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, 2013, (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:
Annual Report, for the year ending December 31, 2013, 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

May 1, 2014

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
3930 Fairview Industrial Drive SE
Post Office Box 1088
Salem, Oregon 97308-1088

Attn: Filing Center

Re: **RG 37 – Annual Report for the year ending December 31, 2013 (FERC Form 2)**

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, 2013. 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

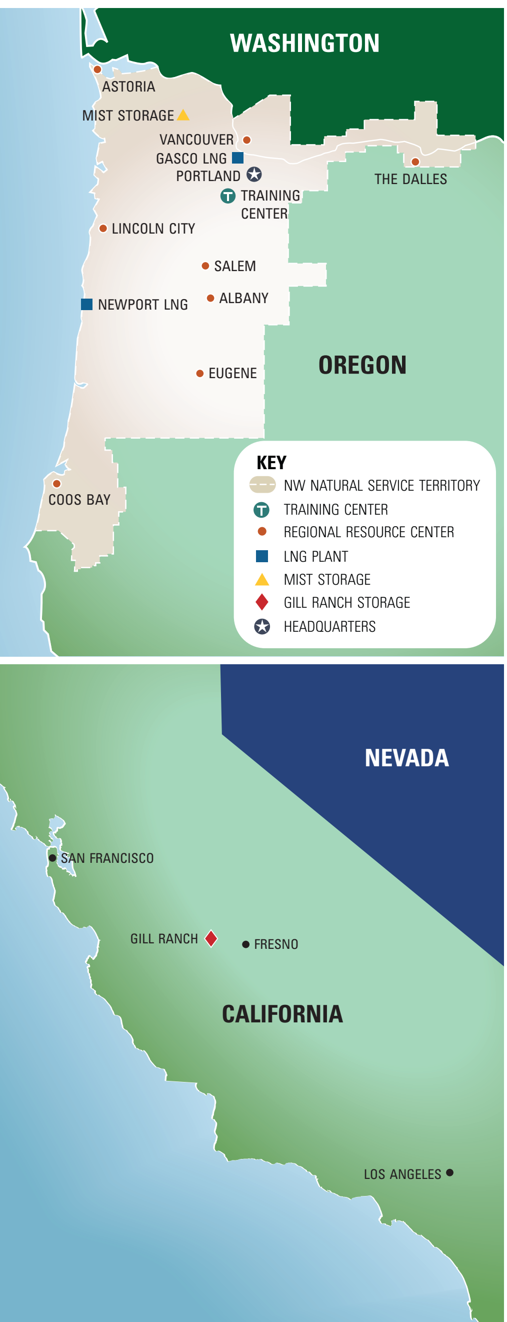
AN ENVIRONMENT RICH WITH POSSIBILITIES

NW Natural® 2013 ANNUAL REPORT

CORPORATE **PROFILE**

NW Natural (NYSE: NWN) is a 155-year-old natural gas local distribution and storage company headquartered in Portland, Oregon. NW Natural serves about 695,000 utility customers in Oregon and Southwest Washington, and provides gas storage to customers on the West Coast. In keeping with its steady growth, the company has increased dividends paid to shareholders for 58 consecutive years.

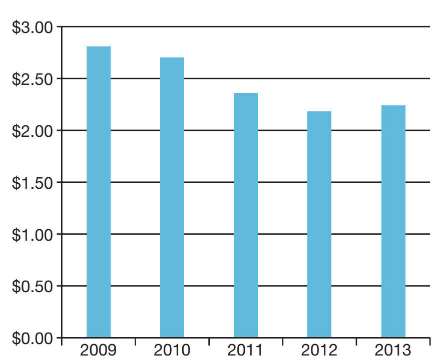
SERVICE TERRITORY AND STORAGE FACILITIES



OVERVIEW	**2013**	**2012**	**PERCENT INCREASE (DECREASE)**
FINANCIAL			
Financial facts ($000):			
Operating revenues	758,518	730,607	4
Utility margin	353,884	344,527	3
Net income	60,538	58,779	3
Financial ratios (%):			
Return on average common equity	8.2	8.2	-
Capital structure at year-end:			
Long-term debt	47.6	48.7	(2)
Common stock equity	52.4	51.3	2
COMMON STOCK			
Shareholder data (000):			
Average shares outstanding – diluted	27,027	26,907	-
Year-end shares outstanding	27,075	26,917	1
Per share data ($):			
Diluted earnings	2.24	2.18	3
Dividends paid	1.83	1.79	2
Book value at year-end	27.77	27.11	2
Market value at year-end	42.82	44.20	(3)
OPERATING			
Gas sales and transportation deliveries (000 therms)	1,146,431	1,111,769	3
Degree days	4,379	4,152	5
Customers at year-end	694,873	685,941	1
Employees at year-end	1,081	1,092	(1)

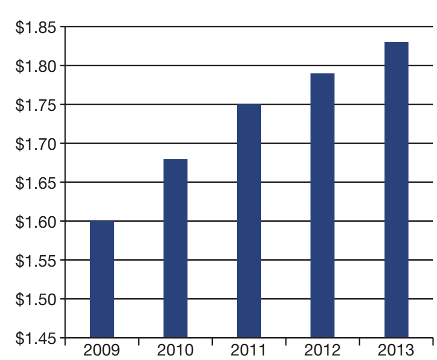
DIVIDENDS PAID ON COMMON STOCK (per share)		
February 15	$ 0.455	$ 0.445
May 15	0.455	0.445
August 15	0.455	0.445
November 15	0.460	0.455
Total dividends paid	$ 1.825	$ 1.790

DILUTED EARNINGS PER SHARE
(in dollars)

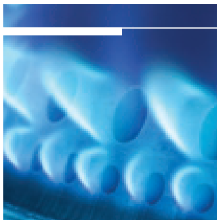


Diluted earnings per share were $2.24 in 2013, up 3% over 2012.

DIVIDENDS PAID PER SHARE
(in dollars)



Annual dividends paid per share in 2013 increased for the 58th consecutive year. The current indicated annual dividend is $1.84 per share.



Gregg Kantor,
President and CEO

We were one of the nation's first utilities to replace all of our cast iron pipes, and will be one of the first to replace all bare steel pipes.

In 2013, NW Natural delivered earnings of $2.24 per share, achieved a number of important operating milestones and worked to bring its customers the many economic and environmental opportunities that natural gas offers.

The Pacific Northwest is known for its ability to foster economic progress in ways that support a vibrant, healthy environment. And it's that intersection of environmental stewardship and the drive for economic growth that provide new and exciting opportunities for natural gas and NW Natural.

No other energy option today can match the advantages that clean, affordable natural gas provides for homes, businesses, vehicle transportation or the power generation sector. But to capitalize on these opportunities NW Natural must continue to execute effectively, maintaining our focus on providing safe, reliable and affordable service.

To that end, last year we made significant investments in our system. We completed several major system reinforcement projects and continued our proactive pipe replacement efforts. With the support of regulators and customer advocates, we were one of the first utilities in the country to have replaced all cast iron in our system, and we will soon complete the removal of all bare steel pipe as well. Currently, we have about 10 miles of bare steel pipe left, and we expect to eliminate it by the end of 2015.

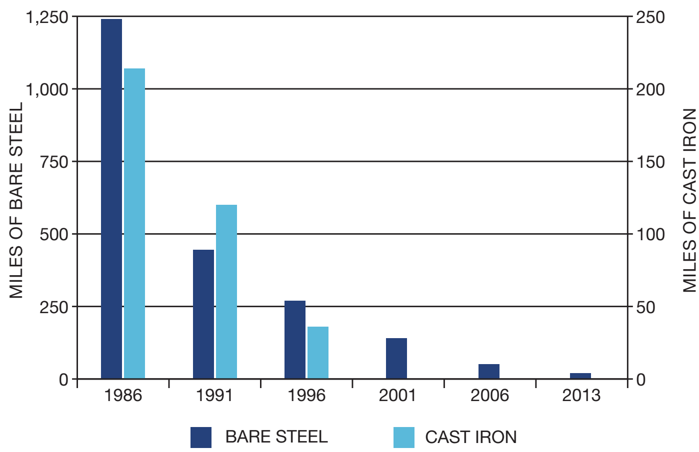
But system safety doesn't end with pipe replacement. We also advanced many of our other safety initia-

2013 HIGHLIGHTS

- Reported net income of $61 million or $2.24 per share, compared to $59 million or $2.18 per share in 2012.
- Posted the highest score in the nation among large utilities in the J.D. Power and Associates' Gas Utility Residential Customer Satisfaction Study.
- Invested $54 million in long-term gas reserves, bringing our cumulative three-year investment to $161 million.
- Grew utility revenues by adding customers and investments driven by a strong price advantage for natural gas and industry-leading online tools.
- Received Public Utility Commission of Oregon (OPUC) approval to earn on $40 million of working gas inventory in rate base, effective Nov. 1, 2013.
- Increased common stock dividends paid for the 58th consecutive year, one of the longest dividend increase records of any company on the NYSE.

tives, including the completion of our new training center in Sherwood, Oregon. Last year, hundreds of company field employees and several municipal fire departments participated in hands-on, scenario-based safety training at our new facility. And we hosted a number of emergency preparedness events for families and organizations in local venues throughout our service territory.

BARE STEEL AND CAST IRON REPLACEMENT



The company has only about 10 miles of bare steel main left in its system. All cast iron pipe was removed by 2000.

Ensuring the safety of our system is job one, but providing excellent customer service is a close second. We are proud to say that our commitment to safety and service continues to be recognized by our customers.

For the third time in six years, NW Natural ranked first in the West among large utilities, and posted the highest score in the nation in J.D. Power and Associates' Gas Utility Residential Customer Satisfaction Study. We've worked hard to be an organization focused on continuous improvement, and these consistently strong results are a testament to that work and to our talented workforce.

Slow but steady recovery

In recent years, we've seen slow but consistent progress toward economic recovery in our service territory. In 2013, improvement in the local economy materialized in two important ways.

The Portland metropolitan area's unemployment rate dropped to a five-year low of 6.6 percent, with the labor market expanding by 1.6 percent over 12 months. That positive momentum was also reflected in the housing sector numbers. By December, home sales were up 14 percent and average home prices rose 13 percent. And with more movement of existing housing stock, new construction activity also rebounded. Housing permits in 2013 were up 46 percent compared to 2012.

These gains helped drive an uptick in our customer growth rate to 1.3 percent in 2013.

To better position us for the housing recovery, NW Natural has developed new tools to more aggressively compete in the residential housing market. With the price of natural gas as much as 60 percent less expensive than oil and electricity in our high-growth areas, we plan to leverage this advantage by ensuring gas service is convenient and easy to access.

Last year, we launched the new Customer Connection Portal that provides a unique online resource for potential customers. This web-based portal automates and enhances a prospective customer's shopping experience.

Now, potential customers can go online from a computer, smartphone or tablet to learn within a few clicks if they can get natural gas to their home.

As part of our commitment to safety, we built a new center that provides hands-on, scenario-based training for employees. The site also allows us to partner with first responders, including local fire departments, to conduct emergency preparedness exercises.



Last year we implemented the Customer Connection Portal, allowing consumers to check for gas availability and schedule a contractor, all from the convenience of a smartphone, computer or tablet.

NW Natural will analyze these inquiries to see where demand for gas service goes beyond our existing system, so we can more effectively plan for future growth.

Using the portal, consumers can also find everything they need to connect to gas: special offers on equipment, contractor information and a tool to compare the cost of natural gas to oil and electricity.

In 2014, we will be expanding the portal to provide special features for our trade allies. Through a secure, personalized account, builders and HVAC contractors will be able to go online to order service, track the progress of their orders and manage multiple projects.

A full regulatory agenda

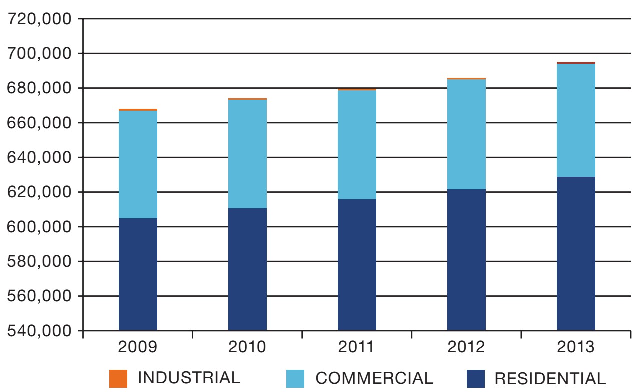
Last year, we continued to work through a number of regulatory dockets stemming from our recent rate case. Specifically, the OPUC opened proceedings: to resolve implementation issues related to our new environmental cost recovery mechanism; to determine whether working gas inventory balances should be added to rate base; to review the current revenue-sharing agreement for interstate storage and optimization services; and to determine whether prepaid pension assets should be added to rate base.

Last fall, we received OPUC approval to add $40 million of working gas inventory to rate base, closing that docket. The associated costs were placed into rates on Nov. 1.

We also announced an all-parties settlement that addressed several implementation issues related to our new environmental cost recovery mechanism. In reviewing the settlement, the Commission voiced support for certain aspects of it, but also expressed a desire to reassess how an earnings test would be applied. As a result, we will be working through the remainder of that proceeding this year.

Through a separate stipulation, the OPUC did rule on one aspect of the environmental docket, allowing $19 million of capital costs related to the construction of a water treatment plant associated with our cleanup efforts to be placed into rates on Nov. 1.

UTILITY CUSTOMERS AT YEAR-END



We added 8,932 new customers in 2013, and now serve 694,873 customers.

OREGON & WASHINGTON RESIDENTIAL RATES
(in dollars per therm)

Today's residential rates are lower than they were 10 years ago.

Abundant, domestic natural gas is providing new economic and environmental opportunities, benefitting homes and businesses nationwide.

On a related matter, we made significant progress on a lawsuit the company filed in 2010 against several insurance carriers to recover on claims for the environmental cleanup effort. By the end of last year, we reached settlements or agreements-in-principle with all but three of the insurers in the litigation. This January we concluded the litigation effort with signed settlements from those remaining insurers.

We are pleased with this outcome. Including all settlements to date, we now have recovered $150 million for investigation and remediation of environmental sites, while avoiding the significant costs associated with trials and the potential for years of appeals.

In 2014, we will continue to work through the remaining regulatory proceedings carried over from our 2012 rate case. We expect these issues to be resolved this year.

New avenues for growth

Without question, abundant, domestic supplies of natural gas have created an environment rich with possibilities.

Last year, we continued to reap the long-term advantages of low natural gas prices through our gas reserves investment in Wyoming. Through year-end, our cumulative investment totaled $161 million. These investments are expected to provide stable prices for a portion of our utility gas supply for years to come.

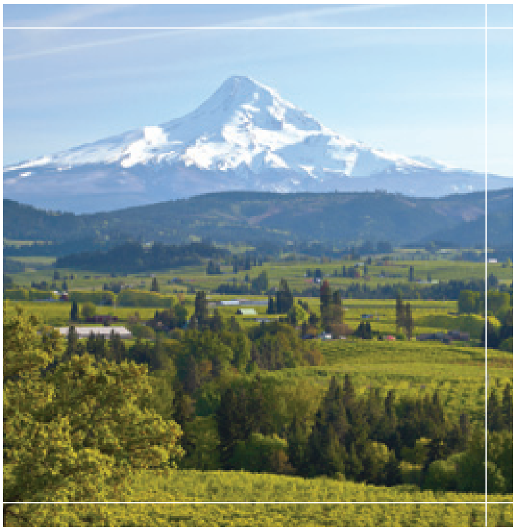
Today, like never before, low natural gas prices make it possible to reduce environmental emissions while decreasing our country's dependence on foreign oil. For example, by switching to compressed natural gas (CNG), fleet operators can cut their fuel costs nearly in half while significantly reducing greenhouse gas emissions.

Given these cost and environmental benefits, it's no surprise that many competitively minded Northwest businesses have been looking for a way to move their vehicles to CNG. Unfortunately, there is little refueling infrastructure currently available in the Pacific Northwest that would allow them to make the switch.

In response, NW Natural proposed a new tariff to provide high-pressure natural gas service to business customers interested in switching their fleet vehicles to CNG. The tariff was approved by the OPUC in January of this year. We believe it provides an important first step in allowing local businesses to save on fuel costs and transition to a cleaner, domestic energy resource.

Generating power with natural gas is another opportunity to further the Northwest's greenhouse gas reduction goals. By 2025, the two coal plants operating in the Northwest are scheduled to be shut down. These significant moves

NW Natural is working to meet the demand for CNG refueling infrastructure. A new tariff allows us to provide high-pressure natural gas service, which will help businesses save fuel costs and transition to a cleaner, domestic fuel.



We believe storage will play an important role in serving demand growth as the nation turns increasingly to natural gas for power generation, transportation and manufacturing.

away from coal will drive the region's electric generation mix to even more renewables and a much greater reliance on natural gas.

Supporting that generation shift is a possible expansion at NW Natural's Mist underground storage facility. The concept is to use new storage capacity at Mist to provide a flexible, on-demand fuel source for a local electric utility's gas-fired generating plants – plants designed to integrate wind resources into the electric system.

Last year, we worked through many of the engineering details for this potential expansion, which would include new storage wells, a compressor station, and additional pipeline facilities. In 2014, we'll be working to refine cost estimates and determine whether the expansion will move forward.

While the Northwest storage situation continues to offer near-term potential, storage values in many other parts of the country remained low in 2013. Despite these conditions, we continue to work hard to find opportunities that add value to our Gill Ranch facility in California.

California's renewable portfolio standard requires that 33 percent of the state's power be generated by renewables by 2020. This change in California's generation mix is increasing the need for flexible power resources to handle the intermittency of wind and solar energy. Our Gill Ranch facility has the potential to support this type of flexible resource.

Overall, we continue to believe that as the nation moves increasingly to natural gas for power generation, transportation and industrial processes, storage will provide long-term value. And whether it's through storage, in vehicles or at the burner tip, the environmental and economic advantages natural gas provides has caught the interest of policymakers.

Last year, Oregon's Governor and one of the state's Public Utility Commissioners led the effort to get Senate Bill 844 passed. We believe this innovative legislation (known as the greenhouse gas emission reduction bill) provides a new, proactive way for NW Natural to invest in projects that have quantifiable environmental benefits for customers – projects that otherwise would not move forward.

The bill took effect Jan. 1, 2014, and a rule-making effort with the OPUC to establish project and investment criteria is under way. We are pleased to have this framework in place, and we look forward to finding those untapped opportunities where natural gas can provide significant environmental benefits for Oregon.

The shale gas revolution is clearly a transformational change for our country, one that offers great economic and environmental opportunities. Now it's our job to make sure NW Natural is positioned to thrive in this new environment, and to deliver those opportunities to our customers and the communities we serve, as well as to our shareholders. That remains our focus in 2014 – and beyond.

Once again, thank you for the confidence and trust you place in NW Natural. We look forward to continuing to work on your behalf.

Gregg S. Kantor
President and CEO

CORPORATE **OFFICERS**

Front

MARGARET D. KIRKPATRICK
Senior Vice President and
General Counsel

DAVID H. ANDERSON
Executive Vice President
and Chief Operating Officer

GREGG S. KANTOR
President and Chief
Executive Officer

LEA ANNE DOOLITTLE
Senior Vice President and
Chief Administrative Officer

STEPHEN P. FELTZ
Senior Vice President and
Chief Financial Officer

Back

GRANT M. YOSHIHARA
Vice President
Utility Operations

MARDILYN SAATHOFF
Vice President Legal,
Risk and Compliance
and Corporate
Secretary

C. ALEX MILLER
Vice President
Regulation and
Treasurer

DAVID R. WILLIAMS
Vice President
Utility Services

J. KEITH WHITE
Vice President Business
Development and
Energy Supply and
Chief Strategic Officer

BRODY J. WILSON
Controller and
Chief Accounting
Officer

BOARD OF **DIRECTORS**

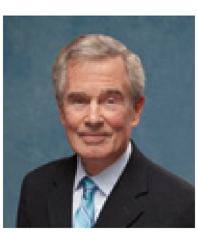
TIMOTHY P. BOYLE
President and Chief
Executive Officer
Columbia Sportswear
Company

**MARTHA L.
"STORMY" BYORUM**
Director, Tecnoglass, Inc.

JOHN D. CARTER
Chairman
of the Board
Schnitzer Steel
Industries, Inc.

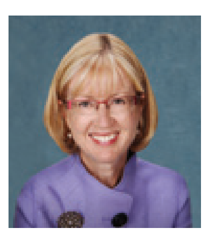
MARK S. DODSON
Former Chief
Executive Officer
NW Natural

C. SCOTT GIBSON
President
Gibson Enterprises

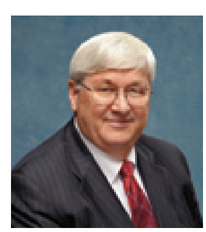


TOD R. HAMACHEK
Chairman of the Board
NW Natural

GREGG S. KANTOR
President and 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

Notice of annual meeting

The 2014 Annual Meeting will be held at 2 p.m., Thursday, May 22, 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 evidence to the meeting showing that you owned NW Natural Common Stock as of the record date, April 3, 2014, 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

February 14, 2014
May 15, 2014
August 15, 2014
November 14, 2014

Certifications

The Chief Executive Officer certified to the NYSE on June 24, 2013, 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, 2012, 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, 2013, 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 non-management directors by writing to NW Natural Board of Directors, c/o Corporate Secretary.

Forward-looking statements

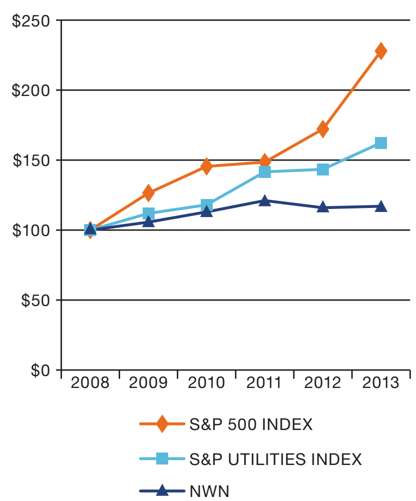
The statements made in this Annual Report that are not purely historical, including statements regarding strategy, growth, future demand for gas, commodity costs, fuel savings, revenues, gas supplies and reserves, investments and returns, business development, potential projects and project timelines, pipeline replacement and safety programs, system reliability, storage performance values, recovery and expansion, governmental policy and legislation, regulatory cost recovery mechanisms, regulatory prudence reviews, regulatory proceedings and actions, economic recovery factors, market trends and the competitive environment 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 (202) 551-8090.

COMPARISON OF FIVE-YEAR CUMULATIVE TOTAL RETURN
(Based on $100 invested on 12/31/2008)



Total shareholder return (annualized) over the five years ending December 31, 2013, for NW Natural was 3.2%, compared to Standard & Poor's (S&P) Utilities Index return of 10.2%, and the S&P 500 Index return of 17.9%.

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

Page 3 - Gregg Kantor: Todd Eckelman.

Page 4 - Get Ready Safety: Corky Miller; Sherwood Training Facility: Courtesy Judd Girard.

Page 6 - CNG Refilling Station: Corky Miller.

Page 7 - Gas Pipeline Installation: Robbie McClaran.

Page 8 - Corporate Officers: Jeff Lee; Board of Directors: Robbie McClaran.

Page 11 - Robert Hess and Chu Lee: Robbie McClaran; NW Natural Headquarters: Corky Miller.

PRINTING

RR Donnelley

NW Natural®

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, 2013

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 28, 2013, the registrant had 26,972,022 shares of its Common Stock outstanding, of which 26,636,200 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 $1,131,505,776.

At February 21, 2014, 27,099,729 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 2014 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, 2013

TABLE OF CONTENTS

GLOSSARY OF TERMS

AVERAGE WEATHER: equal to the 25-year average degree days based on temperatures established in our last Oregon general rate case.

Bcf: one billion cubic feet, a volumetric measure of natural gas, 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.

CALIFORNIA PUBLIC UTILITIES COMMISSION (CPUC): entity that regulates our California gas storage business at our Gill Ranch facility with respect to rates and terms of service, among other matters.

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.

DECOUPLING: a rate mechanism, also referred to as our conservation tariff, which is designed to break the link between earnings and the quantity of natural gas consumed by customers. The design is intended to allow the utility to encourage customers to conserve energy while not adversely affecting its earnings due to reductions in sales volumes.

HEATING DEGREE DAYS: units of measure that reflect temperature-sensitive consumption of natural gas, calculated by subtracting the average of a day's high and low temperatures from 65 degrees Fahrenheit.

DEMAND COST: a component in core utility customer rates that covers the cost of securing firm pipeline capacity, whether that capacity is used or not.

FEDERAL ENERGY REGULATORY COMMISSION (FERC): entity that regulates 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.

GENERAL RATE CASE: a periodic filing with state or federal regulators to establish billing rates for all classes of utility customers.

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.

LIQUEFIED NATURAL GAS (LNG): 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.

PUBLIC UTILITY COMMISSION OF OREGON (OPUC): 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.

PURCHASED GAS ADJUSTMENT (PGA): 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.

RETURN ON EQUITY (ROE): 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 revenue requirements.

SALES SERVICE: service provided whereby a customer purchases both natural gas commodity supply and transportation from the utility.

SITE REMEDIATION AND RECOVERY MECHANISM (SRRM): an Oregon rate mechanism for recovering prudently incurred environmental site remediation costs through customer billings, subject to an earnings test.

SYSTEM INTEGRITY PROGRAM (SIP): an Oregon rate mechanism that provides cost recovery of pipeline and system integrity programs, which are required under various safety standards prescribed by both state and federal regulators.

THERM: the basic unit of natural gas measurement, equal to one hundred thousand Btu's.

TRANSPORTATION SERVICE: service provided whereby a customer purchases natural gas commodity 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.

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION (WUTC): entity that regulates our Washington utility business with respect to rates and terms of service, among other matters.

WEATHER NORMALIZATION: an Oregon rate mechanism applied to residential and commercial customers' bills to adjust for 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.

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, 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;
- objectives;
- goals;
- strategies;
- assumptions and estimates;
- future events or performance;
- trends;
- timing and cyclicality;
- earnings and dividends;
- growth;
- customer rates;
- commodity costs;
- gas reserves;
- operational performance and costs;
- efficacy of derivatives and hedges;
- liquidity and financial positions;
- project development and expansion;
- competition;
- procurement and development of gas supplies;
- estimated expenditures;
- costs of compliance;
- credit exposures;
- potential efficiencies;
- rate recovery and refunds;
- impacts of laws, rules and regulations;
- tax liabilities or refunds;
- levels and pricing of gas storage contracts;
- 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;
- approval and adequacy of regulatory deferrals;
- effects 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. However, 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 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 that we aggregate and report as other.

The utility business is our largest segment, while our gas storage businesses account for a majority of our remaining net income. The following table reflects the percentage allocation between segments and other as of December 31, 2013:

		Non-Utility(1)		
	Utility	Gas Storage(2)	Other	Total
Assets	89.0%	10.4%	0.6%	100.0%
Net Income	90.7%	9.2%	0.1%	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 approximately 695,000 customers with around 90% of our customers located in Oregon and 10% located in Washington. In total, we provide natural gas service to over 100 cities in 18 counties with an estimated population of 3.4 million in our service territory.

The OPUC and WUTC have allocated us an exclusive service territory, 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 that comprises ocean and river shipping, transcontinental railways and highways, and an international airport. The area is a major retail and manufacturing center and home to high-technology industries.

Customers

We serve residential, commercial and industrial customers with no individual customer or industry accounting for over 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. A small amount of utility margin is also derived from other items. The following table presents summary customer information as of December 31, 2013:

	Number of Customers	% of Volumes	% of Utility Margin
Residential	628,634	36%	64%
Commercial	65,321	22%	27%
Industrial	918	42%	8%
Other(1)	N/A	N/A	1%
Total	694,873	100%	100%

(1) Other is derived from 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 election of services, special charges for changes between elections, and in some cases, meeting a minimum or maximum volume requirement before changing options.

Customer growth rates for natural gas utilities in the Pacific Northwest are generally 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 that natural gas is in less than 60% of residential single-family dwellings in our service territory. Therefore, growth in the region comes from both new housing construction and existing homes converting to natural gas. Prior to the most recent recession, our customer growth rate averaged around 3% or higher. From 2009 to 2012, growth dipped below 1%, but in 2013, the 12-month growth rate increased to 1.3%. With natural gas' continued price advantage, operating convenience, and environmental benefits, we believe there is potential for continued growth in all customer categories as the economy recovers. 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 that confront a number of our largest customers that compete 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 margin if customers bypass or switch over to custom contracts that provide 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. In December 2013, we filed a rate petition 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[1]
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	X	
Pension Balancing	X	
Environmental Cost Deferral	X	X
SRRM	X	

[1]Although we do not have the same specific regulatory mechanisms in Washington, we do have approved regulatory deferral orders that allow us to defer certain costs for future recovery through the PGA or future general rate cases, such as our environmental cost deferral order.

In general, these rates and regulatory mechanisms do not provide for 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 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 and our gas reserve investment. We can earn an authorized return on the equivalent rate base investment on our gas reserves.

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"* below.

Gas Supply

The utility strives to secure sufficient, reliable supplies of natural gas to meet the needs of customers at the lowest reasonable cost through a comprehensive strategy that is focused on the following items:

- **Diverse Supply** - providing diversity of supply sources;
- **Diverse Contracts** - maintaining a variety of contract durations and types; and
- **Cost Management** - employing 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 optimize price differentials. Currently, about 63% of our supply comes from Canada, with the balance coming primarily from the U.S. Rocky Mountain region. We believe that 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. We believe that 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, we have seen increased availability of gas supplies throughout North America as a result of the extraction of shale gas and the building of new transmission pipelines to increase transportation capacity out of the U.S. Rocky Mountain region.

We supplement our firm gas supply purchases with gas withdrawals from gas storage facilities, including underground reservoirs, and LNG storage facilities. These storage facilities are generally injected with natural gas during off-peak months during the spring and summer and are 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)	2.7	10.0
Contracted Facilities:		
Jackson Prairie, Washington(2)	0.5	1.1
Alberta, Canada(3)	0.5	2.8
LNG Facilities:		
Owned Facilities:		
Newport, Oregon	0.6	0.9
Portland, Oregon	1.2	0.6
Contracted Facility:		
Plymouth, Washington(4)	0.6	0.5
Total	6.1	15.9

t1) 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 2.7 million therms of daily deliverability and 10 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 does help to manage price risks as it displaces equivalent volumes of spot purchases.

(4) On certain days in December 2013, pipeline transportation service from the Plymouth facility was curtailed. As a result, we no longer assume that the resource will contribute to total peak day capacity beginning with the 2014-2015 heating season. We are currently evaluating this resource and alternative options, but will continue to utilize the facility to manage price risks in the coming year.

The Mist facility is used for both utility and non-utility purposes. Under our regulatory agreement with the OPUC, 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 addition, we have the ability to recall pipeline capacity and supply resources from certain customers if needed.

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 2013, we purchased a total of 762 million therms under contracts with durations outlined in the chart below:

Contract Duration (primary term)	Percent of Purchases
Long-term (one year or longer)	28%
Short-term (more than one month, less than one year)	24
Spot (one month or less)	48
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, our largest individual supplier provided just over 10% of our gas supply requirements in 2013.

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 store and transport gas to our distribution system; our gas reserves contract; 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 effectively (1) 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 it into storage for price stability and to minimize pipeline capacity demand costs;
- investing in gas reserves for longer term price stability with Encana Oil & Gas (USA) Inc. (Encana). See Note 11; and
- using an asset management service provider to produce incremental revenues that are used to reduce our utility's net cost of gas.

We contract with an independent energy marketing company to capture opportunities regarding our unused 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 an opportunity to generate incremental revenues for NW Natural's shareholders from a regulatory incentive-sharing mechanism, which are included in our gas storage segment.

Transportation of Gas Supplies

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.

In 2003, a federal order requiring Northwest Pipeline to replace its 26-inch mainline from the Canadian border to our service territory underscored the potential need for pipeline transportation diversity. That replacement project was completed by Northwest Pipeline in November 2006. We are pursuing options to further diversify the pipeline transportation system into our service territory. Specifically, we are jointly developing plans to build a pipeline that 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, *"2014 Outlook"*.

We incur monthly demand charges related to our firm pipeline transportation contracts. Our largest pipeline agreements are with Northwest Pipeline for firm transportation capacity, which provides access to supplies in British Columbia and the U.S. Rocky Mountains by connecting us with the Northwest Pipeline and GTN systems. These contracts are multi-year contracts with expirations ranging from 2014 to 2044. We actively work with Northwest Pipeline and others to renew contracts in advance of expiration and ensure gas transportation capacity is sufficient to meet our needs.

Rates for interstate pipeline transportation services are established by FERC within the U.S. and by Canadian authorities for services on Canadian pipelines.

Gas Distribution

The goals of our gas distribution operations are:

- **Safety** - Building and maintaining a safe pipeline distribution system;
- **Reliability** - Ensuring gas resource portfolios that are sufficient to satisfy customer requirements under extremely cold weather conditions; and
- **Lowest Reasonable Cost** - Acquiring gas supplies at the lowest reasonable cost for utility customers;
- **Price Stability** - Managing commodity price volatility by making the best use of physical assets and financial instruments; and
- **Cost Recovery** - Managing gas purchase costs to minimize risks associated with regulatory prudence reviews and cost recovery.

These goals are discussed more fully in the following sections.

Safety

Safety and the protection of our employees, our customers and the public at large are and will remain a top priority. We monitor and maintain our pipeline distribution system and storage operations with the goal of ensuring that natural gas is stored and delivered safely, reliably and efficiently. We have had various cost recovery mechanisms since 2004 and currently have a program that integrates the Company's programs for bare steel replacement, transmission pipeline integrity management, and distribution pipeline integrity management into a single program. 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 recent pipeline incidents involving other companies. Most recently, additional regulations from the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) were drafted in 2013 with final regulations expected in 2015 and an effective date in 2016. 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 that costs associated with compliance to federal, state, and local rules would be recoverable in rates.

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 three day design peak event that is based on the most severe cold weather experienced during the last 25 years in our service territory.

Our projected maximum design day firm utility customer sendout totals approximately 9.3 million therms. Of this total, we are currently capable of meeting over 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 be met by gas purchases under firm and recall gas purchase contracts.

