch in 2016, we do not anticipate material changes in our ability to access sources of cash for short-term liquidity.

In November 2011, Gill Ranch issued $40 million of senior collateralized debt, with a fixed interest rate of 7.75% on $20 million and a variable interest rate on the remaining $20 million, with an original maturity date of November 30, 2016. Under the debt agreement, Gill Ranch was subject to certain covenants and restrictions. We amended this agreement twice, which resulted in repayment of the $20 million variable-rate outstanding debt during the second quarter of 2014, suspension of the EBITDA covenant requirement through the maturity date, and maintenance of a debt reserve account, which was fixed at $4.5 million as of June 30, 2015. In addition, under the amended agreement, Gill Ranch was required to receive common equity contributions from its parent NWN Gas Storage of at least $2 million by August 31, 2015 and complied with this requirement. On December 18, 2015, Gill Ranch repaid the $20 million of fixed-rate senior secured debt using available cash and cash flows from operations, including cash from intercompany receivables.

CONSOLIDATED LIQUIDITY. Based on several factors, including our current credit ratings, our commercial paper program, current cash reserves, committed credit facilities, and our expected ability to issue long-term debt in the capital markets, we believe our liquidity is sufficient to meet anticipated near-term cash requirements, including all contractual obligations, investing, and financing activities discussed below.

DIVIDEND POLICY. We have paid quarterly dividends on our common stock each year since stock was first issued to the public in 1951. Annual common stock dividend payments per share, adjusted for stock splits, have increased each year since 1956. The declarations and amount of future dividends will depend upon our earnings, cash flows, financial condition and other factors. The amount and timing of dividends payable on our common stock is at the sole discretion of our Board of Directors.

OFF-BALANCE SHEET ARRANGEMENTS. Except for certain lease and purchase commitments, we have no material off-balance sheet financing arrangements. See "*Contractual Obligations"* below.

Contractual Obligations

The following table shows our contractual obligations at December 31, 2015 by maturity and type of obligation:

	Payments Due in Years Ending December 31,						
In millions	2016	2017	2018	2019	2020	Thereafter	Total
Short-term debt maturities	$ 270.0	$ —	$ —	$ —	$ —	$ —	$ 270.0
Long-term debt maturities	25.0	40.0	22.0	30.0	75.0	409.7	601.7
Interest on long-term debt	34.2	32.1	29.2	28.6	24.4	177.5	326.0
Postretirement benefit payments(1)	23.6	24.1	25.0	26.1	28.4	145.8	273.0
Capital leases	0.6	0.1	—	—	—	—	0.7
Operating leases	5.4	5.4	5.3	5.3	2.8	30.5	54.7
Gas purchases(2)	61.5	—	—	—	—	—	61.5
Gas pipeline capacity commitments	83.2	79.4	75.8	75.7	72.1	340.0	726.2
Other purchase commitments(3)	0.1	—	—	—	—	—	0.1
Other long-term liabilities(4)	16.5	—	—	—	—	—	16.5
Total	$ 520.1	$ 181.1	$ 157.3	$ 165.7	$ 202.7	$ 1,103.5	$ 2,330.4

(1) Postretirement benefit payments primarily consists of two items: (1) estimated qualified defined benefit pension plan payments, which are funded by plan assets and future cash contributions, and (2) required payments to the Western States multiemployer pension plan due to our withdrawal from the plan in December 2013. See Note 8.

(2) Gas purchases include contracts which use price formulas tied to monthly index prices. The commitment amounts presented incorporate the December 2015 first of month index price for each supply basin from which gas is purchased. For a summary of gas purchase and gas pipeline capacity commitments, see Note 14.

(3) Other purchase commitments primarily consist of base gas requirements and remaining balances under existing purchase orders.

(4) Other long-term liabilities includes accrued vacation liabilities for management employees and deferred compensation plan liabilities for executives and directors. The timing of these payments are uncertain; however, these payments are unlikely to all occur in the next 12 months.

In addition to known contractual obligations listed in the above table, we have also recognized liabilities for future environmental remediation or action. The exact timing of payments beyond 12 months with respect to those liabilities cannot be reasonably estimated due to numerous uncertainties surrounding the course of environmental remediation and the preliminary nature of site investigations. See Note 15 for a further discussion of environmental remediation cost liabilities.

At December 31, 2015, 598 of our utility employees were members of the Office and Professional Employees International Union (OPEIU) Local No. 11. In May 2014, our union employees ratified a new labor agreement (Joint Accord) that expires on November 30, 2019. The Joint Accord includes the following items: an average annualized compensation increase of 4% effective June 1, 2014, which includes a 7.9% wage increase to better reflect current market competitive wages, offset by a reduction in bonus pay opportunities for union employees; and a scheduled 3% wage increase effective December 1 each year thereafter, beginning in 2015 with the potential for up to an additional 3% per year based on wage inflation at or above 4%. The Joint Accord also maintains competitive health benefits, including a 15% to 20% premium cost sharing by employees, job flexibility, and other flexibility provisions for the Company.

Short-Term Debt

Our primary source of utility short-term liquidity is from the sale of commercial paper and bank loans. In addition to issuing commercial paper or bank loans to meet working capital requirements, including seasonal requirements to finance gas purchases and accounts receivable, short-term debt may also be used to temporarily fund utility capital requirements. Commercial paper and bank loans are periodically refinanced through the sale of long-term debt or equity securities. Our outstanding commercial paper, which is sold through two commercial banks under an issuing and paying agency agreement, is supported by one or more unsecured revolving credit facilities. See "*Credit Agreements*" below. In the fourth quarter of 2015, we entered into a short-term credit facility loan totaling $50 million, as a short-term bridge through our peak heating season, which was repaid on February 4, 2016.

At December 31, 2015 and 2014, our utility had short-term debt outstanding of $270.0 million and $234.7 million, respectively. The effective interest rate on short-term debt outstanding at December 31, 2015 and 2014 was 0.6% and 0.4%, respectively.

Credit Agreements

We have a $300 million credit agreement, with a feature that allows the Company to request increases in the total commitment amount, up to a maximum of $450 million. The maturity date of the agreement is December 20, 2019.

All lenders under the agreement are major financial institutions with committed balances and investment grade credit ratings as of December 31, 2015 as follows:

In millions		
Lender rating, by category	Loan Commitment	
AA/Aa	$	234
A/A		66
BBB/Baa		—
Total	$	300

Based on credit market conditions, it is possible one or more lending commitments could be unavailable to us if the lender defaulted due to lack of funds or insolvency; however, we do not believe this risk to be imminent due to the lenders' strong investment-grade credit ratings.

Our credit agreement permits the issuance of letters of credit in an aggregate amount of up to $100 million. Any principal and unpaid interest amounts owed on borrowings under the credit agreements is due and payable on or before the maturity date. There were no outstanding balances under this credit agreement at December 31, 2015 or 2014. The credit agreement requires us to maintain a consolidated indebtedness to total capitalization ratio of 70% or less. Failure to comply with this covenant would entitle the lenders to terminate their lending commitments and accelerate the maturity of all amounts outstanding. We were in compliance with this covenant at December 31, 2015 and 2014, with consolidated indebtedness to total capitalization ratios of 52.8% and 53.9%, respectively.

The agreement also requires us to maintain credit ratings with Standard & Poor's (S&P) and Moody's Investors Service, Inc. (Moody’s) and notify the lenders of any change in our senior unsecured debt ratings or senior secured debt ratings, as applicable, by such rating agencies. A change in our debt ratings by S&P or Moody’s is not an event of default, nor is the maintenance of a specific minimum level of debt rating a condition of drawing upon the credit agreement. Rather, interest rates on any loans outstanding under the credit agreements are tied to debt ratings and therefore, a change in the debt rating would increase or decrease the cost of any loans under the credit agreements when ratings are changed. See "*Credit Ratings"* below.

Credit Ratings

Our credit ratings are a factor of our liquidity, potentially affecting our access to the capital markets including the commercial paper market. Our credit ratings also have an impact on the cost of funds and the need to post collateral under derivative contracts. The following table summarizes our current debt ratings from S&P and Moody’s:

	S&P	Moody's
Commercial paper (short-term debt)	A-1	P-2
Senior secured (long-term debt)	AA-	A1
Senior unsecured (long-term debt)	n/a	A3
Corporate credit rating	A+	n/a
Ratings outlook	Stable	Stable

The above credit ratings are dependent upon a number of factors, both qualitative and quantitative, and are subject to change at any time. The disclosure of or reference to these credit ratings is not a recommendation to buy, sell or hold NW Natural securities. Each rating should be evaluated independently of any other rating.

Maturity and Redemption of Long-Term Debt

The following debentures were retired:

	Years Ended December 31,		
In millions	2015	2014	2013
Utility First Mortgage Bonds			
3.95% Series B due 2014	$ —	$ 50	$ —
8.26% Series B due 2014	—	10	—
4.70% Series B due 2015	40	—	—
	40	60	—
Subsidiary Debt			
Variable-rate	—	20	—
Fixed-rate	20	—	—
	$ 60	$ 80	$ —

Cash Flows

Operating Activities

Changes in our operating cash flows are primarily affected by net income, changes in working capital requirements, and other cash and non-cash adjustments to operating results.

Operating activity highlights include:

In millions	2015	2014	2013
Cash provided by operating activities	$ 184.7	$ 215.7	$ 176.4

2015 COMPARED TO 2014. The significant factors contributing to the $31.0 million decrease in operating cash flows were as follows:

- a decrease of $99.4 million in deferred environmental recoveries, net of expenditures, reflecting the receipt of insurance settlements during 2014;
- an increase of $55.0 million from changes in deferred gas costs balances, which reflected lower actual gas prices than prices embedded in the PGA compared to the prior year;
- an increase of $15.0 million from regulatory disallowance of prior environmental cost deferrals in 2015;
- a decrease of $5.3 million from a non-cash recognition of interest income on deferred environmental expenses related to our SRRM order;
- a net decrease of $3.6 million from changes in working capital related to receivables, inventories and accounts payable due to warmer weather in 2015 compared to 2014; and
- an increase of $1.8 million from changes in regulatory balances, other assets and liabilities, and accrued taxes.

2014 COMPARED TO 2013. The significant factors contributing to the $39.3 million increase in operating cash flows were as follows:

- an increase of $105.5 million in deferred environmental recoveries, net of expenditures reflecting the receipt of insurance settlements during 2014;
- an increase of $41.0 million from changes in the accounts receivable balance, primarily due to colder weather in December 2013.
- a decrease of $24.1 million from changes in inventory balances due to refilling gas storage inventory after colder weather in December 2013;
- a decrease of $48.1 million from changes in regulatory balances, an increase in pension liabilities, and an increase in prepaids;
- a decrease of $21.7 million in deferred taxes due to the utilization of NOL carryforwards; and
- a decrease of $17.9 million from changes in deferred gas costs balances, which reflected higher actual gas prices than prices embedded in the PGA compared to the prior year.

During the year ended December 31, 2015, we contributed $14.1 million to our utility's qualified defined benefit pension plan, compared to $10.5 million for 2014 and $9.1 million for 2013. The amounts and timing of future contributions will depend on market interest rates and investment returns on the plans' assets. See Note 8.

Bonus depreciation of 50% has been available for federal and Oregon purposes in 2013, 2014 and 2015. This generated an income tax NOL in 2013, and reduced taxable income in 2014 and 2015, providing cash flow benefits. Bonus depreciation for 2014 and 2015 was not enacted until December 19, 2014 and December 17, 2015, respectively. In both cases it was extended retroactively back to January 1 of the respective year. As a result, estimated income tax payments were made throughout 2014 and 2015 without the benefit of bonus depreciation for the year. This delayed the cash flow benefit of bonus depreciation and contributed to the income tax receivable of $7.9 million and $1.0 million as of December 31, 2015 and 2014, respectively. As a result of the Federal Protecting Americans From Tax Hikes Act of 2015, bonus depreciation is now available in years 2016 through 2019.

We have lease and purchase commitments relating to our operating activities that are financed with cash flows from operations. For information on cash flow requirements related to leases and other purchase commitments, see "Financial Condition—*Contractual Obligations*" above and Note 14.

Investing Activities

Investing activity highlights include:

In millions	2015	2014	2013
Total cash used in investing activities	$ 115.3	$ 144.3	$ 182.1
Capital expenditures	118.3	120.1	138.9
Utility gas reserves	1.5	26.8	54.1

2015 COMPARED TO 2014. The $29.0 million decrease in cash used in investing activities was primarily due to lower utility gas reserves investments compared to 2014; see Note 11.

2014 COMPARED TO 2013. The $37.8 million decrease in cash used in investing activities was primarily due to lower investments in capital expenditures and utility gas reserves as NW Natural ended its original drilling program with Encana in 2014; see Note 11.

Over the five-year period 2016 through 2020, total utility capital expenditures are estimated to be between $850 and $950 million, including the Company's proposed investment in an expansion of our Mist gas storage facility as well as continued refurbishments of the Newport Liquefied Natural Gas (LNG) facility in Oregon over the next three years with an expected investment of approximately $25 million, and upgrading distribution infrastructure in Clark County, Washington, which could total approximately $25 million over the next five years. The estimated level of utility capital expenditures over the next five years reflects assumptions for continued customer growth, technology investments, distribution system maintenance and improvements, and gas storage facilities maintenance. Most of the required funds are expected to be internally generated over the five-year period, and any remaining funding will be obtained through a combination of long-term debt and equity security issuances, with short-term debt and bridge financing providing liquidity.

In 2016, utility capital expenditures are estimated to be between $155 and $175 million, and non-utility capital investments are estimated to be less than $5 million. Gas storage segment capital expenditures in 2016 are expected to be paid from working capital and additional equity contributions from NW Natural as needed.

Financing Activities

Financing activity highlights include:

In millions	2015	2014	2013
Total cash (used in) provided by financing activities	$ (74.7)	$ (71.3)	$ 6.3
Change in short-term debt	35.3	46.5	(2.1)
Change in long-term debt	(60.0)	(80.0)	50.0

2015 COMPARED TO 2014. The $3.4 million increase in cash used in financing activities was primarily due to redeeming $20 million less debt in 2015 compared to 2014. Offsetting this, we issued $11.2 million less of net commercial paper and short-term loans in 2015 compared to 2014.

2014 COMPARED TO 2013. The $77.6 million decrease in cash provided by financing activities was primarily due to using the proceeds from our insurance settlements of $103 million to redeem $60 million of long-term utility debt. In addition, Gill Ranch retired $20 million of variable interest rate debt.

Pension Cost and Funding Status of Qualified Retirement Plans

Pension costs are determined in accordance with accounting standards for compensation and retirement benefits. See "Application of Critical Accounting Policies and Estimates – *Accounting for Pensions and Postretirement Benefits*" below. Pension expense for our qualified defined benefit plan, which is allocated between operation and maintenance expenses, capital expenditures, and the deferred regulatory balancing account, totaled $20.8 million in 2015, an increase of $6.6 million from 2014. The fair market value of pension assets in this plan decreased to $249.3 million at December 31, 2015 from $279.2 million at December 31, 2014. The decrease was due to a loss on plan assets of $9.6 million plus $14.1 million in employer contributions, offset by benefit payments of $34.3 million.

We make contributions to the company-sponsored qualified defined benefit pension plan based on actuarial assumptions and estimates, tax regulations and funding requirements under federal law. Our qualified defined benefit pension plan was underfunded by $162.5 million at December 31, 2015. We plan to make contributions during 2016 of $14.5 million. See Note 8 for further pension disclosures.

Ratios of Earnings to Fixed Charges

For the years ended December 31, 2015, 2014, and 2013, our ratios of earnings to fixed charges, computed using the method outlined by the SEC, were 3.00, 3.13, and 3.16, respectively. For this purpose, earnings consist of net income before taxes plus fixed charges, and fixed charges consist of interest on all indebtedness, the amortization of debt expense and discount or premium and the estimated interest portion of rentals charged to income. See Exhibit 12 for the detailed ratio calculation.

Contingent Liabilities

Loss contingencies are recorded as liabilities when it is probable that a liability has been incurred and the amount of the loss is reasonably estimable in accordance with accounting standards for contingencies. See "*Application of Critical Accounting Policies and Estimates*" below. At December 31, 2015, we had a net regulatory asset of $85.9 million for deferred environmental costs, which includes deferred payments and interest of $51.8 million, $125.0 million for additional costs expected to be paid in the future, and the remaining amortization to be collected in 2016 of $6.8 million, partially offset by $96.5 million of insurance recoveries and $1.2 million of a tariff rider collected in 2015 to be applied to deferred costs. If it is determined that future customer rate recovery of such costs are not probable, then the costs will be charged to expense in the period such determination is made. See Note 15, Note 16, and "Results of Operations—Regulatory Matters—Rate Mechanisms—*Environmental Costs*" above.

New Accounting Pronouncements

For a description of recent accounting pronouncements that may have an impact on our financial condition, results of operations or cash flows, see Note 2.

APPLICATION OF CRITICAL ACCOUNTING POLICIES AND ESTIMATES

In preparing our financial statements in accordance with GAAP, management exercises judgment in the selection and application of accounting principles, including making estimates and assumptions that affect reported amounts of assets, liabilities, revenues, expenses and related disclosures in the financial statements. Management considers our critical accounting policies to be those which are most important to the representation of our financial condition and results of operations and which require management's most difficult and subjective or complex judgments, including accounting estimates that could result in materially different amounts if we reported under different conditions or used different assumptions. Our most critical estimates and judgments include accounting for:

- regulatory accounting;
- revenue recognition;
- derivative instruments and hedging activities;
- pensions and postretirement benefits;
- income taxes;
- environmental contingencies; and
- impairment of long-lived assets.

Management has discussed its current estimates and judgments used in the application of critical accounting policies with the Audit Committee of the Board. Within the context of our critical accounting policies and estimates, management is not aware of any reasonably likely events or circumstances that would result in materially different amounts being reported. For a description of recent accounting pronouncements that could have an impact on our financial condition, results of operations or cash flows, see Note 2.

Regulatory Accounting

Our utility is regulated by the OPUC and WUTC, which establish the rates and rules governing utility services provided to customers, and, to a certain extent, set forth special accounting treatment for certain regulatory transactions. In general, we use the same accounting principles as non-regulated companies reporting under GAAP. However, authoritative guidance for regulated operations (regulatory accounting) requires different accounting treatment for regulated companies to show the effects of such regulation. For example, we account for the cost of gas using a PGA deferral and cost recovery mechanism, which is submitted for approval annually to the OPUC and WUTC. See "Results of Operations—Regulatory Matters—Rate Mechanisms—*Purchased Gas Adjustment*" above. There are other expenses and revenues that the OPUC or WUTC may require us to defer for recovery or refund in future periods. Regulatory accounting requires us to account for these types of deferred expenses (or deferred revenues) as regulatory assets (or regulatory liabilities) on the balance sheet. When we are allowed to recover these regulatory assets from, or are required to refund regulatory liabilities to, customers, we recognize the expense or revenue on the income statement at the same time we realize the adjustment to amounts included in utility rates charged to customers.

The conditions we must satisfy to adopt the accounting policies and practices of regulatory accounting include:

- an independent regulator sets rates;
- the regulator sets the rates to cover specific costs of delivering service; and
- the service territory lacks competitive pressures to reduce rates below the rates set by the regulator.

Because our utility satisfies all three conditions, we continue to apply regulatory accounting to our utility operations. Future accounting changes, regulatory changes or changes in the competitive environment could require us to discontinue the application of regulatory accounting for some or all of our regulated businesses. This would require the write-off of those regulatory assets and liabilities that would no longer be probable of recovery from or refund to customers.

Based on current accounting and regulatory competitive conditions, we believe it is reasonable to expect continued application of regulatory accounting for our utility activities. Further, it is reasonable to expect the recovery or refund of our regulatory assets and liabilities at December 31, 2015 through future customer rates. If we should determine all or a portion of these regulatory assets or liabilities no longer meet the criteria for continued application of regulatory accounting, then we would be required to write-off the net unrecoverable balances against earnings in the period such determination is made. The net balance in regulatory asset and liability accounts as of December 31, 2015 and 2014 was an asset of $70.7 million and $101.2 million, respectively. See Note 2.

Revenue Recognition

Utility and non-utility revenues, which are derived primarily from the sale, transportation, and storage of natural gas, are recognized upon the delivery of gas commodity or services rendered to customers.

Accrued Unbilled Revenue

For a description of our policy regarding accrued unbilled revenue for both the utility and non-utility revenues, see Note 2. The following table presents changes in key metrics if the estimated percentage of unbilled volume at December 31 was adjusted up or down by 1%:

	2015	
In millions	Up 1%	Down 1%
Unbilled revenue increase (decrease)	$ 0.5	$ (0.5)
Utility margin increase (decrease)[(1)]	—	—
Net income increase (decrease)	—	—

(1) Includes impact of regulatory mechanisms including decoupling mechanism.

Derivative Instruments and Hedging Activities

Our gas acquisition and hedging policies set forth guidelines for using financial derivative instruments to support prudent risk management strategies. These policies specifically prohibit the use of derivatives for trading or speculative purposes. We enter into financial derivative contracts to hedge a portion of our utility's natural gas sales requirements. These contracts include swaps, options, and combinations of option contracts. We primarily use these derivative financial instruments to manage commodity price variability. A small portion of our derivative hedging strategy involves foreign currency exchange contracts.

Derivative instruments are recorded on our balance sheet at fair value. If certain regulatory conditions are met, then the derivative instrument fair value is recorded together with an offsetting entry to a regulatory asset or liability account pursuant to regulatory accounting (see Note 2, "*Industry Regulation"*), and no unrealized gain or loss is recognized in current income. The gain or loss from the fair value of a derivative instrument subject to regulatory deferral is included in the recovery from, or refund to, utility customers in future periods (see "*Regulatory Accounting"*, above). If a derivative contract is not subject to regulatory deferral, then the accounting treatment for unrealized gains and losses is recorded in accordance with accounting standards for derivatives and hedging (see Note 2, "*Derivatives*" and "*Industry Regulation"*) which is either in current income or in accumulated other comprehensive income or loss (AOCI or AOCL). Our derivative contracts outstanding at December 31, 2015 were measured at fair value using models or other market accepted valuation methodologies derived from observable market data. Our estimate of fair value may change significantly from period-to-period depending on market conditions and prices. These changes may have an impact on our results of operations, but the impact would largely be mitigated due to the majority of our derivative activities being subject to regulatory deferral treatment. For estimated fair value of unrealized gains and losses, see Note 13.

The following table summarizes the amount of gains and losses realized from commodity price transactions for the last three years:

In millions	2015	2014	2013
Net utility gain (loss) on:			
Commodity			
Swaps	$ (37.7)	$ 10.5	$ (11.0)
Options	—	—	—
Total net gain (loss) realized	$ (37.7)	$ 10.5	$ (11.0)

Realized gains and losses from commodity hedges shown above were recorded as decreases or increases to cost of gas, respectively, and were included in our annual PGA rates.

Pensions and Postretirement Benefits

We maintain a qualified non-contributory defined benefit pension plan, non-qualified supplemental pension plans for eligible executive officers and certain key employees, and other postretirement employee benefit plans covering certain non-union employees. We also have a qualified defined contribution plan (Retirement K Savings Plan) for all eligible employees. Only the qualified defined benefit pension plan and Retirement K Savings Plan have plan assets, which are held in qualified trusts to fund the respective retirement benefits. The qualified defined benefit retirement plan for union and non-union employees was closed to new participants several years ago. These plans are not available to employees at any of our subsidiary companies. Non-union and union employees hired or re-hired after December 31, 2006 and 2009, respectively, and employees of NW Natural subsidiaries are provided an enhanced Retirement K Savings Plan benefit. The postretirement Welfare Benefit Plan for non-union employees was also closed to new participants several years ago.

Net periodic pension and postretirement benefit costs (retirement benefit costs) and projected benefit obligations (benefit obligations) are determined using a number of key assumptions including discount rates, rate of compensation increases, retirement ages, mortality rates and an expected long-term return on plan assets. See Note 8. These key assumptions have a significant impact on the pension amounts recorded and disclosed. Retirement benefit costs consist of service costs, interest costs, the amortization of actuarial gains, losses and prior service costs, the expected returns on plan assets and, in part, on a market-related valuation of assets, if applicable. The market-related asset valuation reflects differences between expected returns and actual investment returns, which we recognize over a three-year period or less from the year in which they occur, thereby reducing year-to-year volatility in retirement benefit costs.

Accounting standards also require balance sheet recognition of the overfunded or underfunded status of pension and postretirement benefit plans in AOCI or AOCL, net of tax, based on the fair value of plan assets compared to the actuarial value of future benefit obligations. However, the retirement benefit costs related to our qualified defined benefit pension and postretirement benefit plans are generally recovered in utility rates, which are set based on accounting standards for pensions and postretirement benefit expenses. We received approval from the OPUC to recognize the overfunded or underfunded status as a regulatory asset or regulatory liability based on expected rate recovery, rather than including it as AOCI or AOCL under common equity. See "*Regulatory Accounting"* above and Note 2, "*Industry Regulation"*.

In 2011, we received regulatory approval from the OPUC and began deferring a portion of our pension expense above or below the amount set in rates to a regulatory balancing account on the balance sheet. At December 31, 2015, the cumulative amount deferred for future pension cost recovery was $43.7 million. The regulatory balancing account includes the recognition of accrued interest on the account balance at the utility's authorized rate of return, with the equity portion of this interest being deferred until amounts are collected in rates.

A number of factors, as discussed above, are considered in developing pension and postretirement benefit assumptions. For the December 31, 2015 measurement date, we reviewed and updated the following key assumptions:

- our weighted-average discount rate assumptions for pensions went from 3.85% for 2014 to 4.21% for 2015, and our weighted-average discount rate assumptions for other postretirement benefits went from 3.74% for 2014 to 4.00% for 2015. The new rate assumptions were determined for each plan based on a matching of benchmark interest rates to the estimated cash flows, which reflect the timing and amount of future benefit payments. Benchmark interest rates are drawn from the Citigroup Above Median Curve, which consists of high quality bonds rated AA- or higher by S&P or Aa3 or higher by Moody's;

- our expected annual rate of future compensation increases, which decreased slightly to a range of 3.25% to 4.50%;
- our expected long-term return on qualified defined benefit plan assets, which remained unchanged at a rate of 7.50%;
- our mortality rate assumptions were updated to the new Society of Actuaries Scale MP-2015, which projects a mortality detriment compared to the previous table used, thereby decreasing benefit plan liabilities; and
- other key assumptions, which were based on actual plan experience and actuarial recommendations.

At December 31, 2015, our net pension liability (benefit obligations less market value of plan assets) for the qualified defined benefit plan decreased $9.5 million compared to 2014. The decrease in our net pension liability is primarily due to the $39.4 million decrease in our pension benefit obligation, offset by a decrease of $29.8 million in plan assets. The liability for non-qualified plans decreased $2.3 million, and the liability for other postretirement benefits decreased $1.0 million in 2015.

We determine the expected long-term rate of return on plan assets by averaging the expected earnings for the target asset portfolio. In developing our expected return, we analyze historical actual performance and long-term return projections, which gives consideration to the current asset mix and our target asset allocation. As of December 31, 2015, the actual annualized returns on plan assets, net of management fees, for the past one-year, five-years, and 10-years were (3.2%), 4.7%, and 4.0%, respectively.

We believe our pension assumptions to be appropriate based on plan design and an assessment of market conditions. However, the following shows the sensitivity of our retirement benefit costs and benefit obligations to changes in certain actuarial assumptions:

Dollars in millions	Change in Assumption	Impact on 2015 Retirement Benefit Costs	Impact on Retirement Benefit Obligations at Dec. 31, 2015
Discount rate:	(0.25)%		
Qualified defined benefit plans		$ 1.3	$ 14.4
Non-qualified plans		—	1.0
Other postretirement benefits		0.1	1.0
Expected long-term return on plan assets:	(0.25)		
Qualified defined benefit plans		0.7	N/A

In July 2012, President Obama signed into law the MAP-21 Act. This legislation changed several provisions affecting pension plans, including temporary funding relief and Pension Benefit Guaranty Corporation (PBGC) premium increases, which reduces the level of minimum required contributions in the near-term but generally increases contributions in the long-run as well as increasing the operational costs of running a pension plan. Prior to the MAP-21 Act, we were using interest rates based on a 24-month average yield of investment grade corporate bonds (also referred to as "segment rate") to calculate minimum contribution requirements. MAP-21 Act established a new minimum and maximum corridor for segment rates based on a 25-year average of bond yields, which is to be used in calculating contribution requirements. In August 2014, HATFA was signed and extends certain aspects of MAP-21 as well as modifies the phase-out periods for the limitations. As a result we anticipate lower contributions over the next five years with contributions increasing thereafter.

Income Taxes

Valuation Allowances

We recognize deferred tax assets to the extent that we believe these assets are more likely than not to be realized. In making such a determination, we consider the available positive and negative evidence, including future reversals of existing taxable temporary differences, projected future taxable income, tax-planning strategies, and results of recent operations. The most significant deferred tax asset currently recorded is for alternative minimum tax credits. We have determined that we are more likely than not to realize all recorded deferred tax assets as of December 31, 2015. See Note 9.

Uncertain Tax Benefits

The calculation of our tax liabilities involves dealing with uncertainties in the application of complex tax laws and regulations in the jurisdictions in which we operate. A tax benefit from a material uncertain tax position will only be recognized when it is more likely than not that the position, or some portion thereof, will be sustained upon examination, including resolution of any related appeals or litigation processes, on the basis of the technical merits. The Company participates in the Compliance Assurance Process (CAP) with the Internal Revenue Service (IRS). Under the CAP program the Company works with the IRS to identify and resolve material tax matters before the federal income tax return is filed each year. No reserves for uncertain tax benefits were recorded during 2013, 2014, or 2015. See Note 9.

Regulatory Matters

Regulatory tax assets and liabilities are recorded to the extent we believe they will be recoverable from, or refunded to, customers in future rates. At December 31, 2015 and 2014, we have regulatory income tax assets of $47.4 million and $51.8 million, respectively, representing future rate recovery of deferred tax liabilities resulting from differences in utility plant financial statement and tax basis and utility plant removal costs. These deferred tax liabilities, and the associated regulatory income tax assets, are currently being recovered through customer rates. See Note 2.

Tax Legislation

When significant proposed or enacted changes in income tax rules occur we consider whether there may be a material impact to our financial position, results of operations, cash flows, or whether the changes could materially affect existing assumptions used in making estimates of tax related balances.

The final tangible property regulations applicable to all taxpayers were issued on September 13, 2013 and were generally effective for taxable years beginning on or after January 1, 2014. In addition, procedural guidance related to the regulations was issued under which taxpayers may make accounting method changes to comply with the regulations. We have evaluated the regulations and do not anticipate any material impact. However, unit-of-property guidance applicable to natural gas distribution networks has not yet been issued and is expected in 2016. We will further evaluate the effect of these regulations after this guidance is issued, but believe our current method is materially consistent with the new regulations and do not expect these regulations to have a material effect on our financial statements.

The Federal Protecting Americans From Tax Hikes Act of 2015 became law on December 17, 2015 and extended federal bonus depreciation through 2019. See "Financial Conditions—*Cash Flows*" above.

Environmental Contingencies
We account for environmental liabilities in accordance with accounting standards under the loss contingency guidance when it is probable that a liability has been incurred and the amount of the loss is reasonably estimable. For a complete discussion of our environmental policy refer to Note 2. For a discussion of our current environmental sites and liabilities refer to Note 15 and "*Contingent Liabilities"* above. In addition, for information regarding the regulatory treatment of these costs and our regulatory recovery mechanism, see "Results of Operations—Rate Matters—Rate Mechanisms —*Environmental Costs*" above.

Impairment of Long-Lived Assets
We review the carrying value of long-lived assets whenever events or changes in circumstances indicate the carrying amount of the assets might not be recoverable. Factors that would necessitate an impairment assessment of long-lived assets include a significant adverse change in the extent or manner in which the asset is used, a significant adverse change in legal factors or business climate that could affect the value of the asset, or a significant decline in the observable market value or expected future cash flows of the asset, among others.

When such factors are present, we assess the recoverability by determining whether the carrying value of the asset will be recovered through expected future cash flows. An asset is determined to be impaired when the carrying value of the asset exceeds the expected undiscounted future cash flows from the use and eventual disposition of the asset. If an impairment is indicated, we record an impairment loss for the difference between the carrying value and the fair value of the long-lived assets. Fair value is estimated using appropriate valuation methodologies, which may include an estimate of discounted cash flows.

We determined there were no long-lived asset impairments in 2015; however our Gill Ranch Storage facility within our Gas Storage Segment was reviewed for impairment. The undiscounted cash flows are in excess of the carrying value of the asset and no impairment was indicated. The cash flows assume a recovery of storage pricing and the ability to contract with higher value customers. Accordingly, if storage pricing does not improve and/or new higher value customers are not obtained, future analysis may result in an impairment of these long-lived assets.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to various forms of market risk including commodity supply risk, commodity price risk, interest rate risk, foreign currency risk, credit risk and weather risk. The following describes our exposure to these risks.

Commodity Supply Risk
We enter into spot, short-term, and long-term natural gas supply contracts, along with associated pipeline transportation contracts, to manage our commodity supply risk. Historically, we have arranged for physical delivery of an adequate supply of gas, including gas in our Mist storage and off-system storage facilities, to meet expected requirements of our core utility customers. Our long-term gas supply contracts are primarily index-based and subject to monthly re-pricing, a strategy that is intended to substantially mitigate credit exposure to our physical gas counterparties. Notional amounts under physical gas contracts were $7.0 million and $4.8 million as of December 31, 2015 and 2014, respectively.

Commodity Price Risk
Natural gas commodity prices are subject to market fluctuations due to unpredictable factors including weather, pipeline transportation congestion, drilling technologies, market speculation, and other factors that affect supply and demand. We manage commodity price risk with financial swaps and physical gas reserves from a long-term investment in working interests in gas leases operated by Jonah Energy. These financial hedge contracts and gas reserves volumes are generally included in our annual PGA filing for recovery, subject to a regulatory prudence review. Notional amounts under financial derivative contracts were $95.5 million and $108.4 million as of December 31, 2015 and 2014, respectively. The fair value of financial swaps as of December 31, 2015 was an unrealized loss of $23.2 million with future cash flows of $19.8 million in 2016, $2.7 million in 2017 and $0.7 million in 2018.

Interest Rate Risk
We are exposed to interest rate risk primarily associated with new debt financing needed to fund capital requirements, including future contractual obligations and maturities of long-term and short-term debt. Interest rate risk is primarily managed through the issuance of fixed-rate debt with varying maturities. We may also enter into financial derivative instruments, including interest rate swaps, options and other hedging instruments, to manage and mitigate interest rate exposure. We did not have any interest rate swaps outstanding as of December 31, 2015 or 2014.

Foreign Currency Risk
The costs of certain pipeline and off-system storage services purchased from Canadian suppliers are subject to changes in the value of the Canadian currency in relation to the U.S. currency. Foreign currency forward contracts are used to hedge against fluctuations in exchange rates for our commodity-related demand and reservation charges paid in Canadian dollars. Notional amounts under foreign currency

forward contracts were $9.0 million and $12.2 million as of December 31, 2015 and 2014, respectively. If all of the foreign currency forward contracts had been settled on December 31, 2015, a loss of $0.4 million would have been realized. See Note 13.

Credit Risk

Credit Exposure to Natural Gas Suppliers

Certain gas suppliers have either relatively low credit ratings or are not rated by major credit rating agencies. To manage this supply risk, we purchase gas from a number of different suppliers at liquid exchange points. We evaluate and monitor suppliers' creditworthiness and maintain the ability to require additional financial assurances, including deposits, letters of credit, or surety bonds, in case a supplier defaults. In the event of a supplier's failure to deliver contracted volumes of gas, the regulated utility would need to replace those volumes at prevailing market prices, which may be higher or lower than the original transaction prices. We expect these costs would be subject to our PGA sharing mechanism discussed above. Since most of our commodity supply contracts are priced at the daily or monthly market index price tied to liquid exchange points, and we have adequate storage flexibility, we believe it is unlikely a supplier default would have a material adverse effect on our financial condition or results of operations.

Credit Exposure to Financial Derivative Counterparties

Based on estimated fair value at December 31, 2015, our overall credit exposure relating to commodity contracts is considered immaterial as it reflects amounts owed to financial derivative counterparties (see table below). However, changes in natural gas prices could result in counterparties owing us money. Therefore, our financial derivatives policy requires counterparties to have at least an investment-grade credit rating at the time the derivative instrument is entered into and specific limits on the contract amount and duration based on each counterparty's credit rating. Due to potential changes in market conditions and credit concerns, we continue to enforce strong credit requirements. We actively monitor and manage our derivative credit exposure and place counterparties on hold for trading purposes or require cash collateral, letters of credit, or guarantees as circumstances warrant. As of December 31, 2015, we do not have any actual derivative credit risk exposure for amounts financial derivative counterparties owe to us.

The following table summarizes our overall financial swap and option credit exposure, based on estimated fair value, and the corresponding counterparty credit ratings. The table uses credit ratings from S&P and Moody's, reflecting the higher of the S&P or Moody's rating or a middle rating if the entity is split-rated with more than one rating level difference:

	Financial Derivative Position by Credit Rating Unrealized Fair Value Loss	
In millions	2015	2014
AA/Aa	(20.0)	(27.2)
A/A	(3.2)	(3.4)
Total	$ (23.2)	$ (30.6)

In most cases, we also mitigate the credit risk of financial derivatives by having master netting arrangements with our counterparties which provide for making or receiving net cash settlements. Generally, transactions of the same type in the same currency that have settlement on the same day with a single counterparty are netted and a single payment is delivered or received depending on which party is due funds.

Additionally we have master contracts in place with each of our derivative counterparties that include provisions for posting or calling for collateral. Generally we can obtain cash or marketable securities as collateral with one day's notice. We use various collateral management strategies to reduce liquidity risk. The collateral provisions vary by counterparty but are not expected to result in the significant posting of collateral, if any. We have performed stress tests on the portfolio and concluded the liquidity risk from collateral calls is not material. Our derivative credit exposure is primarily with investment grade counterparties rated AA-/Aa3 or higher. Contracts are diversified across counterparties to reduce credit and liquidity risk.

Credit Exposure to Insurance Companies

Our credit exposure to insurance companies for loss or damage claims could be material. We regularly monitor the financial condition of insurance companies who provide general liability insurance policy coverage to NW Natural and its predecessors.

Weather Risk

We have a weather normalization mechanism in Oregon; however, we are exposed to weather risk primarily from our regulated utility business. A large percentage of our utility margin is volume driven, and current rates are based on an assumption of average weather. Our weather normalization mechanism in Oregon is for residential and commercial customers, which is intended to stabilize the recovery of our utility's fixed costs and reduce fluctuations in customers' bills due to colder or warmer than average weather. Customers in Oregon are allowed to opt out of the weather normalization mechanism. As of December 31, 2015, approximately 9% of our Oregon customers had opted out. In addition to the Oregon customers opting out, our Washington residential and commercial customers account for approximately 11% of our total customer base and are not covered by weather normalization. The combination of Oregon and Washington customers not covered by a weather normalization mechanism is 20% of all residential and commercial customers. See "Results of Operations—Regulatory Matters—Rate Mechanism—*Weather Normalization Tariff*" above.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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Supplemental Schedules Omitted

All other schedules are omitted because of the absence of the conditions under which they are required or because the required information is included elsewhere in the financial statements.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) or 15d-15(f) under the Securities Exchange Act of 1934, as amended. Our internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles in the United States of America (GAAP). Our internal control over financial reporting includes those policies and procedures that:

(i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions involving company assets;

(ii) provide reasonable assurance that transactions are recorded as necessary to permit the preparation of financial statements in accordance with GAAP, and that receipts and expenditures are being made only in accordance with authorizations of management and the Board of Directors; and

(iii) provide reasonable assurance regarding prevention or timely detection of the unauthorized acquisition, use or disposition of our assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements or fraud. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2015. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control-Integrated Framework (2013)*.

Based on our assessment and those criteria, management has concluded that we maintained effective internal control over financial reporting as of December 31, 2015.

The effectiveness of internal control over financial reporting as of December 31, 2015 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears in this annual report.

/s/ Gregg S. Kantor
Gregg S. Kantor
Chief Executive Officer

/s/ Gregory C. Hazelton
Gregory C. Hazelton
Senior Vice President, Chief Financial Officer, and Treasurer

February 26, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
Northwest Natural Gas Company:

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Northwest Natural Gas Company and its subsidiaries at December 31, 2015 and 2014, and the results of their operations and its cash flows for each of the three years in the period ended December 31, 2015 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

Portland, Oregon
February 26, 2016

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

In thousands, except per share data	Year Ended December 31, 2015	2014	2013
Operating revenues	$ 723,791	$ 754,037	$ 758,518
Operating expenses:			
Cost of gas	327,305	365,490	373,298
Operations and maintenance	157,521	136,982	136,613
Environmental remediation	3,513	—	—
General taxes	30,281	29,407	29,956
Depreciation and amortization	80,923	79,193	75,905
Total operating expenses	599,543	611,072	615,772
Income from operations	124,248	142,965	142,746
Other income, net	7,747	1,933	4,669
Interest expense, net	42,539	44,563	45,172
Income before income taxes	89,456	100,335	102,243
Income tax expense	35,753	41,643	41,705
Net income	53,703	58,692	60,538
Other comprehensive income:			
Change in employee benefit plan liability, net of taxes of ($988) for 2015, $2,857 for 2014, and ($1,304) for 2013	1,561	(4,364)	1,998
Amortization of non-qualified employee benefit plan liability, net of taxes of ($883) for 2015, ($438) for 2014, and ($608) for 2013	1,353	646	935
Comprehensive income	$ 56,617	$ 54,974	$ 63,471
Average common shares outstanding:			
Basic	27,347	27,164	26,974
Diluted	27,417	27,223	27,027
Earnings per share of common stock:			
Basic	$ 1.96	$ 2.16	$ 2.24
Diluted	1.96	2.16	2.24
Dividends declared per share of common stock	1.86	1.85	1.83

See Notes to Consolidated Financial Statements

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS

In thousands	As of December 31, 2015	2014
Assets:		
Current assets:		
Cash and cash equivalents	$ 4,211	$ 9,534
Accounts receivable	68,228	69,818
Accrued unbilled revenue	57,987	57,963
Allowance for uncollectible accounts	(870)	(969)
Regulatory assets	69,178	68,562
Derivative instruments	2,719	243
Inventories	70,868	77,832
Gas reserves	17,094	20,020
Income taxes receivable	7,900	1,000
Deferred tax assets	—	23,785
Other current assets	34,748	34,772
Total current assets	332,063	362,560
Non-current assets:		
Property, plant, and equipment	3,089,380	2,992,560
Less: Accumulated depreciation	906,717	870,967
Total property, plant, and equipment, net	2,182,663	2,121,593
Gas reserves	114,552	129,280
Regulatory assets	370,711	368,908
Derivative instruments	27	—
Other investments	68,066	68,238
Restricted cash	—	3,000
Other non-current assets	8,610	11,366
Total non-current assets	2,744,629	2,702,385
Total assets	$ 3,076,692	$ 3,064,945

See Notes to Consolidated Financial Statements

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS

In thousands	As of December 31, 2015	2014
Liabilities and equity:		
Current liabilities:		
Short-term debt	$ 270,035	$ 234,700
Current maturities of long-term debt	25,000	40,000
Accounts payable	73,219	91,366
Taxes accrued	10,420	10,031
Interest accrued	5,873	6,079
Regulatory liabilities	29,927	19,105
Derivative instruments	22,092	29,894
Other current liabilities	41,148	38,235
Total current liabilities	477,714	469,410
Long-term debt	576,700	621,700
Deferred credits and other non-current liabilities:		
Deferred tax liabilities	530,021	530,965
Regulatory liabilities	339,287	317,205
Pension and other postretirement benefit liabilities	223,105	236,735
Derivative instruments	3,447	3,515
Other non-current liabilities	145,446	118,094
Total deferred credits and other non-current liabilities	1,241,306	1,206,514
Commitments and contingencies (see Note 14 and Note 15)	—	—
Equity:		
Common stock - no par value; authorized 100,000 shares; issued and outstanding 27,427 and 27,284 at December 31, 2015 and 2014, respectively	383,144	375,117
Retained earnings	404,990	402,280
Accumulated other comprehensive loss	(7,162)	(10,076)
Total equity	780,972	767,321
Total liabilities and equity	$ 3,076,692	$ 3,064,945

See Notes to Consolidated Financial Statements

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

In thousands	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Equity
Balance at December 31, 2012	$ 356,571	$ 382,347	$ (9,291)	$ 729,627
Comprehensive income	—	60,538	2,933	63,471
Dividends on common stock	—	(49,204)	—	(49,204)
Tax expense from employee stock plans	(242)	—	—	(242)
Stock-based compensation	2,169	—	—	2,169
Issuance of common stock	6,051	—	—	6,051
Balance at December 31, 2013	364,549	393,681	(6,358)	751,872
Comprehensive income (loss)	—	58,692	(3,718)	54,974
Dividends on common stock	—	(50,093)	—	(50,093)
Tax expense from employee stock plans	(117)	—	—	(117)
Stock-based compensation	1,646	—	—	1,646
Issuance of common stock	9,039	—	—	9,039
Balance at December 31, 2014	375,117	402,280	(10,076)	767,321
Comprehensive income	—	53,703	2,914	56,617
Dividends on common stock	—	(50,993)	—	(50,993)
Tax expense from employee stock plans	(118)	—	—	(118)
Stock-based compensation	3,277	—	—	3,277
Issuance of common stock	4,868	—	—	4,868
Balance at December 31, 2015	$ 383,144	$ 404,990	$ (7,162)	$ 780,972

See Notes to Consolidated Financial Statements

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
In thousands	2015	2014	2013
Operating activities:			
Net income	$ 53,703	$ 58,692	$ 60,538
Adjustments to reconcile net income to cash provided by operations:			
Depreciation and amortization	80,923	79,193	75,905
Regulatory amortization of gas reserves	17,991	19,335	11,089
Deferred tax liabilities, net	26,972	24,772	46,483
Qualified defined benefit pension plan expense	5,697	4,984	5,666
Contributions to qualified defined benefit pension plans	(14,120)	(10,500)	(11,700)
Deferred environmental (expenditures) recoveries, net	(10,568)	88,849	(16,679)
Regulatory disallowance of prior environmental cost deferrals	15,000	—	—
Interest income on deferred environmental expenses	(5,322)	—	—
Amortization of environmental remediation	3,513	—	—
Other	3,709	1,853	(2,580)
Changes in assets and liabilities:			
Receivables, net	2,373	14,948	(26,094)
Inventories	6,964	(17,163)	6,933
Taxes accrued	(6,541)	1,709	286
Accounts payable	(17,175)	(2,020)	7,422
Interest accrued	(206)	(1,024)	1,150
Deferred gas costs	31,918	(23,114)	(5,245)
Other, net	(10,143)	(24,857)	23,216
Cash provided by operating activities	184,688	215,657	176,390
Investing activities:			
Capital expenditures	(118,320)	(120,092)	(138,924)
Utility gas reserves	(1,549)	(26,798)	(54,077)
Proceeds from sale of assets	410	175	8,638
Restricted cash	3,000	1,000	—
Other	1,161	1,392	2,231
Cash used in investing activities	(115,298)	(144,323)	(182,132)
Financing activities:			
Common stock issued, net	3,875	8,986	5,964
Long-term debt issued	—	—	50,000
Long-term debt retired	(60,000)	(80,000)	—
Change in short-term debt	35,335	46,500	(2,050)
Cash dividend payments on common stock	(49,243)	(50,093)	(49,204)
Other	(4,680)	3,336	1,580
Cash (used in) provided by financing activities	(74,713)	(71,271)	6,290
(Decrease) increase in cash and cash equivalents	(5,323)	63	548
Cash and cash equivalents, beginning of period	9,534	9,471	8,923
Cash and cash equivalents, end of period	$ 4,211	$ 9,534	$ 9,471
Supplemental disclosure of cash flow information:			
Interest paid, net of capitalization	$ 39,634	$ 42,602	$ 44,022
Income taxes paid, net of refunds	17,306	19,445	870

See Notes to Consolidated Financial Statements

NORTHWEST NATURAL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND PRINCIPLES OF CONSOLIDATION

The accompanying consolidated financial statements represent the consolidated results of Northwest Natural Gas Company (NW Natural or the Company) and all companies we directly or indirectly control, either through majority ownership or otherwise. We have two core businesses: our regulated local gas distribution business, referred to as the utility segment, which serves residential, commercial, and industrial customers in Oregon and southwest Washington; and our gas storage businesses, referred to as the gas storage segment, which provides storage services for utilities, gas marketers, electric generators, and large industrial users from facilities located in Oregon and California. In addition, we have investments and other non-utility activities we aggregate and report as other.