On February 6, 2014, we experienced our current record customer sendout of 9.0 million therms, which included 7.4 million firm therms. This record day was approximately 9 degrees Fahrenheit warmer than the design day temperature.

We believe that 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 integrated resource plan (IRP) process.

The following table shows the sources of supply that are projected to be used to satisfy the design day sendout for the 2013-2014 winter heating season:

Therms in millions	Therms	Percent
Sources of utility supply:		
Firm supply purchases	3.3	37%
Mist underground storage (utility only)	2.7	29
Company-owned LNG storage	1.8	19
Off-system firm storage contract	0.5	5
Other off-system storage contract[1]	0.6	6
Recall agreements	0.4	4
Total	9.3	100%

[1] On certain days in December 2013, pipeline transportation service from the Plymouth storage facility was curtailed. We were able to use this service in February 2014 primarily through other transportation agreements. We are currently evaluating this resource and alternative options for the 2014-2015 heating season.

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 that our IRP met the requirements of the Washington Administrative Code. Commission acknowledgment of the IRP does not constitute ratemaking approval of any specific resource acquisition strategy or expenditure. However, the OPUC generally indicates that it would give considerable weight in prudence reviews to utility actions that are consistent with acknowledged plans. The WUTC has indicated that the IRP process is one factor it will consider in a prudence review. We plan to file our 2014 IRP in both Oregon and Washington in May 2014.

Lowest Reasonable Cost

We apply cost management strategies, including fixed-price contracts, financial derivative instruments, storage supplies, acquisition of gas reserves, and asset management, to acquire gas supplies at the lowest reasonable cost for utility customers. See "Gas Supply—*Gas Cost Management Strategy"* above.

Price Stability

We use physical assets and financial instruments to manage commodity price volatility. We purchase gas for our storage facility generally during the summer months when gas prices are typically lower. In addition, our gas reserves provide long-term gas price protection for our utility customers. We also mitigate year-to-year commodity price volatility through financial hedge contracts such as commodity price swaps and options.

Cost Recovery

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, 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*."

GAS STORAGE

The gas storage segment includes the following:

- the non-utility portion of the Mist gas storage facility near Mist, Oregon;
- our 75% share of the 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.

In recent years, as a result of the abundant supply of natural gas in North America, we have seen lower, more stable natural gas prices, which has created a challenging gas storage environment. In late 2013 and early 2014, we saw gas price volatility due to the colder than normal winter throughout North America. In the short-term, this gas price volatility increased the demand for, and value of, holding gas storage. However, future gas storage demand and pricing have been negatively affected by projections of spring and summer natural gas prices that are equal to projected gas prices for the winter of 2014-15, making the purchase of spring and summer gas for injection into storage less desirable. As a result of these current trends, we anticipate contracting for the upcoming storage year at lower market prices than in previous periods, especially at our California facility, where some multi-year contracts are expiring. In the longer term, increased demand for natural gas and/or decreased drilling activity could change the current supply/demand imbalance and result in higher gas prices or increased market volatility, which could position this segment for growth.

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:

	Storage Capacity (Bcf)	Maximum Deliverability (Bcf/day)[3]	Maximum Injection (Bcf/day)[3]
Mist Storage[1]	6	0.2	0.1
Gill Ranch Storage[2]	15	0.5	0.2

[1] Approximately 6 Bcf of a total 16 Bcf at Mist is currently available to our gas storage segment. The remaining 10 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.
[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 its facility located in Columbia County, Oregon, near the town of Mist. The Mist field was converted to storage operations for our utility customers in 1989. Since 2001, gas storage capacity at Mist has 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 interstate storage services, firm service agreements with customers are entered into with terms typically ranging from 1 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 production or distribution, electric generation, and energy marketing. Three storage customers currently account for over 90% of our existing non-utility gas storage capacity at Mist, with the largest customer accounting for about half of the total capacity. These three customers have contracts that expire at various dates through 2018.

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 Pacific Northwest storage markets have been impacted by lower gas prices and lack of price volatility, although less than other areas of the country. The need for new, flexible gas-fired 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 in the early planning stages of a potential expansion of our Mist storage facility. If completed, this expansion would be anchored by an agreement to provide gas storage services to Portland General Electric (PGE) to support their gas-fired generation facilities at Port Westward, Oregon. The Mist expansion project is subject to PGE's approval of projected costs and various other approvals, regulatory requirements, and other conditions.

<u>Gill Ranch Facility</u>

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 the fourth quarter of 2010 and currently 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 at historic lows and a greater number of competitors in the area compared to the Pacific Northwest region. As a result, we anticipate contracting at lower market prices than we have in the previous years. We are committed to using a variety of contracting tools to maximize the value from the Gill Ranch facility. In the longer term, the recovery of the California economy and potentially an increased demand for flexible generation could increase demand for natural gas storage and increase price volatility.

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. The 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 28 years in duration; however, the majority of the contracted capacity is shorter term in nature due to current market conditions. In the near-term, we expect Gill Ranch to contract for terms mostly ranging from one to five years. For the 2013-14 gas storage year, Gill Ranch has several storage customers, with the largest single contract accounting for approximately 13% of our storage capacity. We are currently in the process of contracting available capacity for the upcoming 2014-15 gas storage year and expect shorter contract lengths and lower prices reflecting current market 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. There could also be expansions and proposed new construction of storage capacity in northern California that may create increased competition.

SEASONALITY. 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 revenues. In addition, a significant portion of operating costs at Gill Ranch are subject to seasonality 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 that 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 transactions and pipeline capacity release transactions, the results of which 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 immaterial 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. Palomar Gas Holdings, LLC (PGH) 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, "*2014 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; and
- variations between the estimated and actual period of time that must be dedicated to respond to an environmentally-contaminated site.

We seek recovery of environmental costs through insurance and customer rates, and we believe recovery of these costs is probable. We currently have an open proceeding with the OPUC to resolve implementation issues for the SRRM, which allows for regulatory environmental cost recovery. As there is uncertainty surrounding the outcome of this proceeding, we will continue to carefully assess these environmental assets for recoverability. If it is determined that insurance recoveries for environmental costs are insufficient and future rate recovery of such costs are not probable, the costs will be charged to expense in the period such determination is made. See Note 17 and Item 3 *"Legal Proceedings"* for information regarding the recent settlement with remaining defendant insurance companies. See also "Results of Operations—Rate Matters—Rate Mechanisms—*Environmental Costs"* below and Note 15.

Greenhouse Gas Issues

We recognize that 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 that 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, 2013, the utility workforce consisted of 612 members of the Office and Professional Employees International Union (OPEIU) Local No. 11, AFL-CIO, and 469 non-union employees. Our labor agreement with members of OPEIU that covers wages, benefits and working conditions extends to May 31, 2014, and thereafter from year to year unless either party serves notice of its intent to negotiate modifications to the collective bargaining agreement. In 2013, each party served notice of intent to negotiate the terms of an agreement prior to the May 31, 2014 expiration date. We are currently engaged in negotiations to meet this schedule.

At December 31, 2013, our subsidiaries had a combined workforce of 19 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. In 2014, utility capital expenditures are estimated to be between $115 and $135 million, and non-utility capital investments are estimated to be less than $10 million. Additional non-utility spend for gas storage and other investments during and after 2014 will depend largely on future decisions about potential expansion opportunities in gas storage and pipeline projects. For the five-year period ending in 2018, capital expenditures for the utility are estimated to be between $600 and $700 million, while the amount for gas storage and other investments after 2014 will depend largely on the factors discussed previously.

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 (202) 551-8090. The SEC website contains reports, proxy and information statements and other information that 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 us 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 indicate 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, pension expense, transactions with affiliated interests, and other matters. Similarly, in our gas storage businesses FERC has regulatory authority over interstate storage services, and the CPUC has regulatory authority over our Gill Ranch storage operations.

The prices that the OPUC and WUTC allow us to charge for retail service, and the tariff rate that FERC permits us to charge for transmission, 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. For example, in our most recent Oregon rate case concluding in 2012, the OPUC disallowed certain deferred tax amounts for which the deferral was not previously reviewed by the OPUC, resulting in an after tax charge to net income when the order was received. 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.

In our latest general rate case with the OPUC, various items were deferred for future resolution in separate proceedings, including the definition of the earnings test under the SRRM, the prudence of environmental expenditures we have deferred to date, recovery of prepaid pension costs, and our revenue-sharing arrangement on the utility's interstate storage activities. The regulatory proceedings in which these issues will be resolved typically involve multiple parties, including governmental agencies, consumer advocacy groups, and others who are impacted by the use of natural gas. Each party has differing concerns, but all generally have the common objective of limiting amounts included in rates. We cannot predict the 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 initiated litigation against certain of our historical liability insurers for a portion of the costs we have incurred to date and expect to incur in the future. To the extent amounts we recover 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 asset 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 an earnings test, the definition of which was deferred to a later regulatory proceeding. These prudence reviews and earnings tests could reduce the amounts we are allowed to recover, and which could adversely affect our financial condition, results of operations and cash flows.

In addition to litigation against historical insurers, 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, 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 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 cross-Cascades 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. With respect to these projects, 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 cross-Cascades pipeline, Gill Ranch storage and Encana gas reserves. 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 venture with Encana, which operates as a hedge backed by physical gas supplies, involves 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 law 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 gas reserves venture with Encana 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, which 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 hydrocarbons 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 unpredicted 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;
- 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 outcome 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 cyber attacks, which could target or impact our natural gas distribution, transmission or storage facilities and result in a disruption in our operations and ability 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, 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. 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 aging employees retire. 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 May 31, 2014. 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, which could strain relationships with customers and state regulators and cause a loss of revenues. Our collective bargaining agreement may also increase the cost of employing our Union workforce, affect our ability to continue offering market-based salaries and employee benefits, limit our flexibility in dealing with our workforce, and limit 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 interpretation 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 and accidents in other parts of the country, 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 these laws, 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 reserve transaction with Encana which is a hedge 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 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.

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. Insufficient growth in these markets, for economic, political or other reason 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 providers. 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 could also 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 which 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 10% 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 commercial customers' consumption. However, we do not have a conservation tariff in Washington that provides us this protection.

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, 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. Additionally, 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, 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. On a system-wide basis, natural gas is typically injected into storage between April and October when natural gas prices are generally lower and withdrawn during the winter months of November through March when natural gas prices are typically higher. 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 ongoing expansions and proposed construction of 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.

THIRD-PARTY PIPELINE RISK. *Our gas storage businesses depends 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 operation is 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 reason, our ability to operate efficiently and satisfy our customers' needs could be compromised, thereby potentially could have an adverse impact on our financial condition, results of operations and cash flows.

OPERATIONS AT NEW STORAGE FACILITY RISK. *Operations at our new Gill Ranch storage facility involves numerous operational risks that may result in a failure to meet expectations or contractual obligations, additional or unexpected costs and other business risks that could adversely impact our financial condition, results of operations and cash flows.*

In October 2010, we commenced operations at our Gill Ranch storage facility. Operations at a new storage facility involve many risks. Although we believe that Gill Ranch storage facility has been successfully completed to meet our contractual obligations and project specifications with respect to injection, withdrawal and gas specifications, the facility is new, and has a limited operating history. If we fail to inject or withdraw natural gas at the levels we expect or at contracted rates, or cannot deliver natural gas consistent with our expectations or contractual specifications, or otherwise operate as expected, or if operating costs are substantially higher than we expect or if we fail to control those costs, we may not be able to contract for storage at the levels and on the terms we expect, and we could incur higher than expected costs to satisfy our contractual obligations under contracts we obtain, and this could adversely impact 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, 2018. 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 an accelerated pipe replacement program under which we removed and replaced 100% of our cast iron mains by the end of 2000. In 2001, we initiated an accelerated pipe replacement program under which we expect to eliminate all remaining bare steel mains and services in the system 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 and as discussed below, we have only nonmaterial litigation in the ordinary course of business.

In December 2010, NW Natural commenced litigation against certain of its historical liability insurers in Multnomah County Circuit Court, State of Oregon, Case Number 1012-17532. The defendants include Associated Electric & Gas Insurance Services Limited, Allianz Global Risk US Insurance Company, certain underwriters at Lloyd's London, certain London market insurance companies and 10 other insurance companies. In the suit, NW Natural alleged that the defendant insurance companies issued third party liability insurance policies to NW Natural and that the defendants had breached the terms of those policies by failing to reimburse and indemnify NW Natural for liabilities arising from environmental contamination at certain sites caused or alleged to be caused by its historical operations.

NW Natural sought damages in excess of $50 million in losses it had incurred through the date of the complaint, as well as declaratory relief for additional damages it expected to incur in the future. Settlements with certain of the defendant insurance companies resulted in payments received by NW Natural through December 31, 2013 of approximately $48 million.

In January and February 2014, the remaining defendant insurance companies agreed to settle all of NW Natural’s claims for insurance recovery for past and future environmental remediation expenses. In 2014 the Company expects to receive additional payments aggregating approximately $102 million under these settlement agreements signed in 2013 and 2014. Such payments are to be made in the first and second quarters of 2014. As a result of such settlements, the Company anticipates dismissal of the litigation in the second quarter of 2014. See Note 17.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR THE 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 closing trades for our common stock during the past two years were as follows:

	2013		2012	
Quarter Ended	High	Low	High	Low
March 31	$ 46.55	$ 43.40	$ 49.49	$ 44.40
June 30	45.89	41.17	48.56	43.90
September 30	45.15	39.96	50.16	46.04
December 31	44.35	40.75	50.80	41.01

The closing quotations for our common stock on December 31, 2013 and 2012 were $42.82 and $44.20, respectively.

As of February 21, 2014, there were 6,178 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	2013	2012
February 15	$ 0.455	$ 0.445
May 15	0.455	0.445
August 15	0.455	0.445
November 15	0.460	0.455
Total per share	$ 1.825	$ 1.790

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, 2013:

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
10/01/13-10/31/13	—	$ —	—	—
11/01/13-11/30/13	3,406	42.31	—	—
12/01/13-12/31/13	231	43.16	—	—
Total	3,637	$ 42.37	2,124,528	$ 16,732,648

(1) During the quarter ended December 31, 2013, 3,637 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, 2013, no shares of our common stock were accepted as payment for stock option exercises pursuant to our Restated SOP.

(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, 2014 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, 2013, 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	2013	2012	2011	2010	2009
Operating revenues[1]	$ 758,518	$ 730,607	$ 828,055	$ 792,115	$ 988,055
Net income[1]	60,538	58,779	63,044	72,013	74,632
Earnings per share of common stock:					
Basic[1]	$ 2.24	$ 2.19	$ 2.36	$ 2.71	$ 2.82
Diluted[1]	2.24	2.18	2.36	2.70	2.81
Dividends paid per share of common stock	1.83	1.79	1.75	1.68	1.60
Total assets, end of period[1]	$ 2,970,911	$ 2,813,120	$ 2,742,718	$ 2,614,172	$ 2,397,890
Total equity[1]	751,872	729,627	712,158	691,625	659,283
Long-term debt	681,700	691,700	641,700	591,700	601,700

[1] Prior period balances have been adjusted for a prior period error identified during the first quarter of 2013. See Note 16 for additional detail.

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, 2013, 2012, and 2011. References in this discussion to "Notes" are 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 which 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).

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 Palomar Gas Holdings, LLC (PGH), which is pursuing the development of a proposed natural gas pipeline through its wholly-owned subsidiary, Palomar Gas Transmission, LLC (Palomar), 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 results of operations and earnings amounts in total, certain financial measures are expressed in cents per share, which are non-GAAP financial measures. These amounts reflect factors that directly impact earnings. In calculating these financial disclosures, we allocate income tax expense based on the effective tax rate, where applicable. All references in this section to earnings per share (EPS) are on the basis of diluted shares. We use such non-GAAP measures in analyzing our financial performance because we believe they provide useful information to our investors and creditors in evaluating our financial condition and results of operations.

EXECUTIVE SUMMARY

During 2013 we continued to advance our long-term strategic directives. Highlights for the year include:

- increased customer count with close to 9,000 net customer additions for an annual customer growth rate of 1.3%;
- developed new online tools for customers to compare energy cost and service options;
- ranked number one in J.D. Power customer service survey among large gas utilities in the West;
- pursued gas storage development opportunities at our Mist gas storage facility;
- completed construction of a new operations service center, which also serves as a back-up business continuity center, and industry leading training facility;
- completed construction of a new water treatment station at our Gasco site; and
- received regulatory approval for an increased spending limit for our annual system integrity cap-ex tracker, which supports our safety investments.

We manage our business and strategic initiatives with a long-term view on providing natural gas service safely and conveniently to our customers, working with regulators on key policy initiatives, and remaining focused on growing our business. See *"2014 Outlook"* below for more information.

Key financial highlights include:

In millions, except per share data	2013	2012	2011
Consolidated net income	$ 60.5	$ 58.8	$ 63.0
Consolidated EPS	2.24	2.18	2.36
Utility margin	353.9	344.5	343.0

Results for 2013:

- net income and EPS increased primarily due to higher utility margin in 2013 and a one-time tax charge taken in 2012;
- gas storage net income increased primarily due to higher asset management revenues and lower operating costs; and
- utility margin increased primarily due to customer growth and higher rate-base return on our gas reserve and other investments.

See "*Consolidated Earnings and Dividends*" below for additional detail.

2014 OUTLOOK

We are focused on the long-term strategic goals for our business: delivering safe and reliable gas to our customers and growing our gas distribution and gas storage businesses. We believe our 2014 outlook leverages our resources and our history of innovative solutions to continue meeting the needs of customers, regulators, and shareholders. We consider the following components critical in achieving these long term goals:

Deliver Gas	Grow Our Businesses
Ensure Safety and Reliability	Grow Customer Base
Advance Regulatory Dockets and Policy	Pursue Key Initiatives
Collaborate on Regulatory Energy Policies	Develop New Services

SAFETY AND RELIABILITY. Delivering natural gas safely and reliably to our customers and providing employees with a safe work environment are our top priorities. During 2014, we will continue ensuring our pipeline system and facilities are well maintained with ongoing facility improvements and additional investments in our system integrity program. We plan to continue removing the bare steel pipe in our system with complete removal targeted by the end of 2015. We are preparing for new regulations from the U.S. Department of Transportation’s Pipeline and Hazardous Materials Safety Administration (PHMSA) that are expected to be issued in 2015 with a projected effective date of 2016.

Reliability of our system and delivering to our customers on design days is a key priority. In 2014, we plan to file our integrated resource plan with the OPUC and WUTC. This plan will help to define the required infrastructure improvements and expansions necessary to provide safe and reliable gas service to our customers.

REGULATION. Proper regulatory policies and support from our regulators helps ensure the utility can continue to effectively deliver gas to customers and earn a reasonable return for shareholders. During 2014, we plan to resolve open dockets from our 2012 Oregon general rate case, which include: a review of the interstate storage sharing arrangement; the implementation of our new SRRM; and the development of appropriate rate treatment for prepaid pension assets in rate base. In addition to these dockets, we plan to work closely with regulators to create an incentive mechanism for gas utilities to reduce greenhouse gas emissions.

ENERGY POLICIES. The Company is strengthened by innovatively addressing the needs of our customers, employees, and the communities we serve in a challenging economic and regulatory environment. In 2014, we will continue to work with state legislators to help build a strong energy plan for Oregon. In addition, we remain committed to working with environmental agencies to make significant progress towards remediation of our legacy environmental sites.

GROW CUSTOMER BASE. In the utility, we continue to leverage our resources to provide natural gas services to our residential, commercial, and industrial customers. We are beginning to see signs of improvement in the housing market and commercial development in our region and are committed to growing our customer base. We plan to investigate ways of potentially expanding the reach of our current distribution system, including development of new self-service online capabilities for builders, contractors, and homeowners. In our gas storage business, we will focus on maximizing the value of our storage capacity and optimizing revenue opportunities as they arise, while recognizing the unique challenges that currently low, seasonally stable natural gas prices bring to the storage market.

We believe that investing in operating efficiencies and marketing opportunities for our core businesses best positions us for growth now and into the future.

KEY INITIATIVES. Increasing gas usage in our region is likely to require additional infrastructure locally as well as through new connections to gas supplies. Our utility operations and gas storage operations at Mist currently depend on a single bi-directional interstate transmission pipeline to transport gas supplies to customers. We continue to work with regulators and utilities in the Pacific Northwest to advance a new integrated, regional cross-Cascades pipeline to create regional diversity and increased reliability for our system. The need for new connections to gas supply increases as additional, potential large electric load generation and industrial projects are sited within the region.

The need for new flexible gas-fired electric generation has been identified in the Pacific Northwest region to integrate intermittent wind resources into the power system. Natural gas complements wind and solar renewable energy options as a reliable, on-call, electric generation resource. We believe natural gas storage for wind following electric generation plants is needed, and we are working on opportunities to expand our Mist storage facility to support an announced gas fired plant being built by Portland General Electric (PGE) at Port Westward, Oregon to follow wind. The Mist expansion project is subject to several conditions, including, but not limited to, PGE's approval of projected costs.

NEW UTILITY SERVICES. We are currently working to provide the infrastructure necessary to support compressed natural gas (CNG) fleets, and are monitoring the new legislation expected during 2014 that may support natural gas projects such as conversions to natural gas, heavy-duty vehicle conversions to CNG, and industrial projects.

Issues, Challenges and Performance Measures

ECONOMY. The local, national, and global economies showed signs of improvement during 2013. We saw increased utility customer growth and business demand for natural gas. Our utility's customer growth rate was 1.3% in 2013, compared to growth of 0.9% in 2012 and 0.8% in 2011. The local Oregon economy is beginning to show signs of recovery as unemployment rates in the region dropped from approximately 8% in 2012 to under 7% at the end of 2013. We believe our utility is well positioned for continued customer additions and increasing industrial demand as the economy continues to strengthen because of low, stable natural gas prices, our relatively low market penetration, and our ongoing marketing focus of converting homes and businesses to natural gas. 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. Our gas storage business is also impacted by the employment trends throughout the West coast, including California, which was among the hardest hit during the recession, but is experiencing lower unemployment levels in 2013 and improvements in housing prices.

GAS PRICES AND SUPPLIES. Our gas acquisition strategy is to secure sufficient supplies of natural gas to meet the needs of our utility customers and to hedge gas prices so we can effectively manage costs, reduce price volatility, and maintain a competitive price advantage. With recent developments in drilling technologies and the abundance of shale development around the U.S. and in Canada, the current outlook for North American natural gas supply is strong and is projected to remain this way well into the future. This projection is dependent upon a combination of supply outlook and demand factors as well as a regulatory environment that continues to support hydraulic fracturing and other drilling technologies.

Our utility's annual PGA mechanisms in Oregon and Washington, combined with our gas price hedging strategies, enable us to reduce earnings exposure for the Company and secure lower gas costs for our customers. We typically hedge gas prices on 75% of our utility's annual sales requirement based on normal weather, including both physical and financial hedges. We entered the 2013-14 gas year (November 1, 2013 - October 31, 2014) hedged at 75% of our forecasted sales volumes, including 31% in financial swap and option contracts and 44% in physical gas supplies. For further discussion see "Regulatory Matters—Rate Mechanisms—*Purchased Gas Adjustment"* below.

In addition to the amount hedged for the current gas contract year, we are also hedged at approximately 33% for the 2014-15 gas year as of December 31, 2013 and between 7% and 21% for annual requirements over the following five gas years. Our hedge levels are subject to change based on actual load volumes, which depend to a certain extent on weather and economic conditions, and estimated gas reserve production. Also, our storage inventory levels may increase or decrease based on storage expansion, storage contracts with third parties, or storage recall by the utility.

Although less expensive and more stable gas prices provide opportunities to manage costs for our utility customers, they also present challenges for our gas storage businesses by lowering the price of, and reducing the demand for, storage services. Consequently, our ability to sign storage contracts with customers at favorable prices directly impacts our financial results. Increases in demand for natural gas, or decreases in supplies can put upward pressure on gas prices and gas price volatility. Similarly, decreases in demand and increases in supplies can cause downward pressure on gas prices and gas price volatility. Current storage prices remain low due to current low stable gas prices; as a result, in the short-term we are focused on lowering operating costs and finding opportunities in the market to increase revenues through enhanced services for storage customers.

ENVIRONMENTAL COSTS. We accrue all material environmental loss contingencies related to environmental sites for which we are responsible. Due to numerous uncertainties surrounding the nature of environmental investigations and the approval of proposed remediation solutions by regulatory agencies, actual costs could vary significantly from our loss estimates. As a regulated utility, we have been allowed to defer certain costs pursuant to regulatory orders. In our general rate case, the OPUC approved our recovery of environmental costs from investigation and site remediation subject to certain conditions as noted in "Results of Operations—Regulatory Matters—*Rate Mechanisms*" below.

We also recover some of our environmental costs from insurance policies and only seek recovery from customers for amounts not covered by insurance. Ultimate recovery of environmental costs from regulated utility rates will depend on our ability to effectively manage these costs and demonstrate that costs were prudently incurred, and understand the impact of the annual earnings test in Oregon. Environmental cost recovery and carrying charges on amounts charged to Washington customers will be determined in a future proceeding.

CLIMATE CHANGE. We recognize that we are likely to be impacted by future carbon constraints. To address possible constraints, we are seeking clean energy growth opportunities that position us for long-term success in a lower carbon energy economy and to advance our customers' interests in energy conservation, efficiency and environmental stewardship. A variety of federal, state, local and international climate change initiatives, including new regulations, are underway, but we cannot determine the impact of these initiatives at this time. For example, an array of Environmental Protection Agency (EPA) rules impacting coal plants has driven some coal plants to shut down early although the EPA is not mandating coal plant closures. Coal plant shut downs could increase the demand for natural gas as a lower carbon emission fuel and create opportunities for us. Similarly, because natural gas has a relatively low carbon content, it is also possible that future carbon constraints could create additional demand for natural gas for base load electric generation, direct use in homes and businesses, backing up intermittent renewable resources, and as a transportation fuel to displace gasoline and diesel fuels.

As required under EPA greenhouse gas regulations, we annually report our system throughput and unintended greenhouse gas releases. While our carbon dioxide equivalent emission levels are relatively small, the adoption and implementation of any regulations imposing reporting obligations, or limiting emissions of greenhouse gases associated with our operations, could result in an increase in the prices we charge our customers or a decline in the demand for natural gas.

PERFORMANCE MEASURES. We measure our performance and monitor progress on relevant metrics including, but not limited to:

- earnings per share growth;
- utility margin;
- ROE; and
- various operational metrics.

CONSOLIDATED EARNINGS AND DIVIDENDS

Consolidated Earnings

Consolidated highlights include:

In millions, except EPS data	2013	2012	2011
Net income	$ 60.5	$ 58.8	$ 63.0
EPS	2.24	2.18	2.36
ROE	8.2%	8.2%	9.0%

2013 COMPARED TO 2012. The primary factors contributing to the $1.8 million increase in consolidated net income were:

- a $9.4 million increase in utility margin primarily due to customer growth and the rate-base return on our gas reserve and other investments; and
- a $2.7 million after-tax charge taken in 2012 from an Oregon general rate case disallowance.

Partially offsetting the above factors were:

- a $7.1 million increase in operations and maintenance expense primarily due to increased utility payroll and system maintenance and safety program costs; and
- a $2.9 million increase in depreciation and amortization expenses primarily due to higher levels of investment in property, plant, and equipment at the utility.

2012 COMPARED TO 2011. The most significant factors contributing to the $4.3 million decrease in consolidated net income were:

- a $4.1 million increase in operations and maintenance expense primarily due to increases in utility payroll and employee benefit costs, utility training costs, and utility expenses related to our Oregon general rate case;
- a $3.0 million increase in depreciation and amortization expenses primarily due to higher levels of investment in property, plant, and equipment at the utility; and
- a $2.7 million after-tax charge to income tax expense related to a regulatory disallowance from the Oregon general rate case.

Partially offsetting the above factors were:

- a $1.6 million increase in utility margin primarily due to a $7.4 million net charge in 2011 results related to a utility tax law change in Oregon as well as residential and commercial customer growth, partially offset by a decrease in margin primarily due to timing differences from the new billing rate structure resulting from the Oregon general rate case and the effects of warmer weather;
- a $4.1 million increase in gas storage operating income primarily attributable to revenue increases from additional contracted storage capacity at Gill Ranch, partially offset by $2.8 million increase in interest expense due to the full year impact of Gill Ranch notes; and
- a $0.9 million increase in net income from our other non-utility businesses.

Dividends

Dividend highlights include:

Per common share	2013	2012	2011
Dividends paid	$ 1.83	$ 1.79	$ 1.75

The Board of Directors declared a quarterly dividend on our common stock of 46.0 cents per share, payable on February 14, 2014, reflecting an indicated annual dividend rate of $1.84 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 2013, approximately 90% of our utility gas volumes and revenues were derived from Oregon customers, with the remaining 10% 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, but 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 businesses are subject to regulation by the OPUC, 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 FERC regulate intrastate and interstate storage services, respectively, under 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 2013, approximately 56% of our storage revenues were derived from FERC and Oregon regulated operations and approximately 44% 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. In 2008, 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. These customer rates went into effect on January 1, 2009.

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 are effective January 1, 2014, with the rate changes having no significant impact on our revenues.

2013 Regulatory Activities

WORKING GAS INVENTORY SETTLEMENT. On September 30, 2013, the OPUC approved an all-party settlement agreement that allows the Company to include $39.5 million of inventory in rate base and recover $4.5 million in carrying costs. Previously, the Company had been accruing earnings of $4.0 million related to working gas carrying costs for 2013 based on the amount of working gas inventory proposed in our 2012 general rate case. The carrying costs were included in PGA rates beginning November 1, 2013.

GASCO WATER TREATMENT STATION. On October 28, 2013, the OPUC approved placing $19.0 million of capital costs associated with constructing a water treatment station at our Gasco environmental site into rates beginning November 1, 2013. These amounts are subject to refund, with interest, in the event the Commission determines, through a separate docket, that any of these costs were incurred imprudently. On February 13, 2014, NW Natural filed an all-party stipulation in the proceeding with the OPUC, which if approved, would deem Gasco construction costs prudent and would also approve applying $2.5 million of insurance proceeds plus interest to reduce the Gasco costs included in rates beginning November 1, 2014.

SITE REMEDIATION AND RECOVERY MECHANISM (SRRM). In the 2012 Oregon general rate case, this new mechanism was approved to recover the Company's deferred environmental costs. The Commission ordered a separate docket to determine the prudence of deferred costs, the allocation of insurance proceeds, and an earnings test that would be applied to past and future deferred costs. In July 2013, all parties filed a settlement agreement with the OPUC to address how to apply the new mechanism. In November, the Commission rejected the settlement and ordered further proceedings. We have established a schedule for 2014 and are working toward resolving this matter.

INTERSTATE STORAGE SHARING. A docket has been opened to review 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. We anticipate resolution of this docket in 2014.

PREPAID PENSION ASSETS. The Company requested in its last rate case that prepaid pension assets be included in rate base and allowed a return on the investment. A separate docket was ordered by the OPUC to review the rate treatment of pensions on a general, non-utility-specific basis. This pension docket is currently open and we anticipate resolution in 2014. The OPUC has authorized NW Natural to continue collecting pension expense based on the amounts set in our 2003 Oregon general rate case and to defer into a regulatory balancing account the difference between actual expense and collected expense for future rate recovery. We anticipate resolution of this docket in 2014.

CNG TARIFF APPROVED. In January 2014, we received approval from the OPUC to offer business customers a service to install, own, and maintain gas compression equipment that enables them to fuel their vehicle fleets with CNG. NW Natural filed the tariff in June 2013 after receiving requests from businesses interested in switching or increasing the number of their fleet vehicles fueled by CNG. Costs associated with providing this service will be directly paid by business customers using the service. The OPUC will review the tariff in two years to assess the market for CNG at that time.

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, a permanent rate adjustment for our SIP program, temporary rate adjustments, which amortize balances of deferred regulatory accounts, and the removal of temporary rate adjustments effective for the previous year.

In October 2013, the OPUC and WUTC authorized PGA rate changes effective November 1, 2013. The effect of these rate changes was an increase in the average monthly bills of both Oregon and Washington residential customers by 1.5%. This was the first rate increase in five years for both states, reflecting annual adjustments for changes in wholesale costs of natural gas as well as some additional changes to Oregon rate base.

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. Under the Washington PGA mechanism, we defer 100% of the higher or lower actual gas costs, and those gas cost differences are normally passed on to customers through the annual PGA rate adjustment.

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 for refund to customers. Under this provision, if we select the 80% deferral 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 2011-2012, 2012-2013, and 2013-2014 PGA years. The ROE threshold is subject to adjustment annually based on movements in long-term interest rates. For calendar years 2011 and 2012, the ROE threshold after adjustment for long-term interest rates was 10.92% for both years. We refunded $0.7 million to customers based on the 2011 utility earnings test, and there were no refunds required based on the 2012 utility earnings test. For calendar year 2013, the ROE threshold was 10.58% with no refund expected to be required based on our results of operations. The 2013 test is expected to be filed in May of 2014.

GAS RESERVES. In 2011 the OPUC approved the Encana gas reserve transaction to provide long-term gas price protection for our utility customers and determined that the Company's costs under the agreement will be recovered, plus a rate base return on our investment, on an ongoing basis through our annual PGA mechanism, including the regulatory deferral and incentive sharing process for the commodity cost of gas. Gas produced from our interests is sold by Encana at then prevailing market prices with revenues from such sales, net of associated production costs, credited to our cost of gas. Annually, a forecast is established for the amounts related to revenues, costs, and production volumes expected, and any variances between forecasted and actual results are subject to our PGA incentive sharing in Oregon.

DECOUPLING. 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 in the Oregon general rate case with the difference between our 2003 baseline consumption and the consumption decided in our 2012 general rate case being calculated within base rates. This employs a use-per-customer decoupling mechanism, 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. Baseline consumption reflects forecasted customer consumption data used in the Oregon general rate case. 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, 2013, 8% had opted out. We do not have a weather normalization mechanism approved for residential and commercial Washington customers, which account for about 10% 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 under our annual PGA tariff complete the term of their service election.

SYSTEM INTEGRITY PROGRAM (SIP). Since 2002, various laws requiring minimum standards for integrity management programs and SIPs for natural gas transmission and distribution pipelines have been enacted. Most recently, in January 2012 the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 was signed into law and requires increased civil penalties for pipeline safety violations, improvements in prevention programs for pipelines, and additional review and analysis of various aspects of gas transmission lines. We are working diligently with industry associations and federal and state regulators to ensure our compliance with the provisions of this new law.