Our core utility business assets and operating activities are largely included in the parent company, NW Natural. Our direct and indirect wholly-owned subsidiaries include NW Natural Energy, LLC (NWN Energy), NW Natural Gas Storage, LLC (NWN Gas Storage), Gill Ranch Storage, LLC (Gill Ranch), NNG Financial Corporation (NNG Financial), Northwest Energy Corporation (Energy Corp), and NW Natural Gas Reserves, LLC (NWN Gas Reserves). Investments in corporate joint ventures and partnerships we do not directly or indirectly control, and for which we are not the primary beneficiary, are accounted for under the equity method, which includes NWN Energy's investment in Trail West Holdings, LLC (TWH) and NNG Financial's investment in Kelso-Beaver (KB) Pipeline. NW Natural and its affiliated companies are collectively referred to herein as NW Natural. The consolidated financial statements are presented after elimination of all intercompany balances and transactions, except for amounts required to be included under regulatory accounting standards to reflect the effect of such regulation. In this report, the term "utility" is used to describe our regulated gas distribution business, and the term "non-utility" is used to describe our gas storage businesses and other non-utility investments and business activities.

Certain prior year balances in our consolidated financial statements and notes have been reclassified to conform with the current presentation. These reclassifications had no effect on our prior year's consolidated results of operations, financial condition, or cash flows.

2. SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles in the United States of America (GAAP) requires management to make estimates and assumptions that affect reported amounts in the consolidated financial statements and accompanying notes. Actual amounts could differ from those estimates, and changes would most likely be reported in future periods. Management believes the estimates and assumptions used are reasonable.

Industry Regulation

Our principal businesses are the distribution of natural gas, which is regulated by the OPUC and WUTC, and natural gas storage services, which are regulated by either the FERC or the CPUC, and to a certain extent by the OPUC and WUTC. Accounting records and practices of our regulated businesses conform to the requirements and uniform system of accounts prescribed by these regulatory authorities in accordance with U.S. GAAP. Our businesses regulated by the OPUC, WUTC, and FERC earn a reasonable return on invested capital from approved cost-based rates, while our business regulated by the CPUC earns a return to the extent we are able to charge competitive prices above our costs (i.e. market-based rates).

In applying regulatory accounting principles, we capitalize or defer certain costs and revenues as regulatory assets and liabilities pursuant to orders of the OPUC or WUTC, which provide for the recovery of revenues or expenses from, or refunds to, utility customers in future periods, including a return or a carrying charge in certain cases.

At December 31, the amounts deferred as regulatory assets and liabilities were as follows:

	Regulatory Assets	
In thousands	2015	2014
Current:		
Unrealized loss on derivatives[1]	$ 22,092	$ 29,889
Gas costs	8,717	21,794
Environmental costs[2]	9,270	—
Decoupling[3]	18,775	7,505
Other[4]	10,324	9,374
Total current	$ 69,178	$ 68,562
Non-current:		
Unrealized loss on derivatives[1]	$ 3,447	$ 3,515
Pension balancing[5]	43,748	32,541
Income taxes	43,049	47,427
Pension and other postretirement benefit liabilities	184,223	201,845
Environmental costs[2]	76,584	58,859
Gas costs	1,949	5,971
Other[4]	17,711	18,750
Total non-current	$ 370,711	$ 368,908

	Regulatory Liabilities	
In thousands	2015	2014
Current:		
Gas costs	$ 14,157	$ 5,700
Unrealized gain on derivatives[1]	2,659	240
Other[4]	13,111	13,165
Total current	$ 29,927	$ 19,105
Non-current:		
Gas costs	$ 8,869	$ 2,507
Unrealized gain on derivatives[1]	27	—
Accrued asset removal costs[6]	327,047	311,238
Other[4]	3,344	3,460
Total non-current	$ 339,287	$ 317,205

(1) Unrealized gains or losses on derivatives are non-cash items and, therefore, do not earn a rate of return or a carrying charge. These amounts are recoverable through utility rates as part of the annual Purchased Gas Adjustment (PGA) mechanism when realized at settlement.

(2) Environmental costs relate to specific sites approved for regulatory deferral by the OPUC and WUTC. In Oregon, we earn a carrying charge on cash amounts paid, whereas amounts accrued but not yet paid do not earn a carrying charge until expended. We also accrue a carrying charge on insurance proceeds for amounts owed to customers. In Washington, a carrying charge related to deferred amounts will be determined in a future proceeding. Current environmental costs represent remediation costs management expects to collect from customers in the next 12 months. Amounts included in this estimate are still subject to a prudence and earnings test review by the OPUC and do not include the $5 million base rate rider. The amounts allocable to Oregon are recoverable through utility rates, subject to an earnings test. See Note 15.

(3) This deferral represents the margin adjustment resulting from differences between actual and expected volumes.

(4) These balances primarily consist of deferrals and amortizations under approved regulatory mechanisms. The accounts being amortized typically earn a rate of return or carrying charge.

(5) The deferral of certain pension expenses above or below the amount set in rates was approved by the OPUC, with recovery of these deferred amounts through the implementation of a balancing account, which includes the expectation of lower net periodic benefit costs in future years. Deferred pension expense balances include accrued interest at the utility's authorized rate of return, with the equity portion of interest income recognized when amounts are collected in rates.

(6) Estimated costs of removal on certain regulated properties are collected through rates. See "Accounting Policies—*Plant, Property, and Accrued Asset Removal Costs*" below.

The amortization period for our regulatory assets and liabilities ranges from less than one year to an indeterminable period. Our regulatory deferrals for gas costs payable are generally amortized over 12 months beginning each November 1 following the gas contract year during which the deferred gas costs are recorded. Similarly, most of our other regulatory deferred accounts are amortized over 12 months. However, certain regulatory account balances, such as income taxes, environmental costs, pension liabilities, and accrued asset removal costs, are large and tend to be amortized over longer periods once we have agreed upon an amortization period with the respective regulatory agency.

We believe all costs incurred and deferred at December 31, 2015 are prudent. We annually review all regulatory assets and liabilities for recoverability and more often if circumstances warrant. If we should determine that all or a portion of these regulatory assets or liabilities no longer meet the criteria for continued application of regulatory accounting, then we would be required to write off the net unrecoverable balances in the period such determination is made.

Environmental Regulatory Accounting

On February 20, 2015, the OPUC issued an Order (2015 Order) addressing outstanding implementation items related to the Site Remediation and Recovery Mechanism (SRRM). Under the Order, $15 million of $95 million in total environmental remediation expenses deferred through 2012 were disallowed. The OPUC found the $95 million to be prudent but disallowed the $15 million from rate recovery based on its determination of how an earnings test should apply to years between 2003 and 2012, with adjustments for other factors the OPUC deemed relevant. We recognized the $15 million pre-tax disallowance, or $9.1 million after-tax charge, during the first quarter of 2015. The charge was recorded in operations and maintenance expense. Also, as a result of the order, we recognized $5.3 million pre-tax of interest income related to the equity earnings on our deferred environmental expenses.

On January 27, 2016, the OPUC issued an Order addressing the outstanding issues. In November 2015, we began collecting revenues from customers through the SRRM. These collections are included in utility operating revenues and are offset by environmental remediation expense included in operating expense. See Note 15 and Note 16 regarding our SRRM.

New Accounting Standards

Recently Adopted Accounting Pronouncement

PRESENTATION OF DEFERRED TAXES. On November 20, 2015, the FASB (Financial Accounting Standards Board) issued ASU 2015-17, "Balance Sheet Classification of Deferred Taxes." The ASU requires deferred tax liabilities and assets to be classified as noncurrent in a classified statement of financial position. The new requirements are effective for us beginning January 1, 2017 and may be applied either prospectively to all deferred tax liabilities and assets or retrospectively to all periods presented. We have early adopted the change in accounting principle on a prospective basis, and it is reflected within our consolidated balance sheet for the period ended December 31, 2015. Prior periods were not retrospectively adjusted.

Recently Issued Accounting Pronouncements

BENEFIT PLAN ACCOUNTING. On July 31, 2015, the FASB issued ASU 2015-12, "Plan Accounting: Defined Benefit Pension Plans, Defined Contribution Pension Plans, and Health and Welfare Benefit Plans." The ASU outlines a three part update. Only part two of the update is applicable for us, which simplifies the investment disclosure requirements for employee benefit plans by allowing certain disclosures at an aggregated level, reducing the number of ways assets must be grouped and analyzed, and no longer requiring investment strategy disclosures for certain investments. The new requirements are effective for us beginning January 1, 2016, with early adoption permitted. We will be required to apply the disclosure guidance retrospectively and do not expect the ASU to materially affect our financial statements and disclosures.

FAIR VALUE MEASUREMENT. On May 1, 2015, the FASB issued ASU 2015-07, "Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or its Equivalent)." The ASU removes the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share practical expedient and also removes certain disclosure requirements. The new requirements are effective for us beginning January 1, 2016 with retrospective application to all periods presented required and early adoption permitted. We do not expect the ASU to materially affect our financial statements and disclosures.

INTANGIBLES - GOODWILL AND OTHER - INTERNAL-USE SOFTWARE. On April 15, 2015 the FASB issued ASU 2015-05, "Customer's Accounting for Fees Paid in a Cloud Computing Arrangement." The ASU provides customers guidance on how to determine whether a cloud computing arrangement includes a software license. The new requirements are effective for us beginning January 1, 2016. The ASU can be applied prospectively or retrospectively and early adoption is permitted. We intend to apply the guidance prospectively and do not expect the ASU to materially affect our financial statements and disclosures.

DEBT ISSUANCE COSTS. On April 7, 2015, the FASB issued ASU 2015-03, "Simplifying the Presentation of Debt Issuance Costs," which requires the presentation of debt issuance costs in the balance sheet as a direct deduction from the associated debt liability. The new requirements are effective for us beginning January 1, 2016. The new guidance will be applied on a retrospective basis. We do not expect the ASU to materially affect our financial statements and disclosures.

REVENUE RECOGNITION. On May 28, 2014, the FASB issued ASU 2014-09 "Revenue From Contracts with Customers." The underlying principle of the guidance requires entities to recognize revenue depicting the transfer of goods or services to customers at amounts the entity is expected to be entitled to in exchange for those goods or services. The model provides a five-step approach to revenue recognition: (1) identify the contract(s) with the customer; (2) identify the separate performance obligations in the contract(s); (3) determine the transaction price; (4) allocate the transaction price to separate performance obligations; and (5) recognize revenue when, or as, each performance obligation is satisfied. The new requirements prescribe either a full retrospective or simplified transition adoption method. On August 12, 2015, the FASB deferred the effective date by one year to January 1, 2018 for annual reporting periods beginning after December 15, 2017. The FASB also permitted early adoption of the standard, but not before the original effective date of January 1, 2017. We are currently assessing the effect of this standard on our financial statements and disclosures.

Accounting Policies

Plant, Property, and Accrued Asset Removal Costs

Plant and property are stated at cost, including capitalized labor, materials and overhead. In accordance with regulatory accounting standards, the cost of acquiring and constructing long-lived plant and property generally includes an allowance for funds used during construction (AFUDC) or capitalized interest. AFUDC represents the regulatory financing cost incurred when debt and equity funds are used for construction (see "*AFUDC*" below). When constructed assets are subject to market-based rates rather than cost-based rates, the financing costs incurred during construction are included in capitalized interest in accordance with U.S. GAAP, not as regulatory financing costs under AFUDC.

In accordance with long-standing regulatory treatment, our depreciation rates consist of three components: one based on the average service life of the asset, a second based on the estimated salvage value of the asset, and a third based on the asset's estimated cost of removal. We collect, through rates, the estimated cost of removal on certain regulated properties through depreciation expense, with a corresponding offset to accumulated depreciation. These removal costs are non-legal obligations as defined by regulatory accounting guidance. Therefore, we have included these costs as non-current regulatory liabilities rather than as accumulated depreciation on our consolidated balance sheets. In the rate setting process, the liability for removal costs is treated as a reduction to the net rate base on which the regulated utility has the opportunity to earn its allowed rate of return.

The costs of utility plant retired or otherwise disposed of are removed from utility plant and charged to accumulated depreciation for recovery or refund through future rates. Gains from the sale of regulated assets are generally deferred and refunded to customers. For non-utility assets, we record a gain or loss upon the disposal of the property, and the gain or loss is recorded in operating income in the consolidated statements of comprehensive income.

Our provision for depreciation of utility property, plant, and equipment is recorded under the group method on a straight-line basis with rates computed in accordance with depreciation studies approved by regulatory authorities. The weighted-average depreciation rate for utility assets in service was approximately 2.8% for 2015, 2014, and 2013, reflecting the approximate weighted-average economic life of the property. This includes 2015 weighted-average depreciation rates for the following asset categories: 2.7% for transmission and distribution plant, 2.2% for gas storage facilities, 4.6% for general plant, and 2.7% for intangible and other fixed assets.

AFUDC. Certain additions to utility plant include AFUDC, which represents the net cost of debt and equity funds used during construction. AFUDC is calculated using actual interest rates for debt and authorized rates for ROE, if applicable. If short-term debt balances are less than the total balance of construction work in progress, then a composite AFUDC rate is used to represent interest on all debt funds, shown as a reduction to interest charges, and on ROE funds, shown as other income. While cash is not immediately recognized from recording AFUDC, it is realized in future years through rate recovery resulting from the higher utility cost of service. Our composite AFUDC rate was 0.4% in 2015, and 0.3% in 2014 and 2013, respectively.

IMPAIRMENT OF LONG-LIVED ASSETS. We review the carrying value of long-lived assets whenever events or changes in circumstances indicate the carrying amount of the assets may not be recoverable. Factors that would necessitate an impairment assessment of long-lived assets include a significant adverse change in the extent or manner in which the asset is used, a significant adverse change in legal factors or business climate that could affect the value of the asset, or a significant decline in the observable market value or expected future cash flows of the asset, among others.

When such factors are present, we assess the recoverability by determining whether the carrying value of the asset will be recovered through expected future cash flows. An asset is determined to be impaired when the carrying value of the asset exceeds the expected undiscounted future cash flows from the use and eventual disposition of the asset. If an impairment is indicated, we record an impairment loss for the difference between the carrying value and the fair value of the long-lived assets. Fair value is estimated using appropriate valuation methodologies, which may include an estimate of discounted cash flows.

We determined there were no long-lived asset impairments in 2015; however our Gill Ranch Storage facility within our Gas Storage Segment was reviewed for impairment. The undiscounted cash flows are in excess of the carrying value of the asset and no impairment was indicated. The cash flows assume a recovery of storage pricing and the ability to contract with higher value customers. Accordingly, if storage pricing does not improve and/or new higher value customers are not obtained, future analysis may result in an impairment of these long-lived assets.

Cash and Cash Equivalents

For purposes of reporting cash flows, cash and cash equivalents include cash on hand plus highly liquid investment accounts with original maturity dates of three months or less. At December 31, 2015 and 2014, outstanding checks of approximately $2.5 million and $5.5 million, respectively, were included in accounts payable.

Revenue Recognition and Accrued Unbilled Revenue

Utility revenues, derived primarily from the sale and transportation of natural gas, are recognized upon delivery of the gas commodity or service to customers. Revenues include accruals for gas delivered but not yet billed to customers based on estimates of deliveries from meter reading dates to month end (accrued unbilled revenue). Accrued unbilled revenue is dependent upon a number of factors that require management's judgment, including total gas receipts and deliveries, customer use by billing cycle, and weather factors. Accrued unbilled revenue is reversed the following month when actual billings occur. Our accrued unbilled revenue at December 31, 2015 and 2014 was $58.0 million.

Non-utility revenues are derived primarily from the gas storage segment. At our Mist underground storage facility, revenues are primarily firm service revenues in the form of fixed monthly reservation charges. At our Gill Ranch facility, firm storage services resulting from short-term and long-term contracts are typically recognized in revenue ratably over the term of the contract regardless of the actual storage capacity utilized. In addition, we also have asset management service revenue from an independent energy marketing company that optimizes commodity, storage, and pipeline capacity release transactions. Under this agreement, guaranteed asset management revenue is recognized using a straight-line, pro-rata methodology over the term of each contract. Revenues earned above the guaranteed amount are recognized as they are earned.

Revenue Taxes

Revenue-based taxes are primarily franchise taxes, which are collected from customers and remitted to taxing authorities. Revenue taxes are included in operating revenues in the statement of comprehensive income. Revenue taxes were $18.0 million, $18.8 million, and $19.0 million for 2015, 2014, and 2013, respectively.

Accounts Receivable and Allowance for Uncollectible Accounts

Accounts receivable consist primarily of amounts due for natural gas sales and transportation services to utility customers, plus amounts due for gas storage services. We establish an allowance for uncollectible accounts (allowance) for trade receivables, including accrued unbilled revenue, based on the aging of receivables, collection experience of past due account balances including payment plans, and historical trends of write-offs as a percent of revenues. A specific allowance is established and recorded for large individual customer receivables when amounts are identified as unlikely to be partially or fully recovered. Inactive accounts are written-off against the allowance after they are

120 days past due or when deemed uncollectible. Differences between our estimated allowance and actual write-offs will occur based on a number of factors, including changes in economic conditions, customer creditworthiness, and natural gas prices. The allowance for uncollectible accounts is adjusted quarterly, as necessary, based on information currently available.

Inventories

Utility gas inventories, which consist of natural gas in storage for the utility, are stated at the lower of average cost or net realizable value. The regulatory treatment of utility gas inventories provides for cost recovery in customer rates. Utility gas inventories injected into storage are priced in inventory based on actual purchase costs. Utility gas inventories withdrawn from storage are charged to cost of gas during the current period at the weighted-average inventory cost.

Gas storage inventories, which primarily represent inventories at the Gill Ranch storage facility, mainly consist of natural gas received as fuel-in-kind from storage customers. Gas storage inventories are valued at the lower of average cost or net realizable value. Cushion gas is not included in our inventory balances, is recorded at original cost, and classified as a long-term plant asset.

Materials and supplies inventories consist of both utility and non-utility inventories and are stated at the lower of average cost or net realizable value.

Our utility and gas storage inventories totaled $59.3 million and $68.0 million at December 31, 2015 and 2014, respectively. At December 31, 2015 and 2014, our materials and supplies inventories totaled $11.6 million and $9.8 million, respectively.

Gas Reserves

Gas reserves are payments to acquire and produce natural gas reserves. Gas reserves are stated at cost, adjusted for regulatory amortization, with the associated deferred tax benefits recorded as liabilities on the balance sheet. The current portion is calculated based on expected gas deliveries within the next fiscal year. We recognize regulatory amortization of this asset on a volumetric basis calculated using the estimated gas reserves and the estimated therms extracted and sold each month. The amortization of gas reserves is recorded to cost of gas along with gas production revenues and production costs. See Note 11.

Derivatives

Derivatives are measured at fair value and recognized as either assets or liabilities on the balance sheet. Changes in the fair value of the derivatives are recognized currently in earnings unless specific regulatory or hedge accounting criteria are met. Accounting for derivatives and hedges provides an exception for contracts intended for normal purchases and normal sales for which physical delivery is probable. In addition, certain derivative contracts are approved by regulatory authorities for recovery or refund through customer rates. Accordingly, the changes in fair value of these approved contracts are deferred as regulatory assets or liabilities pursuant to regulatory accounting principles. Our financial derivatives generally qualify for deferral under regulatory accounting. Our index-priced physical derivative contracts also qualify for regulatory deferral accounting treatment.

Derivative contracts entered into for utility requirements after the annual PGA rate has been set and during the PGA year are subject to the PGA incentive sharing mechanism. In Oregon we participate in a PGA sharing mechanism under which we are required to select either an 80% or 90% deferral of higher or lower gas costs such that the impact on current earnings from the gas cost sharing is either 20% or 10% of gas cost differences compared to PGA prices, respectively. For the PGA year in Oregon beginning November 1, 2015, we selected the 80% deferral of gas cost differences, and for the PGA years in Oregon beginning November 1, 2014, and 2013, we selected a 90% deferral of gas cost differences. In Washington, 100% of the differences between the PGA prices and actual gas costs are deferred. See Note 13.

Our financial derivatives policy sets forth the guidelines for using selected derivative products to support prudent risk management strategies within designated parameters. Our objective for using derivatives is to decrease the volatility of gas prices, earnings, and cash flows without speculative risk. The use of derivatives is permitted only after the risk exposures have been identified, are determined to exceed acceptable tolerance levels, and are determined necessary to support normal business activities. We do not enter into derivative instruments for trading purposes.

Fair Value

In accordance with fair value accounting, we use the following fair value hierarchy for determining inputs for our debt, pension plan assets, and our derivative fair value measurements:

- Level 1: Valuation is based on quoted prices for identical instruments traded in active markets;
- Level 2: Valuation is based on quoted prices for similar instruments in active markets, quoted prices for identical or similar instruments in markets that are not active, and model-based valuation techniques for which all significant assumptions are observable in the market; and
- Level 3: Valuation is generated from model-based techniques that use significant assumptions not observable in the market. These unobservable assumptions reflect our own estimates of assumptions market participants would use in valuing the asset or liability.

When developing fair value measurements, it is our policy to use quoted market prices whenever available, or to maximize the use of observable inputs and minimize the use of unobservable inputs when quoted market prices are not available. Fair values are primarily developed using industry-standard models that consider various inputs including: (a) quoted future prices for commodities; (b) forward currency prices; (c) time value; (d) volatility factors; (e) current market and contractual prices for underlying instruments; (f) market interest rates and yield curves; (g) credit spreads; and (h) other relevant economic measures.

Income Taxes

We account for income taxes under the asset and liability method, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. Under this method, deferred tax assets and liabilities are determined on the basis of the differences between the financial statement and tax basis of assets and liabilities using enacted tax rates in effect for the year in which the differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the enactment date period unless a regulatory Order specifies deferral of the effect of the change in tax rates over a longer period of time.

Deferred income tax assets and liabilities are also recognized for temporary differences where the deferred income tax benefits or expenses have previously been flowed through in the ratemaking process of the regulated utility. Regulatory tax assets and liabilities are recorded on these deferred tax assets and liabilities to the extent the Company believes they will be recoverable from or refunded to customers in future rates. At December 31, 2015 and 2014, regulatory income tax assets of $47.4 million and $51.8 million, respectively, were recorded, a portion of which is recorded in current assets. These regulatory income tax assets primarily represent future rate recovery of deferred tax liabilities, resulting from differences in utility plant financial statement and tax bases and utility plant removal costs, which were previously flowed through for rate making purposes and to take into account the additional future taxes, which will be generated by that recovery. These deferred tax liabilities, and the associated regulatory income tax assets, are currently being recovered through customer rates.

Deferred investment tax credits on utility plant additions, which reduce income taxes payable, are deferred for financial statement purposes and amortized over the life of the related plant.

The Company recognizes interest and penalties related to unrecognized tax benefits, if any, within income tax expense and accrued interest and penalties within the related tax liability line in the consolidated balance sheets. No accrued interest or penalties for uncertain tax benefits have been recorded. See Note 9.

Environmental Contingencies

Loss contingencies are recorded as liabilities when it is probable a liability has been incurred and the amount of the loss is reasonably estimable in accordance with accounting standards for contingencies. Estimating probable losses requires an analysis of uncertainties that often depend upon judgments about potential actions by third parties. Accruals for loss contingencies are recorded based on an analysis of potential results.

With respect to environmental liabilities and related costs, we develop estimates based on a review of information available from numerous sources, including completed studies and site specific negotiations. It is our policy to accrue the full amount of such liability when information is sufficient to reasonably estimate the amount of probable liability. When information is not available to reasonably estimate the probable liability, or when only the range of probable liabilities can be estimated and no amount within the range is more likely than another, it is our policy to accrue at the low end of the range. Accordingly, due to numerous uncertainties surrounding the course of environmental remediation and the preliminary nature of several site investigations, in some cases, we may not be able to reasonably estimate the high end of the range of possible loss. In those cases we have disclosed the nature of the potential loss and the fact that the high end of the range cannot be reasonably estimated. See Note 15.

Subsequent Events

See Note 16 for information regarding the resolution of the environmental SRRM docket.

3. EARNINGS PER SHARE

Basic earnings per share are computed using net income and the weighted average number of common shares outstanding for each period presented. Diluted earnings per share are computed in the same manner, except it uses the weighted average number of common shares outstanding plus the effects of the assumed exercise of stock options and the payment of estimated stock awards from other stock-based compensation plans that are outstanding at the end of each period presented. Antidilutive stock awards are excluded from the calculation of diluted earnings per common share. Diluted earnings per share are calculated as follows:

In thousands, except per share data	2015	2014	2013
Net income	$ 53,703	$ 58,692	$ 60,538
Average common shares outstanding - basic	27,347	27,164	26,974
Additional shares for stock-based compensation plans (See Note 6)	70	59	53
Average common shares outstanding - diluted	27,417	27,223	27,027
Earnings per share of common stock - basic	$ 1.96	$ 2.16	$ 2.24
Earnings per share of common stock - diluted	$ 1.96	$ 2.16	$ 2.24
Additional information:			
Antidilutive shares	12	18	26

4. SEGMENT INFORMATION

We primarily operate in two reportable business segments: local gas distribution and gas storage. We also have other investments and business activities not specifically related to one of these two reporting segments, which are aggregated and reported as other. We refer to our local gas distribution business as the utility, and our gas storage segment and other as non-utility. Our utility segment also includes the utility portion of our Mist underground storage facility in Oregon and NWN Gas Reserves, which is a wholly-owned subsidiary of Energy Corp. Our gas storage segment includes NWN Gas Storage, which is a wholly-owned subsidiary of NWN Energy, Gill Ranch, which is a wholly-owned subsidiary of NWN Gas Storage, the non-utility portion of Mist, and all third-party asset management services. Other includes NNG Financial and NWN Energy's equity investment in TWH, which is pursuing development of a cross-Cascades transmission pipeline project.

Local Gas Distribution

Our local gas distribution segment is a regulated utility principally engaged in the purchase, sale, and delivery of natural gas and related services to customers in Oregon and southwest Washington. As a regulated utility, we are responsible for building and maintaining a safe and reliable pipeline distribution system, purchasing sufficient gas supplies from producers and marketers, contracting for firm and interruptible transportation of gas over interstate pipelines to bring gas from the supply basins into our service territory, and re-selling the gas to customers subject to rates, terms, and conditions approved by the OPUC or WUTC. Gas distribution also includes taking customer-owned gas and transporting it from interstate pipeline connections, or city gates, to the customers' end-use facilities for a fee, which is approved by the OPUC or WUTC. Approximately 89% of our customers are located in Oregon and 11% in Washington. On an annual basis, residential and commercial customers typically account for around 60% of our utility's total volumes delivered and 90% of our utility's margin. Industrial customers largely account for the remaining volumes and utility margin. A small amount of utility margin is also derived from miscellaneous services, gains or losses from an incentive gas cost sharing mechanism, and other service fees.

Industrial sectors we serve include: pulp, paper, and other forest products; the manufacture of electronic, electrochemical and electrometallurgical products; the processing of farm and food products; the production of various mineral products; metal fabrication and casting; the production of machine tools, machinery and textiles; the manufacture of asphalt, concrete and rubber; printing and publishing; nurseries; government and educational institutions; and electric generation. No individual customer or industry group accounts for over 10% of our utility revenues or utility margins.

Gas Storage

Our gas storage segment includes natural gas storage services provided to customers primarily from two underground natural gas storage facilities, our Gill Ranch gas storage facility, and the non-utility portion of our Mist gas storage facility. In addition to earning revenue from customer storage contracts, we also use an independent energy marketing company to provide asset management services for utility and non-utility capacity, the results of which are included in this business segment.

Mist Gas Storage Facility

Earnings from non-utility assets at our Mist facility in Oregon are primarily related to firm storage capacity revenues. Earnings for the Mist facility also include revenue, net of amounts shared with utility customers, from management of utility assets at Mist and upstream capacity when not needed to serve utility customers. We retain 80% of the pre-tax income from these services when the costs of the capacity have not been included in utility rates, or 33% of the pre-tax income when the costs have been included in utility rates. The remaining 20% and 67%, respectively, are recorded to a deferred regulatory account for crediting back to utility customers.

Gill Ranch Gas Storage Facility
Gill Ranch has a joint project agreement with Pacific Gas and Electric Company (PG&E) to own and operate the Gill Ranch underground natural gas storage facility near Fresno, California. Gill Ranch has a 75% undivided ownership interest in the facility and is also the operator of the facility, which offers storage services to the California market at market-based rates, subject to CPUC regulation including, but not limited to, service terms and conditions and tariff regulations. Although this is a jointly owned property, each owner is independently responsible for financing its share of the Gill Ranch natural gas storage facility. Revenues are primarily related to firm storage capacity as well as asset management revenues.

Other
We have non-utility investments and other business activities, which are aggregated and reported as other.

Other primarily consists of an equity method investment in TWH, which was formed to build and operate an interstate gas transmission pipeline in Oregon (TWP) and other pipeline assets in NNG Financial. For more information on TWP, see Note 12. Other also includes some corporate operating and non-operating revenues and expenses that cannot be allocated to utility operations.

NNG Financial's assets primarily consist of an active, wholly-owned subsidiary which owns a 10% interest in an 18-mile interstate natural gas pipeline. NNG Financial's total assets were $0.7 million and $0.8 million at December 31, 2015 and 2014, respectively.

Segment Information Summary
Inter-segment transactions were insignificant for the periods presented. The following table presents summary financial information concerning the reportable segments:

In thousands	Utility	Gas Storage	Other	Total
2015				
Operating revenues	$ 702,210	$ 21,356	$ 225	$ 723,791
Depreciation and amortization	74,410	6,513	—	80,923
Income from operations	119,215	5,032	1	124,248
Net income	53,391	174	138	53,703
Capital expenditures	115,272	3,048	—	118,320
Total assets at December 31, 2015	2,800,018	261,750	14,924	3,076,692
2014				
Operating revenues	$ 731,578	$ 22,235	$ 224	$ 754,037
Depreciation and amortization	72,660	6,533	—	79,193
Income from operations	138,711	3,987	267	142,965
Net income (loss)	58,587	(364)	469	58,692
Capital expenditures	117,322	2,770	—	120,092
Total assets at December 31, 2014	2,775,011	273,813	16,121	3,064,945
2013				
Operating revenues	$ 727,182	$ 31,112	$ 224	$ 758,518
Depreciation and amortization	69,420	6,485	—	75,905
Income from operations	128,066	14,669	11	142,746
Net income	54,920	5,569	49	60,538
Capital expenditures	137,466	1,458	—	138,924
Total assets at December 31, 2013	2,644,367	310,097	16,447	2,970,911

Utility Margin

Utility margin is a financial measure consisting of utility operating revenues, which are reduced by revenue taxes, the associated cost of gas, and environmental recovery revenues. The cost of gas purchased for utility customers is generally a pass-through cost in the amount of revenues billed to regulated utility customers. Environmental recovery revenues represent collections received from customers through our environmental recovery mechanism in Oregon. These collections are offset by the amortization of environmental liabilities, which is presented as environmental remediation expense in our operating expenses. By subtracting cost of gas and environmental remediation expense from utility operating revenues, utility margin provides a key metric used by our chief operating decision maker in assessing the performance of the utility segment. The gas storage segment and other emphasize growth in operating revenues as opposed to margin because they do not incur a product cost (i.e. cost of gas sold) like the utility and, therefore, use operating revenues and net income to assess performance.

The following table presents additional segment information concerning utility margin:

In thousands	2015	2014	2013
Utility margin calculation:			
Utility operating revenues [(1)]	$ 702,210	$ 731,578	$ 727,182
Less: Utility cost of gas	327,305	365,490	373,298
Environmental remediation expense	3,513	—	—
Utility margin	$ 371,392	$ 366,088	$ 353,884

(1) Utility operating revenues include environmental recovery revenues, which are collections received from customers through our environmental recovery mechanism in Oregon, offset by environmental remediation expense.

5. COMMON STOCK

Common Stock

As of December 31, 2015 and 2014, we had 100 million shares of common stock authorized. As of December 31, 2015, we had reserved 78,857 shares for issuance of common stock under the Employee Stock Purchase Plan (ESPP) and 297,879 shares under our Dividend Reinvestment and Direct Stock Purchase Plan (DRPP). At the Company's election, shares sold through our DRPP may be purchased in the open market or through original issuance of shares reserved for issuance under the DRPP. In July 2015 we moved DRPP to open market purchases.

The Restated Stock Option Plan (SOP) was terminated with respect to new grants in 2012; however, options granted before the Restated SOP was terminated will remain outstanding until the earlier of their expiration, forfeiture, or exercise. There were 352,688 options outstanding at December 31, 2015, which were granted prior to termination of the plan.

Stock Repurchase Program

We have a share repurchase program under which we may purchase our common shares on the open market or through privately negotiated transactions. We currently have Board authorization through May 2016 to repurchase up to an aggregate of the greater of 2.8 million shares or $100 million. No shares of common stock were repurchased pursuant to this program during the year ended December 31, 2015. Since the plan's inception in 2000, a total of 2.1 million shares have been repurchased at a total cost of $83.3 million.

Summary of Changes in Common Stock

The following table shows the changes in the number of shares of our common stock issued and outstanding:

In thousands	Shares
Balance, December 31, 2012	26,917
Sales to employees under ESPP	16
Stock-based compensation	42
Sales to shareholders under DRPP	100
Balance, December 31, 2013	27,075
Sales to employees under ESPP	24
Stock-based compensation	83
Sales to shareholders under DRPP	102
Balance, December 31, 2014	27,284
Sales to employees under ESPP	19
Stock-based compensation	78
Sales to shareholders under DRPP	46
Balance, December 31, 2015	27,427

6. STOCK-BASED COMPENSATION

Our stock-based compensation plans are designed to promote stock ownership in NW Natural by employees and officers. These compensation plans include a Long-Term Incentive Plan (LTIP), an ESPP, and a Restated SOP.

Long-Term Incentive Plan

The LTIP is intended to provide a flexible, competitive compensation program for eligible officers and key employees. Under the LTIP, shares of common stock are authorized for equity incentive grants in the form of stock, restricted stock, restricted stock units, stock options, or performance shares. An aggregate of 850,000 shares were authorized for issuance as of December 31, 2015. Shares awarded under the LTIP may be purchased on the open market or issued as original shares.

Of the 850,000 shares of common stock authorized for LTIP awards at December 31, 2015, there were 186,979 shares available for issuance under any type of award and 250,000 shares available for option grants. This assumes market, performance, and service based grants currently outstanding are awarded at the target level. There were no outstanding grants of restricted stock or stock options under the LTIP at December 31, 2015 or 2014. The LTIP stock awards are compensatory awards for which compensation expense is based on the fair value of stock awards, with expense being recognized over the performance and vesting period of the outstanding awards.

Performance Shares

Since the LTIP's inception in 2001, performance shares, which incorporate market, performance, and service-based factors, have been granted annually with three-year performance periods. The following table summarizes performance share expense information:

Dollars in thousands	Shares[1]	Expense During Award Year[2]	Total Expense for Award
Estimated award:			
2013-2015 grant[3]	8,465	$ 312	$ 1,240
Actual award:			
2012-2014 grant	8,621	582	1,821
2011-2013 grant	9,819	390	960

(1) In addition to common stock shares, a participant also receives a dividend equivalent cash payment equal to the number of shares of common stock received on the award payout multiplied by the aggregate cash dividends paid per share during the performance period.

(2) Amount represents the expense recognized in the third year of the vesting period noted above.

(3) This represents the estimated number of shares to be awarded as of December 31, 2015 as certain performance share measures had been achieved. Amounts are subject to change with final payout amounts authorized by the Board of Directors in February 2016.

The aggregate number of performance shares granted and outstanding at the target and maximum levels were as follows:

Dollars in thousands	Performance Share Awards Outstanding		2015	Cumulative Expense
Performance Period	Target	Maximum	Expense	December 31, 2015
2013-15	34,100	68,200	$ 312	$ 1,240
2014-16	39,725	79,450	632	1,250
2015-17	43,950	87,900	853	853
Total	117,775	235,550	$ 1,797	

For the 2013-2015 performance period, awards will be based on total shareholder return (TSR factor) relative to a peer group of gas distribution companies over the three-year performance period and on performance results achieved relative to specific core and non-core strategies (strategic factor). In addition to the TSR and strategic factors, the 2014-2016 and 2015-2017 performance period awards also included weighting for EPS and Return on Invested Capital (ROIC) factors. Compensation expense is recognized in accordance with accounting standards for stock-based compensation and calculated based on performance levels achieved and an estimated fair value using the Monte-Carlo method. The weighted-average grant date fair value of unvested shares at December 31, 2015 and 2014 was $49.09 and $42.06 per share, respectively. The weighted-average grant date fair value of shares vested during the year was $46.64 per share and for shares granted during the year was $51.78 per share. As of December 31, 2015, there was $2.3 million of unrecognized compensation expense related to the unvested portion of performance awards expected to be recognized through 2017.

Restricted Stock Units

In 2012, the Company began granting RSUs under the LTIP instead of stock options under the Restated SOP. Generally, the RSUs awarded are forfeitable and include a performance-based threshold as well as a vesting period of 4 years from the grant date. Upon vesting, the RSU holder is issued one share of common stock plus a cash payment equal to the total amount of dividends paid per share between the grant date and vesting date of that portion of the RSU. The fair value of an RSU is equal to the closing market price of the Company's common stock on the grant date. During 2015, total RSU expense was $1.3 million compared to $0.9 million in 2014. As of December 31, 2015, there was $2.6 million of unrecognized compensation cost from grants of RSUs, which is expected to be recognized over a period extending through 2019.

Information regarding the RSU activity is summarized as follows:

	Number of RSUs	Weighted - Average Price Per RSU
Nonvested, December 31, 2012	24,864	$ 47.57
Granted	25,748	45.38
Vested	(5,455)	48.01
Forfeited	(590)	46.58
Nonvested, December 31, 2013	44,567	46.27
Granted	38,765	42.19
Vested	(12,060)	46.52
Forfeited	(478)	45.47
Nonvested, December 31, 2014	70,794	44.00
Granted	37,264	46.29
Vested	(19,003)	44.81
Forfeited	(468)	44.99
Nonvested, December 31, 2015	88,587	44.78

Restated Stock Option Plan

The Restated SOP was terminated for new option grants in 2012; however, options granted before the plan terminated will remain outstanding until the earlier of their expiration, forfeiture, or exercise. Any new grants of stock options would be made under the LTIP.

Options under the Restated SOP were granted to officers and key employees designated by a committee of our Board of Directors. All options were granted at an option price equal to the closing market price on the date of grant and may be exercised for a period up to 10 years and seven days from the date of grant. Option holders may exchange shares they have owned for at least 6 months, valued at the current market price, to purchase shares at the option price.

Information regarding the Restated SOP activity is summarized as follows:

	Option Shares	Weighted - Average Price Per Share	Intrinsic Value *(In millions)*
Balance outstanding, December 31, 2012	529,925	$ 42.22	$ 1.3
Exercised	(33,800)	32.16	0.3
Forfeited	(3,975)	43.72	n/a
Balance outstanding, December 31, 2013	492,150	42.89	0.6
Exercised	(69,662)	39.82	0.5
Forfeited	(6,400)	43.59	n/a
Balance outstanding, December 31, 2014	416,088	43.40	2.7
Exercised	(62,900)	39.96	0.5
Forfeited	(500)	45.74	n/a
Balance outstanding and exercisable, December 31, 2015	352,688	44.00	2.3

During 2015, cash of $2.5 million was received for stock options exercised and $0.1 million related tax expense was recognized. During 2015, 2014, and 2013, the total fair value of options that vested was $0.2 million, $0.4 million and $0.5 million, respectively. The weighted average remaining life of options exercisable and outstanding at December 31, 2015 was 3.6 years.

Employee Stock Purchase Plan

The ESPP allows employees to purchase common stock at 85% of the closing price on the trading day immediately preceding the initial offering date, which is set annually. Each eligible employee may purchase up to $21,227 worth of stock through payroll deductions over a 12-month period, with shares issued at the end of the 12-month subscription period.

Stock-Based Compensation Expense

Stock-based compensation expense is recognized as operations and maintenance expense or is capitalized as part of construction overhead. The following table summarizes the financial statement impact of stock-based compensation under our LTIP, Restated SOP and ESPP:

In thousands	2015	2014	2013
Operations and maintenance expense, for stock-based compensation	$ 2,673	$ 2,309	$ 1,876
Income tax benefit	(1,012)	(861)	(765)
Net stock-based compensation effect on net income	$ 1,661	$ 1,448	$ 1,111
Amounts capitalized for stock-based compensation	$ 661	$ 597	$ 331

7. DEBT

Short-Term Debt

Our primary source of short-term funds is from the sale of commercial paper and bank loans. In addition to issuing commercial paper or bank loans to meet seasonal working capital requirements, short-term debt is used temporarily to fund capital requirements. Commercial paper and bank loans are periodically refinanced through the sale of long-term debt or equity securities. Our commercial paper program is supported by one or more committed credit facilities.

In the fourth quarter of 2015, we entered into a short-term credit facility loan totaling $50 million, as a short-term bridge through our peak heating season, which was repaid on February 4, 2016.

At December 31, 2015, total short-term debt outstanding was $270 million, which includes $220 million of commercial paper and a $50 million credit facility. At December 31, 2014 total short-term debt outstanding was $234.7 million, which was comprised entirely of commercial paper. The weighted average interest rate at December 31, 2015 and 2014 was 0.6% and 0.4%, respectively.

The carrying cost of our commercial paper approximates fair value using Level 2 inputs, due to the short-term nature of the notes. See Note 2 for a description of the fair value hierarchy. At December 31, 2015, our commercial paper had a maximum maturity of 77 days and an average maturity of 36 days.

We have a $300 million credit agreement, with a feature that allows us to request increases in the total commitment amount up to a maximum amount of $450 million. The maturity of the agreement is December 20, 2019. We have a letter of credit of $100 million. Any principal and unpaid interest owed on borrowings under the agreement is due and payable on or before the expiration date. There were no outstanding balances under the agreement and no letters of credit issued or outstanding at December 31, 2015 and 2014.

The credit agreement requires that we maintain credit ratings with Standard & Poor's (S&P) and Moody's Investors Service, Inc. (Moody's) and notify the lenders of any change in our senior unsecured debt ratings or senior secured debt ratings, as applicable, by such rating agencies. A change in our debt ratings is not an event of default, nor is the maintenance of a specific minimum level of debt rating a condition of drawing upon the credit facility. However, interest rates on any loans outstanding under the credit facility are tied to debt ratings, which would increase or decrease the cost of any loans under the credit facility when ratings are changed.

The credit agreement also requires us to maintain a consolidated indebtedness to total capitalization ratio of 70% or less. Failure to comply with this covenant would entitle the lenders to terminate their lending commitments and accelerate the maturity of all amounts outstanding. We were in compliance with this covenant at December 31, 2015 and 2014.

Long-Term Debt

The issuance of first mortgage bonds (FMBs), which includes our medium-term notes, under the Mortgage and Deed of Trust (Mortgage) is limited by eligible property, adjusted net earnings and other provisions of the Mortgage. The Mortgage constitutes a first mortgage lien on substantially all of our utility property.

Maturities and Outstanding Long-Term Debt

Retirement of long-term debt for each of the 12-month periods through December 31, 2020 and thereafter are as follows:

In thousands	
Year	
2016	$ 25,000
2017	40,000
2018	22,000
2019	30,000
2020	75,000
Thereafter	409,700

The following table presents our debt outstanding as of December 31:

In thousands	2015	2014
First Mortgage Bonds		
4.70 % Series B due 2015	—	40,000
5.15 % Series B due 2016	25,000	25,000
7.00 % Series B due 2017	40,000	40,000
6.60 % Series B due 2018	22,000	22,000
8.31 % Series B due 2019	10,000	10,000
7.63 % Series B due 2019	20,000	20,000
5.37 % Series B due 2020	75,000	75,000
9.05 % Series A due 2021	10,000	10,000
3.176 % Series B due 2021	50,000	50,000
3.542% Series B due 2023	50,000	50,000
5.62 % Series B due 2023	40,000	40,000
7.72 % Series B due 2025	20,000	20,000
6.52 % Series B due 2025	10,000	10,000
7.05 % Series B due 2026	20,000	20,000
7.00 % Series B due 2027	20,000	20,000
6.65 % Series B due 2027	19,700	19,700
6.65 % Series B due 2028	10,000	10,000
7.74 % Series B due 2030	20,000	20,000
7.85 % Series B due 2030	10,000	10,000
5.82 % Series B due 2032	30,000	30,000
5.66 % Series B due 2033	40,000	40,000
5.25 % Series B due 2035	10,000	10,000
4.00 % due 2042	50,000	50,000
	601,700	641,700
Subsidiary Senior Secured Debt		
Gill Ranch debt due 2016	—	20,000
	601,700	661,700
Less: Current maturities	25,000	40,000
Total long-term debt	$ 576,700	$ 621,700

Subsidiary Senior Secured Debt

On December 18, 2015, Gill Ranch repaid $20 million of fixed-rate senior secured debt outstanding with an interest rate of 7.75%, which included a make whole interest provision using available cash and cash flows from operations, including cash from intercompany receivables.