The OPUC approved specific accounting treatment and cost recovery for our transmission pipeline integrity management program, our SIP, and for related pipeline safety rules adopted by the U.S. Department of Transportation's PHMSA. In addition, the OPUC has provided a two-year extension beginning in November 2012 of our capital expenditure tracking mechanism to recover capital costs related to SIP. We record the costs related to the integrity management program as either capital expenditures or regulatory assets, accumulate the costs over each 12-month period, and recover the revenue requirement associated with these costs, subject to audit, through rate changes effective with the Oregon annual PGA. Our SIP costs are tracked into rates annually, with rate base recovery after the first $4 million of capital costs. An annual cap for expenditures has been set at $12 million, but extraordinary costs above the cap may be approved with written consent of the OPUC staff and other interested parties and approval of the OPUC. During 2013, the Commission approved a temporary increase to the annual cap, authorizing an additional $13.7 million of expenditures above the cap over the next two years to be tracked into rates. With the increased cap, we plan to substantially complete our bare steel replacement by the end of 2015, and as a result this stipulation precludes us from tracking any additional bare steel replacement costs into rates after 2015. We do not have any special accounting or rate treatment for our SIP costs incurred in the state of Washington.

ENVIRONMENTAL COST DEFERRAL. The OPUC has authorized the deferral of environmental costs associated with certain named sites and to accrue carrying costs on amounts deferred, subject to an annual demonstration that we have maximized our insurance recovery or made substantial progress in securing insurance recovery for unrecovered environmental expenses. Through a series of extensions, the OPUC has authorized us to defer environmental costs and accrued carrying costs through January 2014. We filed a request with the OPUC in January 2014 to continue our deferral of costs through January 2015. See Note 15 and 17 for further discussion of our regulatory and insurance recovery of environmental costs and *"2013 Regulatory Activities"* above for information regarding SRRM.

The WUTC also authorized the deferral of environmental costs, if any, that are appropriately allocated to Washington customers. This order was effective January 26, 2011 with cost recovery and a carrying charge to be determined in a future proceeding.

PENSION COST DEFERRAL. 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 were $9.1 million and $7.9 million in 2013 and 2012, respectively. See "*Application of Critical Accounting Policies and Estimates",* below. As noted above, the Company continues to seek rate treatment for amounts invested in prepaid pension assets.

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 revenues from gas storage and asset management of pipeline capacity and gas storage at Mist. Generally amounts are credited to Oregon customers in June, while credits are given to customers in Washington through reductions in rates in the annual PGA filing in November. See "Business Segments—Gas *Storage"* below.

The following table presents the credits to customers:

In millions	2013	2012	2011
Oregon utility customer credit	$ 8.8	$ 9.2	$ 12.5
Washington utility customer credit	0.5	0.8	0.9

Business Segments - Local Gas Distribution Utility Operations

Our utility margin results are largely affected by customer growth and, to a certain extent, by changes in volume due to weather and customers' gas usage patterns. In Oregon, we have a conservation tariff, which adjusts utility margin up or down through deferred accounting 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 our utility's earnings and customer charges. See "Regulatory Matters—*Rate Mechanisms"* above.

Utility segment highlights include:

Dollars and therms in millions, except EPS data	2013	2012	2011
Utility net income	$ 54.9	$ 54.0	$ 59.7
EPS - utility segment	2.03	2.01	2.23
Gas sold and delivered (in therms)	1,146	1,112	1,152
Utility margin[1]	$ 353.9	$ 344.5	$ 343.0

(1) See Utility Margin Table below for a reconciliation and additional detail.

2013 COMPARED TO 2012. The primary factors contributing to the $0.9 million or $0.02 per share increase in net income were as follows:

- a $9.4 million net increase in utility margin primarily due to:
  - a $10.8 million increase related to customer growth and the rate-base return on our gas reserve and other investments, such as our pipeline integrity tracker; and
  - a $3.9 million increase related to the timing impacts of changes in fixed monthly charges and decoupling baselines in the 2012 Oregon general rate case. As a result of changes to the decoupling baseline for average use per customer included in the 2012 rate case, the decoupling mechanism's results this year will not be comparable to last year, although the overall impact on revenues will generally be the same on an annualized basis.

  These increases in margin were partially offset by:
  - a $3.9 million decrease in gains from gas cost incentive sharing due to actual gas prices that were roughly equivalent to estimated PGA prices for the current year as compared to actual gas prices that were lower than estimated PGA prices for the prior year; and
  - a $1.4 million decrease primarily related to the lower Oregon Authorized ROE of 9.5% from the 2012 general rate case.
- a $1.5 million increase in other income and expense, net primarily due to interest on higher average regulatory account balances; and
- a $2.7 million one-time tax charge taken in 2012 from an Oregon general rate case disallowance. See "Application of Critical Accounting Policies and Estimates—*Regulatory Accounting*" below.

These factors were partially offset by:

- a $7.4 increase in operations and maintenance expense primarily due to increased utility payroll and system maintenance and safety program costs;
- a $2.9 million increase in depreciation and amortization expense primarily due to a higher level of investment in utility property, plant, and equipment; and
- a $2.4 million increase in interest expense primarily due to increases in long-term debt outstanding.

Total utility volumes sold and delivered in 2013 increased 3.1% over last year primarily due to the impact of colder weather on residential and commercial use.

2012 COMPARED TO 2011. The primary factors contributing to the $5.6 million or $0.22 per share decrease in net income were as follows:

- an $8.4 million increase in operating expenses, excluding cost of gas, primarily due to higher operations and maintenance expense and depreciation and amortization expense; and
- a $2.7 million one-time tax charge related to the Oregon general rate case. See "Application of Critical Accounting Policies and Estimates—*Regulatory Accounting*" below.

These factors were partially offset by:

- a $1.6 million net increase in utility margin primarily due to:
  - a $7.4 million one-time, pre-tax charge in 2011 related to the repeal of Senate Bill (SB) 408, which did not reoccur in 2012;
  - a 0.9% increase in customers over last year;
  - a $3.4 million increase from the allowed return on our gas reserves investment;
  - a $2.5 million increase in other margin adjustments; and
  - a $1.7 million increase in contribution from our gas cost incentive sharing mechanism.

  These increases in margin were partially offset by a $9.3 million decrease in our residential and commercial margin primarily reflecting:
  - a $3.9 million decrease due to timing differences from the new billing rate structure resulting from the Oregon general rate case;
  - an $8.4 million decrease due to weather from the following three items: (1) positive margin impact realized in the second quarter of 2011 when colder weather was not fully offset by our Oregon weather normalization mechanism, (2) warmer weather during 2012 in Washington, which does not have normalization mechanisms in place, and (3) the effect of warmer weather on margin for Oregon customers that opt out of weather normalization; and
  - a $0.5 million decrease in operating revenues primarily due to rate case impacts including a decrease in our authorized ROE.
- a $1.5 million decrease in utility interest expense due to lower interest rates on both short-term and long-term debt balances.
- a $3.5 million decrease, excluding the $2.7 million one-time tax charge mentioned above, in income taxes due to lower pre-tax utility income.

Total utility volumes sold and delivered in 2012 decreased 3.5% over last year 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	2013	2012	2011	Favorable/(Unfavorable) 2013 vs. 2012	2012 vs. 2011
Utility volumes (therms):					
Residential and commercial sales	671,906	637,885	681,621	34,021	(43,736)
Industrial sales and transportation	474,525	473,884	470,733	641	3,151
Total utility volumes sold and delivered	1,146,431	1,111,769	1,152,354	34,662	(40,585)
Utility operating revenues:					
Residential and commercial sales	$ 673,250	$ 642,337	$ 744,355	$ 30,913	$ (102,018)
Industrial sales and transportation	68,880	70,020	81,313	(1,140)	(11,293)
Regulatory adjustment for income taxes paid[1]	—	—	(7,162)	—	7,162
Other revenues	4,054	5,935	3,713	(1,881)	2,222
Less: Revenue taxes	19,002	18,430	20,741	572	(2,311)
Total utility operating revenues	727,182	699,862	801,478	27,320	(101,616)
Less: Cost of gas	373,298	355,335	458,508	17,963	(103,173)
Utility margin	$ 353,884	$ 344,527	$ 342,970	$ 9,357	$ 1,557
Utility margin:[2]					
Residential and commercial sales	$ 321,608	$ 306,382	$ 315,688	$ 15,226	$ (9,306)
Industrial sales and transportation	28,335	28,586	28,635	(251)	(49)
Miscellaneous revenues	4,308	4,452	4,875	(144)	(423)
Gain (loss) from gas cost incentive sharing	(41)	3,811	2,107	(3,852)	1,704
Other margin adjustments	(326)	1,296	(1,173)	(1,622)	2,469
Regulatory adjustment for income taxes paid[1]	—	—	(7,162)	—	7,162
Utility margin	$ 353,884	$ 344,527	$ 342,970	$ 9,357	$ 1,557
Customers - end of period:					
Residential customers	628,634	621,399	615,670	7,235	5,729
Commercial customers	65,321	63,619	62,948	1,702	671
Industrial customers	918	923	925	(5)	(2)
Total number of customers	694,873	685,941	679,543	8,932	6,398
Actual degree days	4,379	4,152	4,652		
Percent colder (warmer) than average weather[3]	3%	(3)%	9%		

(1) See "*Regulatory Adjustment for Income Taxes Paid*" below for additional information.
(2) Amounts reported as margin for each category of customers are operating revenues, which are net of revenue taxes, less cost of gas.
(3) Average weather represents the 25-year average degree days, as determined in our Oregon general rate case. For 2013, average weather represents the 25-year average degree days as set in our 2012 Oregon general rate case. For 2012, average weather represents degree days based on the 25-year average set in our 2003 Oregon general rate for the months of January through October, plus the 25-year average set in the 2012 Oregon general rate case for the months of November and December. For 2011, average weather represents the 25-year average degree days as set in the 2003 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	2013	2012	2011
Volumes (therms):			
Residential sales	418.6	395.5	424.9
Commercial sales	253.3	242.4	256.7
Total volumes	671.9	637.9	681.6
Operating revenues:			
Residential sales	$ 447.4	$ 428.5	$ 497.2
Commercial sales	225.9	213.8	247.2
Total operating revenues	$ 673.3	$ 642.3	$ 744.4
Utility margin:			
Residential:			
Sales	$ 234.1	$ 211.6	$ 222.5
Weather normalization	(9.0)	(0.1)	(10.2)
Decoupling	2.6	8.6	16.7
Total residential utility margin	227.7	220.1	229.0
Commercial:			
Sales	92.1	84.0	87.0
Weather normalization	(4.0)	0.2	(2.9)
Decoupling	5.8	2.1	2.6
Total commercial utility margin	93.9	86.3	86.7
Total utility margin	$ 321.6	$ 306.4	$ 315.7

2013 COMPARED TO 2012. The primary factors contributing to changes in the residential and commercial markets were as follows:

- sales volumes increased 34.0 million therms, or 5%, primarily reflecting 5% colder weather and customer growth;
- operating revenues increased $30.9 million, or 5%, due to a 5% increase in sales volumes and $36.2 million of credits from gas cost savings which were applied to customer billings in 2012, partially offset by an 9% decrease in average gas prices, which flowed through the Company's PGA rates; and
- utility margin increased $15.2 million, or 5%, primarily reflecting the following:
  - a $10.8 million increase related to customer growth and the rate-base return on our gas reserve and other investments; and
  - a $3.9 million increase related to the timing impacts of changes in fixed monthly charges and decoupling baselines in the 2012 Oregon general rate case.
  - Partially offsetting these increases was a $1.4 million decrease primarily related to the lower Oregon Authorized ROE of 9.5% from the 2012 general rate case.

2012 COMPARED TO 2011. The primary factors contributing to changes in the residential and commercial markets were as follows:

- sales volumes decreased 43.7 million therms, or 6%, primarily reflecting 11% warmer weather;
- operating revenues decreased $102.0 million, or 14%, due to a 6% decrease in sales volumes, a 7% decrease in average gas prices, which flowed through the Company's PGA rates, and $36.2 million of credits on customers' bills in 2012 related to the refund of gas cost savings; and
- utility margin decreased $9.3 million, or 3%, primarily reflecting the following:
  - a $3.9 million decrease due to timing differences from the new billing rate structure resulting from the Oregon general rate case;
  - an $8.4 million decrease due to the following weather impacts: (1) a $3.0 million of positive margin impact realized in the second quarter of 2011 when colder weather was not fully offset by our Oregon weather normalization mechanism, (2) a $3.2 million decrease due to warmer weather in Washington, which does not have normalization mechanisms in place, and (3) a $2.2 million decrease due to the effect of warmer weather on margin for Oregon customers that opt out of weather normalization;
  - a $0.5 million decrease in operating revenues primarily due to rate case impacts including a decrease in our authorized ROE; and
  - a $3.4 million margin increase from our gas reserves investment.

Industrial Sales and Transportation

Operating revenues from industrial customers include the commodity cost component of gas sold under sales service but not under transportation service. Therefore, operating revenues from industrial customers can increase or decrease when customers switch between sales service and transportation service, but generally our margins from these customers are unaffected by these changes because we do not typically include a profit mark-up for the cost of gas. As such, we believe volumes delivered and margins are better measures of performance for the industrial sector.

Industrial sales and transportation highlights include:

In millions	2013	2012	2011
Volumes (therms):			
Industrial - firm sales	34.3	34.9	37.6
Industrial - firm transportation	144.5	131.2	133.0
Industrial - interruptible sales	59.5	59.6	59.1
Industrial - interruptible transportation	236.2	248.2	241.0
Total volumes	474.5	473.9	470.7
Utility margin:			
Industrial - sales and transportation	$ 28.3	$ 28.6	$ 28.6

2013 COMPARED TO 2012. The primary factors contributing to changes in the industrial sales and transportation markets were as follows:

- sales volumes remained relatively flat for 2013 compared to 2012; and
- utility margin decreased 1%, primarily due to lower demand from customers in the pulp and paper segment. These decreases were partially offset by contributions from new customers and added load from existing customers.

2012 COMPARED TO 2011. The primary factors contributing to changes in the industrial sales and transportation markets were as follows:

- sales volumes increased 3.2 million therms, or 1%, primarily reflecting the impact of customers switching to natural gas due to the lower prices of natural gas compared to oil; and
- utility margin remained flat primarily reflecting the loss of a few large industrial customers in 2011 due to the economy. Partially offsetting this decrease was an increase in customers switching to natural gas throughout 2012 due to its price advantage.

Regulatory Adjustment for Income Taxes Paid

Oregon Senate Bill (SB) 408 was in effect from 2007 through 2010 and was a regulatory mechanism for truing up income taxes paid. In May 2011, SB 967 effectively repealed the SB 408 regulatory adjustment for income taxes paid for the 2010 tax year and all years thereafter. Due to the repeal, the Company recorded a $7.4 million write-off including interest in 2011. For additional information, see "Application of Critical Accounting Policies and Estimates—*Revenue Recognition"* below.

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 current or future revenues from residential, commercial and industrial firm customers.

Other revenue highlights include:

In millions	2013	2012	2011
Other operating revenues	$ 4.1	$ 5.9	$ 3.7

2013 COMPARED TO 2012. The primary factors contributing to changes in other revenues were as follows:

- other revenues decreased $1.9 million primarily due to a positive 2012 regulatory adjustment which did not reoccur in 2013.

2012 COMPARED TO 2011. The primary factors contributing to changes in other revenues were as follows:

- other revenues increased $2.2 million primarily due to a net increase in revenues from various regulatory adjustments of approximately $2.7 million, partially offset by a decrease of $0.4 million of miscellaneous fee income.

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, production from gas reserves, 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 whereby we either increase or decrease margin results based on a percentage of actual gas costs as compared to embedded gas costs in the PGA. Under this provision, our net income can be affected by differences between actual and expected gas costs, which occur primarily because of market fluctuations and volatility affecting unhedged gas purchases in the PGA. In addition, we have a regulatory agreement where we earn a rate-base return on our investment in gas reserves, which is reflected in utility margin. See "Regulatory Matters—Rate Mechanisms—*Purchased Gas Adjustment* and *Gas Reserves"* above.

We use natural gas commodity hedge contracts (derivative instruments), primarily fixed-price commodity swaps, consistent with our financial derivatives policies to help manage gas price stability. Gains and losses from these financial hedge contracts are generally included in our PGA and normally do not impact net income because the hedged prices are reflected in our annual PGA rates, subject to a regulatory prudence review. However, hedge contracts entered into after the annual PGA rates are set for Oregon customers can impact net income because we would be required to share in any gains or losses as compared to the corresponding commodity prices built into rates in the PGA. In Washington, 100% of the actual gas costs, including hedge gains and losses allocated to Washington gas sales, are passed through in customer rates. See "Application of Critical Accounting Policies and Estimates—*Accounting for Derivative Instruments and Hedging Activities"* below, "Regulatory Matters—Rate Mechanisms—*Purchased Gas Adjustment"* above, and Note 13.

Cost of gas highlights include:

Dollars and therms in millions		2013		2012		2011
Cost of gas	$	373.3	$	355.3	$	458.5
Total volumes sold and delivered (therms)		1,146		1,112		1,152
Average cost of gas (cents per therm)	$	0.49	$	0.54	$	0.59
Gain from gas cost incentive sharing		—		3.8		2.1

2013 COMPARED TO 2012. The primary factors contributing to changes in cost of gas were as follows:

- cost of gas increased $18.0 million, or 5%, including the $37.7 million of credits applied to customer billings in 2012 related to the refund of gas cost savings. Excluding the customer credits, total cost of gas decreased $19.7 million, or 5%, primarily due to a 3% increase in volumes offset by an 9% decrease in average cost of gas collected through rates, reflecting lower market prices for natural gas.

2012 COMPARED TO 2011. The primary factors contributing to changes in cost of gas were as follows:

- cost of gas decreased $103.2 million, or 23%, including the $37.7 million of credits applied to customer billings in 2012 related to the refund of gas cost savings. Excluding the customer credits, total cost of gas decreased $65.5 million, or 14%, primarily reflecting lower usage due to 11% warmer weather and PGA rate decreases in 2012 and 2011; and
- average cost of gas collected through rates decreased 5 cents per therm, primarily reflecting lower gas prices that were passed on to customers through PGA rate decreases effective November 1, 2011 and 2012.

The effect on net income from our gas cost incentive sharing mechanism was a pre-tax loss in margin of less than $0.1 million in 2013 compared to a pre-tax gain in margin of $3.8 million in 2012 and $2.1 million in 2011. 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% 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 using our utility's storage or transportation capacity is subject to revenue sharing with core utility customers. Under this regulatory incentive sharing mechanism in Oregon, we retain 80% of pre-tax income from Mist gas storage services and from 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. We have a similar sharing mechanism in Washington for pre-tax income derived from gas storage and asset management services.

Our 75% undivided ownership interest in the Gill Ranch facility is held by our wholly-owned subsidiary Gill Ranch, which is also the operator of the facility. Our portion of the facility is currently providing 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 manage the value of our storage assets at Gill Ranch. See Note 4.

Gas storage segment highlights include:

In millions, except EPS data		2013		2012		2011
Gas storage net income	$	5.6	$	4.5	$	4.1
EPS - gas storage segment		0.21		0.17		0.15
Average gas storage contracted capacity (Bcf)		21		21		16

2013 COMPARED TO 2012. Our gas storage segment net income increased $1.0 million primarily due to higher revenues from asset management services and lower operating costs.

2012 COMPARED TO 2011. Our gas storage segment net income increased $0.4 million primarily due to revenue increases at Gill Ranch from additional contracted storage capacity. This increase was partially offset by a full year of interest expense from Gill Ranch's senior secured debt, which was issued in November 2011.

For the 2013-2014 gas storage year we are fully contracted at Gill Ranch and at Mist. We are in the process of contracting for the upcoming 2014-2015 gas storage year, which begins in April 2014. The market outlook for gas storage in 2014 remains challenging. In recent months, the country has seen significant storage withdrawals and gas price volatility due to the extreme cold weather nationally, but current storage values have been negatively impacted by the increase in spring and summer prices as they are similar to winter prices, thus reducing the desirability of purchasing gas. As a result we anticipate contracting for the upcoming storage year at lower market prices than in previous periods, especially at our California facility where some multi-year contracts are expiring. See, "Financial Condition—*Liquidity and Capital Resources*" for more information.

Other

Other primarily consists of NNG Financial's equity investment in KB Pipeline, an equity investment in PGH, which in turn has invested in a cross-Cascades pipeline project, and other miscellaneous non-utility investments and business activities. See Note 4 and Note 12 for further details on other activities and our investment in PGH.

Other highlights include:

In millions, except EPS data	2013	2012	2011
Other net income (loss)	$ —	$ 0.2	$ (0.7)
EPS - other	—	—	(0.02)

2013 COMPARED TO 2012. Other remained relatively flat over 2013 compared to 2012, as anticipated.

2012 COMPARED TO 2011. Other net income increased $0.9 million as our investment in PGH had a $1.3 million impairment charge in 2011, which did not reoccur in 2012.

Consolidated Operations

Operations and Maintenance

Operations and maintenance highlights include:

In millions	2013	2012	2011
Operations and maintenance	$ 136.6	$ 129.5	$ 125.4

2013 COMPARED TO 2012. Operations and maintenance expense increased $7.1 million or 6% in 2013 compared to 2012. The following summarizes the major factors that contributed to this increase:

- a $5.9 million increase in utility payroll expense primarily related to additional customer service positions for new programs and higher incentive compensation; and
- a $2.7 million increase in utility expenses related to system maintenance and safety program costs.

Partially offsetting the above factors were:

- a $0.9 million decrease in utility bad debt expense. See further discussion below.

2012 COMPARED TO 2011. Operations and maintenance expense increased $4.1 million or 3% in 2012 compared to 2011. The following summarizes the major factors that contributed to this increase:

- a $3.7 million increase in utility payroll expense primarily related to an increase in field service employees;
- a $1.7 million increase in utility non-payroll expense including higher costs for new employee training, expenses related to the Oregon general rate case, higher costs for information technology system maintenance and other general customer service cost increases; and
- a $0.9 million increase in utility employee benefit expense, principally related to health care and pension costs, which were driven by an increase in employee count. See below for additional discussion on pension costs.

Partially offsetting the above factors were:

- a $1.1 million reduction in gas storage general and administrative expense primarily reflecting lower costs compared to 2011 when Gill Ranch incurred higher start-up costs; and
- a $0.8 million decrease in utility bad debt expense.

The utility's bad debt expense remains well below 0.5% of operating revenues and has decreased compared to 2012. This decrease is primarily due to lower levels of delinquent account balances during the period and a continuation of lower delinquency rates resulting in an overall decrease to our allowance for uncollectible accounts. Our bad debt expense results are at historically low levels for the Company.

Our accounting expense for pension costs increased in 2013 largely due to lower discount rates; however, the OPUC approved a deferral of our utility pension costs for amounts in excess of what is currently recovered in customer rates. The pension cost deferral is recorded to a regulatory balancing account, which reduces operations and maintenance expense. For the year ended December 31, 2013 and 2012, we deferred pension expenses totaling $9.1 million and $7.9 million, respectively. See Note 8. As a result, increased pension costs had a minimal effect on operations and maintenance expense in 2013 and 2012, with the increase principally related to the cost allocation to our Washington operations, which are not covered by the pension balancing account. For further explanation of the pension balancing account, see "Regulatory Matters—Rate Mechanisms—*Pension Deferral"* above.

General Taxes

General taxes principally consist of property and payroll taxes and regulatory fees.

General tax highlights include:

In millions	2013	2012	2011
General taxes	$ 30.0	$ 30.6	$ 29.3

2013 COMPARED TO 2012. General taxes remained relatively flat for 2013 compared to 2012, as anticipated.

2012 COMPARED TO 2011. General taxes increased $1.3 million or 4% in 2012 compared to 2011 primarily due to a $0.7 increase in property taxes at Gill Ranch, which reflect increased capital investments added to assessed property tax values during 2012, as well as a $0.4 increase in payroll tax expense at the utility.

Depreciation and Amortization

Depreciation and amortization highlights include:

In millions	2013	2012	2011
Depreciation and amortization	$ 75.9	$ 73.0	$ 70.0

2013 COMPARED TO 2012. Depreciation and amortization expense for 2013 increased by $2.9 million compared to 2012 due to an increase in utility depreciation expense on investments in utility plant for system improvements and training facilities.

2012 COMPARED TO 2011. Depreciation and amortization expense for 2012 increased by $3.0 million compared to 2011 primarily due to a $2.7 million increase in investments in utility plant for system improvements and training facilities.

Other Income and Expense, Net

Other income and expense, net highlights include:

In millions	2013	2012	2011
Gains from company-owned life insurance	$ 2.5	$ 2.3	$ 2.2
Interest income	0.1	0.2	0.1
Gain on sale of investments	—	(0.2)	(0.1)
Income (loss) from equity investments	(0.1)	—	(1.6)
Net interest on deferred regulatory accounts[1]	4.5	3.0	4.6
Other non-operating	(2.3)	(2.1)	(2.1)
Total other income and expense, net	$ 4.7	$ 3.2	$ 3.1

[1] Prior period balances have been adjusted for a prior period error identified during the first quarter of 2013. See Note 16 for additional detail.

2013 COMPARED TO 2012. Other income and expense, net increased $1.5 million in 2013 primarily due to interest on higher average regulatory account balances.

2012 COMPARED TO 2011. Other income and expense, net remained relatively flat for 2012 compared to 2011.

Interest Expense, Net

Interest expense, net highlights include:

In millions	2013	2012	2011
Interest expense, net	$ 45.2	$ 43.2	$ 42.1

2013 COMPARED TO 2012. Interest expense, net of amounts capitalized, increased $2.0 million in 2013 primarily due to an increase of $2.3 million at the utility from the issuance of long-term debt. The utility issued $50 million of debt with a coupon rate of 3.542% in August 2013 and $50 million of debt with a coupon rate of 4.00% in October 2012. This increase was partially offset by a $0.7 million reduction in 2013 interest expense at the utility from the retirement of $40 million of long-term debt with a coupon rate of 7.13% in 2012. See Note 7 for further detail.

2012 COMPARED TO 2011. Interest expense, net of amounts capitalized, in 2012 increased $1.1 million primarily due to a $2.8 million increase in interest expense at Gill Ranch from the issuance of $40 million of subsidiary senior secured debt in November 2011, partially offset by a $1.5 million decrease in interest expense at the utility due to lower interest rates on new short-term and long-term debt issuances.

Interest expense also reflects a lower average interest rate used in calculating the allowance for funds used during construction (AFUDC). AFUDC rates, consists of short-term and long-term capital costs as appropriate, were 0.3% in both 2013 and 2012, and 0.5% in 2011.

Income Tax Expense

Income tax expense highlights include:

In millions	2013	2012	2011
Income tax expense	$ 41.7	$ 43.4	$ 42.8
Effective tax rate	40.8%	42.5%	40.5%

2013 COMPARED TO 2012. The decrease in income tax expense of $1.7 million or 4% was primarily due to a $2.7 million one-time tax charge taken in 2012 from an Oregon general rate case disallowance.

2012 COMPARED TO 2011. The increase in income tax expense of $0.6 million or 1% was primarily due to a one-time $2.7 million tax charge related to the 2012 Oregon general rate case. This increase in taxes was partially offset by lower pre-tax consolidated earnings.

EFFECTIVE TAX RATES. The effective tax rate in 2013 was lower due to the tax charge taken in 2012 but consistent with expectations and historical rates. The higher effective tax rate in 2012 was primarily due to the $2.7 million tax charge related to the Oregon general rate case. For more information on our income taxes, including a reconciliation between the statutory federal and state income tax rates and the effective tax rate, see Note 2 and Note 9.

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. When additional capital is required, debt or equity securities are issued depending upon 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,	
	2013	2012
Common stock equity	44.7%	45.3%
Long-term debt	40.5	42.9
Short-term debt, including current maturities of long-term debt	14.8	11.8
Total	100.0%	100.0%

Liquidity and Capital Resources

At December 31, 2013, we had $9.5 million of cash and cash equivalents compared to $8.9 million at December 31, 2012. We also had $4.0 million in restricted cash at Gill Ranch as of December 31, 2013 and 2012, which is being held as collateral for its long-term debt outstanding. 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 months when the utility borrows money to cover the lag between when it purchases natural gas and when customers pay for the gas. Our short-term liquidity is supported by cash balances, internal cash flow from operations, proceeds from the sale of commercial paper notes, borrowings from multi-year credit facilities, cash available from surrender value in company-owned life insurance policies, and proceeds from the sale of long-term debt. We use utility long-term debt proceeds to finance utility capital expenditures, refinance maturing debt of the utility and provide for general corporate purposes of the utility.

Market conditions have improved over the past few years as reflected by tighter credit spreads and increased access to financing for investment grade issuers. 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 from our back-up credit facility. In the event that we are not able to issue new debt due to adverse market conditions or other reasons, we expect that 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 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, 2013, we have Board authorization to issue up to $325 million of additional first mortgage bonds. We currently have OPUC approval to issue up to $25 million of additional long-term debt for approved purposes. We plan to file an application with the OPUC in early 2014 to increase our OPUC long-term debt authorization to $325 million.

In the event that 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 form of collateral, which could expose us to additional cash requirements and may trigger increases in short-term borrowings. However, based upon current financial swap and option contracts outstanding, we do not have any collateral demand exposure as the Company had unrealized gains of $5.4 million at December 31, 2013.

The "Dodd-Frank Wall Street Reform and Consumer Protection Act" (Dodd-Frank Act or DFA) establishes a statutory framework for the comprehensive regulation of financial institutions that participate in the swaps market and, among other things, requires additional government regulation of derivative and over-the-counter transactions and expanded collateral requirements. The Company is not currently subject to regulation as a Swap Dealer under the DFA nor do we expect that it will be in the future based on current or as yet unfinalized rules. Further, we believe we are eligible for and have taken appropriate steps to be an exempt end-user and as such we are exempt from certain reporting obligations under the DFA. We will continue to monitor interpretations and Commodity Futures Trading Commission guidance to determine the impact, if any, on our hedging policies, procedures, results of operations, financial position and liquidity.

Other recent developments that may have a significant impact on our liquidity and capital resources include pension contribution requirements, current tax benefits from bonus depreciation and other tax advantaged investments, environmental expenditures and insurance recoveries, and strategic growth initiatives.

With respect to pensions, 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). See "Application of Critical Accounting Policies—*Accounting for Pensions and Postretirement Benefits*" below.

Regarding federal income tax liabilities, extensions were granted allowing us to take 100% bonus depreciation on qualified expenditures during 2011 and 50% bonus depreciation on a majority of our capital expenditures in 2012 and 2013, which significantly reduced our tax liability for those tax years and is expected to provide cash flow benefits in subsequent years.

Concerning environmental expenditures, we expect to continue using cash resources to fund our environmental liabilities, but we also anticipate recovering amounts through our insurance settlements and utility rates. The amount and timing of these expenditures is uncertain with additional insurance recoveries expected in 2014. See Note 15, Note 17, and "Results of Operations—Regulatory Matters—*Environmental Costs*".

The Company did not issue any one-time refunds or credits to customers from gas cost savings in 2013. In 2012, due to significantly lower gas prices from November 2011 to March 2012, the Company was able to provide $35 million of credits to its Oregon utility customers' bills and $4 million in credits to its Washington customers. See "Results of Operations—Regulatory Matters—Regulatory Mechanisms —*Purchased Gas Adjustment* and —*Customer Credits for Gas Cost Incentive Sharing*" above. In addition, the Company may also provide its Oregon utility customers with interstate storage credits from the regulatory incentive sharing mechanism related to gas storage and asset management services. See "Results of Operations—Regulatory Matters—Regulatory Mechanisms—*Customer Credits for Gas Storage Sharing*" above.

Short-term liquidity for our gas storage segment is supported by cash balances, internal cash flow from operations, external financing, and, to a certain extent, equity investments from its parent company. Gill Ranch has limited operational history, with operations commencing in October 2010. The abundant supply of natural gas, low volatility of natural gas prices, and available gas storage capacity in California have resulted in lower storage market prices than we have seen in previous years. As a result, we are anticipating lower estimated future earnings and cash flows for Gill Ranch. The amount and timing of these cash flows from year to year are uncertain as the majority of Gill Ranch's storage contracts are short-term. While we expect short-term storage prices to be challenging, we do not anticipate material changes in our sources of short-term liquidity and anticipate our operating cash flows will be sufficient.

In November 2011, Gill Ranch issued $40 million of senior secured debt, with a fixed interest rate on $20 million and a variable interest rate on the remaining $20 million. The average combined interest rate on the debt was 7.38% per annum through December 31, 2013. This debt is secured by all of the membership interests in Gill Ranch and is nonrecourse to NW Natural and other entities of the consolidated group. The maturity date of the debt is November 30, 2016.

Under the debt agreements, Gill Ranch is subject to certain covenants and restrictions, including but not limited to a financial covenant that requires Gill Ranch to maintain minimum adjusted EBITDA at various levels over the term of the debt. The minimum adjusted EBITDA increases incrementally over the first few years, reaching its highest level in the 12-month period beginning April 1, 2015. Under the agreements, Gill Ranch is also subject to a debt service reserve requirement of 10% of the outstanding principal amount, certain prepayment penalties, restrictions on dividends out of Gill Ranch unless certain earnings ratios are met, and restrictions on the incurrence of additional debt. At December 31, 2013, we were in compliance with all covenants and restrictions under the debt agreements.

Based on several factors, we believe our Company's 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, 2013 by maturity and type of obligation:

	Payments Due in Years Ending December 31,						
In millions	2014	2015	2016	2017	2018	Thereafter	Total
Commercial paper	$ 188.2	$ —	$ —	$ —	$ —	$ —	$ 188.2
Long-term debt maturities	60.0	40.0	65.0	40.0	22.0	514.7	741.7
Interest on long-term debt	41.8	40.3	37.3	32.1	29.2	271.3	452.0
Postretirement benefit payments(1)	21.9	22.5	23.3	24.1	25.0	148.7	265.5
Capital leases	0.5	0.2	0.1	—	—	—	0.8
Operating leases	5.6	5.5	5.5	5.5	2.9	34.9	59.9
Gas purchases(2)	60.7	—	—	—	—	—	60.7
Gas pipeline capacity commitments	98.7	77.4	66.1	52.1	42.3	217.0	553.6
Gas reserves(3)	49.2	41.8	—	—	—	—	91.0
Other purchase commitments(4)	0.5	0.1	—	—	—	13.6	14.2
Other long-term liabilities(5)	15.2	—	—	—	—	—	15.2
Total	$ 542.3	$ 227.8	$ 197.3	$ 153.8	$ 121.4	$ 1,200.2	$ 2,442.8

(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 the Company withdrawing from the plan in December 2013. See Note 8.