Retirements of Long-Term Debt

The utility redeemed $40 million of FMBs with a coupon rate of 4.70% in June 2015.

Fair Value of Long-Term Debt

Our outstanding debt does not trade in active markets. We estimate the fair value of our debt using utility companies with similar credit ratings, terms, and remaining maturities to our debt that actively trade in public markets. These valuations are based on Level 2 inputs as defined in the fair value hierarchy. See Note 2.

The following table provides an estimate of the fair value of our long-term debt, including current maturities of long-term debt, using market prices in effect on the valuation date:

	December 31,	
In thousands	2015	2014
Carrying amount	$ 601,700	$ 661,700
Estimated fair value	667,168	756,808

8. PENSION AND OTHER POSTRETIREMENT BENEFIT COSTS

We maintain a qualified non-contributory defined benefit pension plan, non-qualified supplemental pension plans for eligible executive officers and other key employees, and other postretirement employee benefit plans. We also have qualified defined contribution plans (Retirement K Savings Plan) for all eligible employees. The qualified defined benefit pension plan and Retirement K Savings Plan have plan assets, which are held in qualified trusts to fund retirement benefits. Effective January 1, 2007 and 2010, the qualified defined benefit retirement plans and postretirement benefits for non-union employees and union employees, respectively, were closed to new participants. These plans were not available to employees of our non-utility subsidiaries. Non-union and union employees hired or re-hired after December 31, 2006 and 2009, respectively, and employees of NW Natural subsidiaries are provided an enhanced Retirement K Savings Plan benefit.

The following table provides a reconciliation of the changes in benefit obligations and fair value of plan assets, as applicable, for the pension and other postretirement benefit plans, excluding the Retirement K Savings Plan, and a summary of the funded status and amounts recognized in the consolidated balance sheets as of December 31:

	Postretirement Benefit Plans			
	Pension Benefits		Other Benefits	
In thousands	2015	2014	2015	2014
Reconciliation of change in benefit obligation:				
Obligation at January 1	$ 487,278	$ 391,089	$ 32,072	$ 28,754
Service cost	8,267	7,213	527	483
Interest cost	18,360	18,198	1,179	1,252
Plan amendments[(1)]	—	—	(3,435)	—
Net actuarial (gain) loss	(32,354)	90,710	2,724	3,454
Benefits paid	(35,923)	(19,932)	(2,018)	(1,871)
Obligation at December 31	$ 445,628	$ 487,278	$ 31,049	$ 32,072
Reconciliation of change in plan assets:				
Fair value of plan assets at January 1	$ 279,164	$ 267,062	$ —	$ —
Actual return on plan assets	(9,599)	19,957	—	—
Employer contributions	15,696	12,077	2,018	1,871
Benefits paid	(35,923)	(19,932)	(2,018)	(1,871)
Fair value of plan assets at December 31	$ 249,338	$ 279,164	$ —	$ —
Funded status at December 31	$ (196,290)	$ (208,114)	$ (31,049)	$ (32,072)

(1) We amended our qualified defined benefit pension plan to establish a health retirement account (HRA) plan for participants. The HRA plan permits participants to obtain reimbursement of health care expenses on a nontaxable basis, and the amendment is effective April 1, 2016.

Our qualified defined benefit pension plan has an aggregate benefit obligation of $411.8 million and $451.2 million at December 31, 2015 and 2014, respectively, and fair values of plan assets of $249.3 million and $279.2 million, respectively.

The following table presents amounts realized through regulatory assets or in other comprehensive loss (income) for the years ended December 31:

	Regulatory Assets						Other Comprehensive Loss (Income)		
	Pension Benefits			Other Postretirement Benefits			Pension Benefits		
In thousands	2015	2014	2013	2015	2014	2013	2015	2014	2013
Net actuarial loss (gain)	$ 419	$ 83,027	$ (51,892)	$ 2,724	$ 3,454	$ (4,283)	$ (2,549)	$ 7,221	$ (3,302)
Amortization of:									
Prior service cost	(230)	(230)	(230)	(197)	(197)	(197)	—	7	7
Actuarial loss	(16,372)	(9,823)	(16,744)	(554)	(221)	(733)	(2,236)	(1,091)	(1,550)
Total	$ (16,183)	$ 72,974	$ (68,866)	$ 1,973	$ 3,036	$ (5,213)	$ (4,785)	$ 6,137	$ (4,845)

The following table presents amounts recognized in regulatory assets and accumulated other comprehensive loss (AOCL) at December 31:

	Regulatory Assets				AOCL	
	Pension Benefits		Other Postretirement Benefits		Pension Benefits	
In thousands	2015	2014	2015	2014	2015	2014
Prior service cost (credit)	$ 406	$ 637	$ (3,143)	$ 488	$ 1	$ 2
Net actuarial loss	176,894	192,846	10,067	7,898	11,870	16,604
Total	$ 177,300	$ 193,483	$ 6,924	$ 8,386	$ 11,871	$ 16,606

The following table presents amounts recognized in AOCL and the changes in AOCL related to our non-qualified employee benefit plans:

	Year Ended December 31,	
In thousands	2015	2014
Beginning balance	$ (10,076)	$ (6,358)
Amounts reclassified to AOCL	2,549	(7,221)
Amounts reclassified from AOCL:		
Amortization of prior service costs	—	(7)
Amortization of actuarial losses	2,236	1,091
Total reclassifications before tax	4,785	(6,137)
Tax (benefit) expense	(1,871)	2,419
Total reclassifications for the period	2,914	(3,718)
Ending balance	$ (7,162)	$ (10,076)

In 2016, an estimated $13.3 million will be amortized from regulatory assets to net periodic benefit costs, consisting of $13.5 million of actuarial losses, and $0.2 million of prior service credits. A total of $1.3 million will be amortized from AOCL to earnings related to actuarial losses in 2016.

Our assumed discount rate for the pension plan and other postretirement benefit plans was determined independently based on the Citigroup Above Median Curve (discount rate curve), which uses high quality corporate bonds rated AA- or higher by S&P or Aa3 or higher by Moody's. The discount rate curve was applied to match the estimated cash flows in each of our plans to reflect the timing and amount of expected future benefit payments for these plans.

Our assumed expected long-term rate of return on plan assets for the qualified pension plan was developed using a weighted average of the expected returns for the target asset portfolio. In developing the expected long-term rate of return assumption, consideration was given to the historical performance of each asset class in which the plans' assets are invested and the target asset allocation for plan assets.

Our investment strategy and policies for qualified pension plan assets held in the retirement trust fund were approved by our retirement committee, which is composed of senior management with the assistance of an outside investment consultant. The policies set forth the guidelines and objectives governing the investment of plan assets. Plan assets are invested for total return with appropriate consideration for liquidity, portfolio risk and return expectations. All investments are expected to satisfy the prudent investments rule under the Employee Retirement Income Security Act of 1974. The approved asset classes may include cash and short-term investments, fixed income, common stock and convertible securities, absolute and real return strategies, real estate, and investments in NW Natural securities. Plan assets may be invested in separately managed accounts or in commingled or mutual funds. Investment re-balancing takes place periodically as needed, or when significant cash flows occur, in order to maintain the allocation of assets within the stated target ranges. The retirement trust fund is not currently invested in NW Natural securities.

The following table presents the pension plan asset target allocation at December 31, 2015:

Asset Category	Target Allocation
U.S. large cap equity	18.0%
U.S. small/mid cap equity	10.0
Non-U.S. equity	18.0
Emerging markets equity	5.0
Long government/credit	20.0
High yield bonds	5.0
Emerging market debt	5.0
Real estate funds	7.0
Absolute return strategy	12.0

Our non-qualified supplemental defined benefit plan obligations were $33.8 million and $36.1 million at December 31, 2015 and 2014, respectively. These plans are not subject to regulatory deferral, and the changes in actuarial gains and losses, prior service costs and transition assets, or obligations are recognized in AOCL, net of tax until they are amortized as a component of net periodic benefit cost. These are unfunded, non-qualified plans with no plan assets; however, we indirectly fund a significant portion of our obligations with company- and trust-owned life insurance and other assets.

Our other postretirement benefit plans are unfunded plans but are subject to regulatory deferral. The actuarial gains and losses, prior service costs and transition assets or obligations for these plans are recognized as a regulatory asset.

Net periodic benefit costs consist of service costs, interest costs, the amortization of actuarial gains and losses and the expected returns on plan assets, which are based in part on a market-related valuation of assets. The market-related valuation reflects differences between expected returns and actual investment returns with the differences recognized over a three-year or less period from the year in which they occur, thereby reducing year-to-year net periodic benefit cost volatility.

The following table provides the components of net periodic benefit cost for the Company's pension and other postretirement benefit plans for the years ended December 31:

	Pension Benefits			Other Postretirement Benefits		
In thousands	2015	2014	2013	2015	2014	2013
Service cost	$ 8,267	$ 7,213	$ 8,698	$ 527	$ 483	$ 656
Interest cost	18,360	18,198	16,400	1,179	1,252	1,157
Expected return on plan assets	(20,676)	(19,496)	(18,721)	—	—	—
Amortization of prior service costs	231	223	223	197	197	197
Amortization of net actuarial loss	18,609	10,914	18,294	554	221	734
Net periodic benefit cost	24,791	17,052	24,894	2,457	2,153	2,744
Amount allocated to construction	(6,834)	(4,625)	(6,712)	(808)	(702)	(856)
Amount deferred to regulatory balancing account[1]	(8,241)	(4,578)	(9,115)	—	—	—
Net amount charged to expense	$ 9,716	$ 7,849	$ 9,067	$ 1,649	$ 1,451	$ 1,888

(1) The deferral of defined benefit pension expenses above or below the amount set in rates was approved by the OPUC, with recovery of these deferred amounts through the implementation of a balancing account. The balancing account includes the expectation of higher net periodic benefit costs than costs recovered in rates in the near-term with lower net periodic benefit costs than costs recovered in rates expected in future years. Deferred pension expense balances include accrued interest at the utility's authorized rate of return, with the equity portion of the interest recognized when amounts are collected in rates. See Note 2.

Net periodic benefit costs are reduced by amounts capitalized to utility plant based on approximately 25% to 35% payroll overhead charge. In addition, a certain amount of net periodic benefit costs are recorded to the regulatory balancing account for pensions. Net periodic pension cost less amounts charged to capital accounts and regulatory balancing accounts are expenses recognized in earnings.

The following table provides the assumptions used in measuring periodic benefit costs and benefit obligations for the years ended December 31:

	Pension Benefits			Other Postretirement Benefits		
	2015	2014	2013	2015	2014	2013
Assumptions for net periodic benefit cost:						
Weighted-average discount rate	3.82%	4.71%	3.84%	3.74%	4.45%	3.56%
Rate of increase in compensation	3.25-5.0%	3.25-5.0%	3.25-5.0%	n/a	n/a	n/a
Expected long-term rate of return	7.50%	7.50%	7.50%	n/a	n/a	n/a
Assumptions for year-end funded status:						
Weighted-average discount rate	4.21%	3.85%	4.73%	4.00%	3.74%	4.45%
Rate of increase in compensation	3.25-4.5%	3.25-5.0%	3.25-5.0%	n/a	n/a	n/a
Expected long-term rate of return	7.50%	7.50%	7.50%	n/a	n/a	n/a

The assumed annual increase in health care cost trend rates used in measuring other postretirement benefits as of December 31, 2015 was 7.50% for both pre- and post-65 populations. These trend rates apply to both medical and prescription drugs. Medical costs and prescription drugs are assumed to decrease gradually each year to a rate of 4.75% by 2024.

Assumed health care cost trend rates can have a significant effect on the amounts reported for the health care plans; however, other postretirement benefit plans have a cap on the amount of costs reimbursable from the Company. A one percentage point change in assumed health care cost trend rates would have the following effects:

In thousands	1% Increase	1% Decrease
Effect on net periodic postretirement health care benefit cost	$ 100	$ (74)
Effect on the accumulated postretirement benefit obligation	742	(665)

We review mortality assumptions annually and will update for material changes as necessary. In 2015, we adopted the Society of Actuaries Scale MP-2015, which projects a mortality detriment compared to the previous table used, thereby decreasing benefit plan liabilities.

The following table provides information regarding employer contributions and benefit payments for the qualified pension plan, non-qualified pension plans and other postretirement benefit plans for the years ended December 31, and estimated future contributions and payments:

In thousands	Pension Benefits	Other Benefits
Employer Contributions:		
2014	$ 12,077	$ 1,871
2015	15,696	2,018
2016 (estimated)	16,695	2,035
Benefit Payments:		
2013	18,855	1,895
2014	19,932	1,871
2015	35,923	2,018
Estimated Future Benefit Payments:		
2016	21,589	2,035
2017	22,028	2,060
2018	22,974	2,073
2019	23,950	2,132
2020	26,242	2,178
2021-2025	134,736	11,068

Employer Contributions to Company-Sponsored Defined Benefit Pension Plans

We make contributions to our qualified defined benefit pension plans based on actuarial assumptions and estimates, tax regulations and funding requirements under federal law. The Pension Protection Act of 2006 (the Act) established funding requirements for defined benefit plans. The Act establishes a 100% funding target over seven years for plan years beginning after December 31, 2008. In 2012 the Moving Ahead for Progress in the 21st Century Act (MAP-21) legislation changed several provisions affecting pension plans, including temporary funding relief and Pension Benefit Guaranty Corporation (PBGC) premium increases, which reduces the level of minimum required contributions in the near-term but generally increases contributions in the long-run and increases the operational costs of running a pension plan. In 2014, the Highway and Transportation Funding Act (HATFA) was signed and extends certain aspects of MAP-21 as well as modifies the phase-out periods for the limitations.

Our qualified defined benefit pension plan is currently underfunded by $162.5 million at December 31, 2015. Including the impacts of MAP-21 and HATFA, we made cash contributions totaling $14.1 million to our qualified defined benefit pension plan for 2015. During 2016, we expect to make contributions of approximately $14.5 million to this plan.

Multiemployer Pension Plan

In addition to the Company-sponsored defined benefit plans presented above, prior to 2014 we contributed to a multiemployer pension plan for our utility's union employees known as the Western States Office and Professional Employees International Union Pension Fund (Western States Plan). The plan's employer identification number is 94-6076144. Effective December 22, 2013, we withdrew from the plan, which was a noncash transaction. Vested participants will receive all benefits accrued through the date of withdrawal. As the plan was underfunded at the time of withdrawal, we were assessed a withdrawal liability of $8.3 million, plus interest, which requires NW Natural to pay $0.6 million each year to the plan for 20 years beginning in July 2014. The cost of the withdrawal liability was deferred to a regulatory account on the balance sheet.

We made payments of $0.6 million for 2015, and as of December 31, 2015 the liability balance was $7.8 million. For 2014 and 2013, contributions to the plan were $0.4 million and $0.5 million, respectively, which was approximately 4% to 5% of the total contributions to the plan by all employer participants in those years.

Defined Contribution Plan

The Retirement K Savings Plan is a qualified defined contribution plan under Internal Revenue Code Section 401(k). Employer contributions totaled $3.7 million, $3.4 million, and $2.2 million for 2015, 2014, and 2013, respectively. The Retirement K Savings Plan includes an Employee Stock Ownership Plan.

Deferred Compensation Plans

The supplemental deferred compensation plans for eligible officers and senior managers are non-qualified plans. These plans are designed to enhance the retirement savings of employees and to assist them in strengthening their financial security by providing an incentive to save and invest regularly.

Fair Value

Below is a description of the valuation methodologies used for assets measured at fair value. In cases where the pension plan is invested through a collective trust fund or mutual fund, our custodian uses the fund's market value. The custodian also provides the market values for investments directly owned.

U.S. LARGE CAP EQUITY and U.S. SMALL/MID CAP EQUITY. These are level 1 and 2 assets. The level 1 assets consist of directly held stocks and mutual funds with a readily determinable fair value, including a published net asset value (NAV). The level 2 assets consist of mutual funds where NAV is not published but the investment can be readily disposed of at NAV or market value. Directly held stocks are valued at the closing price reported in the active market on which the individual security is traded, and mutual funds are valued at NAV. This asset class includes investments primarily in U.S. common stocks.

NON-U.S. EQUITY. These are level 1 and 2 assets. The level 1 assets consist of directly held stocks, and the level 2 assets consist of a commingled trust where the NAV/unit price is not published but the investment can be readily disposed of at the NAV/unit price. Directly held stocks are valued at the closing price reported in the active market on which the individual security is traded, and the commingled trust is valued at the unit price of the trust. This asset class includes investments primarily in foreign equity common stocks.

EMERGING MARKETS EQUITY. This is a level 2 asset consisting of an open-end mutual fund where the NAV price is not published but the investment can be readily disposed of at the NAV. This asset class includes investments primarily in common stocks in emerging markets.

FIXED INCOME. This is a level 2 asset consisting of a mutual fund, valued at NAV, where NAV is not published, but the investment can be readily disposed of at the NAV. This asset class includes investments primarily in investment grade debt and fixed income securities.

LONG GOVERNMENT/CREDIT. These are level 1 and 2 assets. The level 1 assets consist of a fixed-income mutual fund with readily determinable fair value, including a published NAV. The level 2 assets consist of a commingled trust and directly held fixed-income securities whose values are determined by closing prices if available and by matrix prices for illiquid securities. This asset class includes long duration fixed income investments primarily in U.S. treasuries, U.S. government agencies, municipal securities, mortgage-backed securities, asset-backed securities, as well as U.S. and international investment-grade corporate bonds.

HIGH YIELD BONDS. This is a level 2 asset consisting of a limited partnership where valuation is not published but the investment can be readily disposed of at market value. This asset class includes investments primarily in high yield bonds.

EMERGING MARKET DEBT. This is a level 1 asset consisting of a mutual fund with a readily determinable fair value, including a published NAV. This asset class includes investments primarily in emerging market debt.

REAL ESTATE FUNDS. This is a level 1 asset consisting of a mutual fund with a readily determinable fair value, including a published NAV. This asset class includes investments primarily in real estate investment trust (REIT) equity securities globally.

ABSOLUTE RETURN STRATEGY. This is a level 2 asset consisting of a hedge fund of funds where the valuation is not published but the investment can be readily disposed of at unit price. The hedge fund of funds is valued at the weighted average value of investments in various hedge funds, which in turn are valued at the closing price of the underlying securities. This asset class primarily includes investments in common stocks and fixed income securities.

REAL RETURN STRATEGY. This is a Level 1 asset representing a mutual fund with a readily determinable fair value, including a published NAV. This asset class includes an investment in a broad range of assets primarily including fixed income, high-yield bonds and emerging market debt.

CASH AND CASH EQUIVALENTS. This is a Level 2 asset representing mutual funds without published NAV's but the investment can be readily disposed of at the NAV. The mutual funds are valued at the NAV of the shares held by the plan at the valuation date. This asset class includes money market mutual funds.

The preceding valuation methods may produce a fair value calculation that is not indicative of net realizable value or reflective of future fair values. Although we believe these valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different fair value measurement at the reporting date.

Investment securities are exposed to various financial risks including interest rate, market and credit risks. Due to the level of risk associated with certain investment securities, it is reasonably possible that changes in the values of our investment securities will occur in the near term and such changes could materially affect our investment account balances and the amounts reported as plan assets available for benefit payments.

The following table presents the fair value of plan assets, including outstanding receivables and liabilities, of the retirement trust fund:

In thousands	December 31, 2015			
Investments	Level 1	Level 2	Level 3	Total
U.S. large cap equity	$ 44,528	$ —	$ —	$ 44,528
U.S. small/mid cap equity	23,495	—	—	23,495
Non-U.S. equity	20,725	22,823	—	43,548
Emerging markets equity	—	11,120	—	11,120
Long government/credit	—	48,456	—	48,456
High yield bonds	—	12,298	—	12,298
Emerging market debt	7,746	—	—	7,746
Real estate funds	17,261	—	—	17,261
Absolute return strategy	—	36,758	—	36,758
Cash and cash equivalents	—	4,116	—	4,116
Total investments	$ 113,755	$ 135,571	$ —	$ 249,326

	December 31, 2014			
Investments	Level 1	Level 2	Level 3	Total
U.S. large cap equity	$ 39,405	$ 122	$ —	$ 39,527
U.S. small/mid cap equity	27,172	85	—	27,257
Non-U.S. equity	16,369	17,221	—	33,590
Emerging markets equity	—	7,145	—	7,145
Fixed income	—	598	—	598
Long government/credit	40,584	40,235	—	80,819
High yield bonds	—	13,087	—	13,087
Emerging market debt	9,133	—	—	9,133
Real estate funds	18,890	—	—	18,890
Absolute return strategy	—	37,065	—	37,065
Real return strategy	8,308	—	—	8,308
Cash and cash equivalents	—	1,720	—	1,720
Total investments	$ 159,861	$ 117,278	$ —	$ 277,139

	December 31,	
Receivables	2015	2014
Accrued interest and dividend income	$ 486	$ 510
Due from broker for securities sold	88	1,694
Total receivables	$ 574	$ 2,204
Liabilities		
Due to broker for securities purchased	$ 562	$ 179
Total investment in retirement trust	$ 249,338	$ 279,164

9. INCOME TAX

The following table provides a reconciliation between income taxes calculated at the statutory federal tax rate and the provision for income taxes reflected in the consolidated statements of comprehensive income for December 31:

Dollars in thousands	2015	2014	2013
Income taxes at federal statutory rate	$31,310	$35,117	$35,785
Increase (decrease):			
Current state income tax, net of federal tax benefit	4,195	4,666	4,674
Amortization of investment tax credits	(118)	(201)	(271)
Differences required to be flowed-through by regulatory commissions	2,357	2,357	2,357
Gains on company and trust-owned life insurance	(766)	(689)	(864)
Other, net	(1,225)	393	24
Total provision for income taxes	$35,753	$41,643	$41,705
Effective tax rate	40.0%	41.5%	40.8%

The decrease in the effective income tax rate for 2015 compared to 2014 was primarily due to the benefits of depletion deductions from gas reserves activity. The increase from 2014 compared to 2013 was primarily the result of a $0.6 million income tax charge in 2014 related to a higher statutory tax rate in Oregon, which required the revaluation of deferred tax balances.

The provision (benefit) for current and deferred income taxes consists of the following at December 31:

In thousands	2015	2014	2013
Current			
Federal	$ 10,558	$ 14,823	$ (62)
State	61	24	(11)
	10,619	14,847	(73)
Deferred			
Federal	18,729	18,635	35,109
State	6,405	8,161	6,669
	25,134	26,796	41,778
Total provision for income taxes	$ 35,753	$ 41,643	$ 41,705

The following table summarizes the total provision (benefit) for income taxes for the utility and non-utility business segments for December 31:

In thousands	2015	2014	2013
Utility:			
Current	$ 15,890	$ 24,317	$ (73)
Deferred	20,834	19,518	38,073
Deferred investment tax credits	(118)	(201)	(271)
	36,606	43,634	37,729
Non-utility business segments:			
Current	(5,271)	(9,470)	—
Deferred	4,418	7,479	3,976
	(853)	(1,991)	3,976
Total provision for income taxes	$ 35,753	$ 41,643	$ 41,705

The following table summarizes the tax effect of significant items comprising our deferred income tax accounts at December 31:

In thousands	2015	2014
Deferred tax liabilities:		
Plant and property	$ 408,342	$ 386,732
Regulatory income tax assets	47,427	51,805
Regulatory liabilities	46,400	55,776
Non-regulated deferred tax liabilities	49,683	48,683
Total	$ 551,852	$ 542,996
Deferred tax assets:		
Pension and postretirement obligations	$ 4,666	$ 6,537
Alternative minimum tax credit carryforward	16,699	16,788
Loss and credit carryforwards	514	12,657
Total	21,879	35,982
Deferred income tax liabilities, net	529,973	507,014
Deferred investment tax credits	48	166
Deferred income taxes and investment tax credits	$ 530,021	$ 507,180

Management assesses the available positive and negative evidence to estimate if sufficient taxable income will be generated to utilize the existing deferred tax assets. Based upon this assessment, we have determined we are more likely than not to realize all deferred tax assets recorded as of December 31, 2015.