(2) Gas purchases include contracts which use price formulas tied to monthly index prices, plus hedged derivative liabilities. Commitment amounts are based on futures prices as of December 31, 2013. For a summary of derivatives, see Note 13. For a summary of gas purchase and gas pipeline capacity commitments, see Note 14.

(3) Gas reserves payments reflect contractual obligations to invest in additional gas reserves under our agreements. The contracts for such reserves include termination provisions, under which investments in additional reserves would not be required, if conditions for such provisions were met. We have assumed no cancellation for disclosure of gas reserve commitments.

(4) Other purchase commitments primarily consist of base gas requirements and remaining balances under existing purchase orders.

(5) 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, 2013, 612 of our utility employees were members of the Office and Professional Employees International Union (OPEIU) Local No. 11. In July 2009, these union employees and the Company agreed to a five-year labor agreement called the Joint Accord. The 2009 Joint Accord provides for a 1% automatic wage increase each year, plus the potential for up to an additional 2% based on wage inflation and other factors. It also provides competitive health benefits while limiting the cost increases for these benefits to the same level as the annual wage increases. The 2009 Joint Accord extends to May 31, 2014. In 2013, each party served notice of intent to negotiate the terms of an agreement prior to the May 31, 2014 expiration date. We are currently engaged in negotiations to meet this schedule.

Short-Term Debt

Our primary source of utility short-term liquidity is from internal cash flows and the sale of commercial paper. In addition to issuing commercial paper 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 is 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. At December 31, 2013 and 2012, our utility had commercial paper outstanding of $188.2 million and $190.3 million, respectively. The effective interest rate on the utility's commercial paper outstanding at December 31, 2013 and 2012 was 0.3%.

Credit Agreements

In December 2012, we entered into a new multi-year credit agreement for unsecured revolving loans totaling $300 million and an available extension of commitments for two additional one-year periods, subject to lender approval. In December 2013, we extended our commitment for an additional year with an updated maturity date of December 20, 2018. All lenders under the new agreement are major financial institutions with committed balances and investment grade credit ratings as of December 31, 2013 as follows:

In millions Lender rating, by category		Loan Commitment
AA/Aa	$	189
A/A		111
BBB/Baa		—
Total	$	300

Based on credit market conditions, it is possible that one or more lending commitments could be unavailable to us if the lender defaulted due to lack of funds or insolvency; however, the Company does not believe this risk to be eminent due to the lenders' strong investment grade credit ratings.

Our credit agreement allows us to request increases in the total commitment amount, up to a maximum of $450 million. The agreement also permits the issuance of letters of credit in an aggregate amount of up to $200 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 or our prior credit agreement at December 31, 2013 or 2012. 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, 2013 and 2012, with consolidated indebtedness to total capitalization ratios of 55.3% and 54.7%, 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. In addition, 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 in our liquidity, 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. In February 2014, Moody's revised our ratings outlook from negative to stable. 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 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.

Retirements of Long-Term Debt

The following FMBs were retired:

	Years Ended December 31,					
In millions	2013		2012		2011	
Company First Mortgage Bonds						
6.665% Series B due 2011	$	—	$	—	$	10
7.13% Series B due 2012		—		40		—
	$	—	$	40	$	10

Cash Flows

Operating Activities

Year-over-year 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	2013	2012	2011
Cash provided by operating activities	$ 176.4	$ 168.8	$ 233.5

2013 COMPARED TO 2012. The significant factors contributing to the $7.6 million increase in operating cash flows were as follows:

- an increase of $15.8 million in other, net primarily due to inflows from changes in net regulatory balances offset by a decrease in pension liabilities;
- an increase of $12.4 million from net changes in gas cost balances, which primarily reflects $39 million in credits refunded to customers in 2012;
- an increase of $11.8 million due to lower cash contributions to qualified defined benefit pension plans as a result of new IRS funding rules, commonly referred to as MAP-21;
- an increase of $8.0 million from changes in accounts payable balances; and
- an increase of $4.7 million due to changes in the amortization of gas reserves balance.

Partially offsetting these increases was:

- a decrease of $48.3 million from changes in the accounts receivable balance, primarily due to customer growth and 29% colder weather in December 2013.

During the year ended December 31, 2013, we contributed $11.7 million to our utility's qualified defined benefit pension plans, which was significantly higher than the $5.7 million in non-cash expense recognized on the income statement. In 2012, we contributed $23.5 million and had $5.4 million in non-cash expense. We expect pension contributions to exceed non-cash expense for the next few years, but contribution amounts will be less than previously anticipated due to the new federal funding requirements under MAP-21. The amounts and timing of future contributions will depend on market interest rates and investment returns on the plans' assets. See Note 8.

Also significantly affecting cash flows over the past few years has been income tax relief, including the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (2010 Act) and American Taxpayer Relief Act of 2012 (2012 Act). The 2010 Act allowed 100% bonus depreciation on qualified property placed in service between September 9, 2010 and December 31, 2011, and also extended the 50% bonus depreciation deduction to qualifying property placed in service during 2012. The 2012 Act extended 50% bonus depreciation through 2013 for modified accelerated cost recovery system (MACRS) property with a recovery period of 20 years or less. These and other tax benefits resulted in a net operating loss for 2010, which was carried back to the tax year 2009 and resulted in a federal income tax refund of $22.3 million received in 2011 and an additional $2.1 million received in 2012. We generated taxable income in 2011 that was fully offset by the net operating loss (NOL) carried forward from 2010. We generated NOL carryforwards during 2012 and 2013. As of December 31, 2013, we had an estimated federal income tax receivable balance of $3.2 million and an estimated NOL carryforward balance of $113.0 million. In 2011, Oregon conformed with federal bonus depreciation, contributing to a state NOL carryforward of $113.7 million. We anticipate being able to use the full amount of both NOL carryforward balances in future years prior to expiration. The NOLs would otherwise expire in 20 years for federal and 15 years for Oregon.

Final tangible property regulations applicable to all taxpayers were issued by the Treasury Department on September 13, 2013. These regulations are generally effective for taxable years beginning on or after January 1, 2014. In addition, procedural guidance related to the regulations was recently 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 2014. We will evaluate the impact of this guidance once it is finalized.

2012 COMPARED TO 2011. The significant factors contributing to the $64.6 million decrease in operating cash flow for 2012 compared to 2011 are as follows:

- a decrease of $38.1 million in deferred environmental expenditures, net of recoveries, primarily due to insurance recoveries for environmental claims received in 2011;
- a decrease of $30.9 million in taxes accrued, primarily due to federal tax refunds totaling $36.6 million received in 2011; and
- a decrease of $26.2 million from changes in the deferred gas cost savings balance, which was reduced when approximately $39 million was refunded to customers in June and July 2012.

Partially offsetting these decreases was:

- an increase of $28.4 million from reductions in receivable balances primarily due to higher receivable balances from colder weather at the end of 2011, which were collected early in 2012.

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	2013	2012	2011
Total cash used in investing activities	$ 182.1	$ 184.7	$ 153.1
Capital expenditures	138.9	132.0	100.5
Proceeds from sale of assets	(8.6)	—	—
Utility gas reserves	54.1	54.1	50.6

2013 COMPARED TO 2012. The $2.5 million decrease in cash used in investing activities was due to proceeds received from the sale of assets. This decrease was partially offset by higher capital expenditures, reflecting increased investments for new customer acquisitions, completion of our Gasco Source Control water treatment station, and additional expenditures for system integrity and bare steel pipe removal.

2012 COMPARED TO 2011. The $31.6 million increase in cash used in investing activities was due to higher capital expenditures reflecting expenditures relating to a new utility training and back-up emergency operations facility, and several upgrades to existing building facilities. In addition, we also invested additional monies in utility gas reserves.

Over the five-year period 2014 through 2018, total utility capital expenditures are estimated to be between $600 and $700 million and utility expenditures under the existing gas reserves agreement are estimated to be around $90 million. The estimated level of utility capital expenditures over the next five years reflects assumptions for continued customer growth, technology, distribution system improvements and gas storage facilities. Most of the required funds are expected to be internally generated over the five-year period, and any remaining funding will be obtained through the issuance of long-term debt or equity securities, with short-term debt providing liquidity and bridge financing. In 2014, utility capital expenditures are estimated to be between $115 and $135 million, and non-utility capital investments are estimated to be less than $10 million. Additional non-utility spend for gas storage and other investments during and after 2014 will depend largely on future decisions about potential expansion opportunities in gas storage and pipeline projects. Gas storage segment capital expenditures in 2014 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	2013	2012	2011
Total cash provided by (used in) financing activities	$ 6.3	$ 18.9	$ (78.0)
Change in short-term debt	(2.1)	48.7	(115.8)
Change in long-term debt	50.0	10.0	80.0

2013 COMPARED TO 2012. The $12.6 million decrease in cash provided by financing activities was primarily due to changes in our short-term debt balances, which decreased $2.1 million in 2013 compared to an increase of $48.7 million in 2012. This decrease was partially offset by changes in our long-term debt balances, which increased due to $40 million of long-term debt retired in 2012. We continue to use long-term debt proceeds to finance capital expenditures, refinance maturing short-term or long-term debt maturities, and to fund other general corporate purposes.

2012 COMPARED TO 2011. The $97.0 million increase to cash provided by financing activity was primarily due to changes in our short-term debt balances, which increased $48.7 million in 2012 compared to a decrease of $115.8 million in 2011. In 2012, we retired $40 million of long-term debt and issued $50 million of long-term debt.

We have a stock repurchase program approved through May 2014 which provides authorization to repurchase up to 2.8 million shares of NW Natural common stock or up to $100 million. The purchases may be made in the open market or through privately negotiated transactions. No repurchases were made in 2013, 2012 or 2011 under the program. Since the program's inception, we have repurchased an aggregate 2.1 million shares of common stock at a total cost of $83.3 million, at an average price of $39.19 per share. See Part II, Item 5, "Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities" above.

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 are allocated between operation and maintenance expenses, capital expenditures, and the deferred regulatory balancing account, totaled $21.5 million in 2013, an increase of $2.4 million from 2012. The fair market value of pension assets in this plan increased to $267.1 million at December 31, 2013 from $249.6 million at December 31, 2012. The increase was due to a return on plan assets of $22.9 million plus $11.7 million in employer contributions, partially offset by benefit payments of $17.1 million.

We make contributions to company-sponsored qualified defined benefit pension plans based on actuarial assumptions and estimates, tax regulations and funding requirements under federal law. Our qualified defined benefit pension plans were underfunded by $95.3 million at December 31, 2013. We plan to make contributions during 2014 of $15 million.

We also contributed to a multiemployer pension plan for our union employees (the Union Plan, or otherwise known as Western States Plan) pursuant to our collective bargaining agreement. We made contributions totaling $0.5 million to the Union Plan in 2013 and $0.4 million in 2012. Effective December 22, 2013, we withdrew from the plan and have been assessed a withdrawal liability of approximately $8.3 million, which requires NW Natural to contribute $0.6 million each year to the plan for the next 20 years. See Note 8 for further pension disclosures.

Ratios of Earnings to Fixed Charges

For the years ended December 31, 2013, 2012, and 2011, our ratios of earnings to fixed charges, computed using the Securities and Exchange Commission (SEC) method, were 3.16, 3.26, and 3.38, 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. The prior period amounts have been corrected for the prior period error identified in the first quarter of 2013. See Note 16 for detail on the prior period correction and 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 Part II, Item 7, "*Application of Critical Accounting Policies and Estimates*" below. At December 31, 2013, we had a regulatory asset of $148.4 million for deferred environmental costs, which includes $98.1 million for additional costs expected to be paid in the future and $20.3 million of accrued interest. Additionally, in 2014, a settlement was reached in our environmental insurance recovery litigation with remaining insurers. If it is determined that insurance recoveries for environmental costs are insufficient and future rate recovery of such costs are not probable, the costs will be charged to expense in the period such determination is made. For further discussion of contingent liabilities see Note 15, for an update regarding insurance settlements see Note 17, and see also "Results of Operations—Regulatory Matters—Rate Mechanisms—*Environmental Costs*".

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 using 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; and
- environmental contingencies.

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, regulatory and competitive conditions, we believe that it is reasonable to expect continued application of regulatory accounting for our utility activities, and that our regulatory assets and liabilities at December 31, 2013 are reasonably likely to be recovered or refunded through future customer rates. 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 against earnings in the period such determination is made. The net balance in regulatory asset and liability accounts as of December 31, 2013 and 2012 was $60.4 million and $125.8 million, respectively. See Note 2 "*Industry Regulation*".

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. Revenues are accrued for gas delivered and services rendered to customers, but not yet billed, based on estimates from the last meter reading date to month end (accrued unbilled revenue). Accrued unbilled revenue is based on a percentage estimate of amounts unbilled each month, which is dependent upon a number of factors, some of which require management's judgment. These factors include:

- total gas receipts and deliveries;
- customer meter reading dates;
- customer usage patterns; and
- weather.

Accrued unbilled revenue estimates are reversed the following month when actual billings occur. Accrued unbilled revenue at December 31, 2013 and 2012 was $61.5 million and $57.0 million, respectively. The increase in accrued unbilled revenue at year-end 2013 was primarily due to higher volumes in December 2013, reflecting colder weather late in the month, and higher customer billing rates.

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%:

	2013	
In millions	Up 1%	Down 1%
Unbilled revenue increase (decrease)	$ 0.6	$ (0.6)
Utility margin increase (decrease) [1]	—	—
Net income increase (decrease)	—	—

[1] Includes impact of regulatory mechanisms including decoupling mechanism.

SENATE BILL 408 AND 967. From 2007 through 2010, utility revenues included the recognition of a regulatory adjustment for income taxes paid (SB 408). Under Oregon SB 408, utilities were required to automatically implement a rate refund, or a rate surcharge, to utility customers on an annual basis. The refund or surcharge amount was based on estimated differences between income taxes paid and income taxes collected in customer rates. We recorded the refund, or surcharge, each quarter based on the annual amount to be recognized.

In 2011, SB 967 effectively repealed SB 408. The new law required utilities in Oregon to reverse amounts accrued for the 2010 and 2011 tax years, which resulted in us recording a one-time pre-tax charge to earnings in the second quarter of 2011 in the amount of $7.4 million ($4.4 million after-tax or 17 cents per share). For further discussion, see "Results of Operations—Business Segments-Local Gas Distribution Utility Operations—*Regulatory Adjustment for Income Taxes Paid"* above.

NON-UTILITY REVENUES. Non-utility revenues, derived primarily from our gas storage segment, are recognized upon delivery of service to customers. Revenues from our asset management partner are recognized as earned based on multiple revenue elements, which is generally over the period of each asset management deal, except for contracts with a guaranteed amount, which are amortized pro-rata over the life of the contract.

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. The accounting rules for determining whether a contract meets the definition of a derivative instrument or qualifies for hedge accounting treatment are complex. The contracts that meet the definition of a derivative instrument 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 (AOCI) under common stock equity on the balance sheet. Our derivative contracts outstanding at December 31, 2013 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.

Commodity-based derivative contracts entered into by the utility after our annual PGA filing for the current gas contract period are subject to a regulatory incentive sharing mechanism in Oregon. See "Results of Operations—Regulatory Matters—Rate Mechanisms—*Purchased Gas Adjustment"* above. The portion not deferred to a regulatory account pursuant to that sharing agreement is recognized either in current income for contracts not qualifying for hedge accounting or in AOCI for contracts qualifying for hedge accounting.

The following table summarizes the amount of gains and losses realized from commodity price, and currency hedge transactions for the last three years:

In millions	2013	2012	2011
Net utility loss on:			
Commodity			
Swaps	$ (11.0)	$ (69.5)	$ (53.8)
Options	—	(0.7)	(2.7)
Total net loss realized	$ (11.0)	$ (70.2)	$ (56.5)

Realized losses from commodity hedges shown above were recorded as increases to cost of gas and were included in our annual PGA rates.

Pensions and Postretirement Benefits

We maintain a qualified non-contributory defined benefit pension plan, several 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. Effective December 31, 2012, the defined benefit pension plans for union and non-union employees were merged into one plan. The qualified defined benefit retirement plans for union and non-union employees were 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. As such, 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, 2013, the cumulative amount deferred for future pension cost recovery was $25.7 million. The regulatory balancing account includes the recognition of accrued interest on the account balance at the utility's actual cost of long-term debt.

A number of factors, as discussed above, are considered in developing pension and postretirement benefit assumptions. For the December 31, 2013 measurement date, we reviewed and updated:

- our weighted-average discount rate assumptions for pensions went from 3.85% in 2012 to 4.73% in 2013, and our weighted-average discount rate assumptions for other postretirement benefits went from 3.56% in 2012 to 4.45% in 2013. 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 remained unchanged at a range of 3.25% to 5.0%;
- our expected long-term return on qualified defined benefit plan assets, which remained unchanged at a rate of 7.50%; and
- other key assumptions, which were based on actual plan experience and actuarial recommendations.

At December 31, 2013, our net pension liability (benefit obligations less market value of plan assets) for the qualified defined benefit plan decreased $59.1 million compared to 2012. The decrease in our net pension liability is primarily due to the $41.6 million decrease in our pension benefit obligation and an increase of $17.5 million in plan assets. The liability for non-qualified plans decreased $3.2 million, and the liability for other postretirement benefits decreased $4.4 million in 2013.

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, 2013, the actual annualized returns on plan assets, net of management fees, for the past one-year, five-years, and 10-years were 9.8%, 9.6%, and 5.6%, 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 future changes in certain actuarial assumptions:

Dollars in millions	Change in Assumption	Impact on 2013 Retirement Benefit Costs	Impact on Retirement Benefit Obligations at Dec. 31, 2013
Discount rate:	(0.25)%		
Qualified defined benefit plans		$ 1.0	$ 11.4
Non-qualified plans		—	0.7
Other postretirement benefits		—	0.7
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 changes 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 2014, we expect to contribute approximately $15 million under the adjusted 24-month segment rate using MAP-21 corridor.

Income Taxes

We account for income taxes in accordance with accounting standards that require the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between financial statement carrying amount and tax basis of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. At December 31, 2013 and 2012, our net long-term deferred tax liability totaled $486.8 million and $444.4 million, respectively. After application of the federal statutory tax rate to book income, judgment is required with respect to the timing and deductibility of expense in our tax returns. For state and local income taxes, judgment is also required with respect to the apportionment among the various jurisdictions. A valuation allowance is recorded if we expect that it is more likely than not that our deferred tax assets will not be realized. At December 31, 2013, we did not record a valuation allowance due to our expectation that all of these assets and liabilities will be realized.

These accounting standards also require the recognition of deferred income tax assets and liabilities for temporary differences where regulators require us to flow through deferred income tax benefits or expenses in the ratemaking process of the regulated utility (regulatory tax assets and liabilities). This is consistent with the ratemaking policies of the OPUC and WUTC. Regulatory tax assets and liabilities are recorded to the extent we believe they will be recoverable from, or refunded to, customers in future rates. As part of the Oregon general rate case, the OPUC ruled that we cannot recover deferred amounts that represent the increase in deferred income taxes caused by the 2009 Oregon tax rate change. As a result, we recognized a one time, after tax charge of $2.7 million in 2012 to write off the regulatory asset related to this rate change. At December 31, 2013 and 2012, we had regulatory assets representing differences between book and tax basis related to pre-1981 property of $56.2 million and $60.3 million, respectively, and recorded an offsetting deferred tax liability. We are currently recovering these pre-1981 deferred tax assets over a period of approximately 25 years. See Note 2 and Note 9.

Uncertain tax positions are accounted for in accordance with accounting standards that require management's assessment of the expected treatment of a tax position taken in a filed tax return, or planned to be taken in a future tax return, that has not been reflected in measuring income tax expense for financial reporting purposes. Until such positions are sustained by the taxing authorities, we would not recognize the tax benefits resulting from such positions and would report the tax effect as a liability in the Company's consolidated balance sheet. As of December 31, 2013, we had no reserves for uncertain tax positions.

In 2012, the Company settled an examination of tax years 2006 through 2009 with the state of Oregon. This settlement resulted in an additional $0.2 million state tax expense due to Oregon, including interest. However, the Company also filed an amended tax return with the state of California for tax year 2007 in which it claimed a refund of $0.2 million and recognized a reduction in state tax expense of $0.2 million. The net effect of these two state tax changes was negligible.

The Company is currently under IRS examination for tax years 2009-2011 and we expect resolution in 2014. The Company is also subject to examination for tax year 2012. To date, the IRS has not proposed any material adjustments.

Interest and penalties related to any future income tax deficiencies would be recorded in income tax expense in our consolidated statements of income.

Environmental Contingencies

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. Estimates of loss contingencies, including estimates of legal costs when such costs are probable of being incurred and are reasonably estimable and related disclosures are updated when new information becomes available. Estimating probable losses requires an analysis of uncertainties that often depends upon judgments about potential actions by third parties. Accruals for loss contingencies are recorded based on an analysis of potential results. When information is sufficient to estimate only a range of potential liabilities, and no point within the range is more likely than any other, we recognize an accrued liability at the low end of the range and disclose the range. See "*Contingent Liabilities"* above. It is possible, however, that the actual range of potential liabilities could be significantly different than estimated amounts currently accrued and disclosed, with the result that our financial condition and results of operations could be materially affected by changes in the assumptions or estimates related to these contingencies.

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. Using sampling data, feasibility studies, existing technology, and enacted laws and regulations, we estimate that the total future expenditures for environmental investigation, monitoring and remediation are $98.1 million as of December 31, 2013. 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, then 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.

We continue to seek recovery of such costs through insurance and through customer rates, and we believe recovery of these costs is probable. In 2014, a settlement was reached in our environmental insurance recovery litigation with remaining insurers. In addition, we have a new SRRM in Oregon with a proceeding currently open to resolve implementation issues including the prudence of deferred costs, the allocation of insurance proceeds, and an earnings test that would be applied to past and future deferred costs. As there is uncertainty surrounding this mechanism and the open proceeding, we will continue to carefully assess these environmental assets for recoverability. If it is determined that insurance recoveries for environmental costs are insufficient and future rate recovery of such costs are not probable, the costs will be charged to expense in the period such determination is made. See "Results of Operations—Rate Matters—Rate Mechanisms—*Environmental Costs*" above, Note 15, and Note 17.

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 facility, to meet expected requirements of our core utility customers. Our gas purchase 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.

Commodity Price and Storage Value Risk

Natural gas commodity prices and storage values are subject to market fluctuations due to unpredictable factors including weather, pipeline transportation congestion, drilling technologies, potential market speculation and other factors that affect supply and demand. In addition to managing storage positions through a combination of short- and long-term fixed price contracts, we use financial swap and option contracts to convert certain natural gas supply contracts from floating prices to fixed or capped prices. We also manage risk with physical gas reserves from a long-term investment in working interests in gas leases operated by Encana. These financial hedge contracts and gas reserve volumes are generally included in our annual PGA filing for recovery, subject to a regulatory prudence review. We also regularly monitor and manage the financial exposure and liquidity risk of our storage position.

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.

Foreign Currency Risk

The costs of certain natural gas commodity supplies and certain pipeline 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 and commodity-related demand charges paid in Canadian dollars. If all of the foreign currency forward contracts had been settled on December 31, 2013, a loss of $0.3 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 monthly market index price tied to liquid exchange points, and we have adequate storage flexibility, we believe that it is unlikely that a supplier default would have an adverse effect on our financial condition or results of operations.

CREDIT EXPOSURE TO FINANCIAL DERIVATIVE COUNTERPARTIES. Based on estimated fair value at December 31, 2013, our overall credit exposure relating to commodity contracts is considered to be immaterial as it reflects amounts we owed to our 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, 2013, actual financial swap and option derivative credit risk exposure totals $5.4 million, which reflects amounts that 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 Gain (Loss)	
In millions	2013	2012
AAA/Aaa	$ —	$ —
AA/Aa	4.5	(5.0)
A/A	0.9	—
BBB/Baa	—	—
Total	$ 5.4	$ (5.0)

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 a 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 that 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 FOR ENVIRONMENTAL DAMAGE CLAIMS. We regularly monitor the financial condition of insurance companies who provide or provided general liability insurance policy coverage to NW Natural and its predecessors with respect to environmental damage claims. We have filed claims for our environmental costs with a number of insurance companies. The majority of these companies have credit ratings of A or better from A.M. Best Co. (AM Best). AM Best is a global independent credit rating agency who has provided quantitative and qualitative analysis of insurance company balance sheet strength for over 100 years. AM Best uses a rating scale that ranges from A++ (Superior financial strength) to F (In Liquidation), with a rating of A considered Excellent. A strong credit rating from AM Best is not a guarantee that an insurance company will be able to meet its contractual obligations. The remaining insurance companies who do not have credit ratings of A or better are expected to have sufficient funds in reserves to cover these claims. Our credit exposure to insurance companies for environmental claims could be material; however, we have recently settled with remaining insurers for these claims with payment expected in 2014. See Note 17. In the event we are unable to recover environmental expenses from these insurance policies, we will seek recovery of unreimbursed amounts through customer rates.

Weather Risk

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. We have a weather normalization mechanism 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, 2013, approximately 8% of our Oregon customers had opted out. In addition to the Oregon customers opting out, our Washington residential and commercial customers account for approximately 10% 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 less than 20% of all residential and commercial customers. See "Results of Operations—Regulatory Matters—Rate Mechanism—*Weather Normalization Tariff*" above.

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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) and 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, 2013. 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 (1992)*.

Based on our assessment and those criteria, management has concluded that we maintained effective internal control over financial reporting as of December 31, 2013.

The effectiveness of internal control over financial reporting as of December 31, 2013 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
President and Chief Executive Officer

/s/ Stephen P. Feltz
Stephen P. Feltz
Senior Vice President and Chief Financial Officer

February 28, 2014

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 table of contents present fairly, in all material respects, the financial position of Northwest Natural Gas Company and its subsidiaries at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 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 table of contents 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, 2013, based on criteria established in *Internal Control - Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, 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 28, 2014

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

In thousands, except per share data	Year Ended December 31, 2013	2012	2011
Operating revenues	$ 758,518	$ 730,607	$ 828,055
Operating expenses:			
Cost of gas	373,298	355,335	458,508
Operations and maintenance	136,613	129,477	125,417
General taxes	29,956	30,598	29,281
Depreciation and amortization	75,905	73,017	70,004
Total operating expenses	615,772	588,427	683,210
Income from operations	142,746	142,180	144,845
Other income and expense, net	4,669	3,159	3,112
Interest expense, net	45,172	43,157	42,088
Income before income taxes	102,243	102,182	105,869
Income tax expense	41,705	43,403	42,825
Net income	60,538	58,779	63,044
Other comprehensive income:			
Change in employee benefit plan liability, net of taxes of ($1,304) for 2013, $1,339 for 2012, and $1,161 for 2011	1,998	(2,156)	(1,779)
Amortization of non-qualified employee benefit plan liability, net of taxes of ($608) for 2013, ($434) for 2012, and ($383) for 2011	935	665	583
Comprehensive income	$ 63,471	$ 57,288	$ 61,848
Average common shares outstanding:			
Basic	26,974	26,831	26,687
Diluted	27,027	26,907	26,744
Earnings per share of common stock:			
Basic	$ 2.24	$ 2.19	$ 2.36
Diluted	2.24	2.18	2.36
Dividends declared per share of common stock	1.83	1.79	1.75

See Notes to Consolidated Financial Statements

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS

	As of December 31,	
In thousands	2013	2012
Assets:		
Current assets:		
Cash and cash equivalents	$ 9,471	$ 8,923
Accounts receivable	81,889	61,229
Accrued unbilled revenue	61,527	56,955
Allowance for uncollectible accounts	(1,656)	(2,518)
Regulatory assets	22,635	52,448
Derivative instruments	5,311	1,950
Inventories	60,669	67,602
Gas reserves	20,646	14,966
Income taxes receivable	3,534	2,552
Deferred tax assets	45,241	—
Other current assets	21,181	19,592
Total current assets	330,448	283,699
Non-current assets:		
Property, plant, and equipment	2,918,739	2,786,008
Less: Accumulated depreciation	855,865	812,396
Total property, plant, and equipment, net	2,062,874	1,973,612
Gas reserves	121,998	84,693
Regulatory assets	369,603	382,255
Derivative instruments	1,880	3,639
Other investments	67,851	67,667
Restricted cash	4,000	4,000
Other non-current assets	12,257	13,555
Total non-current assets	2,640,463	2,529,421
Total assets	$ 2,970,911	$ 2,813,120

See Notes to Consolidated Financial Statements

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS

In thousands	As of December 31, 2013	2012
Liabilities and equity:		
Current liabilities:		
Short-term debt	$ 188,200	$ 190,250
Current maturities of long-term debt	60,000	—
Accounts payable	96,126	85,613
Taxes accrued	10,856	9,588
Interest accrued	7,103	5,953
Regulatory liabilities	28,335	20,792
Derivative instruments	1,891	10,796
Other current liabilities	40,280	45,444
Total current liabilities	432,791	368,436
Long-term debt	681,700	691,700
Deferred credits and other non-current liabilities:		
Deferred tax liabilities	532,036	444,377
Regulatory liabilities	303,485	288,113
Pension and other postretirement benefit liabilities	149,354	215,792
Derivative instruments	615	578
Other non-current liabilities	119,058	74,497
Total deferred credits and other non-current liabilities	1,104,548	1,023,357
Commitments and contingencies (see Note 14 and Note 15)	—	—
Equity:		
Common stock - no par value; authorized 100,000 shares; issued and outstanding 27,075 and 26,917 at December 31, 2013 and 2012, respectively	364,549	356,571
Retained earnings	393,681	382,347
Accumulated other comprehensive loss	(6,358)	(9,291)
Total equity	751,872	729,627
Total liabilities and equity	$ 2,970,911	$ 2,813,120

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 Dec. 31, 2010	$ 342,978	$ 355,251	$ (6,604)	$ 691,625
Comprehensive income (loss)	—	63,044	(1,196)	61,848
Dividends paid on common stock	—	(46,690)	—	(46,690)
Tax expense from employee stock option plan	(26)	—	—	(26)
Stock-based compensation	1,769	—	—	1,769
Issuance of common stock	3,632	—	—	3,632
Common stock expense	30	(30)	—	—
Balance at Dec. 31, 2011	348,383	371,575	(7,800)	712,158
Comprehensive income (loss)	—	58,779	(1,491)	57,288
Dividends paid on common stock	—	(48,007)	—	(48,007)
Tax expense from employee stock option plan	(149)	—	—	(149)
Stock-based compensation	1,291	—	—	1,291
Issuance of common stock	7,046	—	—	7,046
Balance at Dec. 31, 2012	356,571	382,347	(9,291)	729,627
Comprehensive income	—	60,538	2,933	63,471
Dividends paid on common stock	—	(49,204)	—	(49,204)
Tax expense from employee stock option plan	(242)	—	—	(242)
Stock-based compensation	2,169	—	—	2,169
Issuance of common stock	6,051	—	—	6,051
Balance at Dec. 31, 2013	$ 364,549	$ 393,681	$ (6,358)	$ 751,872

See Notes to Consolidated Financial Statements

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

In thousands	Year Ended December 31, 2013	2012	2011
Operating activities:			
Net income	$ 60,538	$ 58,779	$ 63,044
Adjustments to reconcile net income to cash provided by operations:			
Depreciation and amortization	75,905	73,017	70,004
Regulatory amortization of gas reserves	11,089	6,340	1,143
Deferred tax liabilities, net	46,483	42,079	46,319
Non-cash expenses related to qualified defined benefit pension plans	5,666	5,448	7,191
Contributions to qualified defined benefit pension plans	(11,700)	(23,500)	(22,045)
Deferred environmental expenditures, net of recoveries	(16,679)	(12,503)	25,586
Other	(2,580)	(2,350)	(863)
Changes in assets and liabilities:			
Receivables	(26,094)	22,170	(6,246)
Inventories	6,933	6,761	6,022
Taxes accrued	286	3,334	34,189
Accounts payable	7,422	(602)	148
Interest accrued	1,150	96	675
Deferred gas costs	(5,245)	(17,644)	8,565
Other, net	23,216	7,413	(270)
Cash provided by operating activities	176,390	168,838	233,462
Investing activities:			
Capital expenditures	(138,924)	(132,029)	(100,534)
Utility gas reserves	(54,077)	(54,085)	(50,597)
Proceeds from sale of assets	8,638	—	—
Restricted cash	—	—	(3,076)
Other	2,231	1,437	1,142
Cash used in investing activities	(182,132)	(184,677)	(153,065)
Financing activities:			
Common stock issued, net	5,964	6,758	3,040
Long-term debt issued	50,000	50,000	90,000
Long-term debt retired	—	(40,000)	(10,000)
Change in short-term debt	(2,050)	48,650	(115,835)
Cash dividend payments on common stock	(49,204)	(48,007)	(46,690)
Other	1,580	1,528	1,464
Cash provided by (used in) financing activities	6,290	18,929	(78,021)
Increase in cash and cash equivalents	548	3,090	2,376
Cash and cash equivalents, beginning of period	8,923	5,833	3,457
Cash and cash equivalents, end of period	$ 9,471	$ 8,923	$ 5,833

Supplemental disclosure of cash flow information:			
Interest paid	$ 44,022	$ 43,061	$ 41,413
Income taxes paid	870	2,979	1,756

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 that 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 storage facilities located in Oregon and California. In addition, we have investments and other non-utility activities that we aggregate and report as other.

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 that 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 Palomar Gas Holdings, LLC (PGH) 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 significant 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.

During the first quarter of 2013, we identified an error in the rate used to calculate interest on regulatory assets. We assessed the materiality of this error on prior period financial statements and concluded it was not material to any prior annual or interim periods; however, the cumulative impact would have been material to the annual and interim periods for 2013, if corrected in 2013. As a result, in accordance with accounting standards, we have revised our prior period financial statements as shown in Note 16 to correct this error.

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

2. SIGNIFICANT ACCOUNTING POLICIES UPDATE

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 that 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. 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 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 provides 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 2013	2012
Current:		
Unrealized loss on derivatives[1]	$ 1,891	$ 10,796
Other[2]	20,744	41,652
Total current	$ 22,635	$ 52,448
Non-current:		
Unrealized loss on derivatives[1]	$ 615	$ 578
Pension balancing[3]	25,713	14,727
Income tax asset	51,814	55,879
Pension and other postretirement benefit liabilities[3]	125,855	182,688
Environmental costs[4]	148,389	121,144
Other[2]	17,217	7,239
Total non-current	$ 369,603	$ 382,255

In thousands	Regulatory Liabilities 2013	2012
Current:		
Gas costs	$ 7,510	$ 9,100
Unrealized gain on derivatives[1]	5,290	1,950
Other[2]	15,535	9,742
Total current	$ 28,335	$ 20,792
Non-current:		
Gas costs	$ 2,172	$ —
Unrealized gain on derivatives[1]	1,880	3,639
Accrued asset removal costs	296,294	281,213
Other[2]	3,139	3,261
Total non-current	$ 303,485	$ 288,113

(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 PGA mechanism when realized at settlement.

(2) Other primarily consists of several deferrals and amortizations under other approved regulatory mechanisms. The accounts being amortized typically earn a rate of return or carrying charge.

(3) Certain utility pension costs are approved for regulatory deferral, including amounts recorded to the pension balancing account, to mitigate the effects of higher and lower pension expenses. Pension costs that are deferred include an interest component when recognized in net periodic benefit costs. See Note 8.

(4) Environmental costs relate to specific sites approved for regulatory deferral by the OPUC and WUTC. In Oregon, we earn a carrying charge on amounts paid, whereas amounts accrued but not yet paid do not earn a carrying charge until expended. In Washington, a carrying charge related to deferred amounts will be determined in a future proceeding. For further information on environmental matters, see Note 15.

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 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, 2013 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.

New Accounting Standards

Recently Adopted Standards

BALANCE SHEET OFFSETTING. In December 2011, the Financial Accounting Standards Board (FASB) issued authoritative guidance regarding the offsetting of assets and liabilities on the balance sheet. The standard is intended to provide more comparable guidance between the GAAP and international accounting standards by requiring entities to disclose both gross and net amounts for assets and liabilities offset on the balance sheet as well as other disclosures concerning their enforceable master netting arrangements. This guidance was effective for annual reporting periods beginning on or after January 1, 2013. The adoption of this standard did not have a material effect on our financial statement disclosures. See Note 13.

RECLASSIFICATIONS FROM ACCUMULATED OTHER COMPREHENSIVE INCOME. In February 2013, the FASB issued authoritative guidance, which requires an entity to present significant amounts reclassified from each component of accumulated other comprehensive income (AOCI). This standard is intended to improve the reporting of these reclassifications by presenting the information concerning amounts reclassified into net income from AOCI in a single location. This information has historically has been presented throughout the financial statements. This guidance was effective for reporting periods beginning after December 15, 2012. The adoption of this standard did not have a material effect on our financial statement disclosures. See Note 8.

Recently Issued Accounting Pronouncements

OBLIGATIONS RESULTING FROM JOINT AND SEVERAL LIABILITY ARRANGEMENTS. In February 2013, the FASB issued guidance regarding the recognition, measurement and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date. Under the new guidance, an entity is required to measure fixed obligations as the sum of the amount the reporting entity agreed to pay on the basis of its arrangement among its co-obligors plus any additional amount the reporting entity expects to pay on behalf of its co-obligors. In addition, an entity must disclose the nature and amount of the obligation as well as other information about the obligations. The guidance is effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. We are currently assessing the impact, if any, of this guidance on our financial position, results of operations, or disclosures.

PRESENTATION OF UNRECOGNIZED TAX BENEFIT. In July 2013, the FASB issued guidance that requires an unrecognized tax benefit, or a portion of an unrecognized tax benefit, be presented in the financial statements as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss, or a tax credit carryforward, except under certain circumstances. The new guidance is effective for fiscal years and interim periods within those years, beginning after December 15, 2013. This guidance is not expected to have an impact on our financial position, results of operations, 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 “Allowance for Funds Used During Construction” 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 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 upon 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 that is recorded in other income and expense, net 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% in 2013, 2012, and 2011, reflecting the approximate weighted average economic life of the property. This includes 2013 weighted average depreciation rates for the following asset categories: 2.7% for transmission and distribution plant, 2.2% for gas storage facilities, 4.3% for general plant, and 4.1% 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 rates were 0.3% in 2013 and 2012, and 0.5% in 2011.

IMPAIRMENT OF LONG-LIVED ASSETS. We review the carrying value of long-lived assets whenever events or changes in circumstances indicate that 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.

If such factors indicate a potential impairment, we assess the recoverability by determining if the carrying value of the asset exceeds the sum of the projected future cash flows over the remaining economic life of the asset. An asset is determined to be impaired when the carrying value is not recoverable through undiscounted future cash flows, and in those cases, we would estimate the fair value of the asset using appropriate valuation methodologies, which may include an estimate of discounted cash flows. Any impairment would be measured as the difference between the asset’s carrying amount and its estimated fair value.

While we determined there were no material impairments of long-lived assets during the year ended December 31, 2013, if our gas storage facilities experience sustained decreases in future cash flows due to a prolonged, slow recovery of the gas storage market, future assessments could result in an impairment.

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, 2013 and 2012, outstanding checks of approximately $2.8 million and $2.3 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 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, 2013 and 2012 was $61.5 million and $57.0 million, respectively.

From 2007 through 2010, utility margin also included the recognition of a regulatory adjustment for income taxes paid pursuant to a legislative rule (commonly referred to as SB 408) in effect for certain gas and electric utilities in Oregon. In 2011, SB 408 was repealed and replaced by Senate Bill SB 967. SB 967 required utilities to eliminate amounts accrued under SB 408, which resulted in a one-time pre-tax charge of $7.4 million in 2011.

Non-utility revenues are derived primarily from the gas storage segment. At our Mist underground storage facility, revenues are recognized upon delivery of services to customers. 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 primarily from an independent energy marketing company that optimizes commodity 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. See Note 4.

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.

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. With respect to these trade receivables, including accrued unbilled revenue, we establish an allowance for uncollectible accounts (allowance) 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. With respect to large individual customer receivables, a specific allowance is established and recorded 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 to be 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 the level of natural gas prices. Each quarter the allowance for uncollectible accounts is adjusted, 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 that are injected into storage are priced into inventory based on actual purchase costs. Utility gas inventories that are 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, consist primarily of natural gas that we 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. It is recorded at original cost and classified as a long-term plant asset.

Material 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 $51.4 million and $58.8 million at December 31, 2013 and 2012, respectively. At December 31, 2013 and 2012, our materials and supplies inventories totaled $9.3 million and $8.8 million, respectively.

Gas Reserves

Our gas reserves are stated at cost, adjusted for regulatory amortization, with the associated deferred tax benefits recorded as liabilities on the balance sheet. Transactional costs to enter into the agreement and payments by NW Natural to acquire gas reserves are recognized as gas reserves 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

In accordance with accounting for derivatives and hedges, we measure derivatives at fair value and recognize them as either assets or liabilities on the balance sheet. Accounting for derivatives requires that changes in the fair value be recognized currently in earnings unless specific 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. The Company's 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 that PGA year has begun 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 years in Oregon beginning November 1, 2013, 2012 and 2011, 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.

<u>Fair Value</u>

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 upon quoted prices for identical instruments traded in active markets;
- Level 2: Valuation is based upon 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 that 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; (h) and other relevant economic measures.

<u>Income Tax Expense</u>

NW Natural and its wholly-owned subsidiaries file consolidated federal, state, and local income tax returns. Income taxes are currently allocated based on each entity's respective taxable income or loss and tax credits as if each entity filed a separate return. We account for income taxes in accordance with accounting standards for income taxes. Accounting for income taxes requires recognition of deferred tax liabilities and assets for the future tax consequences of events that have been included in the consolidated financial statements or tax returns. Under this method, deferred tax liabilities and assets are determined based on the difference 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. See Note 9.

Accounting for income taxes also requires recognition of deferred income tax assets and liabilities for temporary differences where regulators prohibit deferred income tax treatment for ratemaking purposes. We have recorded deferred tax liabilities of $56.2 million and $60.3 million at December 31, 2013 and 2012, respectively, to recognize future taxes payable resulting from transactions that have previously been reflected in the financial statements for these temporary differences. Regulatory assets or liabilities corresponding to such additional deferred income tax assets or liabilities may be recorded to the extent we believe they will be recoverable from or payable to customers through the ratemaking process. A corresponding regulatory asset has been recorded which represents the probable future revenue that will result from inclusion in rates charged to customers for taxes which will be paid in the future. The probable future revenue to be recorded takes into consideration the additional future taxes which will be generated by that revenue. Amounts applicable to income taxes due from customers primarily represent differences between the financial statement and tax basis of net utility plant in service and actual removal costs incurred.

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 or lease.

Environmental Contingencies
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. 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, then 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.

Subsequent Events
See Note 17 for information regarding the Company's environmental insurance settlements.

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. Diluted earnings per share are calculated as follows:

In thousands, except per share data	2013	2012	2011
Net income	$ 60,538	$ 58,779	$ 63,044
Average common shares outstanding - basic	26,974	26,831	26,687
Additional shares for stock-based compensation plans (See Note 6)	53	76	57
Average common shares outstanding - diluted	27,027	26,907	26,744
Earnings per share of common stock - basic	$ 2.24	$ 2.19	$ 2.36
Earnings per share of common stock - diluted	$ 2.24	$ 2.18	$ 2.36
Additional information:			
Antidilutive shares not included in net income per diluted common share calculation	26	1	2

4. SEGMENT INFORMATION

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 also includes NWN Gas Reserves, which is a wholly-owned subsidiary of Energy Corp, and the utility portion of 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 all third-party asset management services. Other includes NNG Financial and NWN Energy's equity investment in PGH, which is pursuing development of a cross-Cascades pipeline project (see Other, below).

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 90% of our customers are located in Oregon and 10% 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 under contractual arrangement, the results of which are included in this business segment. For the years ended December 31, 2013, 2012 and 2011, this business segment derived a majority of its revenues from firm and interruptible gas storage contracts and from asset management services.

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 gas storage segment also include revenues, net of amounts shared with core utility customers, from management of utility assets at Mist and upstream capacity when not needed to serve utility customers. In Oregon, the gas storage segment retains 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 credited to a deferred regulatory account for crediting back to utility customers. We have a similar sharing mechanism in Washington for revenue derived from storage and third party asset management services.

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.

Other

We have immaterial 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 an interstate gas transmission pipeline in Oregon (Palomar) and other pipeline assets in NNG Financial. For more information on Palomar, see Note 12. Other also includes some operating and non-operating revenues and expenses of the parent company that cannot be allocated to utility operations.

NNG Financial holds certain non-utility financial investments, but its 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 $1.2 million and $1.1 million at December 31, 2013 and 2012, respectively.

Segment Information Summary

The following table presents summary financial information concerning the reportable segments. Inter-segment transactions are insignificant.

In thousands	Utility	Gas Storage	Other	Total
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
2012				
Operating revenues	$ 699,862	$ 30,520	$ 225	$ 730,607
Depreciation and amortization	66,545	6,472	—	73,017
Income from operations	128,854	13,226	100	142,180
Net income	54,049	4,521	209	58,779
Capital expenditures	130,151	1,541	337	132,029
Total assets at December 31, 2012	2,505,655	291,568	15,897	2,813,120
2011				
Operating revenues	$ 801,478	$ 26,354	$ 223	$ 828,055
Depreciation and amortization	63,843	6,161	—	70,004
Income from operations	135,722	9,090	33	144,845
Net income (loss)	59,673	4,101	(730)	63,044
Capital expenditures	94,049	6,485	—	100,534

Utility Margin

Utility margin is a financial measure consisting of utility operating revenues less revenue taxes and the associated cost of gas. Cost of gas purchased for utility customers is generally a pass-through cost in the amount of revenues billed to regulated utility customers. By netting costs of gas 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 following table presents additional segment information concerning utility margin. The gas storage and other segments emphasize growth in operating revenues and net income as opposed to margin because these segments do not incur commodity cost of sales like the utility and, therefore, use operating revenues and net income to assess performance.

In thousands	2013	2012	2011
Utility margin calculation:			
Utility operating revenues	$ 727,182	$ 699,862	$ 801,478
Less: Utility cost of gas	373,298	355,335	458,508
Utility margin	$ 353,884	$ 344,527	$ 342,970

5. COMMON STOCK

Common Stock

As of December 31, 2013 and 2012, we had 100 million shares of common stock authorized. As of December 31, 2013, we had reserved 122,184 shares for issuance of common stock under the Employee Stock Purchase Plan (ESPP) and 96,991 shares under our Dividend Reinvestment and Direct Stock Purchase Plan (DRPP). In the second quarter of 2012, our Restated Stock Option Plan (Restated SOP) was terminated for new stock option grants. There were 492,150 options outstanding at December 31, 2013, which were granted prior to termination of the plan. These options will remain outstanding to the earlier of their forfeiture, exercise or expiration.

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 2014 to repurchase up to an aggregate of 2.8 million shares, but not to exceed $100 million. No shares of common stock were repurchased pursuant to this program during the year ended December 31, 2013. 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, 2010	26,668
Sales to employees under ESPP	15
Stock-based compensation	24
Sales to shareholders under DRPP	49
Balance, December 31, 2011	26,756
Sales to employees under ESPP	18
Stock-based compensation	47
Sales to shareholders under DRPP	96
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

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. A variety of equity programs may be granted under the LTIP. The Restated SOP was terminated for new stock option grants in 2012.

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, 2013. Shares awarded under the LTIP may be purchased on the open market or issued as new shares.

Of the 850,000 shares of common stock authorized for LTIP awards at December 31, 2013, there were 241,169 shares available for issuance under any type of award. This assumes that market, performance, and service based grants currently outstanding are awarded at the target level. Additionally, 250,000 shares of common stock were available for option grants at December 31, 2013. There were no outstanding grants of restricted stock or stock options under the LTIP at December 31, 2013 or 2012. 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:

Expense in millions	Shares (1)	Expense During Award Year(3)	Total Expense for Award
Estimated award:			
2011-2013 grant(2)	9,516	$ 0.4	$ 1.0
Actual award:			
2010-2012 grant	9,924	0.5	1.2
2009-2011 grant	8,428	0.4	0.8

(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) This represents the estimated number of shares to be awarded as of December 31, 2013 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 2014.
(3) Amount represents the expense recognized in the third year of the vesting period noted above.

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		2013	Cumulative Expense
Performance Period	Target	Maximum	Expense	December 31, 2013
2011-13	37,950	75,900	$ 390	$ 960
2012-14	35,340	70,680	603	1,238
2013-15	37,300	74,600	486	486
Total	110,590	221,180	$ 1,479	

For each of these performance periods, awards will be based on total shareholder return 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. Compensation expense is recognized in accordance with the accounting standard 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, 2013 and 2012 was $43.39 and $51.42 per share, respectively. The weighted-average grant date fair value of shares vested during the year was $30.86 per share and for shares granted during the year was $38.96 per share. As of December 31, 2013, there was $1.6 million of unrecognized compensation cost related to the unvested portion of performance awards expected to be recognized through 2015.

Restricted Stock Units

In 2012, the Company began granting RSUs under the LTIP instead of stock options under the Restated SOP. The majority of RSUs include a performance-based threshold and generally have a vesting period of four years from the grant date. An RSU obligates the Company upon vesting to issue the RSU holder 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 the RSU. The fair value of the RSU is equal to the closing market price of the Company's common stock on the grant date.

Information regarding the RSU activity is summarized as follows:

	Number of RSUs	Weighted - Average Price Per RSU
Nonvested, Dec. 31, 2011	—	$ —
Granted	25,224	47.58
Vested	—	—
Forfeited	(360)	48.00
Nonvested, Dec. 31, 2012	24,864	47.57
Granted	25,748	45.38
Vested	(5,455)	48.01
Forfeited	(590)	46.58
Nonvested, Dec. 31, 2013	44,567	46.27

As of December 31, 2013, there was $1.5 million of unrecognized compensation cost from grants of RSUs, which is expected to be recognized over a period extending through 2017.

Restated Stock Option Plan

The Restated SOP was terminated for new option grants in 2012; however, options that had been 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. We did not grant new stock options during 2012 or 2013.

At December 31, 2013, a total of 492,150 shares of common stock remained reserved for issuance under the Restated SOP. As the plan is closed, there are no additional shares available for grant. Options under the Restated SOP were granted only 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 7 days from the date of grant. Option holders may exchange shares they have owned for at least six months, valued at the current market price, to purchase shares at the option price.

The fair value of each stock option is estimated on the grant date using the Black-Scholes option pricing model with the following weighted average assumptions and outcomes:

	2011
Risk-free interest rate	2.0%
Expected life (in years)	4.5
Expected market price volatility factor	24.5%
Expected dividend yield	3.8%
Forfeiture rate	3.1%
Weighted average grant date fair value	$ 6.73

The expected life of our grants was calculated based on our actual experience with previously exercised option grants. The risk-free interest rate was based on the implied yield currently available on U.S. Treasury zero-coupon issues with a life equal to the expected life of the options. Historical data was used to estimate the volatility factor, measured on a daily basis, for a period equal to the duration of the expected life of the option awards. The dividend yield was based on management’s current estimate for future dividend payouts at the time of grant. We expense the total cost of stock option awards granted to retirement eligible employees at the date of grant in accordance with stock option accounting guidance and the retirement vesting provisions of our option agreements.

Information regarding the Restated SOP activity is summarized as follows:

	Option Shares	Weighted - Average Price Per Share	Intrinsic Value *(In millions)*
Balance outstanding, Dec. 31, 2010	490,460	$ 40.82	$ 2.8
Granted	122,700	45.74	n/a
Exercised	(24,185)	33.88	0.3
Forfeited	(9,750)	44.38	n/a
Balance outstanding, Dec. 31, 2011	579,225	42.09	3.4
Exercised	(46,825)	40.62	0.4
Forfeited	(2,475)	43.78	n/a
Balance outstanding, Dec. 31, 2012	529,925	42.22	1.3
Exercised	(33,800)	32.16	0.3
Forfeited	(3,975)	43.72	n/a
Balance outstanding, Dec. 31, 2013	492,150	42.89	0.6
Exercisable, Dec. 31, 2013	409,036	42.41	0.6

During 2013, cash of $1.1 million was received for option shares exercised and $0.2 million related tax benefit was realized. During 2013, 2012, and 2011, the total fair value of options that vested was $0.5 million, $0.6 million and $0.6 million, respectively. The weighted average remaining life of options exercisable and outstanding at December 31, 2013, was 4.8 years and 5.1 years, respectively. As of December 31, 2013, there was $0.2 million of unrecognized compensation cost related to the unvested portion of outstanding stock option awards expected to be recognized during 2014.

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 $21,236 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	2013	2012	2011
Operations and maintenance expense, for stock-based compensation	$ 1,876	$ 1,668	$ 1,477
Income tax benefit	(765)	(707)	(597)
Net stock-based compensation effect on net income	$ 1,111	$ 961	$ 880
Amounts capitalized for stock-based compensation	$ 331	$ 294	$ 261

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. At December 31, 2013 and 2012, the amounts of commercial paper debt outstanding were $188.2 million and $190.3 million, respectively, and the average interest rate was 0.3% at year-end for both periods. 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, 2013, our commercial paper had a maximum maturity of 136 days and an average maturity of 66 days. There were no bank loans outstanding at December 31, 2013 or 2012.

On December 20, 2012, NW Natural entered into a five-year $300 million credit agreement, pursuant to which we may extend commitments for two additional one-year periods subject to lender approval. In December 2013, we extended our commitment for an additional year with an updated maturity date of December 20, 2018. The credit agreement allows us to request increases in the total commitment amount up to a maximum amount of $450 million and permits letters of credit in an aggregate amount of up to $200 million. Any principal and unpaid interest owed on borrowings under the agreement are 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, 2013 and 2012.

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, 2013 and 2012.

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. In addition, our Gill Ranch subsidiary senior secured debt is secured by all of the membership interests in Gill Ranch as well as Gill Ranch's debt service reserve account.

Retirement of long-term debt for each of the 12-month periods through December 31, 2018 are as follows:

In thousands	
Year	
2014	$ 60,000
2015	40,000
2016	65,000
2017	40,000
2018	22,000

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

In thousands	2013	2012
First Mortgage Bonds		
8.26 % Series B due 2014	$ 10,000	$ 10,000
3.95 % Series B due 2014	50,000	50,000
4.70 % Series B due 2015	40,000	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	—
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 % Series due 2042	50,000	50,000
	701,700	651,700
Subsidiary Senior Secured Debt		
Gill Ranch debt due 2016	40,000	40,000
	741,700	691,700
Less: Current maturities of long-term debt	60,000	—
Total long-term debt	$ 681,700	$ 691,700

First Mortgage Bonds

NW Natural issued $50 million of FMBs on August 19, 2013 with a coupon rate of 3.542% and a 10-year maturity. In October 2012, the utility issued $50 million of FMBs with a coupon rate of 4.00% and a maturity date of October 31, 2042.

Subsidiary Senior Secured Debt

In November 2011, Gill Ranch issued $40 million of senior secured debt, which consists of $20 million of fixed rate debt with an interest rate of 7.75% and $20 million of variable interest rate debt with an interest rate of LIBOR plus 5.50%, or 7.00%, whichever is higher. At December 31, 2013, the variable interest rate was 7.00%. This debt is secured by all of the membership interests in Gill Ranch and is nonrecourse to NW Natural. The maturity date of this debt is November 30, 2016.

Under the debt agreements, Gill Ranch is subject to certain covenants and restrictions including, but not limited to, a financial covenant that requires Gill Ranch to maintain minimum adjusted earnings before interest, taxes, depreciation and amortization (EBITDA) at various levels over the term of the debt. The minimum adjusted EBITDA increases incrementally over the first few years, reaching its highest level in the 12-month period beginning April 1, 2015. Under the debt agreements, Gill Ranch is also subject to a debt service reserve requirement of 10% of the outstanding principal amount, certain prepayment penalties, restrictions on dividends out of Gill Ranch unless certain earnings ratios are met, and restrictions on incurrence of additional debt. Gill Ranch was in compliance with all existing debt provisions and covenants for the year ended December 31, 2013.

Fair Value of Long-Term Debt

As our outstanding debt does not trade in active markets, we estimated the fair value of our outstanding long-term debt using outstanding debt issuances that actively trade in public markets and companies that have similar credit ratings, terms and remaining maturities to our debt. 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	2013	2012
Carrying amount	$ 741,700	$ 691,700
Estimated fair value	806,359	834,664

8. PENSION AND OTHER POSTRETIREMENT BENEFIT COSTS

We maintain qualified non-contributory defined benefit pension plans, a few 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. Only 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 December 31, 2012, the defined benefit pension plans for non-union and union employees were merged into one plan. The qualified defined benefit retirement plan for non-union and union employees was closed to new participants effective January 1, 2007. The postretirement benefits plan for non-union employees was closed to new participants effective January 1, 2010. 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	2013	2012	2013	2012
Reconciliation of change in benefit obligation:				
Obligation at January 1	$ 435,889	$ 391,127	$ 33,119	$ 30,049
Service cost	8,698	8,047	656	592
Interest cost	16,400	17,295	1,157	1,267
Net actuarial (gain) loss	(51,043)	37,615	(4,283)	3,182
Benefits paid	(18,855)	(18,195)	(1,895)	(1,971)
Obligation at December 31	$ 391,089	$ 435,889	$ 28,754	$ 33,119
Reconciliation of change in plan assets:				
Fair value of plan assets at January 1	$ 249,603	$ 215,970	$ —	$ —
Actual return on plan assets	22,872	26,683	—	—
Employer contributions	13,442	25,145	1,895	1,971
Benefits paid	(18,855)	(18,195)	(1,895)	(1,971)
Fair value of plan assets at December 31	$ 267,062	$ 249,603	$ —	$ —
Funded status at December 31	$ (124,027)	$ (186,286)	$ (28,754)	$ (33,119)

Our qualified defined benefit pension plan has an aggregate benefit obligation of $362.4 million and $404.0 million at December 31, 2013 and 2012, respectively, and fair values of plan assets of $267.1 million and $249.6 million, respectively.

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

	Regulatory Assets						Other Comprehensive Income		
	Pension Benefits			Other Postretirement Benefits			Pension Benefits		
In thousands	2013	2012	2011	2013	2012	2011	2013	2012	2011
Net actuarial (gain) loss	$ (51,892)	$ 26,504	$ 66,404	$ (4,283)	$ 3,182	$ 2,225	$ (3,302)	$ 3,511	$ 2,948
Amortization of:									
Transition obligation	—	—	—	—	(411)	(411)	—	—	—
Prior service cost	(230)	(230)	(230)	(197)	(197)	(197)	7	35	(122)
Actuarial loss	(16,744)	(14,482)	(10,731)	(733)	(435)	(289)	(1,550)	(1,150)	(854)
Total	$ (68,866)	$ 11,792	$ 55,443	$ (5,213)	$ 2,139	$ 1,328	$ (4,845)	$ 2,396	$ 1,972

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	2013	2012	2013	2012	2013	2012
Prior service cost	$ 867	$ 1,097	$ 685	$ 882	$ (5)	$ (12)
Net actuarial loss	119,638	188,278	4,665	9,681	10,475	15,327
Total	$ 120,505	$ 189,375	$ 5,350	$ 10,563	$ 10,470	$ 15,315

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	2013	2012
Beginning balance	$ (9,291)	$ (7,800)
Amounts reclassified to AOCL	3,302	(3,495)
Amounts reclassified from AOCL:		
Amortization of prior service costs	(7)	(35)
Amortization of actuarial losses	1,550	1,134
Total reclassifications before tax	4,845	(2,396)
Tax (benefit) expense	(1,912)	905
Total reclassifications for the period	2,933	(1,491)
Ending balance	$ (6,358)	$ (9,291)

In 2014, an estimated $9.8 million will be amortized from regulatory assets to net periodic benefit costs, consisting of $9.4 million of actuarial losses, and $0.4 million of prior service costs. A total of $1.0 million will be amortized from AOCL to earnings related to actuarial losses.

Our assumed discount rate was determined independently for each pension plan and other postretirement benefit plan 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 the Company's 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 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 employees 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 expectation. All investments are expected to satisfy the requirements of the rule of prudent investments as set forth under the Employee Retirement Income Security Act of 1974. The approved asset classes 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. Our expected long-term rate of return is based upon historical index returns by asset class, adjusted by a factor based on our historical return experience, diversified asset allocation and active portfolio management by professional investment managers. The retirement trust fund is not currently invested in any NW Natural securities.

The following is our pension plan asset target allocation at December 31, 2013:

Asset Category	Target Allocation
U.S. large cap equity	13.0%
U.S. small/mid cap equity	8.5
Non-U.S. equity	13.0
Emerging markets equity	3.5
Long government/credit	30.0
High yield bonds	5.0
Emerging market debt	5.0
Real estate funds	6.0
Absolute return strategy	11.0
Real return strategy	5.0

Our non-qualified supplemental defined benefit plan obligations were $28.7 million and $31.9 million at December 31, 2013 and 2012, 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. Although these are unfunded plans with no plan assets due to their nature as non-qualified plans, we indirectly fund a 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, and the amortization of actuarial gains and losses.

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

The following tables provide the components of net periodic benefit cost for the Company's pension and other postretirement benefit plans for the years ended December 31 and the assumptions used in measuring these costs and benefit obligations:

	Pension Benefits			Other Postretirement Benefits		
In thousands	2013	2012	2011	2013	2012	2011
Service cost	$ 8,698	$ 8,047	$ 7,122	$ 656	$ 592	$ 614
Interest cost	16,400	17,295	18,134	1,157	1,267	1,404
Expected return on plan assets	(18,721)	(19,082)	(17,867)	—	—	—
Amortization of transition obligations	—	—	—	—	411	411
Amortization of prior service costs	223	195	352	197	197	197
Amortization of net actuarial loss	18,294	15,631	11,584	734	435	289
Net periodic benefit cost	24,894	22,086	19,325	2,744	2,902	2,915
Amount allocated to construction	(6,712)	(5,820)	(4,905)	(856)	(882)	(878)
Amount deferred to regulatory balancing account[1]	(9,115)	(7,876)	(6,008)	—	—	—
Net amount charged to expense	$ 9,067	$ 8,390	$ 8,412	$ 1,888	$ 2,020	$ 2,037

[1] Effective January 1, 2011, the OPUC approved the deferral of certain pension expenses above or below the amount set in rates, 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. See Note 2.

Net periodic benefit costs above are reduced by amounts capitalized to utility plant based on approximately 30% to 40% payroll overhead charge to construction work orders. In addition, a certain amount of net periodic benefit costs are recorded to the regulatory balancing account for pensions, with the remaining net amount charged to expense and recognized in current earnings.

	Pension Benefits			Other Postretirement Benefits		
	2013	2012	2011	2013	2012	2011
Assumptions for net periodic benefit cost:						
Weighted-average discount rate	3.84%	4.51%	5.49%	3.56%	4.33%	5.16%
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%	8.00%	8.25%	n/a	n/a	n/a
Assumptions for year-end funded status:						
Weighted-average discount rate	4.73%	3.85%	4.51%	4.45%	3.56%	4.33%
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%	8.00%	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, 2013 was 9.0% for pre-65 and 7.9% for 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 5.0% by 2021.

Assumed health care cost trend rates can have a significant effect on the amounts reported for the health care plans. 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	$ 73	$ (64)
Effect on the accumulated postretirement benefit obligation	739	(660)

The impact of a change in retirement benefit costs on operating results would be less than the amounts shown above because a portion would be capitalized to utility plant, and a certain amount would be recorded to the regulatory balancing account with the remaining amount recognized in current earnings.

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:		
2012	$ 25,559	$ 1,971
2013	13,907	1,895
2014 (estimated)	15,607	1,892
Benefit Payments:		
2011	18,269	1,870
2012	18,195	1,971
2013	18,855	1,895
Estimated Future Benefit Payments:		
2014	19,450	1,892
2015	20,033	1,927
2016	20,671	2,001
2017	21,424	2,053
2018	22,337	2,112
2019-2023	129,177	10,823

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 new 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 addition, in July 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 as well as increasing the operational costs of running a pension plan. Our qualified defined benefit pension plan is currently underfunded by $95.3 million at December 31, 2013. Including the impacts of MAP-21, we expect to make contributions during 2014 of approximately $15 million.

Multiemployer Pension Plan

In addition to the Company-sponsored defined benefit plans referred to above, we contribute 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) in accordance with our collective bargaining agreement. The employer identification number of the plan is 94-6076144. The cost of this plan, and corresponding future liabilities, are in addition to pension amounts in the tables above. The Western States Plan is managed by a board of trustees that includes equal representation from participating employers and labor unions. Contribution rates are established by collective bargaining agreements, and benefit levels are set by the board of trustees based on the advice of an independent actuary regarding the level of benefits that agreed-upon contributions are expected to support.

The Western States Plan has reported an accumulated funding deficit for the current plan year and remains in critical status. A plan is considered to be in critical status if its funded status is below 65%. Federal law requires pension plans in critical status to adopt a rehabilitation plan designed to restore the financial health of the plan. Rehabilitation plans may specify benefit reductions, contribution surcharges, or a combination of the two. The Western States Plan trustees adopted a rehabilitation plan that reduced benefit accrual rates and adjustable benefits for active employee participants and increased future employer contribution rates. These changes are expected to improve the funded status of the plan. Our contributions to the Western States Plan amounted to $0.5 million in 2013 and $0.4 million in 2012, and 2011, which is approximately 4% to 5% of the total contributions to the plan by all employer participants.

Under the terms of our current collective bargaining agreement, which became effective in July 2009, we could withdraw from the Western States Plan at any time. 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 have been assessed a withdrawal liability of $8.3 million, which requires NW Natural to pay $0.6 million each year to the plan for the next 20 years. We have deferred the withdrawal liability to a regulatory account on the balance sheet.

Defined Contribution Plan

The Retirement K Savings Plan provided to our employees is a qualified defined contribution plan under Internal Revenue Code Section 401(k). Employer contributions to this plan totaled $2.2 million in 2013 and 2012, and $2.4 million in 2011. 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

Following 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 an open-end mutual fund and 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 mutual fund is valued at NAV, while 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. These are level 1 assets representing a mutual fund with readily determinable fair value, including published NAV's. 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 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 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. These are level 2 assets 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. These are level 1 assets 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. These are level 1 assets 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) securities.

ABSOLUTE RETURN STRATEGY. These are level 2 assets consisting of a hedge fund of funds where 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 includes investments primarily in common stocks and fixed income securities.

REAL RETURN STRATEGY. These are level 1 assets 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. These are level 2 assets representing mutual funds without published NAV's but the investment can be readily disposed of at NAV. The mutual funds are valued at the NAV of the shares held by the plan at the valuation date. This asset class primarily 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 that such changes could materially affect our investment account balances and the amounts reported as plan assets available for benefits 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, 2013			
Investments	Level 1	Level 2	Level 3	Total
U.S. large cap equity	$ 39,124	$ 79	$ —	$ 39,203
U.S. small/mid cap equity	30,465	55	—	30,520
Non-U.S. equity	16,782	17,202	—	33,984
Emerging markets equity	7,405	—	—	7,405
Fixed income	—	367	—	367
Long government/credit	33,152	32,763	—	65,915
High yield bonds	—	12,890	—	12,890
Emerging market debt	9,987	—	—	9,987
Real estate funds	16,559	—	—	16,559
Absolute return strategy	—	35,339	—	35,339
Real return strategy	13,031	—	—	13,031
Cash and cash equivalents	—	1,418	—	1,418
Total investments	$ 166,505	$ 100,113	$ —	$ 266,618

	December 31, 2012			
Investments	Level 1	Level 2	Level 3	Total
U.S. large cap equity	$ 29,047	$ 1,891	$ —	$ 30,938
U.S. small/mid cap equity	21,624	1,312	—	22,936
Non-U.S. equity	13,931	15,812	—	29,743
Emerging markets equity	8,004	—	—	8,004
Fixed income	—	8,824	—	8,824
Long government/credit	30,098	29,249	—	59,347
High yield bonds	—	12,017	—	12,017
Emerging market debt	11,421	—	—	11,421
Real estate funds	15,992	—	—	15,992
Absolute return strategy	—	32,078	—	32,078
Real return strategy	12,932	—	—	12,932
Cash and cash equivalents	—	1,459	—	1,459
Total investments	$ 143,049	$ 102,642	$ —	$ 245,691

	December 31,	
Receivables	2013	2012
Accrued interest and dividend income	$ 468	$ 388
Due from broker for securities sold	1,154	4,459
Total receivables	$ 1,622	$ 4,847
Liabilities		
Due to broker for securities purchased	$ 1,178	$ 935
Total investment in retirement trust	$ 267,062	$ 249,603

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 the three years ended December 31:

Dollars in thousands	2013	2012	2011
Income taxes at federal statutory rate	$35,785	$35,764	$37,056
Increase (decrease):			
Current state income tax, net of federal tax benefit	4,674	4,773	4,945
Amortization of investment and energy tax credits	(271)	(350)	(442)
Differences required to be flowed-through by regulatory commissions	2,357	1,718	1,647
Gains on company and trust-owned life insurance	(864)	(800)	(786)
Regulatory asset impairment	—	2,700	—
Other, net	24	(402)	405
Total provision for income taxes	$41,705	$43,403	$42,825
Effective tax rate	40.8%	42.5%	40.5%

The decrease in the effective income tax rate for 2013 compared to 2012 was primarily due to the one-time, after-tax charge of $2.7 million in 2012 related to the OPUC's rate case order that the Company could not recover deferred tax amounts resulting from the 2009 Oregon income tax rate change.