The Company estimates it has Oregon net operating loss (NOL) carryforwards of $3.9 million at December 31, 2015. The NOL carryforwards will be carried forward to reduce our current tax liability in future years. We anticipate that we will be able to utilize the NOL carryforwards before they begin to expire in 2028. Alternative minimum tax (AMT) credits of $16.7 million, general business credits of $0.3 million, and charitable contribution carryforwards of $2.3 million are also available. The AMT credits do not expire, and we anticipate fully using the general business credits and charitable contribution carryforwards before they begin to expire in 2033 and 2016, respectively.

As a result of certain realization requirements prescribed in the accounting guidance for income taxes, the tax benefit of statutory depletion is recognized no earlier than the year in which the depletion is deductible on the Company's federal income tax return. Income tax expense was decreased by $0.9 million in 2015 as a result of realizing deferred depletion benefit from 2013 and 2014. This benefit is included in Other in the statutory rate reconciliation table.

Uncertain tax positions are accounted for in accordance with accounting standards that require management's assessment of the anticipated settlement outcome of material uncertain tax positions taken in a prior year, or planned to be taken in the current year. Until such positions are sustained, we would not recognize the uncertain tax benefits resulting from such positions. No reserves for uncertain tax positions existed as of December 31, 2015, 2014, or 2013.

The Company's examination by the Internal Revenue Service (IRS) for tax years 2009 through 2011 was completed during the first quarter of 2014. The examination did not result in a material change to the returns as originally filed or previously adjusted for net operating loss carrybacks. The IRS Compliance Assurance Process (CAP) examinations of the 2013 and 2014 tax years were completed in the first and fourth quarters of 2015, respectively. There were no material changes to these returns as filed. The 2015 year is currently under IRS CAP examination. The Company's 2016 CAP application has been accepted by the IRS. Under the CAP program the Company works with the IRS to identify and resolve material tax matters before the tax return is filed each year. As of December 31, 2015, tax year 2012 remains open for federal examination, and tax years 2012 through 2015 remain open for state examination.

10. PROPERTY, PLANT, AND EQUIPMENT

The following table sets forth the major classifications of our property, plant, and equipment and accumulated depreciation at December 31:

In thousands	2015	2014
Utility plant in service	$2,745,485	$2,661,097
Utility construction work in progress	39,288	24,886
Less: Accumulated depreciation	867,377	836,510
Utility plant, net	1,917,396	1,849,473
Non-utility plant in service	296,839	297,295
Non-utility construction work in progress	7,768	9,282
Less: Accumulated depreciation	39,340	34,457
Non-utility plant, net	265,267	272,120
Total property, plant, and equipment	$2,182,663	$2,121,593
Capital expenditures in accrued liabilities	$ 8,985	$ 8,757

The weighted average depreciation rate was 2.8% for utility assets and 2.2% for non-utility assets in 2015, 2014, and 2013.

Accumulated depreciation does not include the accumulated provision for asset removal costs of $327.0 million and $311.2 million at December 31, 2015 and 2014, respectively. These accrued asset removal costs are reflected on the balance sheet as regulatory liabilities. See Note 2. During 2014, we acquired $1.3 million of equipment under capital leases. In 2015, we did not acquire any equipment under capital leases.

11. GAS RESERVES

We have invested $188 million through our gas reserves program in the Jonah Field located in Wyoming as of December 31, 2015. Gas reserves are stated at cost, net of regulatory amortization, with the associated deferred tax benefits recorded as liabilities on the balance sheet. Our investment in gas reserves provides long-term price protection for utility customers and currently incorporates two agreements: the original agreement with Encana Oil & Gas (USA) Inc. under which we invested $178 million and the amended agreement with Jonah Energy LLC under which an additional $10 million was invested.

We entered into our original agreements with Encana in 2011 under which we hold working interests in certain sections of the Jonah Field. Gas produced in these sections is sold at prevailing market prices, and revenues from such sales, net of associated operating and production costs and amortization, are credited to the utility's cost of gas. The cost of gas, including a carrying cost for the rate base investment, is included in our annual Oregon PGA filing, which allows us to recover these costs through customer rates. Our net investment under the original agreement earns a rate of return.

In March 2014, we amended the original gas reserves agreement in order to facilitate Encana's proposed sale of its interest in the Jonah field to Jonah Energy. Under the amendment, we ended the drilling program with Encana, but increased our working interests in our assigned sections of the Jonah field. We also retained the right to invest in new wells with Jonah Energy. The amended agreements allow us to invest in additional wells on a well-by-well basis with drilling costs and resulting gas volumes shared at our amended proportionate working interest for each well in which we invest. We elected to participate in some of the additional wells drilled in 2014, and may have the opportunity to participate in more wells in the future.

In September 2015, the OPUC adopted an all-party settlement, under which volumes produced from the additional wells drilled in 2014 are included in our Oregon PGA beginning November 1, 2015 at a fixed rate of $0.4725 per therm, which approximates the 10-year hedge rate plus financing costs at the inception of the investment.

Gas reserves acted to hedge the cost of gas for approximately 11% and 10% of our utility's gas supplies for the years ended December 31, 2015 and 2014, respectively.

The following table outlines our net gas reserves investment at December 31:

In thousands	2015	2014
Gas reserves, current	$ 17,094	$ 20,020
Gas reserves, non-current	170,453	167,190
Less: Accumulated amortization	55,901	37,910
Total gas reserves[1]	131,646	149,300
Less: Deferred taxes on gas reserves	27,203	18,551
Net investment in gas reserves[1]	$ 104,443	$ 130,749

(1) Our investment in additional wells included in total gas reserves was $8.0 million ($4.3 million net of deferred taxes) and $9.2 million ($8.4 million net of deferred taxes) at December 31, 2015 and December 31, 2014, respectively.

Our investment is included on our balance sheet under gas reserves with our maximum loss exposure limited to our current investment balance.

12. INVESTMENTS

Investments include financial investments in life insurance policies, which are accounted for at cash surrender value, net of policy loans, and equity investments in certain partnerships and limited liability companies, which are accounted for under the equity method. The following table summarizes our other investments at December 31:

In thousands	2015	2014
Investments in life insurance policies	$ 52,308	$ 52,366
Investments in gas pipeline	13,866	13,962
Other	1,892	1,910
Total other investments	$ 68,066	$ 68,238

Investment in Life Insurance Policies

We have invested in key person life insurance contracts to provide an indirect funding vehicle for certain long-term employee and director benefit plan liabilities. The amount in the above table is reported at cash surrender value, net of policy loans.

Investments in Gas Pipeline

TWP, a wholly-owned subsidiary of TWH, is pursuing the development of a new gas transmission pipeline that would provide an interconnection with our utility distribution system. NWN Energy, a wholly-owned subsidiary of NW Natural owns 50% of TWH, and 50% is owned by TransCanada American Investments Ltd., an indirect wholly-owned subsidiary of TransCanada Corporation.

VIE Analysis
TWH is a VIE, with our investment in TWP reported under equity method accounting. We have determined we are not the primary beneficiary of TWH's activities as we only have a 50% share of the entity and there are no stipulations that allow us a disproportionate influence over it. Our investments in TWH and TWP are included in other investments on our balance sheet. If we do not develop this investment, then our maximum loss exposure related to TWH is limited to our equity investment balance, less our share of any cash or other assets available to us as a 50% owner. Our investment balance in TWH was $13.4 million at December 31, 2015 and 2014.

Impairment Analysis
Our investments in nonconsolidated entities accounted for under the equity method are reviewed for impairment at each reporting period and following updates to our corporate planning assumptions. If it is determined a loss in value is other than temporary, a charge is recognized for the difference between the investment's carrying value and its estimated fair value. Fair value is based on quoted market prices when available or on the present value of expected future cash flows. Differing assumptions could affect the timing and amount of a charge recorded in any period.

In 2011, TWP withdrew its original application with the FERC for a proposed natural gas pipeline in Oregon and informed FERC that it intended to re-file an application to reflect changes in the project scope aligning the project with the region's current and future gas infrastructure needs. TWP continues working with customers in the Pacific Northwest to further understand their gas transportation needs and determine the commercial support for a revised pipeline proposal. A new FERC certificate application is expected to be filed to reflect a revised scope based on these regional needs.

Our equity investment was not impaired at December 31, 2015 as the fair value of expected cash flows from planned development exceeded our remaining equity investment of $13.4 million at December 31, 2015. However, if we learn that the project is not viable or will not go forward, then we could be required to recognize a maximum charge of up to approximately $13.4 million based on the current amount of our equity investment, net of cash and working capital at TWP. We will continue to monitor and update our impairment analysis as required.

13. DERIVATIVE INSTRUMENTS

We enter into financial derivative contracts to hedge a portion of our utility's natural gas sales requirements. These contracts include swaps, options and combinations of option contracts. We primarily use these derivative financial instruments to manage commodity price variability. A small portion of our derivative hedging strategy involves foreign currency exchange contracts.

We enter into these financial derivatives, up to prescribed limits, primarily to hedge price variability related to our physical gas supply contracts as well as to hedge spot purchases of natural gas. The foreign currency forward contracts are used to hedge the fluctuation in foreign currency exchange rates for pipeline demand charges paid in Canadian dollars.

In the normal course of business, we also enter into indexed-price physical forward natural gas commodity purchase contracts and options to meet the requirements of utility customers. These contracts qualify for regulatory deferral accounting treatment.

We also enter into exchange contracts related to the third-party asset management of our gas portfolio, some of which are derivatives that do not qualify for hedge accounting or regulatory deferral, but are subject to our regulatory sharing agreement. These derivatives are recognized in operating revenues in our gas storage segment, net of amounts shared with utility customers.

Notional Amounts
The following table presents the absolute notional amounts related to open positions on our derivative instruments:

	At December 31,	
In thousands	2015	2014
Natural gas (in therms):		
Financial	346,875	287,475
Physical	404,645	420,980
Foreign exchange	$ 9,025	$ 12,230

Purchased Gas Adjustment (PGA)
Derivatives entered into by the utility for the procurement or hedging of natural gas for future gas years generally receive regulatory deferral accounting treatment. Derivative contracts entered into after the start of the PGA period are subject to our PGA incentive sharing mechanism in Oregon. In general, our commodity hedging for the current gas year is completed prior to the start of the upcoming gas year, and hedge prices are reflected in our weighted-average cost of gas in the PGA filing. As of November 1, 2015, we reached our target hedge percentage of approximately 75% for the 2015-16 gas year. These hedge prices were included in the PGA filings and qualified for regulatory deferral.

Unrealized and Realized Gain/Loss

The following table reflects the income statement presentation for the unrealized gains and losses from our derivative instruments:

	December 31, 2015		December 31, 2014	
In thousands	Natural gas commodity	Foreign exchange	Natural gas commodity	Foreign exchange
Expense to cost of gas	$ (22,600)	$ (419)	$ (32,784)	$ (382)
Operating revenues	226	—	—	—
Less:				
Amounts deferred to regulatory accounts on balance sheet	22,434	419	32,782	382
Total gain (loss) in pre-tax earnings	$ 60	$ —	$ (2)	$ —

UNREALIZED GAIN/LOSS. Outstanding derivative instruments related to regulated utility operations are deferred in accordance with regulatory accounting standards. The cost of foreign currency forward and natural gas derivative contracts are recognized immediately in the cost of gas; however, costs above or below the amount embedded in the current year PGA are subject to a regulatory deferral tariff and therefore, are recorded as a regulatory asset or liability.

REALIZED GAIN/LOSS. We realized net losses of $37.7 million and net gains of $10.5 million for the years ended December 31, 2015 and 2014, respectively, from the settlement of natural gas financial derivative contracts. Realized gains and losses are recorded in cost of gas, deferred through our regulatory accounts, and amortized through customer rates in the following year.

Credit Risk Management of Financial Derivatives Instruments

No collateral was posted with or by our counterparties as of December 31, 2015 or 2014. We attempt to minimize the potential exposure to collateral calls by counterparties to manage our liquidity risk. Counterparties generally allow a certain credit limit threshold before requiring us to post collateral against loss positions. Given our counterparty credit limits and portfolio diversification, we have not been subject to collateral calls in 2015 or 2014. Our collateral call exposure is set forth under credit support agreements, which generally contain credit limits. We could also be subject to collateral call exposure where we have agreed to provide adequate assurance, which is not specific as to the amount of credit limit allowed, but could potentially require additional collateral in the event of a material adverse change.

Based upon current commodity financial swap and option contracts outstanding, which reflect unrealized losses of $23.2 million at December 31, 2015, we have estimated the level of collateral demands, with and without potential adequate assurance calls, using current gas prices and various credit downgrade rating scenarios for NW Natural as follows:

		Credit Rating Downgrade Scenarios			
In thousands	(Current Ratings) A+/A3	BBB+/ Baa1	BBB/ Baa2	BBB-/ Baa3	Speculative
With Adequate Assurance Calls	$ —	$ —	$ —	$4,852	$ 21,185
Without Adequate Assurance Calls	—	—	—	4,164	15,497

Our financial derivative instruments are subject to master netting arrangements; however, they are presented on a gross basis in our statement of financial position. The Company and its counterparties have the ability to set-off their obligations to each other under specified circumstances. Such circumstances may include a defaulting party, a credit change due to a merger affecting either party, or any other termination event.

If netted by counterparty, our derivative position would result in an asset of $2.7 million and a liability of $25.5 million as of December 31, 2015. As of December 31, 2014, our derivative position would have resulted in an asset of $0.2 million and a liability of $33.4 million.

We are exposed to derivative credit and liquidity risk primarily through securing fixed price natural gas commodity swaps to hedge the risk of price increases for our natural gas purchases made on behalf of customers. We utilize master netting arrangements through International Swaps and Derivatives Association contracts to minimize this risk along with collateral support agreements with counterparties based on their credit ratings. In certain cases we require guarantees or letters of credit from counterparties to meet our minimum credit requirement standards.

Our financial derivatives policy requires counterparties to have a certain investment-grade credit rating at the time the derivative instrument is entered into, and the policy specifies limits on the contract amount and duration based on each counterparty's credit rating. We do not speculate with derivatives; instead, we use derivatives to hedge our exposure above risk tolerance limits. Any increase in market risk created by the use of derivatives should be offset by the exposures they modify.

We actively monitor our derivative credit exposure and place counterparties on hold for trading purposes or require other forms of credit assurance, such as letters of credit, cash collateral or guarantees as circumstances warrant. Our ongoing assessment of counterparty credit risk includes consideration of credit ratings, credit default swap spreads, bond market credit spreads, financial condition, government actions and market news. We use a Monte-Carlo simulation model to estimate the change in credit and liquidity risk from the volatility of natural gas prices. The results of the model are used to establish earnings-at-risk trading limits. Our credit risk for all outstanding financial derivatives at December 31, 2015 extends to March 2018.

We could become materially exposed to credit risk with one or more of our counterparties if natural gas prices experience a significant increase. If a counterparty were to become insolvent or fail to perform on its obligations, we could suffer a material loss; however, we would expect such a loss to be eligible for regulatory deferral and rate recovery, subject to a prudence review. All of our existing counterparties currently have investment-grade credit ratings.

Fair Value

In accordance with fair value accounting, we include non-performance risk in calculating fair value adjustments. This includes a credit risk adjustment based on the credit spreads of our counterparties when we are in an unrealized gain position, or on our own credit spread when we are in an unrealized loss position. The inputs in our valuation models include natural gas futures, volatility, credit default swap spreads and interest rates. Additionally, our assessment of non-performance risk is generally derived from the credit default swap market and from bond market credit spreads. The impact of the credit risk adjustments for all outstanding derivatives was immaterial to the fair value calculation at December 31, 2015. As of December 31, 2015 and 2014, the net fair value was a liability of $22.8 million and a liability of $33.2 million, respectively, using significant other observable, or level 2, inputs. No level 3 inputs were used in our derivative valuations, and there were no transfers between level 1 or level 2 during the years ended December 31, 2015 and 2014. See Note 2.

14. COMMITMENTS AND CONTINGENCIES

Leases

We lease land, buildings and equipment under agreements that expire in various years, including a 99-year land lease that extends through 2108. Rental expense under operating leases was $5.5 million, $5.9 million, and $5.1 million for the years ended December 31, 2015, 2014, and 2013, respectively. The following table reflects the future minimum lease payments due under non-cancelable leases at December 31, 2015. These commitments relate principally to the lease of our office headquarters, underground gas storage facilities and computer equipment.

In thousands	Operating leases	Capital leases	Minimum lease payments
2016	$ 5,417	$ 564	$ 5,981
2017	5,363	156	5,519
2018	5,348	3	5,351
2019	5,313	—	5,313
2020	2,765	—	2,765
Thereafter	30,475	—	30,475
Total	$ 54,681	$ 723	$ 55,404

Gas Purchase and Pipeline Capacity Purchase and Release Commitments

We have signed agreements providing for the reservation of firm pipeline capacity under which we are required to make fixed monthly payments for contracted capacity. The pricing component of the monthly payment is established, subject to change, by U.S. or Canadian regulatory bodies. In addition, we have entered into long-term sale agreements to release firm pipeline capacity. We also enter into short-term and long-term gas purchase agreements.

The aggregate amounts of these agreements were as follows at December 31, 2015:

In thousands	Gas Purchase Agreements	Pipeline Capacity Purchase Agreements	Pipeline Capacity Release Agreements
2016	$ 61,464	$ 79,487	$ 3,739
2017	—	79,370	—
2018	—	75,796	—
2019	—	75,683	—
2020	—	72,091	—
Thereafter	—	340,027	—
Total	61,464	722,454	3,739
Less: Amount representing interest	123	110,899	11
Total at present value	$ 61,341	$ 611,555	$ 3,728

Our total payments for fixed charges under capacity purchase agreements were $85.2 million for 2015, $94.3 million for 2014, and $98.2 million for 2013. Included in the amounts were reductions for capacity release sales of $4.4 million for 2015, $4.8 million for 2014, and $4.5 million for 2013. In addition, per-unit charges are required to be paid based on the actual quantities shipped under the agreements. In certain take-or-pay purchase commitments, annual deficiencies may be offset by prepayments subject to recovery over a longer term if future purchases exceed the minimum annual requirements.

Environmental Matters

Refer to Note 15 for a discussion of environmental commitments and contingencies.

15. ENVIRONMENTAL MATTERS

We own, or previously owned, properties that may require environmental remediation or action. We estimate the range of loss for environmental liabilities based on current remediation technology, enacted laws and regulations, industry experience gained at similar sites and an assessment of the probable level of involvement and financial condition of other potentially responsible parties (PRPs). When amounts are prudently expended related to site remediation, we have a recovery mechanism in place to collect 96.68% of remediation costs from Oregon customers, and we are allowed to defer environmental remediation costs allocated to customers in Washington annually until they are reviewed for prudence at a subsequent proceeding.

Our sites are subject to the remediation process prescribed by the Environmental Protection Agency (EPA) and the Department of Environmental Quality (ODEQ). The process begins with a remedial investigation (RI) to determine the nature and extent of contamination and then a risk assessment (RA) to establish whether the contamination at the site poses unacceptable risks to humans and the environment. Next, a feasibility study (FS) or an engineering evaluation/cost analysis (EE/CA) evaluates various remedial alternatives. It is at this point in the process when we are able to estimate a range of remediation costs and record a reasonable potential remediation liability, or make an adjustment to our existing liability. From this study, the regulatory agency selects a remedy and issues a Record of Decision (ROD).

After the ROD is issued, we negotiate a consent decree or consent judgment for designing and implementing the remedy. We have the ability to further refine estimates of remediation liabilities at that time.

Remediation may include treatment of contaminated media such as sediment, soil and groundwater, removal and disposal of media, or institutional controls such as legal restrictions on future property use. Following construction of the remedy, the EPA and ODEQ also have requirements for ongoing maintenance, monitoring and other post-remediation care that may continue for many years. Where appropriate and reasonably known, we will provide for these costs in our remediation liabilities described above.

Due to the numerous uncertainties surrounding the course of environmental remediation and the preliminary nature of several site investigations, in some cases, we may not be able to reasonably estimate the high end of the range of possible loss. In those cases, we have disclosed the nature of the possible loss and the fact that the high end of the range cannot be reasonably estimated where a range of potential loss is available. Unless there is an estimate within the range of possible losses that is more likely than other cost estimates within that range, we record the liability at the low end of this range. It is likely changes in these estimates and ranges will occur throughout the remediation process for each of these sites due to our continued evaluation and clarification concerning our responsibility, the complexity of environmental laws and regulations and the determination by regulators of remediation alternatives. In addition to remediation costs, we could also be subject to Natural Resource Damages (NRD) claims. We will assess the likelihood and probability of each claim and recognize a liability if deemed appropriate. As of December 31, 2015, we have not received any material NRD claims.

Environmental Sites

The following table summarizes information regarding liabilities related to environmental sites, which are recorded in other current liabilities and other noncurrent liabilities on the balance sheet at December 31:

	Current Liabilities		Non-Current Liabilities	
In thousands	2015	2014	2015	2014
Portland Harbor site:				
Gasco/Siltronic Sediments	$ 2,229	$ 1,767	$ 42,641	$ 38,019
Other Portland Harbor	1,972	1,934	5,073	4,338
Gasco Upland site	10,599	9,535	52,117	37,117
Siltronic Upland site	951	957	337	348
Central Service Center site	25	171	—	—
Front Street site	1,155	1,020	7,748	122
Oregon Steel Mills	—	—	179	179
Total	$ 16,931	$ 15,384	$ 108,095	$ 80,123

PORTLAND HARBOR SITE. The Portland Harbor is an EPA listed Superfund site that is approximately 10 miles long on the Willamette River and is adjacent to NW Natural's Gasco uplands and the Siltronic uplands sites. We are a PRP to the Superfund site and have joined with some of the other PRPs (the Lower Willamette Group or LWG) to develop a Portland Harbor Remedial Investigation/ Feasibility Study (RI/FS), which we submitted to the EPA in 2012. In August 2015, the EPA issued its own Draft Feasibility Study (Draft FS) for comment. The EPA Draft FS provides a new range of remedial costs for the entire Portland Harbor Superfund Site, which includes the Gasco/ Siltronic Sediment site, discussed below. The range of present value costs estimated by the EPA for various remedial alternatives for the entire Portland Harbor, as provided by the EPA's Draft FS, is $791 million to $2.45 billion. The range provided in the EPA's Draft FS is based on cost alternatives the EPA estimates to have an accuracy between -30% and +50% of actual costs, depending on the scope of work. While the EPA's Draft FS provides a higher range of costs than the LWG's submission in 2012, our potential liability is still a portion of the costs of the remedy the EPA will select for the entire Portland Harbor Superfund site. The cost of that remedy is expected to be allocated among more than 100 PRPs. We are participating in a non-binding allocation process in an effort to settle this potential liability. The new EPA Draft FS does not provide any additional clarification around allocation of costs.

We manage our liability related to the Superfund site as two distinct remediation projects, the Gasco/Siltronic Sediments and Other Portland Harbor projects.