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

In thousands	2013	2012	2011
Current			
Federal	$ (62)	$ 1,693	$ 130
State	(11)	99	(929)
	(73)	1,792	(799)
Deferred			
Federal	35,109	31,187	35,021
State	6,669	10,424	8,603
	41,778	41,611	43,624
Total provision for income taxes	$ 41,705	$ 43,403	$ 42,825
Total income taxes paid	$ 870	$ 2,979	$ 1,756

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

In thousands	2013	2012	2011
Utility:			
Current	$ (73)	$ 1,909	$ (4,646)
Deferred	38,073	39,163	49,595
Deferred investment and energy tax credits	(271)	(350)	(422)
	37,729	40,722	44,527
Non-utility business segments:			
Current	—	(117)	3,846
Deferred	3,976	2,798	(5,548)
	3,976	2,681	(1,702)
Total provision for income taxes	$ 41,705	$ 43,403	$ 42,825

The following table summarizes the tax effect of significant items comprising our deferred income tax accounts for the two years ended December 31:

In thousands	2013	2012
Deferred tax liabilities:		
Plant and property	$ 362,160	$ 322,527
Regulatory income tax assets	56,183	60,253
Regulatory liabilities	71,971	49,197
Non-regulated deferred tax liabilities	47,516	43,824
Total	$ 537,830	$ 475,801
Deferred tax assets:		
Regulatory assets	$ —	$ (7,724)
Unfunded pension and postretirement obligations	4,112	6,024
Non-regulated deferred tax assets	—	(1,235)
Alternative minimum tax credit carryforward	1,939	1,986
Loss and credit carryforwards	45,351	32,997
Total	51,402	32,048
Deferred income tax liabilities, net	486,428	443,753
Deferred investment tax credits	367	624
Deferred income taxes and investment tax credits	$ 486,795	$ 444,377

We have determined that we are more likely than not to realize all recorded deferred tax assets as of December 31, 2013.

On December 17, 2010, President Obama signed into law the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010, which allows 100% bonus depreciation for qualified property placed in service between September 9, 2010 through December 31, 2011. It also extended the 50% bonus depreciation deduction to qualifying property placed in service through 2012. On January 2, 2013, President Obama signed into law the American Taxpayer Relief Act of 2012, which extended 50% bonus depreciation under §168(k) through 2013 for modified accelerated cost recovery system (MACRS) property with a recovery period of 20 years or less.

The Company estimates that it has net operating loss (NOL) carryforwards of $113.0 million for federal taxes and $113.7 million for Oregon taxes at December 31, 2013. 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 entire NOL carryforwards before they expire in 20 years for federal and 15 years for Oregon.

Uncertain tax positions are accounted for in accordance with accounting standards that require management's assessment of the expected treatment of a tax position taken in a filed tax return, or planned to be taken in a future tax return, that has not been reflected in measuring income tax expense for financial reporting purposes. Until such positions are sustained by the taxing authorities, we would not recognize the tax benefits resulting from such positions and would report the tax effect as a liability in our consolidated balance sheet. As of December 31, 2013, we had no reserves for uncertain tax positions.

As of December 31, 2013, the Company was under examination by the Internal Revenue Service for tax years 2009 through 2011, with resolution expected in 2014. The Company is also subject to examination for tax year 2012.

In 2012 the Company settled the Oregon Department of Revenue examination of tax years 2006 through 2009. This settlement resulted in an additional $0.2 million state tax expense, including interest, but that amount was offset by a corresponding refund claim with the state of California.

Interest and penalties related to any future income tax deficiencies are recorded within income tax expense in the consolidated statements of comprehensive income.

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	2013	2012
Utility plant in service	$2,585,901	$2,435,886
Utility construction work in progress	28,855	46,831
Less: Accumulated depreciation	827,380	789,201
Utility plant, net	1,787,376	1,693,516
Non-utility plant in service	297,330	296,781
Non-utility construction work in progress	6,653	6,510
Less: Accumulated depreciation	28,485	23,195
Non-utility plant, net	275,498	280,096
Total property, plant, and equipment	$2,062,874	$1,973,612

The weighted average depreciation rate was 2.8% for utility assets and 2.2% for non-utility assets in 2013, 2012, and 2011.

Accumulated depreciation does not include the accumulated provision for asset removal costs of $296.3 million and $281.2 million at December 31, 2013 and 2012, respectively. These accrued asset removal costs are reflected on the balance sheets as regulatory liabilities. See Note 2.

11. GAS RESERVES

Our gas reserves are stated at cost, net of regulatory amortization, with the associated deferred tax benefits recorded as liabilities on the balance sheet.

We entered into our agreements with Encana Oil & Gas (USA) Inc. (Encana) to develop and produce physical gas reserves. These agreements are intended to provide long-term gas price protection for our utility customers rather than serving as a source of gas supply. Encana began drilling in 2011 under these agreements, and gas, which is currently being produced from our working interests in these gas fields, is sold by Encana at then prevailing market prices, with revenues from such sales, net of associated production costs, credited to our cost of gas. The cost of gas, including a carrying cost for the net rate base investment, is part of our annual Oregon PGA filing, which allows us to recover our costs through customer rates in a manner previously approved by the OPUC. This transaction acted to hedge the cost of gas for approximately 6% of our gas supplies for the year ended December 31, 2013. The following table outlines our net gas reserves investment at December 31:

In thousands	2013	2012
Gas reserves, current	$ 20,646	$ 14,966
Gas reserves, non-current	140,573	92,179
Less: Accumulated amortization	18,575	7,486
Total gas reserves	142,644	99,659
Less: Deferred taxes on gas reserves	42,117	28,329
Net investment in gas reserves	$ 100,527	$ 71,330

<u>Variable Interest Entity (VIE) Analysis</u>
We concluded that the arrangement with Encana qualifies as a variable interest (VI) as our interest represents a minor portion of total extraction activities. 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	2013	2012
Investments in life insurance policies	$ 51,791	$ 51,439
Investments in gas pipeline joint ventures	14,048	14,216
Other	2,012	2,012
Total other investments	$ 67,851	$ 67,667

<u>Investment in Life Insurance Policies</u>
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.

Equity Method Investments
Palomar, a wholly-owned subsidiary of PGH, is pursuing the development of a new gas transmission pipeline that would provide an interconnection with our utility distribution system. PGH 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.

VIE Analysis
PGH is a development stage VIE. As of December 31, 2013, there were no changes to our VIE analysis and, as such, we continue to report Palomar under equity method accounting based on the determination that we are not the primary beneficiary of PGH's activities, as defined by the authoritative guidance related to consolidations, due to the fact that we have a 50% share and there are no stipulations that allow disproportionate influence over the entity. Our investment in PGH and Palomar are included in other investments on our balance sheet. Our maximum loss exposure related to PGH is limited to our equity investment balance, less our share of any cash or other assets available to us as a 50% owner.

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. When it is determined that 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, Palomar 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. Palomar 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.

Due to project scope changes in 2011, a portion of the assets were impaired and, as a result, we recorded a pre-tax charge of $1.3 million for our share of these costs at December 31, 2011. There have been no significant changes or impairments to the project since 2011. Our remaining equity investment was not impaired at December 31, 2013 as the fair value of expected cash flows from planned development exceeded our remaining equity investment of $13.4 million at December 31, 2013. 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 $13.2 million based on the current amount of our equity investment, net of cash and working capital at Palomar. We will continue to monitor and update our impairment analysis as required.

13. DERIVATIVE INSTRUMENTS

We enter into financial derivative contracts to meet 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. Our financial derivatives used to meet our utility's natural gas requirements qualify for regulatory accounting deferral.

We enter into these financial derivatives, up to prescribed limits, 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 optimization of our gas portfolio, which are derivatives that do not qualify for hedge accounting or regulatory deferral, but are subject to our regulatory sharing agreement.

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

	At December 31,	
In thousands	2013	2012
Natural gas (in therms):		
Financial	389,225	395,820
Physical	552,500	398,250
Foreign exchange	$ 15,002	$ 13,231

PGA
Derivatives entered into by the utility for the procurement or hedging of natural gas for future gas years and prior to our annual PGA filing receive regulatory deferred accounting treatment. Derivative contracts entered into after the annual PGA rate is set for the current gas contract year are subject to our PGA incentive sharing mechanism, which provides for either an 80% or 90% deferral of any gains and losses as regulatory assets or liabilities, with the remaining 20% or 10% recognized in current income. For the current gas year we have selected the 90% deferral option. 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 included in the Company's weighted-average cost of gas (WACOG) in the PGA filing. As of November 1, 2013, we reached our target hedge percentage for the 2013-14 gas year, and these hedge prices were included in the PGA filing 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. Outstanding derivative instruments related to regulated utility operations are deferred in accordance with regulatory accounting standards.

	December 31, 2013		December 31, 2012	
In thousands	Natural gas commodity	Foreign exchange	Natural gas commodity	Foreign exchange
Benefit (expense) to cost of gas	$ 4,985	$ (300)	$ (5,850)	$ 65
Less:				
Amounts deferred to regulatory accounts on balance sheet	(4,964)	300	5,850	(65)
Total gain in pre-tax earnings	$ 21	$ —	$ —	$ —

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.

We realized net losses of $11.0 million and $70.2 million for the years ended December 31, 2013 and 2012, respectively, from the settlement of natural gas financial derivative contracts. These realized losses were recorded as increases to the cost of gas.

Credit Risk Management of Financial Derivatives Instruments

No collateral was posted with or by our counterparties as of December 31, 2013 or 2012. 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 2013 or 2012. 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 financial swap and option contracts outstanding, which reflect unrealized gains of $5.4 million at December 31, 2013, we do not have any collateral demand exposure.

Our financial derivative instruments are subject to master netting arrangements; however, they are presented on a gross basis on the face of 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 when there is a defaulting party or in the event of a credit change due to a merger that affects either party or any other termination event.

If netted by counterparty, our derivative position would result in an asset of $7.2 million and a liability of $2.5 million as of December 31, 2013. As of December 31, 2012, our derivative position would result in an asset of $5.6 million and a liability of $11.4 million.

We are exposed to derivative credit risk primarily through securing pay-fixed natural gas commodity swaps to hedge the risk of price increases for our natural gas purchases 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 in order for them 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 utilize 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 utilize a Monte-Carlo simulation model to estimate the change in credit and liquidity risk from the volatility of natural gas prices. We use the results of the model to establish earnings-at-risk trading limits. Our credit risk for all outstanding financial derivatives at December 31, 2013 currently does not extend beyond March 2016.

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, but we would expect such loss to be eligible for regulatory deferral and rate recovery, subject to prudence review. All of our existing counterparties currently have investment-grade credit ratings.

Fair Value
In accordance with fair value accounting, we include nonperformance 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 techniques 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, 2013. As of December 31, 2013 and 2012, the net fair value was an asset of $4.7 million and a liability of $5.8 million, respectively, using significant other observable, or level 2, inputs. We have used no level 3 inputs in our derivative valuations. We did not have any transfers between level 1 or level 2 during the years ended December 31, 2013 and 2012. 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 $5.1 million, $4.8 million and $5.4 million for the years ended December 31, 2013, 2012 and 2011, respectively. The following table reflects the future minimum lease payments due under non-cancelable leases at December 31, 2013. 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
2014	$ 5,611	$ 462	$ 6,073
2015	5,530	196	5,726
2016	5,510	82	5,592
2017	5,506	12	5,518
2018	2,858	—	2,858
Thereafter	34,836	—	34,836
Total	$ 59,851	$ 752	$ 60,603

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, 2013:

In thousands	Gas Purchase Agreements	Pipeline Capacity Purchase Agreements	Pipeline Capacity Release Agreements
2014	$ 60,692	$ 94,923	$ 3,739
2015	—	77,433	—
2016	—	66,146	—
2017	—	52,084	—
2018	—	42,263	—
Thereafter	—	216,995	—
Total	60,692	549,844	3,739
Less: Amount representing interest	20	113,437	—
Total at present value	$ 60,672	$ 436,407	$ 3,739

Our total payments for fixed charges under capacity purchase agreements were $98.2 million in 2013, $94.3 million in 2012, and $94.2 million in 2011. Included in the amounts were reductions for capacity release sales of $4.5 million for 2013, $4.2 million for 2012, and $3.1 million for 2011. 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
See Note 15 Environmental Matters 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. 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. Unless there is an estimate within a 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 that 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 the 2012 Oregon general rate case, the new SRRM mechanism was approved to recover the Company's deferred environmental costs. The Commission ordered a separate docket to determine the prudence of deferred costs, the allocation of insurance proceeds, and an earnings test that would be applied to past and future deferred costs.

In July 2013, all parties filed a settlement agreement with the OPUC to address how to apply the new mechanism. In November, the Commission rejected the settlement and ordered further proceedings. We have established a schedule with parties for 2014 and are working toward resolution of this matter.

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. We annually review all regulatory assets for recoverability and more often if circumstances warrant. If we should determine that 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 determination is made.

In December 2010, NW Natural commenced litigation against certain of its historical liability insurers in Multnomah County Circuit Court, State of Oregon (see Part I, Item 3 "Legal Proceedings"). In the complaint, NW Natural sought damages in excess of $50 million in losses it incurred through the date of the complaint, as well as declaratory relief for additional losses it expects to incur in the future. As of February 6, 2014, we had settled with all defendant insurance companies in this litigation. As a result of this settlement, the Company expects to receive additional payments aggregating approximately $102 million in 2014 related to the settlements. Such payments are to be made in the first and second quarters of 2014. Through December 31, 2013, we have received approximately $48 million. See Note 17 for additional information.

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	2013	2012	2013	2012
Portland Harbor site:				
Gasco/Siltronic Sediments	$ 1,278	$ 2,207	$ 37,954	$ 36,087
Other Portland Harbor	1,766	1,767	3,478	3,160
Gasco Upland site	11,010	18,722	39,508	5,028
Siltronic Upland site	763	637	406	379
Central Service Center site	85	140	248	396
Front Street site	1,274	993	122	—
Oregon Steel Mills	—	—	179	185
Total	$ 16,176	$ 24,466	$ 81,895	$ 45,235

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	2013	2012
Cash paid[(1)]	$ 98,817	$ 71,124
Total regulatory asset deferral[(2)]	148,389	121,144

[(1)] Includes $20.1 million reclassified to utility plant in 2013 associated with the water treatment station of which a portion was paid in 2012.
[(2)] Includes cash paid, remaining liability, and interest, net of insurance reimbursement and amounts reclassified to utility plant for the water treatment station.

PORTLAND HARBOR SITE. The Portland Harbor is an EPA listed Superfund site that is approximately 11 miles long on the Willamette River and is adjacent to NW Natural's Gasco upland and Siltronic upland sites. We have been notified that we are a potentially responsible party to the Superfund site and we have joined with other potentially responsible parties (the Lower Willamette Group or LWG) to develop a Portland Harbor Remedial Investigation/ Feasibility Study (RI/FS). The LWG submitted a draft Feasibility Study (FS) to the Environmental Protection Agency (EPA) in March 2012 that provides a range of remedial costs for the entire Portland Harbor Superfund Site, which includes the Gasco/Siltronic Sediment site, discussed below. The range of costs estimated for various remedial alternatives for the entire Portland Harbor, as provided in the draft FS, is $169 million to $1.8 billion. NW Natural's potential liability is 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 potentially responsible parties. NW Natural is participating in a non-binding allocation process in an effort to settle this potential liability. We manage our liability related to the Superfund site as two distinct remediation projects, the Gasco/Siltronic Sediment 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 upland and Siltronic upland sites. NW Natural submitted a draft Engineering Evaluation/Cost Analysis (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 range from $39.2 million to $350 million. We have recorded a liability of $39.2 million for the sediment clean-up, which reflects the low end of the EE/CA range, 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. 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 which is performing the RI/FS for the EPA. 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 accrued a liability for these claims which is at the low end of the range of the potential liability and the high end of the range cannot be reasonably estimated. This liability is not included in the range of costs provided in the draft FS for the Portland Harbor.

Gasco upland site. NW Natural owns 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. We manage the Gasco site in two parts, the uplands portion and the groundwater source control action.

In May 2007, we completed a revised Remedial Investigation Report for the uplands portion and submitted it to ODEQ for review. 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 and the high end of the range cannot be reasonably estimated at this time.

In September 2013, we completed construction and placed into service 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 due to the uncertainty associated with the duration of running the water treatment station, which will be highly dependent upon the remedy determined for both the upland portion as well as the final remedy for our Gasco sediment exposure.

On October 28, 2013, the OPUC approved placing $19.0 million of capital costs associated with constructing a water treatment station at our Gasco environmental site into rates beginning November 1, 2013. These amounts are subject to refund, with interest, in the event the Commission determines, through a separate docket, that any of these costs were incurred imprudently. On February 13, 2014, NW Natural filed an all-party stipulation in the proceeding with the OPUC, which if approved would deem Gasco construction costs prudent and would also approve applying $2.5 million of insurance proceeds plus interest to reduce the Gasco costs included in rates beginning November 1, 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 liabilities, and in the case of the Oregon Steel Mills site, pending litigation, liabilities for each of these sites has been recognized at their respective low end of the range of potential liability; the high end of the range could not be reasonably estimated as of December 31, 2013.

Siltronic upland site. Siltronic is the location of a manufactured gas plant formerly owned by NW Natural. 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. Studies for source control investigation have been presented to ODEQ and a final sampling plan required by ODEQ is currently being developed.

Oregon Steel Mills site. See "Legal Proceedings," below.

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, NW Natural does 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 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 that the ultimate disposition of this matter will have a material effect on our financial condition, results of operations or cash flows.

16. REVISION OF PRIOR PERIOD FINANCIAL STATEMENTS

During the first quarter of 2013, we identified an error in the rate used to calculate interest on certain regulatory assets. Accounting standards allow for the capitalization of all or part of an incurred cost that would otherwise be charged to expense if the regulator provides orders that create probable recovery of past costs through future revenues. Historically we had accrued 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. As the equity component of our ROR is not an incurred cost that would otherwise be charged to expense, this portion of the carrying cost should not have been capitalized for financial reporting purposes.

We assessed the materiality of this error on prior period financial statements and concluded it was not material to any prior annual or interim periods; however, the cumulative impact would have been material to the annual and interim periods for 2013, if corrected in 2013. As a result, in accordance with accounting standards, we revised our prior period financial statements as described below to correct this error. The revision had no effect on reported cash flows.

The adjustment impacted years 2003 through 2012 with a cumulative pre-tax decrease over that period of $5.6 million to regulatory assets and other income and expense. The revision decreased net income by $1.1 million and $0.9 million for the years ended December 31, 2012 and 2011, respectively. The cumulative decrease to January 1, 2011 retained earnings was $1.4 million as a result of the revision.

The following table presents the income statement impacts of this revision for the years ended December 31:

	2012			2011		
In thousands, except per share data	Reported Balance	Adjust-ment	Adjusted Balance	Reported Balance	Adjust-ment	Adjusted Balance
Other income and expense, net	$ 4,936	$ (1,777)	$ 3,159	$ 4,523	$ (1,411)	$ 3,112
Income before income taxes	103,959	(1,777)	102,182	107,280	(1,411)	105,869
Income tax expense	44,104	(701)	43,403	43,382	(557)	42,825
Net Income	59,855	(1,076)	58,779	63,898	(854)	63,044
Comprehensive income	58,364	(1,076)	57,288	62,702	(854)	61,848
Basic EPS	2.23	(0.04)	2.19	2.39	(0.03)	2.36
Diluted EPS	2.22	(0.04)	2.18	2.39	(0.03)	2.36

The following table presents the balance sheet impacts of this revision as of December 31:

	2012			2011		
In thousands	Reported Balance	Adjustment	Adjusted Balance	Reported Balance	Adjustment	Adjusted Balance
Non-current assets:						
Regulatory assets	$ 387,888	$ (5,633)	$ 382,255	$ 371,392	$ (3,856)	$ 367,536
Total non-current assets	2,535,054	(5,633)	2,529,421	2,397,885	(3,856)	2,394,029
Total assets	2,818,753	(5,633)	2,813,120	2,746,574	(3,856)	2,742,718
Liabilities and equity:						
Deferred credits and other non-current liabilities:						
Deferred tax liabilities	$ 446,604	$ (2,227)	$ 444,377	$ 413,209	$ (1,526)	$ 411,683
Total deferred credits and other non-current liabilities	1,025,584	(2,227)	1,023,357	975,922	(1,526)	974,396
Equity:						
Retained earnings	385,753	(3,406)	382,347	373,905	(2,330)	371,575
Total equity	733,033	(3,406)	729,627	714,488	(2,330)	712,158
Total liabilities and equity	2,818,753	(5,633)	2,813,120	2,746,574	(3,856)	2,742,718

The following tables present the income statement and balance sheet corrections for the following quarters:

	2012							
	First Quarter		Second Quarter		Third Quarter		Fourth Quarter	
In thousands, except per share data	Reported Balance	Adjusted Balance	Reported Balance	Adjusted Balance	Reported Balance	Adjusted Balance	Reported Balance	Adjusted Balance
Other income and expense, net	$ 1,005	$ 472	$ 921	$ 620	$ 1,710	$ 1,180	$ 1,300	$ 887
Income (loss) before income taxes	68,480	67,947	2,296	1,995	(13,594)	(14,124)	46,777	46,364
Income tax expense (benefit)	27,873	27,663	887	768	(3,036)	(3,245)	18,380	18,217
Net income (loss)	40,607	40,284	1,409	1,227	(10,558)	(10,879)	28,397	28,147
Comprehensive income (loss)	40,773	40,450	1,575	1,393	(10,391)	(10,712)	26,407	26,157
Basic EPS	1.52	1.50	0.05	0.05	(0.39)	(0.41)	1.06	1.05
Diluted EPS	1.51	1.50	0.05	0.05	(0.39)	(0.41)	1.05	1.04
Non-current assets:								
Regulatory assets	$ 368,521	$ 364,132	$ 366,981	$ 362,290	$ 367,692	$ 362,472	$ 387,888	$ 382,255
Total non-current assets	2,416,372	2,411,983	2,448,359	2,443,668	2,492,467	2,487,247	2,535,054	2,529,421
Total assets	2,727,262	2,722,873	2,635,141	2,630,450	2,690,368	2,685,148	2,818,753	2,813,120
Liabilities and equity:								
Deferred credits and other non-current liabilities:								
Deferred tax liabilities	$ 438,486	$ 436,750	$ 440,073	$ 438,217	$ 430,885	$ 428,821	$ 446,604	$ 444,377
Total deferred credits and other non-current liabilities	999,028	997,292	991,007	989,151	985,729	983,665	1,025,584	1,023,357
Equity:								
Retained earnings	402,599	399,946	392,082	389,247	369,584	366,428	385,753	382,347
Total equity	745,971	743,318	737,570	734,735	717,559	714,403	733,033	729,627
Total liabilities and equity	2,727,262	2,722,873	2,635,141	2,630,450	2,690,368	2,685,148	2,818,753	2,813,120

	2011							
	First Quarter		Second Quarter		Third Quarter		Fourth Quarter	
In thousands, except per share data	Reported Balance	Adjusted Balance	Reported Balance	Adjusted Balance	Reported Balance	Adjusted Balance	Reported Balance	Adjusted Balance
Other income and expense, net	$ 1,214	$ 1,291	$ 1,122	$ 779	$ 1,781	$ 1,426	$ 406	$ (384)
Income (loss) before income taxes	68,627	68,704	3,509	3,166	(14,012)	(14,367)	49,156	48,366
Income tax expense (benefit)	27,854	27,884	1,316	1,181	(5,700)	(5,840)	19,912	19,600
Net income (loss)	40,773	40,820	2,193	1,985	(8,312)	(8,527)	29,244	28,766
Comprehensive income (loss)	40,919	40,966	2,339	2,131	(8,166)	(8,381)	27,610	27,132
Basic EPS	1.53	1.53	0.08	0.07	(0.31)	(0.32)	1.09	1.08
Diluted EPS	1.53	1.53	0.08	0.07	(0.31)	(0.32)	1.09	1.07
Non-current assets:								
Regulatory assets	$ 345,452	$ 343,085	$ 326,081	$ 323,371	$ 328,757	$ 325,692	$ 371,392	$ 367,536
Total non-current assets	2,290,848	2,288,481	2,294,100	2,291,390	2,317,293	2,314,228	2,397,885	2,394,029
Total assets	2,571,553	2,569,186	2,521,994	2,519,284	2,567,840	2,564,775	2,746,574	2,742,718
Liabilities and equity:								
Deferred credits and other non-current liabilities:								
Deferred tax liabilities	$ 396,357	$ 395,419	$ 398,825	$ 397,751	$ 394,217	$ 393,003	$ 413,209	$ 411,683
Total deferred credits and other non-current liabilities	873,714	872,776	874,842	873,768	866,927	865,713	975,922	974,396
Equity:								
Retained earnings	385,899	384,470	376,489	374,853	356,574	354,723	373,905	371,575
Total equity	723,228	721,799	714,628	712,992	696,605	694,754	714,488	712,158
Total liabilities and equity	2,571,553	2,569,186	2,521,994	2,519,284	2,567,840	2,564,775	2,746,574	2,742,718

17. SUBSEQUENT EVENT

In December 2010, NW Natural commenced litigation against certain of its historical liability insurers. NW Natural alleged that the defendant insurance companies issued third party liability insurance policies to NW Natural and that the defendants had breached the terms of those policies by failing to reimburse and indemnify NW Natural for liabilities arising from environmental contamination at certain sites caused or alleged to be caused by its historical operations.

NW Natural sought damages in excess of $50 million in losses it had incurred through the date of the complaint, as well as declaratory relief for additional damages it expected to incur in the future. Settlements with certain of the defendant insurance companies resulted in payments received by NW Natural through December 31, 2013 of approximately $48 million.

In January and February 2014, the remaining defendant insurance companies agreed to settle all of NW Natural's claims. In 2014 the Company expects to receive additional payments aggregating approximately $102 million under settlement agreements signed in 2013 and 2014. Such payments are to be made in the first and second quarters of 2014. As a result of such settlements, the Company anticipates dismissal of the litigation in the second quarter of 2014.

The settlements are recognized in regulatory accounts with the treatment determined through the SRRM. We expect the open regulatory docket regarding SRRM to be resolved during 2014.

NORTHWEST NATURAL GAS COMPANY
QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

In thousands, except share data	Quarter ended March 31	June 30	September 30	December 31
2013				
Operating revenues	$ 277,861	$ 131,714	$ 88,195	$ 260,748
Net income (loss)	37,639	2,126	(8,233)	29,006
Basic earnings (loss) per share[1]	1.40	0.08	(0.31)	1.07
Diluted earnings (loss) per share[1]	1.40	0.08	(0.31)	1.07
2012				
Operating revenues	$ 309,639	$ 103,991	$ 87,501	$ 229,476
Net income (loss)[2]	40,284	1,227	(10,879)	28,147
Basic earnings (loss) per share[1][2]	1.50	0.05	(0.41)	1.05
Diluted earnings (loss) per share[1][2]	1.50	0.05	(0.41)	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.
(2) Prior period balances have been adjusted for a prior period error identified during the first quarter of 2013. See Note 16 for reconciliation to amounts previously reported.

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
2013					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$ 2,518	$ 199	$ —	$ 1,061	$ 1,656
2012					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$ 2,895	$ 1,130	$ —	$ 1,507	$ 2,518
2011					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$ 2,950	$ 1,919	$ —	$ 1,974	$ 2,895

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, 2013 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

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information concerning our Board of Directors, its Committees and the Audit Committee financial expert contained in NW Natural’s definitive Proxy Statement for the May 22, 2014 Annual Meeting of Shareholders is hereby incorporated by reference. The information concerning "Section 16(a) Beneficial Ownership Reporting Compliance" and "Corporate Governance" contained in our definitive Proxy Statement for the May 22, 2014 Annual Meeting of Shareholders is hereby incorporated by reference.

Name	Age at Dec. 31, 2013	Positions held during last five years
Gregg S. Kantor	56	President and Chief Executive Officer (2009-); President and Chief Operating Officer (2007-2008); Executive Vice President (2006-2007); Senior Vice President, Public and Regulatory Affairs (2003-2006).
David H. Anderson	52	Executive Vice President and Chief Operating Officer (2014-); Executive Vice President Operations and Regulation (2013-2014); Senior Vice President and Chief Financial Officer (2004-2013).
Stephen P. Feltz	58	Senior Vice President and Chief Financial Officer (2013-); Assistant Secretary (2007-); Treasurer and Controller (1999-2013).
Margaret D. Kirkpatrick	59	Senior Vice President and General Counsel (2013-); Vice President and General Counsel (2005-2013).
Lea Anne Doolittle	58	Senior Vice President and Chief Administrative Officer (2013-); Senior Vice President (2008-); Vice President, Human Resources (2000-2007).
J. Keith White	60	Vice President, Business Development and Energy Supply/Chief Strategic Officer (2007-); Managing Director, Gas Operations and Wholesale Services (2005-2006); Managing Director and Chief Strategic Officer (2003-2005).
David R. Williams	60	Vice President, Utility Services (2007-); Director of Utility Operations, Districts and Managed Labor Relations (2004-2006).
Grant M. Yoshihara	58	Vice President, Utility Operations (2007-); Managing Director, Utility Services (2005-2006); Director, Utility Services (2004-2005).
C. Alex Miller	56	Vice President Regulation and Treasurer (2013-); Vice President, Finance and Regulation (2009-2013); Assistant Treasurer (2008-2013); General Manager of Rates and Regulatory Affairs (2002-2009).
MardiLyn Saathoff	57	Vice President Legal, Risk and Compliance (2013-); Deputy General Counsel (2010-2013); Chief Governance Officer and Corporate Secretary (2008-); Chief Compliance Officer and Assistant General Counsel, Tektronix, Inc. (2005-2008).
Brody J. Wilson	34	Controller (2013-); Acting Controller (2013); Accounting Director (2012-2013); Senior Manager, PriceWaterhouseCoopers LLP (2009-2012); Manager, PriceWaterhouseCoopers LLP (2007-2009).
David A. Weber	54	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 22, 2014. 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 22, 2014 Annual Meeting of Shareholders is hereby incorporated by reference. Information related to Executive Officers as of December 31, 2013 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, 2013 (see Note 6 to the Consolidated Financial Statements):

	(a)	**(b)**	**(c)**
Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	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)]	152,007	n/a	443,198
LTIP Restricted Stock Units (Target Award)[(1)(2)]	50,972	n/a	443,198
LTIP Stock Options[(2)]	—	—	250,000
Restated Stock Option Plan	492,150	$ 42.89	—
Employee Stock Purchase Plan	26,191	35.69	95,993
Equity compensation plans not approved by security holders:			
Executive Deferred Compensation Plan (EDCP)[(3)]	1,326	n/a	n/a
Directors Deferred Compensation Plan (DDCP)[(3)]	55,253	n/a	n/a
Deferred Compensation Plan for Directors and Executives (DCP)[(4)]	134,711	n/a	n/a
Total	912,610		789,191

(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, 2013, the number of shares shown in column (a) would increase by 152,007 shares and the number of shares shown in column (c) would decrease by the same amount of shares.

(2) The aggregate 443,198 shares are available for future issuance under the LTIP as Restricted Stock Units, Performance Share Awards, or LTIP Stock Options. An additional 250,000 shares are available for LTIP Stock Option Issuance at December 31, 2013, but those additional shares are not available for issuance of LTIP Restricted Stock Units or Performance Share Awards.

(3) 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.

(4) 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 22, 2014 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 22, 2014 Annual Meeting of Shareholders is hereby incorporated by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information captioned "2013 and 2012 Audit Firm Fees" in the Company’s definitive Proxy Statement for the May 22, 2014 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 93.

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
President and Chief Executive Officer
Date: February 28, 2014

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 President and Chief Executive Officer	Principal Executive Officer and Director	February 28, 2014
/s/ Stephen P. Feltz Stephen P. Feltz Senior Vice President and Chief Financial Officer	Principal Financial Officer	February 28, 2014
/s/ Brody J. Wilson Brody J. Wilson Controller	Principal Accounting Officer	February 28, 2014
/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	)
/s/ C. Scott Gibson C. Scott Gibson	Director	February 28, 2014)
/s/ Tod R. Hamachek Tod R. Hamachek	Director	)
/s/ Jane L. Peverett Jane L. Peverett	Director	)
/s/ Kenneth Thrasher Kenneth Thrasher	Director	)

NORTHWEST NATURAL GAS COMPANY

Exhibit Index to Annual Report on Form 10-K
For the Fiscal Year Ended December 31, 2013

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 period ending June 30, 2008, File No. 1-15973).
*3b.	Bylaws as amended May 24, 2012 (incorporated herein by reference to Exhibit 3.1 to Form 8-K dated May 24, 2012, 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. 0-994).
*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.	Gill Ranch Note Purchase Agreement, dated November 30, 2011, among Gill Ranch Storage, LLC and the parties listed thereto (incorporated herein by reference to Exhibit 4m. to Form 10-K for 2011, File No. 1-15973).
*4i.	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).
*4j.	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).

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 Credit Agreement between Northwest Natural Gas Company and each financial institutions, effective as of December 20, 2013.

*10a Carry and Earning Agreement (incorporated herein by reference to Exhibit 10.1 to Form 10-Q for the quarter ended March 31, 2011, 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:

*10b. Executive Supplemental Retirement Income Plan 2010 Restatement (incorporated herein by reference to Exhibit 10b. to Form 10-K for 2009, File No. 1-15973).

*10c. Supplemental Executive Retirement Plan, effective September 1, 2004 restated 2011 (incorporated herein by reference to Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2011, File No. 1-15973).

*10d. 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).

*10e. 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).

*10f. 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).

*10g. 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).

*10h. Form of Restated Stock Option Plan Agreement (incorporated herein by reference to Exhibit 10h. to Form 10-K for 2009, File No. 1-15973).

*10i. 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).

*10j. 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).

*10k. Deferred Compensation Plan for Directors and Executives effective January 1, 2005, restated as of January 1, 2012 (incorporated herein by reference to Exhibit 10k. to Form 10-K for 2011, File No. 1-15973).

*10l. 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).

*10l.(1) 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).

*10m. 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).

*10n. Executive Annual Incentive Plan, effective February 23, 2012 (incorporated herein by reference to Exhibit 10n. to Form 10-K for 2011, File No. 1-15973).

*10o. Form of Agreement to Recoupment Provisions of Executive Annual Incentive Plan, effective as of January 1, 2010 (incorporated herein by reference to Exhibit 10o. to Form 10-K for 2009, File No. 1-15973).

*10p. 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).

*10q. Severance agreement dated December 19, 2008 between the Company and Gregg S. Kantor (incorporated herein by reference to Exhibit 10.1 to Form 8-K dated December 23, 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 2013, File No. 1-15973)

*10s. Form of Long-Term Incentive Award Agreement under the Long-Term Incentive Plan (2011-2013) (incorporated herein by reference to Exhibit 10u. to Form 10-K for 2011, File No. 1-15973).

*10t. Form of Long-Term Incentive Award Agreement under the Long-Term Incentive Plan (2012-2014) (incorporated herein by reference to Exhibit 10v. to Form 10-K for 2011, File No. 1-15973).

*10u. 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).

10v. Form of Long-Term Incentive Award Agreement under the Long-Term Incentive Plan (2014-2016).

*10w. Form of Consent dated December 14, 2006 entered into by each executive officer (incorporated herein by reference to Exhibit 10.1 to Form 8-K dated December 19, 2006, File No. 1-15973).

*10x. 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).

*10aa. 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).

*10bb. 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 14, 2011, File No. 1-15973).

*10cc. 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)

*10dd. Annual Incentive Plan for NW Natural Gas Storage, LLC, as amended February 2, 2012 (incorporated herein by reference to Exhibit 10cc. to Form 10-K for 2012, File No. 1-15973).

*10ee. Long Term Incentive Plan for NW Natural Gas Storage, LLC (incorporated herein by reference to Exhibit 10dd. to Form 10-K for 2012, File No. 1-15973).

*10ff. Form of Change in Control Severance Agreement between the Company and an executive officer (incorporated herein by reference to Exhibit 10ee. to Form 10-K for 2012, File No. 1-15973).

101. The following materials from Northwest Natural Gas Company Annual Report on Form 10-K for the fiscal year ended December 31, 2013, 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

EXHIBIT 12

NORTHWEST NATURAL GAS COMPANY

Ratios of Earnings to Fixed Charges

(Unaudited)

In thousands, except share data	Year Ended December 31, 2013	2012	2011	2010	2009
Fixed Charges, as defined:					
Interest on Long-Term Debt	$ 40,825	$ 39,175	$ 37,515	$ 39,198	$ 37,447
Other Interest	2,709	2,314	2,976	1,587	1,937
Amortization of Debt Discount and Expense	1,877	1,848	1,729	1,766	1,503
Interest Portion of Rentals	1,910	1,864	2,213	2,130	1,735
Total Fixed Charges, as defined	47,321	45,201	44,433	44,681	42,622
Earnings, as defined:					
Net Income[1]	60,538	58,779	63,044	72,013	74,632
Taxes on Income[1]	41,705	43,403	42,825	49,033	46,349
Fixed Charges, as above	47,321	45,201	44,433	44,681	42,622
Total Earnings, as defined	$ 149,564	$ 147,383	$ 150,302	$ 165,727	$ 163,603
Ratios of Earnings to Fixed Charges	3.16	3.26	3.38	3.71	3.84

[1] Prior period balances have been adjusted for a prior period error identified during the first quarter of 2013. See Note 16 for additional detail on this error.

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 28, 2014 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 28, 2014

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 28, 2014

/s/ Gregg S. Kantor
Gregg S. Kantor
President and Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, Stephen P. Feltz, 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 28, 2014

/s/ Stephen P. Feltz
Stephen P. Feltz
Senior Vice President and Chief Financial Officer

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, the President and Chief Executive Officer, and STEPHEN P. FELTZ, the Senior Vice President and Chief Financial Officer, 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, 2013 (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 28th day of February 2014.

/s/ Gregg S. Kantor
Gregg S. Kantor
President and Chief Executive Officer

/s/ Stephen P. Feltz
Stephen P. Feltz
Senior Vice President and
Chief Financial Officer

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.

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INVESTOR AND SHAREHOLDER INFORMATION

Robert Hess

Director, Investor Relations
(800) 422-4012, Ext. 2388
rsh@nwnatural.com

Chu Lee

Manager, Shareholder Services
(800) 422-4012, Ext. 2402
c4l@nwnatural.com

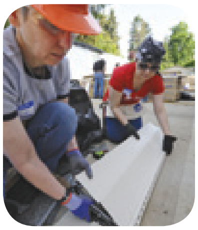
Stock transfer agent and registrar

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 all bond issues:
Deutsche Bank Trust Company Americas
60 Wall Street
New York, NY 10005
(800) 735-7777

Community and 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 Weatherization Program

NW Natural offers a program to our low-income customers designed to reduce their natural gas use through the installation of energy-efficient equipment and weatherization measures. Find out more about this innovative Oregon program.

View the Low-Income Energy-Efficiency Program Annual Report at nwnatural.com/aboutnwnatural/environmentalstewardship.

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/aboutnwnatural/environmentalstewardship.

NW Natural®

We grew up here.

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PORTLAND, OREGON 97209
NWNATURAL.COM
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UBI: 93-0256722 | 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, 2013

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

Brody J. Wilson, Controller
220 N. W. Second Avenue
Portland, Oregon 97209

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

Form 2 Approved
OMB No.1902-0028
(Expires 10/31/2014)

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

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

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

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
NW Natural Gas Company	**End of** 12/31/2013

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

GENERAL INFORMATION

I Purpose

FERC Forms 2, 2-A, and 3-Q are designed to collect financial and operational information from natural gas companies subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be 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, 2013
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** Controller
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, 2014

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** Controller
13 Signature	**14 Date Signed (Mo, Day, Yr)** 04/29/14

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, 2013

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, 2013

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".

☐ 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, 2013

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 — Controller
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	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission	(Mo, Da, Yr)	Dec. 31, 2013

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	Palomar Gas Holdings, LLC	I/J	Intermediate holding company	50%	5
6	Palomar Gas Transmission, 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 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 Palomar operating companies.

6 Palomar Gas Transmission, LLC, wholly-owned by Palomar Gas Holdings, LLC, was formed in 2007 to develop an interstate gas

7 BL Credit Holdings, LLC, wholly-owned by Palomar Gas Transmission, 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

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 an affliate of TPG Capital.

* These companies are 100% owned indirectly through our joint venture Palomar Gas 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, 2013

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 stock-holders 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.	3. Give the date and place of such meeting:
10/31/2013 List of stockholders to whom dividends were paid on 11/15/2013.	Total: 17,998,940 By proxy: 16,795,367	Date: 5/23/2013 Place: Portland, Oregon Location: Oregon Convention Center

Line No.	Name (Title) and Address of Security Holder (a)	VOTING SECURITIES Number of votes as of (date): 10/31/2013 Total Votes (b)	Common Stock (c)	Preferred Stock (d)	Other (e)
4	TOTAL votes of all voting securities	27,002,556	27,002,556		
5	TOTAL number of security holders	6,249	6,249		
6	TOTAL votes of security holders listed below	24,319,053	24,319,053		
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, 2013

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)	24,116,430	89.31%
2	P. O. Box 20		
3	Bowling Green Station		
4	New York, NY 10004-1408		
5			
6	David H. Anderson & (2)	42,528	0.16%
7	Susan S. Anderson JT TEN		
8	1688 Leslie Ln		
9	Lake Oswego, OR 97034-2179		
10			
11	Wachovia Bank N.A. TTEE (3)	29,209	0.11%
12	Northwest Natural Gas Co Umbrella TR for Directors		
13	DTD 1-1-91 Restated 12/15/05 for A/C Exec Serv		
14	One West Fourth St NC 6251		
15	Winston-Salem, NC 27101		
16			
17	Rodger P. Shute	25,891	0.10%
18	5570 - 248th PL SE		
19	Issaquah, WA 98029-7619		
20			
21	Wachovia Bank N.A. TTEE (4)	20,080	0.07%
22	Northwest Natural Gas Co Umbrella TR for Directors		
23	DTD 1-1-91 Restated 12/15/05 NEDSCP A/C Exec Serv		
24	One West Fourth St NC 6251		
25	Winston-Salem, NC 27101		
26			
27	Gregg S. Kantor (5)	19,749	0.07%
28	1709 SW Westwood Court		
29	Portland, OR 97239		
30			
31	Daniel J. Clement &	18,161	0.07%
32	Elizabeth J. Clement JT TEN		
33	55 Turtle Creek Rd		
34	Lewisburg, PA 17837-8122		
35			
36	Betty Lou Beck	16,149	0.06%
37	4755 SE Washington Place		
38	Milwaukie, OR 97222		
39			
40	Mary Susan Pape (6)	15,646	0.06%
41	3693 North Shasta Loop		
42	Eugene, OR 97405		
43			
44	EPS for Northwest Natural Gas Company ESPP Balance Account (7)	15,210	0.06%
45	Attn: Head of Relationship Management		
46	6201 15th Avenue		
47	Brooklyn, NY 11219		
48			
49	(1) Per Schedule 13G filed with the SEC by BlackRock, Inc., 40 East 52nd Street, New York, NY 10022, Parnassus Investments, 1 Market Street, Suite 1600, San Francisco, CA 94105, and The Vanguard Group, Inc., 100 Vanguard Blvd., Malvern, PA 19355, as of December 31, 2013, each held shares through Cede & Company, and was a beneficial owner of 9.40%, 7.43% and 6.38%, respectively, of NW Natural common stock.		
50	(2) Chief Operating Officer and Executive Vice President Operations and Regulation		
51	(3) Current, Retired and Former Directors - Timothy Boyle, Martha Byorum, John Carter, Tod R. Hamacheck, Wayne Kuni, Randall C. Papé, & Richard Woolworth		
52	(4) Current, Retired and Former Directors - Timothy Boyle, Martha Byorum, John Carter, Thomas Dewey, Scott C. Gibson, Tod R. Hamacheck, Wayne Kuni, Richard Reiten, Robert Ridgley, Melody Teppola, Russell Tromely, & Richard Woolworth		
53	(5) President and Chief Executive Officer		
54	(6) Beneficiary of former director		
55	(7) Company's employee stock purchase plan administrative account		

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, 2013

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)
57-59	Officers	Stock Options for Officers as of 12/31/2013	Stock Rights for for Officers as of 12/31/2013 (1)	
60	David H. Anderson	50,000	13,850	*
61	Lea Anne Doolittle	21,000	6,275	*
62	Stephen P. Feltz	14,000	7,200	*
63	Gregg S. Kantor	103,000	36,200	*
64	Margaret D. Kirkpatrick	33,500	8,528	*
65	C. Alex Miller	8,100	3,700	*
66	MardiLyn Saathoff	12,000	4,138	*
67	David A. Weber	11,625	1,811	*
68	J. Keith White	21,000	6,275	*
69	David R. Williams	14,000	5,535	*
70	Brody J. Wilson	0	1,532	*
71	Grant M. Yoshihara	14,000	5,535	*

(1) Includes performance based stock and performance based restricted stock units

* Less than one percent.

Name of Respondent	This Report is:	Date of Report	Year of Report
Northwest Natural Gas Company	x An Original A Resubmission		Dec. 31, 2013

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)

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, 2013

IMPORTANT CHANGES DURING THE YEAR (Continued)

1. None
2. None
3. None
4. None
5. A portion of the Mid-Willamette Valley Feeder went into service in October 2013.
6. None
7. None
8. Bargaining unit pay increase of 2.1% effective June 1, 2013. Non-bargaining unit salary increase of 2.8% effective March 1, 2013.
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 13-394 on October 29, 2013. The approval of these filings decreased the Company's annual Oregon revenues by $19.3 million, or 2.9 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, 2013, 615,278 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, 2013.

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, 2013 at the WUTC Open Meeting held on October 30, 2013. 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 increased the Company's annual Washington revenues by $1.5 million, or 2.1 percent. As of June 30, 2013, 72,092 customers were affected.

12. Effective February 28, 2013: David H. Anderson was promoted from Senior Vice President & Chief Financial Officer to Executive Vice President Operations & Regulation; Stephen P. Feltz was promoted from Treasurer & Controller to Senior Vice President & Chief Financial Officer. Effective September 26, 2013: Brody J. Wilson was promoted from Acting Controller to Controller.

13. 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, 2013

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Reference Page Number (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	2,571,773,870	2,421,753,691
3	Construction Work in Progress (107)	200-201	28,855,246	46,831,561
4	TOTAL Utility Plant (Total of lines 2 and 3)	-	2,600,629,116	2,468,585,252
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 111, 115)	200-201	(1,122,660,165)	(1,069,505,970)
6	Net Utility Plant (Total of line 4 less 5)	-	1,477,968,951	1,399,079,282
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)	-	1,477,968,951	1,399,079,282
11	Utility Plant Adjustments (116)	122		
12	Gas Stored-Base Gas (117.1)	220	14,127,180	14,132,362
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	71,526,223	71,769,127
18	(Less) Accum. Prov. for Depreciation and Amortization (122)	-	(14,645,670)	(13,971,513)
19	Investments in Associated Companies (123)	222-223		
20	Investment in Subsidiary Companies (123.1)	224-225	313,634,760	173,634,088
21	(For Cost of Account 123.1, See Footnote Page 224, line 40)	-		
22	Noncurrent Portion of Allowances	-		
23	Other Investments (124)	222-223	53,653,145	137,994,144
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)	-	1,880,000	3,639,000
29	Long-Term Portion of Derivative Assets - Hedges (176)	-		
30	TOTAL Other Property and Investments (Total of lines 17-20, 22-29)	-	426,048,458	373,064,846
31	**CURRENT AND ACCRUED ASSETS**			
32	Cash (131)	-	1,105,049	2,052,716
33	Special Deposits (132-134)	-	684,026	3,208,901
34	Working Funds (135)	-	171,589	179,309
35	Temporary Cash Investments (136)	222-223	3,256,583	2,294,639
36	Notes Receivable (141)	-		
37	Customer Accounts Receivable (142)	-	70,304,483	53,210,566
38	Other Accounts Receivable (143)	-	6,337,297	7,282,491
39	(Less) Accum. Prov. for Uncollectible Accounts-Credit (144)	-	(1,656,495)	(2,518,468)
40	Notes Receivable from Associated Companies (145)	-		
41	Accounts Receivable from Associated Companies (146)	-	400,485	198,858
42	Fuel Stock (151)	-		
43	Fuel Stock Expense Undistributed (152)	-		

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, 2013

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 (d)
44	Residuals (Elec) and Extracted Products (Gas) (153)	-		
45	Plant Material and Operating Supplies (154)	-	8,991,883	8,481,222
46	Merchandise (155)	-		
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	42,972,904	49,579,996
53	Liq. Natural Gas Stored and Held for Processing (164.2-164.3)	220	8,355,600	9,161,076
54	Prepayments (165)	230	15,637,512	15,011,793
55	Advances for Gas - Encana (166-167)	-		14,966,000
56	Interest and Dividends Receivable (171)	-		
57	Rents Receivable (172)	-		
58	Accrued Utility Revenues (173)	-	61,527,045	56,955,005
59	Miscellaneous Current and Accrued Assets (174)	-		
60	Derivative Instrument Assets (175)	-	5,611,000	1,885,000
61	(Less) Long-Term Portion of Derivative Instrument Assets (175)	-		
62	Derivative Instrument Assets - Hedges (176)	-	(300,000)	65,000
63	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)	-		
64	TOTAL Current and Accrued Assets (Total of lines 32 thru 63)	-	223,398,961	222,014,104
65	**DEFERRED DEBITS**			
66	Unamortized Debt Expense (181)	259	10,747,385	11,608,117
67	Extraordinary Property Losses (182.1)	230		
68	Unrecovered Plant and Regulatory Study Costs (182.2)	230		
69	Other Regulatory Assets (182.3)	232	56,182,552	60,253,011
70	Prelim. Survey and Investigation Charges (Electric) (183)	-		
71	Prelim. Survey and Invest. Charges (Gas) (183.1, 183.2)	-	9,135	5,472
72	Clearing Accounts (184)	-		
73	Temporary Facilities (185)	-		
74	Miscellaneous Deferred Debits (186)	233	334,891,188	378,652,412
75	Def. Losses from Disposition of Utility Plant (187)	-		
76	Research, Devel. and Demonstration Expend. (188)	-		
77	Unamortized Loss on Reacquired Debt (189)	260	3,573,974	3,972,026
78	Accumulated Deferred Income Taxes (190)	234-235	7,382,403	
79	Unrecovered Purchased Gas Costs (191)	-	(3,555,857)	(9,879,390)
80	Total Deferred Debits (Total of lines 66 thru 79)		409,230,780	444,611,648
81	Total Assets and Other Debits (Total of lines 10-15, 30,64,and 80		2,550,774,330	2,452,902,242

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, 2013

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 (d)
1	**PROPRIETARY CAPITAL**			
2	Common Stock Issued (201)	250-251	362,873,478	354,901,381
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	25,350	20,215
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254		
11	Retained Earnings (215, 215.1, 216)	118-119	407,401,768	392,918,528
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	(9,507,172)	(7,165,128)
13	(Less) Reacquired Capital Stock (217)	250-251		
14	Accumulated Other Comprehensive Income (219)	117	(6,358,470)	(9,290,677)
15	TOTAL Proprietary Capital (Total of lines 2 thru 14)	-	756,084,818	733,034,183
16	**LONG-TERM DEBT**			
17	Bonds (221)	256-257	701,700,000	651,700,000
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	(60,000,000)	
24	TOTAL Long-Term Debt (Total of lines 17 thru 23)	-	641,700,000	651,700,000
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases - Noncurrent (227)	-	354,776	480,565
27	Accumulated Provision for Property Insurance (228.1)	-	55,000	27,000
28	Accumulated Provision for Injuries and Damages (228.2)	-	98,317,877	69,975,593
29	Accumulated Provision for Pensions and Benefits (228.3)	-	168,017,481	234,731,169
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 (d)
32	Long-Term Portion of Derivative Instrument Liabilities	-	615,000	578,000
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)		267,360,134	305,792,327
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Current Portion of Long-term Debt		60,000,000	
38	Notes Payable (231)	-	188,200,000	190,250,000
39	Accounts Payable (232)	-	90,605,928	83,460,604
40	Notes Payable to Associated Companies (233)	-		
41	Accounts Payable to Associated Companies (234)	-	2,090,177	9,206,487
42	Customer Deposits (235)	-	5,770,711	5,741,561
43	Taxes Accrued (236)	262-263	7,262,980	7,104,158
44	Interest Accrued (237)	-	6,834,518	5,699,333
45	Dividends Declared (238)	-		(14)
46	Matured Long-Term Debt (239)	-		
47	Matured Interest (240)	-		
48	Tax Collections Payable (241)	-	6,594,769	5,318,090
49	Miscellaneous Current and Accrued Liabilities (242)	268	24,245,114	17,193,821
50	Obligations Under Capital Leases-Current (243)	-	(393,935)	(568,829)
51	Derivative Instrument Liabilities (244)		2,506,000	11,374,000
52	(Less) Long-Term Portion of Derivative Instrument Liabilities		(615,000)	(578,000)
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)		393,101,262	334,201,211
56	**DEFERRED CREDITS**			
57	Customer Advances for Construction (252)	-	3,138,288	3,260,756
58	Accumulated Deferred Investment Tax Credits (255)	-	367,186	624,159
59	Deferred Gains from Disposition of Utility Plant (256)	-		
60	Other Deferred Credits (253)	269	8,279,454	
61	Other Regulatory Liabilities (254)		7,130,000	5,589,000
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	473,613,188	418,700,606
66	TOTAL Deferred Credits (Total of lines 49 thru 55)		492,528,116	428,174,521
67	TOTAL Liabilities and Other Credits (Total of lines 15, 24, 35, 55 and 66)		2,550,774,330	2,452,902,242

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

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	746,183,842	718,292,421		
3	Operating Expenses					
4	Operation Expenses (401)	320-325	480,675,611	457,169,882		
5	Maintenance Expenses (402)	320-325	21,526,521	19,641,738		
6	Depreciation Expense (403)	336-338	69,419,404	66,545,411		
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)					
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	46,495,489	46,081,132		
15	Income Taxes - Federal (409.1)	262-263	(221,300)	1,700,020		
16	- Other (409.1)	262-263	(10,751)	208,589		
17	Provision for Deferred Income Taxes (410.1)	276-277	62,169,960	72,474,185		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	276-277	23,952,662	32,595,085		
19	Investment Tax Credit Adj. - Net (411.4)		(256,973)	(364,026)		
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)		655,845,299	630,861,846		
26	Net Utility Operating income (Enter Total of line 2 less 25) (Carry forward to page 116, line 27)		90,338,543	87,430,575		

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
		746,183,842	718,292,421			2
						3
		480,675,611	457,169,882			4
		21,526,521	19,641,738			5
		69,419,404	66,545,411			6
						7
						8
						9
						10
						11
						12
						13
		46,495,489	46,081,132			14
		(221,300)	1,700,020			15
		(10,751)	208,589			16
		62,169,960	72,474,185			17
		23,952,662	32,595,085			18
		(256,973)	(364,026)			19
						20
						21
						22
						23
						24
		655,845,299	630,861,846			25
		90,338,543	87,430,575			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, 2013

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)	-	90,338,543	87,430,575		
28	**Other Income and Deductions**					
29	Other Income	-				
30	Nonutility Operating Income	-				
31	Revenues From Merch, Jobbing and Contract Work (415)	-	4,331,108	4,012,744		
32	(Less) Costs and Exp. of Merch, Job & Contract Work (416)	-	4,552,628	4,120,494		
33	Revenues From Nonutility Operations (417)	-	29,513,612	26,227,824		
34	(Less) Expenses of Nonutility Operations (417.1)	-	14,406,325	11,740,676		
35	Nonoperating Rental Income (418)	-	486,409	477,820		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	(2,342,044)	(2,966,995)		
37	Interest and Dividend Income (419)	-	5,991,367	5,005,407		
38	Allow. for Other Funds Used During Constr (419.1)	-	6,759			
39	Miscellaneous Nonoperating Income (421)	-	47,814	49,867		
40	Gain on disposition of Property (421.1)	-				
41	TOTAL Other Income (Total of lines 31 thru 40)		19,076,072	16,945,497		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)	-				
44	Miscellaneous Amortization (425)	-				
45	Donations (426.1)	340	1,204,736	1,209,282		
46	Life Insurance (426.2)	-	(2,467,719)	(2,284,376)		
47	Penalties (426.3)	-	60,840	3,751		
48	Expenditures for Certain Civic, Political and Related Activities (426.4)	-	1,056,330	977,462		
49	Other Deductions (426.5)	-	279,469	185,575		
50	TOTAL Other Income Deductions (Total of Lines 43 thru 49)	340	133,656	91,694		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	653,866	653,942		
53	Income Taxes - Federal (409.2)	262-263		(7,134)		
54	Income Taxes - Other (409.2)	262-263		(1,565)		
55	Provision for Deferred Inc. Taxes (410.2)	272-277	6,692,679	5,110,271		
56	(Less) Provision for Deferred Inc. Taxes - Cr. (411.2)	272-277	530,323	407,729		
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)		6,816,222	5,347,785		
60	Net Other Income and Deductions (Total of Lines 41, 50, 59)		12,126,194	11,506,018		
61	**Interest Charges**					
62	Interest on Long-Term Debt (427)	256-257	37,844,956	36,200,663		
63	Amortization of Debt Disc. and Expense (428)	258-259	1,373,975	1,344,676		
64	Amortization of Loss on Reacquired Debt (428.1)	260	398,052	398,052		
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, 2013

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	1,673,387	1,265,046		
69	(Less) Allow. for Borrowed Funds Used During Const.-Cr. (432)	-	171,108	127,180		
70	Net Interest Charges (Total of lines 62 thru 69)		41,119,262	39,081,257		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		61,345,475	59,855,336		
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)		61,345,475	59,855,336		

Note: 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 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
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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	(9,290,677)
2	Unrealized Gains/losses on available-for-sale securities, net of tax	
3	Pension liability adjustment, net of tax	1,997,623
4	Amortization of pension liabilities, net of tax	934,584
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	(6,358,470)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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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		392,918,528	378,102,582
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)		63,687,519	62,822,331
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		(49,204,279)	(48,006,442)
11.02	Stock Dividends			
12	TOTAL Dividends Declared - Common Stock (Account 438) (Total of lines 11.01 thru 11.02)		(49,204,279)	(48,006,442)
13	Transfers from Acct. 216.1, Unappropriated Undistributed Subsidiary Earnings			57
14	Balance - End of Year (Total of lines 1, 4, 5, 6, 8, 10, 12, and 13)		407,401,768	392,918,528

Name of Respondent	This Report Is:	Date of Report	Year of Report
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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)	407,401,768	392,918,528
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (ACCOUNT 216.1)		
20	Balance - Beginning of Year (Debit or Credit)	(7,165,128)	(4,198,076)
21	Equity in Earnings for Year (Credit) (Account 418.1)	(2,342,044)	(2,966,995)
22	(Less) Dividends Received (Debit)		
23	Other Changes (Explain) (see Note below)		(57)
24	Balance - End of year (Total of lines 20 thru 23)	(9,507,172)	(7,165,128)

Note> In the previous year, Other Changes are immaterial rounding differences.

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, 2013

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 78(c) on page 116)	61,345,475	59,855,336
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	70,740,334	67,876,720
5	Amortization of (Specify)		
5.01	FAS 109 Deferred Taxes	(4,070,459)	(8,201,801)
5.02	FAS 109 Regulatory Asset	4,070,459	8,201,801
6	Deferred Income Taxes (Net)	51,600,638	34,576,611
7	Investment Tax Credit Adjustments (Net)	(256,973)	(364,026)
8	Net (Increase) Decrease in Receivables	(17,212,323)	16,215,014
9	Net (Increase) Decrease in Inventory	7,412,568	6,580,478
10	Net (Increase) Decrease in Allowances Inventory		
11	Net Increase (Decrease) in Payables and Accrued Expenses	1,323,035	12,128,340
12	Pension Liability Adjustment, net of tax	2,932,206	(1,491,027)
13	Unrealized loss from price risk management activities	(8,928,999)	(52,479,000)
14	(Less) Allowance for Other Funds Used During Construction	(171,108)	(127,180)
15	(Less) Undistributed Earnings from Subsidiary Companies	2,342,044	2,966,995
16	Other: Net (Increase) Decrease in Unbilled Revenues	(4,572,040)	4,970,039
16.01	Deferred Debits - Net	38,692,812	(14,479,171)
16.02	Net (Increase) Decrease in Other Current Assets & Liab.	7,220,742	13,230,542
16.03	Other - Noncurrent Liab., Deferred Credits, & Other Invest.	(32,654,137)	17,578,653
16.04	Unearned Compensation	196,573	439,855
17	Net Cash Provided by (Used in) Operating Activities		
18	(Total of lines 2 thru 16.04)	180,010,847	167,478,179
19			
20	Cash Flows from Investment Activities:		
21	Construction and Acquisition of Plant (including land):		
22	Gross Additions to Utility Plant (less nuclear fuel)	(156,941,858)	(136,357,797)
23	Gross Additions to Nuclear Fuel		
24	Gross Additions to Common Utility Plant		
25	Gross Additions to Nonutility Plant	(403,869)	317,159
26	(Less) Allowance for Other Funds Used During Constr.	171,108	127,180
27	Other: (1) (2)	106,940,222	(45,409,654)
28	Cash Outflows for Plant (Total of lines 22 thru 27)	(50,234,397)	(181,323,112)
29			
30	Acquisition of Other Noncurrent Assets (d)		
31	Proceeds from Disposal of Noncurrent Assets (d)	3,472,463	421,385
32			
33	Investments in & Advances to Assoc. & Sub. Companies		
34	Contributions & Advances from Assoc. & Sub. Companies (3)	(142,342,716)	(3,224,999)
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)		

(1) Reflects gas reserves investment of $99.5 million transferred to NW Natural Gas Reserves, LLC a subsidary of Northwest Energy Corporation on March 1, 2013.
(2) Includes $8.6 million of proceeds from sale of plant assets during 2013, which will be refunded to rate payers.
(3) Includes investment in Northwest Energy Corporation, which is the holding company for NW Natural Gas Reserves, LLC and our gas reserves investment.

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, 2013

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		
40 42	Collections on Loans		
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)	(189,104,650)	(184,126,726)
50			
51	Cash Flows from Financing Activities:		
52	Proceeds from Issuance of:		
53	Long-Term Debt (b)	50,000,000	50,000,000
54	Preferred Stock		
55	Common Stock	7,780,659	7,749,012
56	Other: Capital Leases	49,105	(66,742)
57	Net Increase in Short-Term Debt (c)		48,649,964
58			
59	Cash Provided by Outside Sources (Total of lines 53 thru 58)	57,829,764	106,332,234
60			
61	Payments for Retirement of:		
62	Long-Term Debt (b)		(40,000,000)
63	Preferred Stock		
64	Common Stock		
65	Other: Conversion of Preference Stock to Common Stock		
66	Net Decrease in Short-Term Debt (c)	(2,050,000)	
67			
67	Capital Stock Expense		
68	Dividends on Preferred Stock		
69	Dividends on Common Stock	(49,204,279)	(48,006,441)
70	Net Cash Provided by (Used in) Financing Activities		
71	(Total of lines 59 thru 69)	6,575,485	18,325,793
72			
73	Net Increase (Decrease) in Cash and Cash Equivalents		
74	(Total of lines 18, 49, and 71)	(2,518,318)	1,677,246
75			
76	Cash and Cash Equivalents at Beginning of Period	7,735,565	6,058,319
77			
78	Cash and Cash Equivalents at End of Period	5,217,247	7,735,565

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, 2013

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 that 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 storage facilities located in Oregon and California. In addition, we have investments and other non-utility activities that we aggregate and report as other.

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 that 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 Palomar Gas Holdings, LLC (PGH) 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 significant 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.

During the first quarter of 2013, we identified an error in the rate used to calculate interest on regulatory assets. We assessed the materiality of this error on prior period financial statements and concluded it was not material to any prior annual or interim periods; however, the cumulative impact would have been material to the annual and interim periods for 2013, if corrected in 2013. As a result, in accordance with accounting standards, we have revised our prior period financial statements as shown in Note 16 to correct this error.

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

2. SIGNIFICANT ACCOUNTING POLICIES UPDATE

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 that 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. 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 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 provides 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 2013	Regulatory Assets 2012
Current:		
Unrealized loss on derivatives[1]	$ 1,891	$ 10,796
Other[2]	20,744	41,652
Total current	$ 22,635	$ 52,448
Non-current:		
Unrealized loss on derivatives[1]	$ 615	$ 578
Pension balancing[3]	25,713	14,727
Income tax asset	51,814	55,879
Pension and other postretirement benefit liabilities[3]	125,855	182,688
Environmental costs[4]	148,389	121,144
Other[2]	17,217	7,239
Total non-current	$ 369,603	$ 382,255

In thousands	Regulatory Liabilities 2013	Regulatory Liabilities 2012
Current:		
Gas costs	$ 7,510	$ 9,100
Unrealized gain on derivatives[1]	5,290	1,950
Other[2]	15,535	9,742
Total current	$ 28,335	$ 20,792
Non-current:		
Gas costs	$ 2,172	$ —
Unrealized gain on derivatives[1]	1,880	3,639
Accrued asset removal costs	296,294	281,213
Other[2]	3,139	3,261
Total non-current	$ 303,485	$ 288,113

(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 PGA mechanism when realized at settlement.

(2) Other primarily consists of several deferrals and amortizations under other approved regulatory mechanisms. The accounts being amortized typically earn a rate of return or carrying charge.

(3) Certain utility pension costs are approved for regulatory deferral, including amounts recorded to the pension balancing account, to mitigate the effects of higher and lower pension expenses. Pension costs that are deferred include an interest component when recognized in net periodic benefit costs. See Note 8.

(4) Environmental costs relate to specific sites approved for regulatory deferral by the OPUC and WUTC. In Oregon, we earn a carrying charge on amounts paid, whereas amounts accrued but not yet paid do not earn a carrying charge until expended. In Washington, a carrying charge related to deferred amounts will be determined in a future proceeding. For further information on environmental matters, see Note 15.

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 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, 2013 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.

New Accounting Standards

Recently Adopted Standards

BALANCE SHEET OFFSETTING. In December 2011, the Financial Accounting Standards Board (FASB) issued authoritative guidance regarding the offsetting of assets and liabilities on the balance sheet. The standard is intended to provide more comparable guidance between the GAAP and international accounting standards by requiring entities to disclose both gross and net amounts for assets and liabilities offset on the balance sheet as well as other disclosures concerning their enforceable master netting arrangements. This guidance was effective for annual reporting periods beginning on or after January 1, 2013. The adoption of this standard did not have a material effect on our financial statement disclosures. See Note 13.

RECLASSIFICATIONS FROM ACCUMULATED OTHER COMPREHENSIVE INCOME. In February 2013, the FASB issued authoritative guidance, which requires an entity to present significant amounts reclassified from each component of accumulated other comprehensive income (AOCI). This standard is intended to improve the reporting of these reclassifications by presenting the information concerning amounts reclassified into net income from AOCI in a single location. This information has historically has been presented throughout the financial statements. This guidance was effective for reporting periods beginning after December 15, 2012. The adoption of this standard did not have a material effect on our financial statement disclosures. See Note 8.