Gasco/Siltronic Sediments. In 2009, NW Natural and Siltronic Corporation entered into a separate Administrative Order on Consent with the EPA to evaluate and design specific remedies for sediments adjacent to the Gasco uplands and Siltronic uplands sites. We submitted a draft EE/CA to the EPA in May 2012 to provide the estimated cost of potential remedial alternatives for this site. At this time, the estimated costs for the various sediment remedy alternatives in the draft EE/CA as well as costs for the additional studies and design work needed before the clean-up can occur, and for regulatory oversight throughout the clean-up range from $44.9 million to $350 million. We have recorded a liability of $44.9 million for the sediment clean-up, which reflects the low end of the range. At this time, we believe sediments at this site represent the largest portion of our liability related to the Portland Harbor site, discussed above.

Other Portland Harbor. NW Natural incurs costs related to its membership in the LWG. NW Natural also incurs costs related to natural resource damages from these sites. The Company and other parties have signed a cooperative agreement with the Portland Harbor Natural Resource Trustee council to participate in a phased natural resource damage assessment to estimate liabilities to support an early restoration-based settlement of natural resource damage claims. Natural resource damage claims may arise only after a remedy for clean-up has been settled. We have recorded a liability for these claims which is at the low end of the range of the potential liability; the high end of the range cannot be reasonably estimated at this time. This liability is not included in the range of costs provided in the draft FS for the Portland Harbor or noted above.

GASCO UPLANDS SITE. A predecessor of NW Natural owned a former gas manufacturing plant that was closed in 1958 (Gasco site) and is adjacent to the Portland Harbor site described above. The Gasco site has been under investigation by us for environmental contamination under the ODEQ Voluntary Clean-Up Program. It is not included in the range of remedial costs for the Portland Harbor site noted above. We manage the Gasco site in two parts, the uplands portion and the groundwater source control action.

We submitted a revised Remedial Investigation Report for the uplands to ODEQ in May 2007. In March 2015, ODEQ approved the RA NW Natural submitted in 2010, enabling us to begin work on the FS in 2016. We have recognized a liability for the remediation of the uplands portion of the site which is at the low end of the range of potential liability; the high end of the range cannot be reasonably estimated at this time.

In September 2013, we completed construction of a groundwater source control system, including a water treatment station, at the Gasco site. We are working with ODEQ on monitoring the effectiveness of the system and at this time it is unclear what, if any, additional actions ODEQ may require subsequent to the initial testing of the system or as part of the final remedy for the uplands portion of the Gasco site. We have estimated the cost associated with the ongoing operation of the system and have recognized a liability which is at the low end of the range of potential cost. We cannot estimate the high end of the range at this time due to the uncertainty associated with the duration of running the water treatment station, which is highly dependent on the remedy determined for both the upland portion as well as the final remedy for our Gasco sediment exposure.

Beginning November 1, 2013, capital asset costs of $19.0 million for the Gasco water treatment station were placed into rates with OPUC approval. The OPUC deemed these costs prudent. Beginning November 1, 2014, the OPUC approved the application of $2.5 million from insurance proceeds plus interest to reduce the total amount of Gasco capital costs to be recovered through rate base. A portion of these proceeds was noncash in 2014.

OTHER SITES. In addition to those sites above, we have environmental exposures at four other sites: Siltronic, Central Service Center, Front Street and Oregon Steel Mills. Due to the uncertainty of the design of remediation, regulation, timing of the remediation and in the case of the Oregon Steel Mills site, pending litigation, liabilities for each of these sites have been recognized at their respective low end of the range of potential liability; the high end of the range could not be reasonably estimated at this time.

Siltronic Upland. A portion of the Siltronic property adjacent to the Gasco site was formerly owned by Portland Gas and Coke, NW Natural's predecessor. We are currently conducting an investigation of manufactured gas plant wastes on the uplands at this site for the ODEQ.

Central Service Center site. We are currently performing an environmental investigation of the property under the ODEQ's Independent Cleanup Pathway. This site is on ODEQ's list of sites with confirmed releases of hazardous substances, and cleanup is necessary.

Front Street site. The Front Street site was the former location of a gas manufacturing plant we operated (the former Portland Gas Manufacturing site, or PGM). At ODEQ's request, we conducted a sediment and source control investigation and provided findings to ODEQ. In December 2015, we completed a FS on the former Portland Gas Manufacturing site. The FS provided a range of $7.6 million to $12.9 million for remedial costs. We have recorded a liability at the low end of the range of possible loss as no alternative in the range is considered more likely than another. Further, we have recognized an additional liability of $1.3 million for additional studies and design costs as well as regulatory oversight throughout the clean-up that will be required to assist in ODEQ making a remedy selection and completing a design.

Oregon Steel Mills site. Refer to the "Legal Proceedings," below.

<u>**Site Remediation and Recovery Mechanism**</u>

We have a SRRM through which we track and have the ability to recover past deferred and future prudently incurred environmental remediation costs allocable to Oregon, subject to an earnings test.

REGULATORY ACTIVITIES. An Order from the OPUC in February 2015 deemed certain environmental remediation expenses and associated carrying costs deferred through March 31, 2014 prudent. Our settlement with insurance carriers resulting in insurance proceeds received was also deemed prudent in the Order. Under the Order, we were required to forgo the collection of $15 million out of approximately $95 million of environmental remediation expenses and associated carrying costs we had deferred through 2012. The OPUC disallowed this amount from rate recovery based on its determination of how an earnings test should apply to amounts deferred from 2003 to 2012, with adjustments for other factors the OPUC deemed relevant. See Note 2 for information regarding the regulatory disallowance of past deferred costs under the Order received from the OPUC in February 2015.

We submitted the required compliance filing demonstrating the proposed implementation of the Order and SRRM in March 2015. In September 2015, as a result of discussions with the parties, we withdrew our original compliance filing and submitted a revised filing. The parties raised three issues with our proposed implementation of the Order. First, the parties asserted that interest on the $15 million charge should be separately disallowed, in addition to the specified $15 million. This interest would total approximately $2.8 million. Second, the parties raised issues with how the state allocation rates from the Order are applied to our environmental remediation sites. Third, a customer group disagreed with our treatment of expenses put into the SRRM amortization account.

In addition, we requested clarification from the OPUC regarding the amount of Oregon-allocated insurance proceeds to be held in a secured account. In September

2015, the OPUC resolved the issue by adopting an all-party settlement, which provided that we did not need to obtain a secured account. Instead, under the order, insurance proceeds used to offset future environmental expenses will accrue interest at a rate equal to the five-year treasury rate plus 100 basis points. Currently, Oregon-allocated insurance proceeds total approximately $93 million on a pre-tax basis.

On January 27, 2016, the OPUC issued an Order addressing the outstanding issues. See Note 16 regarding this subsequent event.

COLLECTIONS FROM CUSTOMERS. The SRRM provides us with the ability to recover past deferred and future prudently incurred environmental remediation costs allocable to Oregon, subject to an earnings test. The SRRM created three classes of deferred environmental remediation expense:

- Pre-review - This class of costs represents remediation spend that has not yet been deemed prudent by the OPUC. Carrying costs on these remediation expenses are recorded at our authorized cost of capital. The Company anticipates the prudence review for annual costs and approval of the earnings test prescribed by the OPUC to occur by the third quarter of the following year.
- Post-review - This class of costs represents remediation spend that has been deemed prudent and allowed after applying the earnings test, but is not yet included in amortization. We earn a carrying cost on these amounts at a rate equal to the five-year treasury rate plus 100 basis points.
- Amortization - This class of costs represents amounts included in current customer rates for collection and is generally calculated as one-fifth of the post-review deferred balance. We earn a carrying cost equal to the amortization rate determined annually by the OPUC, which approximates a short-term borrowing rate. We included $8.4 million of deferred remediation expense approved by the OPUC for collection during the 2015-2016 PGA year.

In addition to the collection amount noted above, the Order also provides for the annual collection of $5 million from Oregon customers through a tariff rider. As we collect amounts from customers, we recognize these collections as revenue and separately amortize our deferred regulatory asset balance through operating expense.

We received total environmental insurance proceeds of approximately $150 million as a result of settlements from our litigation that was dismissed in July 2014. Under the OPUC Order, one-third of the Oregon allocated proceeds were applied to costs deferred through 2012, and the remaining two-thirds will be applied to costs over the next 20 years. Annually, the Order provided for the application of $5 million of insurance proceeds against deferred remediation expense deemed prudent in the same annual period; annual amounts not utilized are carried forward to apply against future prudently incurred costs. We accrue interest on the insurance proceeds in the customer's favor at a rate equal to the five-year treasury rate plus 100 basis points. As of December 31, 2015, we have applied $53.2 million of insurance proceeds to prudently incurred remediation costs.

The following table presents information regarding the total amount of cash paid for environmental sites and the total regulatory asset deferred as of December 31:

In thousands	2015	2014
Cash paid	$ 124,325	$ 113,740
Total regulatory asset deferral(1)	85,854	58,859
Current regulatory assets(2)	9,270	—
Long-term regulatory assets	76,584	58,859

(1) Includes cash paid, remaining liability and interest, net of insurance reimbursement, amounts collected from customers, and amounts reclassified to utility plant for the water treatment station.

(2) Environmental costs relate to specific sites approved for regulatory deferral by the OPUC and WUTC. In Oregon, we earn a carrying charge on cash amounts paid, whereas amounts accrued but not yet paid do not earn a carrying charge until expended. We also accrue a carrying charge on insurance proceeds for amounts owed to customers. In Washington, a carrying charge related to deferred amounts will be determined in a future proceeding. Current environmental costs represent remediation costs management expects to collect from customers in the next 12 months. Amounts included in this estimate are still subject to a prudence and earnings test review by the OPUC and do not include the $5 million base rate rider. The Oregon amounts are recoverable through utility rates, subject to an earnings test.

ENVIRONMENTAL EARNINGS TEST. The Order directed us to implement an annual environmental earnings test for our prudently incurred remediation expense. Prudently incurred Oregon allocated annual remediation expense and interest in excess of the $5 million tariff rider and $5 million insurance proceeds application plus interest on the insurance proceeds are recoverable through the SRRM, to the extent the utility earns at or below our authorized Return On Equity (ROE). To the extent the utility earns more than its authorized ROE in a year, the utility is required to cover environmental expenses and interest on expenses greater than the $10 million (plus interest from insurance proceeds) with those earnings that exceed its authorized ROE.

Under the Order, the OPUC will revisit the deferral and amortization of future remediation expenses, as well as the treatment of remaining insurance proceeds three years from the original Order, or earlier if the Company gains greater certainty about its future remediation costs, to consider whether adjustments to the mechanism may be appropriate.

WASHINGTON DEFERRAL. In Washington, cost recovery and carrying charges on amounts deferred for costs associated with services provided to Washington customers will be determined in a future proceeding. Annually, we review all regulatory assets for recoverability or more often if circumstances warrant. If we should determine all or a portion of these regulatory assets no longer meet the criteria for continued application of regulatory accounting, then we would be required to write off the net unrecoverable balances against earnings in the period such a determination is made.

Legal Proceedings

NW Natural is subject to claims and litigation arising in the ordinary course of business. Although the final outcome of any of these legal proceedings cannot be predicted with certainty, including the matter described below, we do not expect that the ultimate disposition of any of these matters will have a material effect on our financial condition, results of operations or cash flows. See also Part I, Item 3, "Legal Proceedings."

OREGON STEEL MILLS SITE. In 2004, NW Natural was served with a third-party complaint by the Port of Portland (the Port) in a Multnomah County Circuit Court case, Oregon Steel Mills, Inc. v. The Port of Portland. The Port alleges that in the 1940s and 1950s petroleum wastes generated by our predecessor, Portland Gas & Coke Company, and 10 other third-party defendants, were disposed of in a waste oil disposal facility operated by the United States or Shaver Transportation Company on property then owned by the Port and now owned by Evraz Oregon Steel Mills. The complaint seeks contribution for unspecified past remedial action costs incurred by the Port regarding the former waste oil disposal facility as well as a declaratory judgment allocating liability for future remedial action costs. No date has been set for trial. Although the final outcome of this proceeding cannot be predicted with certainty, we do not expect the ultimate disposition of this matter will have a material effect on our financial condition, results of operations or cash flows. For additional information regarding other commitments and contingencies, see Note 14.

16. SUBSEQUENT EVENT

On January 27, 2016, the Public Utility Commission of Oregon (OPUC) issued an Order (2016 OPUC Order) deciding the three issues raised as a result of our required Site Remediation Recovery Mechanism (SRRM) compliance filing. The OPUC ordered: (1) the disallowance of $2.8 million of interest earned on the previously disallowed environmental expenditures amounts; (2) the allocation of 96.68% of environmental remediation costs for all environmental sites to Oregon; and (3) our treatment of $13.8 million of expenses put into the SRRM amortization account was correct and in compliance with prior OPUC orders.

Under a prior OPUC order we were required to forgo collection of $15 million out of approximately $95 million of environmental remediation expenses and associated carrying costs that the Company had deferred through 2012 based on the OPUC's determination of how an earnings test should apply to amounts deferred from 2003 to 2012, with adjustments for other factors the OPUC deemed relevant. We recognized interest of approximately $2.8 million on the $15 million charge after that time. This interest is shown as a regulatory asset in our financial statements, and the disallowance will result in a $2.8 million pre-tax charge in the first quarter of 2016. Consistent with our accounting policy for recognition of regulatory actions, we recognize the financial impacts in the period in which the order was received.

With respect to allocation of 96.68% of environmental remediation costs to Oregon, we currently have a deferral order in Washington to defer environmental costs and insurance proceeds; however, recovery of those costs has not yet been determined. We have deferred costs for certain sites that only served Oregon customers and have, as a result of this order, determined it appropriate to reserve against 3.32% of these deferrals until resolution of recovery in Washington can be determined. The total reserve amount is approximately $0.5 million and will be recorded in the first quarter of 2016 in accordance with the Company's policy. Consistent with our compliance filing filed in September 2015, the OPUC also ordered the same allocation factors should be applied to insurance proceeds, resulting in the application of 96.68% of the Company's recovered insurance proceeds to Oregon.

With respect to a third issue raised in the proceeding by a customer group that the Company should not be allowed to apply and recover portions of the SRRM amounts in 2013, 2014, and 2015 because that would constitute retroactive ratemaking, the OPUC ordered in the Company's favor. The OPUC ordered our treatment of $13.8 million of expenses put into the SRRM amortization account, to be amortized over five years, was correct and complied with the original order. For more information regarding our SRRM, see Note 15.

NORTHWEST NATURAL GAS COMPANY
QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

	Quarter ended			
In thousands, except share data	March 31	June 30	September 30	December 31
2015				
Operating revenues	$ 261,665	$ 138,280	$ 93,128	$ 230,718
Net income (loss)	28,486	2,197	(6,685)	29,705
Basic earnings (loss) per share[(1)]	1.04	0.08	(0.24)	1.08
Diluted earnings (loss) per share[(1)]	1.04	0.08	(0.24)	1.08
2014				
Operating revenues	$ 293,386	$ 133,169	$ 87,199	$ 240,283
Net income (loss)	37,884	1,071	(8,733)	28,470
Basic earnings (loss) per share[(1)]	1.40	0.04	(0.32)	1.05
Diluted earnings (loss) per share[(1)]	1.40	0.04	(0.32)	1.04

(1) Quarterly earnings (loss) per share are based upon the average number of common shares outstanding during each quarter. Variations in earnings between quarterly periods are due primarily to the seasonal nature of our business.

NORTHWEST NATURAL GAS COMPANY
SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

COLUMN A	COLUMN B	COLUMN C		COLUMN D	COLUMN E
		Additions		Deductions	
In thousands (year ended December 31)	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts	Net write-offs	Balance at end of period
2015					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$ 969	$ 760	$ —	$ 859	$ 870
2014					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$ 1,656	$ 599	$ —	$ 1,286	$ 969
2013					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$ 2,518	$ 199	$ —	$ 1,061	$ 1,656

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

Our management, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, has completed an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (the Exchange Act)). Based upon this evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of the period covered by this report, our disclosure controls and procedures were effective to ensure that information required to be disclosed by us and included in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission (SEC) rules and forms and that such information is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

(b) Changes in Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in the Exchange Act Rule 13a-15(f).

There have been no changes in our internal control over financial reporting that occurred during the quarter ended December 31, 2015 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. The statements contained in Exhibit 31.1 and Exhibit 31.2 should be considered in light of, and read together with, the information set forth in this Item 9(a).

ITEM 9B. OTHER INFORMATION

On February 24, 2016, the Organization and Executive Compensation Committee of the Company's Board of Directors approved, and the Company entered into, an amendment to the Long Term Incentive Award Agreement dated February 25, 2015 between the Company and Gregg S. Kantor, Chief Executive Officer of the Company. The amendment changes the minimum age to qualify for a pro-rated payment on retirement under the agreement from 60 to 55. The Company has previously announced that Mr. Kantor intends to retire as an employee of the Company on December 31, 2016, which is four months before his 60th birthday. Accordingly, the effect of the amendment will be to make Mr. Kantor eligible for a pro rata payout of his 2015-2017 performance share award upon his planned retirement. Assuming retirement on December 31, 2016, the pro-rated target number of shares of Company common stock under this award will be 9,500 shares, and the award can payout between 0% and 200% of target based on Company performance. The same change was made in the agreement for Mr. Kantor's 2016-2018 performance share award granted on February 24, 2016. Assuming retirement on December 31, 2016, the pro-rated target number of shares of Company common stock under this award will be 2,525 shares, and this award also can payout between 0% and 200% of target based on Company performance.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The "Information Concerning Nominees and Continuing Directors", "Corporate Governance", and "Section 16(a) Beneficial Ownership Reporting Compliance" contained in our definitive Proxy Statement for the May 26, 2016 Annual Meeting of Shareholders is hereby incorporated by reference.

Name	Age at Dec. 31, 2015	Positions held during last five years
Gregg S. Kantor	58	Chief Executive Officer (2009-); President (2009-2015); President and Chief Operating Officer (2007-2008); Executive Vice President (2006-2007); Senior Vice President, Public and Regulatory Affairs (2003-2006).
David H. Anderson	54	President and Chief Operating Officer (2016-); Executive Vice President and Chief Operating Officer (2014-2015); Executive Vice President Operations and Regulation (2013-2014); Senior Vice President and Chief Financial Officer (2004-2013).
Gregory C. Hazelton	51	Senior Vice President, Chief Financial Officer and Treasurer (2016-); Senior Vice President and Chief Financial Officer (2015-2016); Vice President of Finance, Treasurer and Controller, Hawaiian Electric Industries, Inc. (2013-2015); Managing Director, UBS Investment Bank, Global Power and Utilities Group; Associate Director, UBS Investment Bank, Global Power and Utilities Group (2011-2013); Executive Director, UBS Investment Bank, Global Power and Utilities Group (2008-2011).
Lea Anne Doolittle	60	Senior Vice President and Chief Administrative Officer (2013-); Senior Vice President (2008-2013); Vice President, Human Resources (2000-2007).
MardiLyn Saathoff	59	Senior Vice President, General Counsel and Regulation (2016-)Senior Vice President and General Counsel (2015-2016); Vice President Legal, Risk and Compliance (2013-2014); Deputy General Counsel (2010-2013); Chief Governance Officer and Corporate Secretary (2008-2014).
David R. Williams	62	Vice President, Utility Services (2007-); Director of Utility Operations, Districts and Managed Labor Relations (2004-2006).
Grant M. Yoshihara	60	Vice President, Utility Operations (2007-); Managing Director, Utility Services (2005-2006); Director, Utility Services (2004-2005).
C. Alex Miller	58	Vice President Regulation and Treasurer (2013-2016); Vice President, Finance and Regulation (2009-2013); Assistant Treasurer (2008-2013); General Manager of Rates and Regulatory Affairs (2002-2009).
Ngoni Murandu	41	Vice President and Chief Information Officer (2016-); Chief Information Officer (2014-2016); Vice President and Chief Information Officer, NANA Development Corporation (2010-2014).
Shawn M. Filippi	43	Vice President, Chief Compliance Officer and Corporate Secretary (2016-); Vice President and Corporate Secretary (2015-2016); Senior Legal Counsel (2011-2014); Assistant Corporate Secretary (2010-2014); Associate Legal Counsel (2005-2010).
Kimberly A. Heiting	46	Vice President, Communications and Chief Marketing Officer (2015-); Chief Marketing & Communications Officer (2013-2014); Chief Corporate Communications Officer (2011-2013); Communications Director (2005-2011).
Thomas J. Imeson	65	Vice President of Public Affairs (2014-); Director of Public Affairs, Port of Portland (2006-2014).
Margaret D. Kirkpatrick	60	Senior Vice President, Environmental Policy and Affairs (2015); Senior Vice President and General Counsel (2013-2014); Vice President and General Counsel (2005-2013).
Brody J. Wilson	36	Chief Accounting Officer, Controller and Assistant Treasurer (2016-); Controller (2013-2015); Acting Controller (2013); Accounting Director (2012-2013); Senior Manager, PriceWaterhouseCoopers LLP (2009-2012); Manager, PriceWaterhouseCoopers LLP (2007-2009).
David A. Weber	56	President and Chief Executive Officer, NW Natural Gas Storage, LLC and Gill Ranch Storage, LLC (2012-); Interim President and Chief Executive Officer, NW Natural Gas Storage LLC, and Gill Ranch Storage, LLC (2011-2012); Chief Operating Officer NW Natural Gas Storage, LLC and Gill Ranch Storage LLC (November 2010 - January 2011); Managing Director of Information Services and Chief Information Officer (2005 - 2011); Director of Information Services and Chief Information Officer (2001-2005).

Each executive officer serves successive annual terms; present terms end on May 26, 2016. There are no family relationships among our executive officers, directors or any person chosen to become one of our officers or directors.

NW Natural has adopted a Code of Ethics (Code) applicable to all employees and officers that is available on our website at www.nwnatural.com. We intend to disclose on our website at www.nwnatural.com any amendments to the Code or waivers of the Code for executive officers.

ITEM 11. EXECUTIVE COMPENSATION

The information concerning "Executive Compensation", "Report of the Organization and Executive Compensation Committee", and "Compensation Committee Interlocks and Insider Participation" contained in our definitive Proxy Statement for the May 26, 2016 Annual Meeting of Shareholders is hereby incorporated by reference. Information related to Executive Officers as of December 31, 2015 is reflected in Part III, Item 10, above.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The following table sets forth information regarding compensation plans under which equity securities of NW Natural are authorized for issuance as of December 31, 2015 (see Note 6 to the Consolidated Financial Statements):

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders:			
LTIP Performance Share Awards (Target Award)[1][2]	117,775	n/a	393,210
LTIP Restricted Stock Units (Target Award)[1][2]	88,587	n/a	393,210
LTIP Stock Options[3]	—	—	643,210
Restated Stock Option Plan	352,688	$ 44.00	—
Employee Stock Purchase Plan	20,726	40.51	58,131
Equity compensation plans not approved by security holders:			
Executive Deferred Compensation Plan (EDCP)[4]	1,251	n/a	n/a
Directors Deferred Compensation Plan (DDCP)[4]	48,370	n/a	n/a
Deferred Compensation Plan for Directors and Executives (DCP)[5]	149,485	n/a	n/a
Total	778,882		701,341

(1) Shares issued pursuant to Performance Share Awards and Restricted Stock Units under the LTIP do not include an exercise price, but are payable when the award criteria are satisfied. If the maximum awards were paid pursuant to the Performance Share Awards outstanding at December 31, 2015, the number of shares shown in column (a) would increase by 117,775 shares and the number of shares shown in column (c) would decrease by the same amount of shares.

(2) The aggregate 393,210 shares are available for future issuance under the LTIP as Restricted Stock Units, Performance Share Awards, or stock options. An additional 250,000 shares are available for LTIP Stock Option Issuance at December 31, 2015, but those additional shares are not available for issuance of LTIP Restricted Stock Units or Performance Share Awards.

(3) Shares balance includes 393,210 shares available for future issuance under the LTIP as Restricted Stock Units, Performance Share Awards, or stock options; and an additional 250,000 shares available for LTIP Stock Option Issuance only at December 31, 2015, and are not available for issuance of LTIP Restricted Stock Units or Performance Share Awards.

(4) Prior to January 1, 2005, deferred amounts were credited, at the participant's election, to either a "cash account" or a "stock account." If deferred amounts were credited to stock accounts, such accounts were credited with a number of shares of NW Natural common stock based on the purchase price of the common stock on the next purchase date under our Dividend Reinvestment and Direct Stock Purchase Plan, and such accounts were credited with additional shares based on the deemed reinvestment of dividends. Cash accounts are credited quarterly with interest at a rate equal to Moody's Average Corporate Bond Yield plus two percentage points, subject to a 6% minimum rate. At the election of the participant, deferred balances in the stock accounts are payable after termination of Board service or employment in a lump sum, in installments over a period not to exceed 10 years in the case of the DDCP, or 15 years in the case of the EDCP, or in a combination of lump sum and installments. Amounts credited to stock accounts are payable solely in shares of common stock and cash for fractional shares, and amounts in the above table represent the aggregate number of shares credited to participant's stock accounts. We have contributed common stock to the trustee of the Umbrella Trusts such that the Umbrella Trusts hold approximately the number of shares of common stock equal to the number of shares credited to all participants' stock accounts.

(5) Effective January 1, 2005, the EDCP and DDCP were closed to new participants and replaced with the DCP. The DCP continues the basic provisions of the EDCP and DDCP under which deferred amounts are credited to either a "cash account" or a "stock account." Stock accounts represent a right to receive shares of NW Natural common stock on a deferred basis, and such accounts are credited with additional shares based on the deemed reinvestment of dividends. Effective January 1, 2007, cash accounts are credited quarterly with interest at a rate equal to Moody's Average Corporate Bond Yield. Our obligation to pay deferred compensation in accordance with the terms of the DCP will generally become due on retirement, death, or other termination of service, and will be paid in a lump sum or in installments of five, 10, or 15 years as elected by the participant in accordance with the terms of the DCP. Amounts credited to stock accounts are payable solely in shares of common stock and cash for fractional shares, and amounts in the above table represent the aggregate number of shares credited to participant's stock accounts. We have contributed common stock to the trustee of the Supplemental Trust such that this trust holds approximately the number of common shares equal to the number of shares credited to all participants' stock accounts. The right of each participant in the DCP is that of a general, unsecured creditor of the Company.

The information captioned “Beneficial Ownership of Common Stock by Directors and Executive Officers” and "Security Ownership of Common Stock of Certain Beneficial Owners" contained in our definitive Proxy Statement for the May 26, 2016 Annual Meeting of Shareholders is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information captioned "Transactions with Related Persons" and "Corporate Governance" in the Company’s definitive Proxy Statement for the May 26, 2016 Annual Meeting of Shareholders is hereby incorporated by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information captioned "2015 and 2014 Audit Firm Fees" in the Company’s definitive Proxy Statement for the May 26, 2016 Annual Meeting of Shareholders is hereby incorporated by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as part of this report:

1. A list of all Financial Statements and Supplemental Schedules is incorporated by reference to Item 8.

2. List of Exhibits filed:

   Reference is made to the Exhibit Index commencing on page 92.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

NORTHWEST NATURAL GAS COMPANY

By: /s/ Gregg S. Kantor
Gregg S. Kantor
Chief Executive Officer
Date: February 26, 2016

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated.

Signature	Title	Date
/s/ Gregg S. Kantor Gregg S. Kantor Chief Executive Officer	Principal Executive Officer and Director	February 26, 2016
/s/ Gregory C. Hazelton Gregory C. Hazelton Senior Vice President, Chief Financial Officer and Treasurer	Principal Financial Officer	February 26, 2016
/s/ Brody J. Wilson Brody J. Wilson Chief Accounting Officer, Controller and Assistant Treasurer	Principal Accounting Officer	February 26, 2016
/s/ Timothy P. Boyle Timothy P. Boyle	Director	)))
/s/ Martha L. Byorum Martha L. Byorum	Director	)))
/s/ John D. Carter John D. Carter	Director	)))
/s/ Mark S. Dodson Mark S. Dodson	Director	)) February 26, 2016
/s/ C. Scott Gibson C. Scott Gibson	Director	)))
/s/ Tod R. Hamachek Tod R. Hamachek	Director	)))
/s/ Jane L. Peverett Jane L. Peverett	Director	)))
/s/ Kenneth Thrasher Kenneth Thrasher	Director	))
/s/ Malia H. Wasson Malia H. Wasson	Director	))

NORTHWEST NATURAL GAS COMPANY

Exhibit Index to Annual Report on Form 10-K
For the Fiscal Year Ended December 31, 2015

Exhibit Number	Document
*3a.	Restated Articles of Incorporation, as filed and effective May 31, 2006 and amended June 3, 2008 (incorporated herein by reference to Exhibit 3.1 to Form 10-Q for the quarter ended June 30, 2008, File No. 1-15973).
*3b.	Bylaws as amended May 22, 2014 (incorporated herein by reference to Exhibit 3.1 to Form 8-K dated May 22, 2014, File No. 1-15973).
*4a.	Copy of Mortgage and Deed of Trust, dated as of July 1, 1946, to Bankers Trust and R. G. Page (to whom Stanley Burg is now successor), Trustees (incorporated herein by reference to Exhibit 7(j) in File No. 2-6494); and copies of Supplemental Indentures Nos. 1 through 14 to the Mortgage and Deed of Trust, dated respectively, as of June 1, 1949, March 1, 1954, April 1, 1956, February 1, 1959, July 1, 1961, January 1, 1964, March 1, 1966, December 1, 1969, April 1, 1971, January 1, 1975, December 1, 1975, July 1, 1981, June 1, 1985 and November 1, 1985 (incorporated herein by reference to Exhibit 4(d) in File No. 33-1929); Supplemental Indenture No. 15 to the Mortgage and Deed of Trust, dated as of July 1, 1986 (filed as Exhibit 4(c) in File No. 33-24168); Supplemental Indentures Nos. 16, 17 and 18 to the Mortgage and Deed of Trust, dated, respectively, as of November 1, 1988, October 1, 1989 and July 1, 1990 (incorporated herein by reference to Exhibit 4(c) in File No. 33-40482); Supplemental Indenture No. 19 to the Mortgage and Deed of Trust, dated as of June 1, 1991 (incorporated herein by reference to Exhibit 4(c) in File No. 33-64014); and Supplemental Indenture No. 20 to the Mortgage and Deed of Trust, dated as of June 1, 1993 (incorporated herein by reference to Exhibit 4(c) in File No. 33-53795).
*4b.	Copy of Indenture, dated as of June 1, 1991, between the Company and Bankers Trust Company, Trustee, relating to the Company's Unsecured Medium-Term Notes (incorporated herein by reference to Exhibit 4(e) in File No. 33-64014).
*4c.	Officers' Certificate dated June 12, 1991 creating Series A of the Company's Unsecured Medium-Term Notes (incorporated herein by reference to Exhibit 4e. to Form 10-K for 1993, File No. 0-994).
*4d.	Officers' Certificate dated June 18, 1993 creating Series B of the Company's Unsecured Medium-Term Notes (incorporated herein by reference to Exhibit 4f. to Form 10-K for 1993, File No. 0-994).
*4e.	Officers' Certificate dated January 17, 2003 relating to Series B of the Company's Unsecured Medium-Term Notes and supplementing the Officers' Certificate dated June 18, 1993 (incorporated herein by reference to Exhibit 4f.(1) to Form 10-K for 2002, File No. 1-15973).
*4f.	Form of Secured Medium-Term Notes, Series B (incorporated herein by reference to Exhibit 4.1 to Form 8-K dated October 4, 2004, File No. 1-15973).
*4g.	Form of Unsecured Medium-Term Notes, Series B (incorporated herein by reference to Exhibit 4.2 to Form 8-K dated October 4, 2004, File No. 1-15973).
*4h.	Twenty-First Supplemental Indenture, providing, among other things, for First Mortgage Bonds, 4.00% Series Due 2042, dated as of October 15, 2012, by and between Northwest Natural Gas Company, Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company), and Stanley Burg (Successor to R.G. Page and J.C. Kennedy) (incorporated herein by reference to Exhibit 4.1 to Form 8-K dated October 26, 2012, File No.1-15973).
*4i.	Form of Credit Agreement among Northwest Natural Gas Company and the parties thereto, with JPMorgan Chase Bank, N.A. as administrative agent and U.S. Bank, N.A. and Wells Fargo Bank, N.A. as co-syndication agents, dated as of December 20, 2012 (incorporated herein by reference to Exhibit 4.1 to Form 8-K dated December 20, 2012, File No.1-15973).
*4j.	Form of Letter Agreement, between each of JPMorgan Chase Bank, N.A., Bank of America, N.A., Canadian Imperial Bank of Commerce, Royal Bank of Canada, TD Bank, N.A., Union Bank, N.A., US Bank, N.A., and Wells Fargo Bank, N.A., with JPMorgan Chase Bank, N.A. as Administrative Agent, extending the maturity date of the Credit Agreement between Northwest Natural Gas Company and each financial institution, effective as of December 20, 2013 (incorporated herein by reference to Exhibit 4k to Form 10-K for 2013, File No. 1-15973).

*4k. Form of Letter Agreement, between each of JPMorgan Chase Bank, N.A., Bank of America, N.A., Canadian Imperial Bank of Commerce, Royal Bank of Canada, TD Bank, N.A., Union Bank, N.A., US Bank, N.A., and Wells Fargo Bank, N.A., with JPMorgan Chase Bank, N.A. as Administrative Agent, extending the maturity date of the Credit Agreement between Northwest Natural Gas Company and each financial institution, effective as of December 20, 2014 (incorporated herein by reference to Exhibit 4m to Form 10-K for 2014, File No. 1-15973).

*4l. First Amendment to Credit Agreement, between the Company JPMorgan Chase Bank, N.A., Bank of America, N.A., Canadian Imperial Bank of Commerce, Royal Bank of Canada, TD Bank, N.A., Union Bank, N.A., US Bank, N.A., and Wells Fargo Bank, N.A., with JPMorgan Chase Bank, N.A. as Administrative Agent, dated as of December 20, 2014 (incorporated herein by reference to Exhibit 4n to Form 10-K for 2014, File No. 1-15973).

*10a Carry and Earning Agreement by and between Encana Oil & Gas (USA) Inc. and Northwest Natural Gas Company, dated effective as of May 1, 2011, and First Amendment to Carry and Earning Agreement dated March 11, 2011 (incorporated herein by reference to Exhibit 10.1 to Form 10-Q for the quarter ended March 31, 2011, File No. 1-15973). †

*10b Second Amendment to Carry and Earning Agreement by and between Encana Oil and Gas (USA) Inc. and NWN Gas Reserves, LLC., dated as of March 7, 2014 (incorporated herein by reference to Exhibit 10 to Form 10-Q for the quarter ended March 31, 2014, File No. 1-15973).

12 Statement re computation of ratios of earnings to fixed charges.

21 Subsidiaries of Northwest Natural Gas Company.

23 Consent of PricewaterhouseCoopers LLP.

31.1 Certification of Principal Executive Officer Pursuant to Rule 13a-14(a)/15-d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002.

31.2 Certification of Principal Financial Officer Pursuant to Rule 13a-14(a)/15-d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002.

32.1 Certification of Principal Executive Officer and Principal Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Executive Compensation Plans and Arrangements:

*10c. Executive Supplemental Retirement Income Plan 2010 Restatement (incorporated herein by reference to Exhibit 10b. to Form 10-K for 2009, File No. 1-15973).

*10d. Supplemental Executive Retirement Plan, 2011 Restatement (incorporated herein by reference to Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2011, File No. 1-15973).

*10e. Northwest Natural Gas Company Supplemental Trust, effective January 1, 2005, restated as of December 15, 2005 (incorporated herein by reference to Exhibit 10.7 to Form 8-K dated December 16, 2005, File No. 1-15973).

*10f. Northwest Natural Gas Company Umbrella Trust for Directors, effective January 1, 1991, restated as of December 15, 2005 (incorporated herein by reference to Exhibit 10.5 to Form 8-K dated December 16, 2005, File No. 1-15973).

*10g. Northwest Natural Gas Company Umbrella Trust for Executives, effective January 1, 1988, restated as of December 15, 2005 (incorporated herein by reference to Exhibit 10.6 to Form 8-K dated December 16, 2005, File No. 1-15973).

*10h. Restated Stock Option Plan, as amended effective December 14, 2006 (incorporated herein by reference to Exhibit 10c. to Form 10-K for 2006, File No. 1-15973).

*10i. Form of Restated Stock Option Plan Agreement (incorporated herein by reference to Exhibit 10h. to Form 10-K for 2009, File No. 1-15973).

*10j. Executive Deferred Compensation Plan, effective as of January 1, 1987, restated as of February 26, 2009 (incorporated herein by reference to Exhibit 10e. to Form 10-K for 2008, File No. 1-15973).

*10k. Directors Deferred Compensation Plan, effective June 1, 1981, restated as of February 26, 2009 (incorporated herein by reference to Exhibit 10f. to Form 10-K for 2008, File No. 1-15973).

*10l. Deferred Compensation Plan for Directors and Executives effective January 1, 2005, restated as of September 24, 2015 (incorporated herein by reference to Exhibit 10a to Form 10-Q for the quarter ended September 30, 2015).

*10m. Form of Indemnity Agreement as entered into between the Company and each director and certain executive officers (incorporated herein by reference to Exhibit 10l. to Form 10-K for 2009, File No. 1-15973).

*10n. Form of Indemnity Agreement as entered into between the Company and certain executive officers (incorporated herein by reference to Exhibit 10l.(1) to Form 10-K for 2009, File No. 1-15973).

*10o. Non-Employee Directors Stock Compensation Plan, as amended effective December 15, 2005 (incorporated herein by reference to Exhibit 10.2 to Form 8-K dated December 16, 2005, File No. 1-15973).

10p. Executive Annual Incentive Plan, effective February 23, 2012, as amended effective January 1, 2016.

*10q. Form of Change in Control Severance Agreement between the Company and each executive officer (incorporated herein by reference to Exhibit 10o. to Form 10-K for 2008, File No. 1-15973).

*10r. Northwest Natural Gas Company Long-Term Incentive Plan, as amended and restated effective May 24, 2012 (incorporated herein by reference to Exhibit 10r to Form 10-K for 2012, File No. 1-15973).

*10s. Severance Agreement between Northwest Natural Gas Company and an executive officer, dated as of June 30, 2015 (incorporated herein by reference to Exhibit 10.1 to Form 8-K dated June 24, 2015).

*10t. Form of Long-Term Incentive Award Agreement under the Long Term Incentive Plan (2013-2015) (incorporated herein by reference to Exhibit 10v. to Form 10K for 2012, File No. 1-15973).

*10u. Form of Long-Term Incentive Award Agreement under the Long Term Incentive Plan (2014-2016) (incorporated herein by reference to Exhibit 10v. to Form 10-K for 2013, File No. 1-15973).

*10v. Form of Long-Term Incentive Award Agreement under the Long Term Incentive Plan (2015-2017) (incorporated by reference to Exhibit 10w to Form 10-K for 2014, File No. 1-15973).

10w. Form of Long-Term Incentive Award Agreement under the Long Term Incentive Plan (2016-2018).

10x. Form of Long-Term Incentive Award Agreement under the Long Term Incentive Plan between the Company and an Executive Officer (2016-2018).

10y. Agreement to Amend the Long-Term Incentive Award Agreement, under the Long-Term Incentive Plan dated February 25, 2016 by and between the Company and an executive officer.

*10z. Form of Consent dated December 14, 2006 entered into by each executive officer with respect to amendments to the Executive Supplemental Retirement Income Plan, the Supplemental Executive Retirement Plan and certain change in control severance agreements (incorporated herein by reference to Exhibit 10.1 to Form 8-K dated December 19, 2006, File No. 1-15973).

*10aa. Consent to Amendment of Deferred Compensation Plan for Directors and Executives, dated February 28, 2008 entered into by each executive officer (incorporated herein by reference to Exhibit 10bb to Form 10-K for 2007, File No. 1-15973).

10bb. Form of Restricted Stock Unit Award Agreement under Long-Term Incentive Plan (2016).

*10cc. Form of Restricted Stock Unit Award Agreement under the Long-Term Incentive Plan (2013) (incorporated herein by reference to Exhibit 10aa. to Form 10-K for 2012, File No. 1-15978).

*10dd. Form of Restricted Stock Unit Award Agreement under the Long-Term Incentive Plan (2012) (incorporated herein by reference to Exhibit 10.1 to Form 8-K dated December 20, 2011, File No. 1-15973).

*10ee. Form of Special Restricted Stock Unit Award Agreement under the Long-Term Incentive Plan between the Company and an executive officer (incorporated herein by reference to Exhibit 10cc. to Form 10-Q for the period ending September 30, 2013, File No. 1-15973).

*10ff. Form of Special Restricted Stock Unit Award Agreement under the Long-Term Incentive Plan between the Company and an executive officer. (incorporated herein by reference to Form 10-Q for the quarter ended March 31, 2014, File No. 1-15973).

*10gg. Form of Special Retention Restricted Stock Unit Award Agreement between the Company and an executive officer, dated as of June 30, 2015 (incorporated herein by reference to Exhibit 10.2 to Form 8-K dated June 24, 2015).

*10hh. Hire-On Bonus Agreement between the Company and an executive officer, dated as of June 30, 2015 (incorporated herein by reference to Exhibit 10.3 to Form 8-K dated June 24, 2015).

10ii. Annual Incentive Plan for NW Natural Gas Storage, LLC, as amended effective January 1, 2016.

10jj. Long-Term Incentive Plan for NW Natural Gas Storage, LLC, as amended effective January 1, 2016.

101. The following materials from Northwest Natural Gas Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2015, formatted in Extensible Business Reporting Language (XBRL):
(i) Consolidated Statements of Income;
(ii) Consolidated Balance Sheets;
(iii) Consolidated Statements of Cash Flows; and
(iv) Related notes.

*Incorporated herein by reference as indicated

† Certain portions of the exhibit have been omitted based upon a request for confidential treatment filed by us with the Securities and Exchange Commission. The omitted portions of the exhibit have been separately filed by us with the Securities and Exchange Commission.

EXHIBIT 12

NORTHWEST NATURAL GAS COMPANY

Ratios of Earnings to Fixed Charges

(Unaudited)

In thousands, except share data	Year Ended December 31, 2015	2014	2013	2012	2011
Fixed Charges, as defined:					
Interest on Long-Term Debt	$ 37,918	$ 40,066	$ 40,825	$ 39,175	$ 37,515
Other Interest	3,173	2,718	2,709	2,314	2,976
Amortization of Debt Discount and Expense	1,760	1,963	1,877	1,848	1,729
Interest Portion of Rentals	1,976	2,302	1,910	1,864	2,213
Total Fixed Charges, as defined	44,827	47,049	47,321	45,201	44,433
Earnings, as defined:					
Net Income	53,703	58,692	60,538	58,779	63,044
Taxes on Income	35,753	41,643	41,705	43,403	42,825
Fixed Charges, as above	44,827	47,049	47,321	45,201	44,433
Total Earnings, as defined	$ 134,283	$ 147,384	$ 149,564	$ 147,383	$ 150,302
Ratios of Earnings to Fixed Charges	3.00	3.13	3.16	3.26	3.38

EXHIBIT 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-8 (Nos. 333-70218, 333-100885, 333-120955, 333-134973, 333-139819, 333-180350 and 333-187005) and in the Registration Statement on Form S-3 (No. 333-192641) of Northwest Natural Gas Company of our report dated February 26, 2016 relating to the consolidated financial statements, financial statement schedule and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Portland, Oregon
February 26, 2016

EXHIBIT 31.1

CERTIFICATION

I, Gregg S. Kantor, certify that:

1. I have reviewed this annual report on Form 10-K of Northwest Natural Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: February 26, 2016

/s/ Gregg S. Kantor
Gregg S. Kantor
Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, Gregory C. Hazelton, certify that:

1. I have reviewed this annual report on Form 10-K for Northwest Natural Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: February 26, 2016

/s/ Gregory C. Hazelton
Gregory C. Hazelton
Senior Vice President, Chief Financial Officer, and Treasurer

EXHIBIT 32.1

NORTHWEST NATURAL GAS COMPANY

Certificate Pursuant to Section 906
of Sarbanes – Oxley Act of 2002

Each of the undersigned, GREGG S. KANTOR, Chief Executive Officer, and GREGORY C. HAZELTON, the Senior Vice President, Chief Financial Officer, and Treasurer of NORTHWEST NATURAL GAS COMPANY (the Company), DOES HEREBY CERTIFY that:

1. The Company's Annual Report on Form 10-K for the year ended December 31, 2015 (the Report) fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. Information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

IN WITNESS WHEREOF, each of the undersigned has caused this instrument to be executed this 26th day of February 2016.

/s/ Gregg S. Kantor
Gregg S. Kantor
Chief Executive Officer

/s/ Gregory C. Hazelton
Gregory C. Hazelton
Senior Vice President,
Chief Financial Officer, and
Treasurer

A signed original of this written statement required by Section 906 of the Sarbanes-Oxley Act of 2002 has been provided to Northwest Natural Gas Company and will be retained by Northwest Natural Gas Company and furnished to the Securities and Exchange Commission or its staff upon request.

INVESTOR AND SHAREHOLDER INFORMATION

Nikki Sparley
Director, Investor Relations
Toll free (800) 422-4012, Ext. 2530
Direct (503) 721-2530
nikki.sparley@nwnatural.com

Chu Lee
Manager, Shareholder Services
Toll free (800) 422-4012, Ext. 2402
Direct (503) 220-2402
chu.lee@nwnatural.com

Stock transfer agent and registrar

For common stock:
American Stock Transfer & Trust Company
6201 15th Avenue
Brooklyn, NY 11219
(888) 777-0321
web: amstock.com
email: info@amstock.com

Trustee and bond paying agent

For bond issues:
Deutsche Bank Trust Company Americas
60 Wall Street
New York, NY 10005
(800) 735-7777

COMMUNITY & SUSTAINABILITY REPORT

Learn more about NW Natural's community involvement and philanthropic contributions, environmental stewardship, employee safety efforts and other company initiatives.

View the Community & Sustainability Annual Report at nwnatural.com/aboutnwnatural/community.

LOW-INCOME PROGRAMS

NW Natural helps low-income customers manage their bills through a variety of programs. Shareholders and customers support the Gas Assistance Program (GAP), which supplements the federal and state assistance programs. In addition, the Oregon Low-Income Gas Assistance Program (OLGA) uses public purpose fees to help low-income customers pay their utility bills. The Oregon Low-Income Energy Efficiency Program (OLIEE), also paid for by public purpose charges, helps customers in need acquire high-efficiency equipment and weatherization.

View the Low-Income Programs at nwnatural.com/residential.

ENERGY-EFFICIENCY PROGRAMS

NW Natural partners with Energy Trust of Oregon to offer our Oregon and Washington customers energy-efficiency programs and services. Learn more about the results of these programs and the benefits to our customers.

View the Energy Trust of Oregon Annual Report at nwnatural.com/residential.

NW Natural®

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