Recently Issued Accounting Pronouncements

OBLIGATIONS RESULTING FROM JOINT AND SEVERAL LIABILITY ARRANGEMENTS. In February 2013, the FASB issued guidance regarding the recognition, measurement and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date. Under the new guidance, an entity is required to measure fixed obligations as the sum of the amount the reporting entity agreed to pay on the basis of its arrangement among its co-obligors plus any additional amount the reporting entity expects to pay on behalf of its co-obligors. In addition, an entity must disclose the nature and amount of the obligation as well as other information about the obligations. The guidance is effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. We are currently assessing the impact, if any, of this guidance on our financial position, results of operations, or disclosures.

PRESENTATION OF UNRECOGNIZED TAX BENEFIT. In July 2013, the FASB issued guidance that requires an unrecognized tax benefit, or a portion of an unrecognized tax benefit, be presented in the financial statements as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss, or a tax credit carryforward, except under certain circumstances. The new guidance is effective for fiscal years and interim periods within those years, beginning after December 15, 2013. This guidance is not expected to have an impact on our financial position, results of operations, 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 "Allowance for Funds Used During Construction" 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 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 upon 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 that is recorded in other income and expense, net 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% in 2013, 2012, and 2011, reflecting the approximate weighted average economic life of the property. This includes 2013 weighted average depreciation rates for the following asset categories: 2.7% for transmission and distribution plant, 2.2% for gas storage facilities, 4.3% for general plant, and 4.1% 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 rates were 0.3% in 2013 and 2012, and 0.5% in 2011.

IMPAIRMENT OF LONG-LIVED ASSETS. We review the carrying value of long-lived assets whenever events or changes in circumstances indicate that 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.

If such factors indicate a potential impairment, we assess the recoverability by determining if the carrying value of the asset exceeds the sum of the projected future cash flows over the remaining economic life of the asset. An asset is determined to be impaired when the carrying value is not recoverable through undiscounted future cash flows, and in those cases, we would estimate the fair value of the asset using appropriate valuation methodologies, which may include an estimate of discounted cash flows. Any impairment would be measured as the difference between the asset's carrying amount and its estimated fair value.

While we determined there were no material impairments of long-lived assets during the year ended December 31, 2013, if our gas storage facilities experience sustained decreases in future cash flows due to a prolonged, slow recovery of the gas storage market, future assessments could result in an impairment.

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, 2013 and 2012, outstanding checks of approximately $2.8 million and $2.3 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 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, 2013 and 2012 was $61.5 million and $57.0 million, respectively.

From 2007 through 2010, utility margin also included the recognition of a regulatory adjustment for income taxes paid pursuant to a legislative rule (commonly referred to as SB 408) in effect for certain gas and electric utilities in Oregon. In 2011, SB 408 was repealed and replaced by Senate Bill SB 967. SB 967 required utilities to eliminate amounts accrued under SB 408, which resulted in a one-time pre-tax charge of $7.4 million in 2011.

Non-utility revenues are derived primarily from the gas storage segment. At our Mist underground storage facility, revenues are recognized upon delivery of services to customers. 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 primarily from an independent energy marketing company that optimizes commodity 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. See Note 4.

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.

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. With respect to these trade receivables, including accrued unbilled revenue, we establish an allowance for uncollectible accounts (allowance) 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. With respect to large individual customer receivables, a specific allowance is established and recorded 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 to be 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 the level of natural gas prices. Each quarter the allowance for uncollectible accounts is adjusted, 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 that are injected into storage are priced into inventory based on actual purchase costs. Utility gas inventories that are 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, consist primarily of natural gas that we 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. It is recorded at original cost and classified as a long-term plant asset.

Material 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 $51.4 million and $58.8 million at December 31, 2013 and 2012, respectively. At December 31, 2013 and 2012, our materials and supplies inventories totaled $9.3 million and $8.8 million, respectively.

Gas Reserves

Our gas reserves are stated at cost, adjusted for regulatory amortization, with the associated deferred tax benefits recorded as liabilities on the balance sheet. Transactional costs to enter into the agreement and payments by NW Natural to acquire gas reserves are recognized as gas reserves 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

In accordance with accounting for derivatives and hedges, we measure derivatives at fair value and recognize them as either assets or liabilities on the balance sheet. Accounting for derivatives requires that changes in the fair value be recognized currently in earnings unless specific 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. The Company's 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 that PGA year has begun 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 years in Oregon beginning November 1, 2013, 2012 and 2011, 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 upon quoted prices for identical instruments traded in active markets;
- Level 2: Valuation is based upon 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 that 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; (h) and other relevant economic measures.

Income Tax Expense

NW Natural and its wholly-owned subsidiaries file consolidated federal, state, and local income tax returns. Income taxes are currently allocated based on each entity's respective taxable income or loss and tax credits as if each entity filed a separate return. We account for income taxes in accordance with accounting standards for income taxes. Accounting for income taxes requires recognition of deferred tax liabilities and assets for the future tax consequences of events that have been included in the consolidated financial statements or tax returns. Under this method, deferred tax liabilities and assets are determined based on the difference 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. See Note 9.

Accounting for income taxes also requires recognition of deferred income tax assets and liabilities for temporary differences where regulators prohibit deferred income tax treatment for ratemaking purposes. We have recorded deferred tax liabilities of \$56.2 million and \$60.3 million at December 31, 2013 and 2012, respectively, to recognize future taxes payable resulting from transactions that have previously been reflected in the financial statements for these temporary differences. Regulatory assets or liabilities corresponding to such additional deferred income tax assets or liabilities may be recorded to the extent we believe they will be recoverable from or payable to customers through the ratemaking process. A corresponding regulatory asset has been recorded which represents the probable future revenue that will result from inclusion in rates charged to customers for taxes which will be paid in the future. The probable future revenue to be recorded takes into consideration the additional future taxes which will be generated by that revenue. Amounts applicable to income taxes due from customers primarily represent differences between the financial statement and tax basis of net utility plant in service and actual removal costs incurred.

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 or lease.

Environmental Contingencies

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. 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, then 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.

Subsequent Events
See Note 17 for information regarding the Company's environmental insurance settlements.

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. Diluted earnings per share are calculated as follows:

In thousands, except per share data	2013	2012	2011
Net income	$ 60,538	$ 58,779	$ 63,044
Average common shares outstanding - basic	26,974	26,831	26,687
Additional shares for stock-based compensation plans (See Note 6)	53	76	57
Average common shares outstanding - diluted	27,027	26,907	26,744
Earnings per share of common stock - basic	$ 2.24	$ 2.19	$ 2.36
Earnings per share of common stock - diluted	$ 2.24	$ 2.18	$ 2.36
Additional information:			
Antidilutive shares not included in net income per diluted common share calculation	26	1	2

4. SEGMENT INFORMATION

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 also includes NWN Gas Reserves, which is a wholly-owned subsidiary of Energy Corp, and the utility portion of 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 all third-party asset management services. Other includes NNG Financial and NWN Energy's equity investment in PGH, which is pursuing development of a cross-Cascades pipeline project (see Other, below).

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 90% of our customers are located in Oregon and 10% 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 under contractual arrangement, the results of which are included in this business segment. For the years ended December 31, 2013, 2012 and 2011, this business segment derived a majority of its revenues from firm and interruptible gas storage contracts and from asset management services.

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 gas storage segment also include revenues, net of amounts shared with core utility customers, from management of utility assets at Mist and upstream capacity when not needed to serve utility customers. In Oregon, the gas storage segment retains 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 credited to a deferred regulatory account for crediting back to utility customers. We have a similar sharing mechanism in Washington for revenue derived from storage and third party asset management services.

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.

Other
We have immaterial 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 an interstate gas transmission pipeline in Oregon (Palomar) and other pipeline assets in NNG Financial. For more information on Palomar, see Note 12. Other also includes some operating and non-operating revenues and expenses of the parent company that cannot be allocated to utility operations.

NNG Financial holds certain non-utility financial investments, but its 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 $1.2 million and $1.1 million at December 31, 2013 and 2012, respectively.

Segment Information Summary
The following table presents summary financial information concerning the reportable segments. Inter-segment transactions are insignificant.

In thousands	Utility	Gas Storage	Other	Total
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
2012				
Operating revenues	$ 699,862	$ 30,520	$ 225	$ 730,607
Depreciation and amortization	66,545	6,472	—	73,017
Income from operations	128,854	13,226	100	142,180
Net income	54,049	4,521	209	58,779
Capital expenditures	130,151	1,541	337	132,029
Total assets at December 31, 2012	2,505,655	291,568	15,897	2,813,120
2011				
Operating revenues	$ 801,478	$ 26,354	$ 223	$ 828,055
Depreciation and amortization	63,843	6,161	—	70,004
Income from operations	135,722	9,090	33	144,845
Net income (loss)	59,673	4,101	(730)	63,044
Capital expenditures	94,049	6,485	—	100,534

Utility Margin
Utility margin is a financial measure consisting of utility operating revenues less revenue taxes and the associated cost of gas. Cost of gas purchased for utility customers is generally a pass-through cost in the amount of revenues billed to regulated utility customers. By netting costs of gas 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 following table presents additional segment information concerning utility margin. The gas storage and other segments emphasize growth in operating revenues and net income as opposed to margin because these segments do not incur commodity cost of sales like the utility and, therefore, use operating revenues and net income to assess performance.

In thousands	2013	2012	2011
Utility margin calculation:			
Utility operating revenues	$ 727,182	$ 699,862	$ 801,478
Less: Utility cost of gas	373,298	355,335	458,508
Utility margin	$ 353,884	$ 344,527	$ 342,970

5. COMMON STOCK

Common Stock

As of December 31, 2013 and 2012, we had 100 million shares of common stock authorized. As of December 31, 2013, we had reserved 122,184 shares for issuance of common stock under the Employee Stock Purchase Plan (ESPP) and 96,991 shares under our Dividend Reinvestment and Direct Stock Purchase Plan (DRPP). In the second quarter of 2012, our Restated Stock Option Plan (Restated SOP) was terminated for new stock option grants. There were 492,150 options outstanding at December 31, 2013, which were granted prior to termination of the plan. These options will remain outstanding to the earlier of their forfeiture, exercise or expiration.

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 2014 to repurchase up to an aggregate of 2.8 million shares, but not to exceed $100 million. No shares of common stock were repurchased pursuant to this program during the year ended December 31, 2013. 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, 2010	26,668
Sales to employees under ESPP	15
Stock-based compensation	24
Sales to shareholders under DRPP	49
Balance, December 31, 2011	26,756
Sales to employees under ESPP	18
Stock-based compensation	47
Sales to shareholders under DRPP	96
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

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. A variety of equity programs may be granted under the LTIP. The Restated SOP was terminated for new stock option grants in 2012.

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, 2013. Shares awarded under the LTIP may be purchased on the open market or issued as new shares.

Of the 850,000 shares of common stock authorized for LTIP awards at December 31, 2013, there were 241,169 shares available for issuance under any type of award. This assumes that market, performance, and service based grants currently outstanding are awarded at the target level. Additionally, 250,000 shares of common stock were available for option grants at December 31, 2013. There were no outstanding grants of restricted stock or stock options under the LTIP at December 31, 2013 or 2012. 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:

Expense in millions	Shares [1]	Expense During Award Year[3]	Total Expense for Award
Estimated award:			
2011-2013 grant[2]	9,516	$ 0.4	$ 1.0
Actual award:			
2010-2012 grant	9,924	0.5	1.2
2009-2011 grant	8,428	0.4	0.8

[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] This represents the estimated number of shares to be awarded as of December 31, 2013 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 2014.

[3] Amount represents the expense recognized in the third year of the vesting period noted above.

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		2013	Cumulative Expense
Performance Period	Target	Maximum	Expense	December 31, 2013
2011-13	37,950	75,900	$ 390	$ 960
2012-14	35,340	70,680	603	1,238
2013-15	37,300	74,600	486	486
Total	110,590	221,180	$ 1,479	

For each of these performance periods, awards will be based on total shareholder return 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. Compensation expense is recognized in accordance with the accounting standard 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, 2013 and 2012 was $43.39 and $51.42 per share, respectively. The weighted-average grant date fair value of shares vested during the year was $30.86 per share and for shares granted during the year was $38.96 per share. As of December 31, 2013, there was $1.6 million of unrecognized compensation cost related to the unvested portion of performance awards expected to be recognized through 2015.

Restricted Stock Units

In 2012, the Company began granting RSUs under the LTIP instead of stock options under the Restated SOP. The majority of RSUs include a performance-based threshold and generally have a vesting period of four years from the grant date. An RSU obligates the Company upon vesting to issue the RSU holder 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 the RSU. The fair value of the RSU is equal to the closing market price of the Company's common stock on the grant date.

Information regarding the RSU activity is summarized as follows:

	Number of RSUs	Weighted - Average Price Per RSU
Nonvested, Dec. 31, 2011	—	$ —
Granted	25,224	47.58
Vested	—	—
Forfeited	(360)	48.00
Nonvested, Dec. 31, 2012	24,864	47.57
Granted	25,748	45.38
Vested	(5,455)	48.01
Forfeited	(590)	46.58
Nonvested, Dec. 31, 2013	44,567	46.27

As of December 31, 2013, there was $1.5 million of unrecognized compensation cost from grants of RSUs, which is expected to be recognized over a period extending through 2017.

Restated Stock Option Plan

The Restated SOP was terminated for new option grants in 2012; however, options that had been 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. We did not grant new stock options during 2012 or 2013.

At December 31, 2013, a total of 492,150 shares of common stock remained reserved for issuance under the Restated SOP. As the plan is closed, there are no additional shares available for grant. Options under the Restated SOP were granted only 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 7 days from the date of grant. Option holders may exchange shares they have owned for at least six months, valued at the current market price, to purchase shares at the option price.

The fair value of each stock option is estimated on the grant date using the Black-Scholes option pricing model with the following weighted average assumptions and outcomes:

	2011
Risk-free interest rate	2.0%
Expected life (in years)	4.5
Expected market price volatility factor	24.5%
Expected dividend yield	3.8%
Forfeiture rate	3.1%
Weighted average grant date fair value	$ 6.73

The expected life of our grants was calculated based on our actual experience with previously exercised option grants. The risk-free interest rate was based on the implied yield currently available on U.S. Treasury zero-coupon issues with a life equal to the expected life of the options. Historical data was used to estimate the volatility factor, measured on a daily basis, for a period equal to the duration of the expected life of the option awards. The dividend yield was based on management’s current estimate for future dividend payouts at the time of grant. We expense the total cost of stock option awards granted to retirement eligible employees at the date of grant in accordance with stock option accounting guidance and the retirement vesting provisions of our option agreements.

Information regarding the Restated SOP activity is summarized as follows:

	Option Shares	Weighted - Average Price Per Share	Intrinsic Value *(In millions)*
Balance outstanding, Dec. 31, 2010	490,460	$ 40.82	$ 2.8
Granted	122,700	45.74	n/a
Exercised	(24,185)	33.88	0.3
Forfeited	(9,750)	44.38	n/a
Balance outstanding, Dec. 31, 2011	579,225	42.09	3.4
Exercised	(46,825)	40.62	0.4
Forfeited	(2,475)	43.78	n/a
Balance outstanding, Dec. 31, 2012	529,925	42.22	1.3
Exercised	(33,800)	32.16	0.3
Forfeited	(3,975)	43.72	n/a
Balance outstanding, Dec. 31, 2013	492,150	42.89	0.6
Exercisable, Dec. 31, 2013	409,036	42.41	0.6

During 2013, cash of $1.1 million was received for option shares exercised and $0.2 million related tax benefit was realized. During 2013, 2012, and 2011, the total fair value of options that vested was $0.5 million, $0.6 million and $0.6 million, respectively. The weighted average remaining life of options exercisable and outstanding at December 31, 2013, was 4.8 years and 5.1 years, respectively. As of December 31, 2013, there was $0.2 million of unrecognized compensation cost related to the unvested portion of outstanding stock option awards expected to be recognized during 2014.

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 $21,236 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	2013	2012	2011
Operations and maintenance expense, for stock-based compensation	$ 1,876	$ 1,668	$ 1,477
Income tax benefit	(765)	(707)	(597)
Net stock-based compensation effect on net income	$ 1,111	$ 961	$ 880
Amounts capitalized for stock-based compensation	$ 331	$ 294	$ 261

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. At December 31, 2013 and 2012, the amounts of commercial paper debt outstanding were $188.2 million and $190.3 million, respectively, and the average interest rate was 0.3% at year-end for both periods. 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, 2013, our commercial paper had a maximum maturity of 136 days and an average maturity of 66 days. There were no bank loans outstanding at December 31, 2013 or 2012.

On December 20, 2012, NW Natural entered into a five-year $300 million credit agreement, pursuant to which we may extend commitments for two additional one-year periods subject to lender approval. In December 2013, we extended our commitment for an additional year with an updated maturity date of December 20, 2018. The credit agreement allows us to request increases in the total commitment amount up to a maximum amount of $450 million and permits letters of credit in an aggregate amount of up to $200 million. Any principal and unpaid interest owed on borrowings under the agreement are 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, 2013 and 2012.

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, 2013 and 2012.

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. In addition, our Gill Ranch subsidiary senior secured debt is secured by all of the membership interests in Gill Ranch as well as Gill Ranch's debt service reserve account.

Retirement of long-term debt for each of the 12-month periods through December 31, 2018 are as follows:

In thousands	
Year	
2014	$ 60,000
2015	40,000
2016	65,000
2017	40,000
2018	22,000

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

In thousands	2013	2012
First Mortgage Bonds		
8.26 % Series B due 2014	$ 10,000	$ 10,000
3.95 % Series B due 2014	50,000	50,000
4.70 % Series B due 2015	40,000	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	—
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 % Series due 2042	50,000	50,000
	701,700	651,700
Subsidiary Senior Secured Debt		
Gill Ranch debt due 2016	40,000	40,000
	741,700	691,700
Less: Current maturities of long-term debt	60,000	—
Total long-term debt	$ 681,700	$ 691,700

First Mortgage Bonds
NW Natural issued $50 million of FMBs on August 19, 2013 with a coupon rate of 3.542% and a 10-year maturity. In October 2012, the utility issued $50 million of FMBs with a coupon rate of 4.00% and a maturity date of October 31, 2042.

Subsidiary Senior Secured Debt
In November 2011, Gill Ranch issued $40 million of senior secured debt, which consists of $20 million of fixed rate debt with an interest rate of 7.75% and $20 million of variable interest rate debt with an interest rate of LIBOR plus 5.50%, or 7.00%, whichever is higher. At December 31, 2013, the variable interest rate was 7.00%. This debt is secured by all of the membership interests in Gill Ranch and is nonrecourse to NW Natural. The maturity date of this debt is November 30, 2016.

Under the debt agreements, Gill Ranch is subject to certain covenants and restrictions including, but not limited to, a financial covenant that requires Gill Ranch to maintain minimum adjusted earnings before interest, taxes, depreciation and amortization (EBITDA) at various levels over the term of the debt. The minimum adjusted EBITDA increases incrementally over the first few years, reaching its highest level in the 12-month period beginning April 1, 2015. Under the debt agreements, Gill Ranch is also subject to a debt service reserve requirement of 10% of the outstanding principal amount, certain prepayment penalties, restrictions on dividends out of Gill Ranch unless certain earnings ratios are met, and restrictions on incurrence of additional debt. Gill Ranch was in compliance with all existing debt provisions and covenants for the year ended December 31, 2013.

Fair Value of Long-Term Debt
As our outstanding debt does not trade in active markets, we estimated the fair value of our outstanding long-term debt using outstanding debt issuances that actively trade in public markets and companies that have similar credit ratings, terms and remaining maturities to our debt. 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	2013	2012
Carrying amount	$ 741,700	$ 691,700
Estimated fair value	806,359	834,664

8. PENSION AND OTHER POSTRETIREMENT BENEFIT COSTS

We maintain qualified non-contributory defined benefit pension plans, a few 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. Only 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 December 31, 2012, the defined benefit pension plans for non-union and union employees were merged into one plan. The qualified defined benefit retirement plan for non-union and union employees was closed to new participants effective January 1, 2007. The postretirement benefits plan for non-union employees was closed to new participants effective January 1, 2010. 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	2013	2012	2013	2012
Reconciliation of change in benefit obligation:				
Obligation at January 1	$ 435,889	$ 391,127	$ 33,119	$ 30,049
Service cost	8,698	8,047	656	592
Interest cost	16,400	17,295	1,157	1,267
Net actuarial (gain) loss	(51,043)	37,615	(4,283)	3,182
Benefits paid	(18,855)	(18,195)	(1,895)	(1,971)
Obligation at December 31	$ 391,089	$ 435,889	$ 28,754	$ 33,119
Reconciliation of change in plan assets:				
Fair value of plan assets at January 1	$ 249,603	$ 215,970	$ —	$ —
Actual return on plan assets	22,872	26,683	—	—
Employer contributions	13,442	25,145	1,895	1,971
Benefits paid	(18,855)	(18,195)	(1,895)	(1,971)
Fair value of plan assets at December 31	$ 267,062	$ 249,603	$ —	$ —
Funded status at December 31	$ (124,027)	$ (186,286)	$ (28,754)	$ (33,119)

Our qualified defined benefit pension plan has an aggregate benefit obligation of $362.4 million and $404.0 million at December 31, 2013 and 2012, respectively, and fair values of plan assets of $267.1 million and $249.6 million, respectively.

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

	Regulatory Assets						Other Comprehensive Income		
	Pension Benefits			Other Postretirement Benefits			Pension Benefits		
In thousands	2013	2012	2011	2013	2012	2011	2013	2012	2011
Net actuarial (gain) loss	$ (51,892)	$ 26,504	$ 66,404	$ (4,283)	$ 3,182	$ 2,225	$ (3,302)	$ 3,511	$ 2,948
Amortization of:									
Transition obligation	—	—	—	—	(411)	(411)	—	—	—
Prior service cost	(230)	(230)	(230)	(197)	(197)	(197)	7	35	(122)
Actuarial loss	(16,744)	(14,482)	(10,731)	(733)	(435)	(289)	(1,550)	(1,150)	(854)
Total	$ (68,866)	$ 11,792	$ 55,443	$ (5,213)	$ 2,139	$ 1,328	$ (4,845)	$ 2,396	$ 1,972

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	2013	2012	2013	2012	2013	2012
Prior service cost	$ 867	$ 1,097	$ 685	$ 882	$ (5)	$ (12)
Net actuarial loss	119,638	188,278	4,665	9,681	10,475	15,327
Total	$ 120,505	$ 189,375	$ 5,350	$ 10,563	$ 10,470	$ 15,315

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	2013	2012
Beginning balance	$ (9,291)	$ (7,800)
Amounts reclassified to AOCL	3,302	(3,495)
Amounts reclassified from AOCL:		
Amortization of prior service costs	(7)	(35)
Amortization of actuarial losses	1,550	1,134
Total reclassifications before tax	4,845	(2,396)
Tax (benefit) expense	(1,912)	905
Total reclassifications for the period	2,933	(1,491)
Ending balance	$ (6,358)	$ (9,291)

In 2014, an estimated $9.8 million will be amortized from regulatory assets to net periodic benefit costs, consisting of $9.4 million of actuarial losses, and $0.4 million of prior service costs. A total of $1.0 million will be amortized from AOCL to earnings related to actuarial losses.

Our assumed discount rate was determined independently for each pension plan and other postretirement benefit plan 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 the Company's 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 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 employees 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 expectation. All investments are expected to satisfy the requirements of the rule of prudent investments as set forth under the Employee Retirement Income Security Act of 1974. The approved asset classes 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. Our expected long-term rate of return is based upon historical index returns by asset class, adjusted by a factor based on our historical return experience, diversified asset allocation and active portfolio management by professional investment managers. The retirement trust fund is not currently invested in any NW Natural securities.

The following is our pension plan asset target allocation at December 31, 2013:

Asset Category	Target Allocation
U.S. large cap equity	13.0%
U.S. small/mid cap equity	8.5
Non-U.S. equity	13.0
Emerging markets equity	3.5
Long government/credit	30.0
High yield bonds	5.0
Emerging market debt	5.0
Real estate funds	6.0
Absolute return strategy	11.0
Real return strategy	5.0

Our non-qualified supplemental defined benefit plan obligations were $28.7 million and $31.9 million at December 31, 2013 and 2012, 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. Although these are unfunded plans with no plan assets due to their nature as non-qualified plans, we indirectly fund a 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, and the amortization of actuarial gains and losses.

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

The following tables provide the components of net periodic benefit cost for the Company's pension and other postretirement benefit plans for the years ended December 31 and the assumptions used in measuring these costs and benefit obligations:

	Pension Benefits			Other Postretirement Benefits		
In thousands	2013	2012	2011	2013	2012	2011
Service cost	$ 8,698	$ 8,047	$ 7,122	$ 656	$ 592	$ 614
Interest cost	16,400	17,295	18,134	1,157	1,267	1,404
Expected return on plan assets	(18,721)	(19,082)	(17,867)	—	—	—
Amortization of transition obligations	—	—	—	—	411	411
Amortization of prior service costs	223	195	352	197	197	197
Amortization of net actuarial loss	18,294	15,631	11,584	734	435	289
Net periodic benefit cost	24,894	22,086	19,325	2,744	2,902	2,915
Amount allocated to construction	(6,712)	(5,820)	(4,905)	(856)	(882)	(878)
Amount deferred to regulatory balancing account[1]	(9,115)	(7,876)	(6,008)	—	—	—
Net amount charged to expense	$ 9,067	$ 8,390	$ 8,412	$ 1,888	$ 2,020	$ 2,037

[1] Effective January 1, 2011, the OPUC approved the deferral of certain pension expenses above or below the amount set in rates, 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. See Note 2.

Net periodic benefit costs above are reduced by amounts capitalized to utility plant based on approximately 30% to 40% payroll overhead charge to construction work orders. In addition, a certain amount of net periodic benefit costs are recorded to the regulatory balancing account for pensions, with the remaining net amount charged to expense and recognized in current earnings.

	Pension Benefits			Other Postretirement Benefits		
	2013	2012	2011	2013	2012	2011
Assumptions for net periodic benefit cost:						
Weighted-average discount rate	3.84%	4.51%	5.49%	3.56%	4.33%	5.16%
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%	8.00%	8.25%	n/a	n/a	n/a
Assumptions for year-end funded status:						
Weighted-average discount rate	4.73%	3.85%	4.51%	4.45%	3.56%	4.33%
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%	8.00%	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, 2013 was 9.0% for pre-65 and 7.9% for 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 5.0% by 2021.

Assumed health care cost trend rates can have a significant effect on the amounts reported for the health care plans. 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	$ 73	$ (64)
Effect on the accumulated postretirement benefit obligation	739	(660)

The impact of a change in retirement benefit costs on operating results would be less than the amounts shown above because a portion would be capitalized to utility plant, and a certain amount would be recorded to the regulatory balancing account with the remaining amount recognized in current earnings.

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:		
2012	$ 25,559	$ 1,971
2013	13,907	1,895
2014 (estimated)	15,607	1,892
Benefit Payments:		
2011	18,269	1,870
2012	18,195	1,971
2013	18,855	1,895
Estimated Future Benefit Payments:		
2014	19,450	1,892
2015	20,033	1,927
2016	20,671	2,001
2017	21,424	2,053
2018	22,337	2,112
2019-2023	129,177	10,823

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 new 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 addition, in July 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 as well as increasing the operational costs of running a pension plan. Our qualified defined benefit pension plan is currently underfunded by $95.3 million at December 31, 2013. Including the impacts of MAP-21, we expect to make contributions during 2014 of approximately $15 million.

Multiemployer Pension Plan

In addition to the Company-sponsored defined benefit plans referred to above, we contribute 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) in accordance with our collective bargaining agreement. The employer identification number of the plan is 94-6076144. The cost of this plan, and corresponding future liabilities, are in addition to pension amounts in the tables above. The Western States Plan is managed by a board of trustees that includes equal representation from participating employers and labor unions. Contribution rates are established by collective bargaining agreements, and benefit levels are set by the board of trustees based on the advice of an independent actuary regarding the level of benefits that agreed-upon contributions are expected to support.

The Western States Plan has reported an accumulated funding deficit for the current plan year and remains in critical status. A plan is considered to be in critical status if its funded status is below 65%. Federal law requires pension plans in critical status to adopt a rehabilitation plan designed to restore the financial health of the plan. Rehabilitation plans may specify benefit reductions, contribution surcharges, or a combination of the two. The Western States Plan trustees adopted a rehabilitation plan that reduced benefit accrual rates and adjustable benefits for active employee participants and increased future employer contribution rates. These changes are expected to improve the funded status of the plan. Our contributions to the Western States Plan amounted to $0.5 million in 2013 and $0.4 million in 2012, and 2011, which is approximately 4% to 5% of the total contributions to the plan by all employer participants.

Under the terms of our current collective bargaining agreement, which became effective in July 2009, we could withdraw from the Western States Plan at any time. 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 have been assessed a withdrawal liability of $8.3 million, which requires NW Natural to pay $0.6 million each year to the plan for the next 20 years. We have deferred the withdrawal liability to a regulatory account on the balance sheet.

Defined Contribution Plan

The Retirement K Savings Plan provided to our employees is a qualified defined contribution plan under Internal Revenue Code Section 401(k). Employer contributions to this plan totaled $2.2 million in 2013 and 2012, and $2.4 million in 2011. 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

Following 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 an open-end mutual fund and 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 mutual fund is valued at NAV, while 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. These are level 1 assets representing a mutual fund with readily determinable fair value, including published NAV's. 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 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 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. These are level 2 assets 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. These are level 1 assets 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. These are level 1 assets 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) securities.

ABSOLUTE RETURN STRATEGY. These are level 2 assets consisting of a hedge fund of funds where 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 includes investments primarily in common stocks and fixed income securities.

REAL RETURN STRATEGY. These are level 1 assets 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. These are level 2 assets representing mutual funds without published NAV's but the investment can be readily disposed of at NAV. The mutual funds are valued at the NAV of the shares held by the plan at the valuation date. This asset class primarily 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 that such changes could materially affect our investment account balances and the amounts reported as plan assets available for benefits 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, 2013			
Investments	Level 1	Level 2	Level 3	Total
U.S. large cap equity	$ 39,124	$ 79	$ —	$ 39,203
U.S. small/mid cap equity	30,465	55	—	30,520
Non-U.S. equity	16,782	17,202	—	33,984
Emerging markets equity	7,405	—	—	7,405
Fixed income	—	367	—	367
Long government/credit	33,152	32,763	—	65,915
High yield bonds	—	12,890	—	12,890
Emerging market debt	9,987	—	—	9,987
Real estate funds	16,559	—	—	16,559
Absolute return strategy	—	35,339	—	35,339
Real return strategy	13,031	—	—	13,031
Cash and cash equivalents	—	1,418	—	1,418
Total investments	$ 166,505	$ 100,113	$ —	$ 266,618

	December 31, 2012			
Investments	Level 1	Level 2	Level 3	Total
U.S. large cap equity	$ 29,047	$ 1,891	$ —	$ 30,938
U.S. small/mid cap equity	21,624	1,312	—	22,936
Non-U.S. equity	13,931	15,812	—	29,743
Emerging markets equity	8,004	—	—	8,004
Fixed income	—	8,824	—	8,824
Long government/credit	30,098	29,249	—	59,347
High yield bonds	—	12,017	—	12,017
Emerging market debt	11,421	—	—	11,421
Real estate funds	15,992	—	—	15,992
Absolute return strategy	—	32,078	—	32,078
Real return strategy	12,932	—	—	12,932
Cash and cash equivalents	—	1,459	—	1,459
Total investments	$ 143,049	$ 102,642	$ —	$ 245,691

	December 31,	
Receivables	2013	2012
Accrued interest and dividend income	$ 468	$ 388
Due from broker for securities sold	1,154	4,459
Total receivables	$ 1,622	$ 4,847
Liabilities		
Due to broker for securities purchased	$ 1,178	$ 935
Total investment in retirement trust	$ 267,062	$ 249,603

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 the three years ended December 31:

Dollars in thousands	2013	2012	2011
Income taxes at federal statutory rate	$35,785	$35,764	$37,056
Increase (decrease):			
Current state income tax, net of federal tax benefit	4,674	4,773	4,945
Amortization of investment and energy tax credits	(271)	(350)	(442)
Differences required to be flowed-through by regulatory commissions	2,357	1,718	1,647
Gains on company and trust-owned life insurance	(864)	(800)	(786)
Regulatory asset impairment	—	2,700	—
Other, net	24	(402)	405
Total provision for income taxes	$41,705	$43,403	$42,825
Effective tax rate	40.8%	42.5%	40.5%

The decrease in the effective income tax rate for 2013 compared to 2012 was primarily due to the one-time, after-tax charge of $2.7 million in 2012 related to the OPUC's rate case order that the Company could not recover deferred tax amounts resulting from the 2009 Oregon income tax rate change.

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

In thousands	2013	2012	2011
Current			
Federal	$ (62)	$ 1,693	$ 130
State	(11)	99	(929)
	(73)	1,792	(799)
Deferred			
Federal	35,109	31,187	35,021
State	6,669	10,424	8,603
	41,778	41,611	43,624
Total provision for income taxes	$ 41,705	$ 43,403	$ 42,825
Total income taxes paid	$ 870	$ 2,979	$ 1,756

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

In thousands	2013	2012	2011
Utility:			
Current	$ (73)	$ 1,909	$ (4,646)
Deferred	38,073	39,163	49,595
Deferred investment and energy tax credits	(271)	(350)	(422)
	37,729	40,722	44,527
Non-utility business segments:			
Current	—	(117)	3,846
Deferred	3,976	2,798	(5,548)
	3,976	2,681	(1,702)
Total provision for income taxes	$ 41,705	$ 43,403	$ 42,825

The following table summarizes the tax effect of significant items comprising our deferred income tax accounts for the two years ended December 31:

In thousands	2013	2012
Deferred tax liabilities:		
Plant and property	$ 362,160	$ 322,527
Regulatory income tax assets	56,183	60,253
Regulatory liabilities	71,971	49,197
Non-regulated deferred tax liabilities	47,516	43,824
Total	$ 537,830	$ 475,801
Deferred tax assets:		
Regulatory assets	$ —	$ (7,724)
Unfunded pension and postretirement obligations	4,112	6,024
Non-regulated deferred tax assets	—	(1,235)
Alternative minimum tax credit carryforward	1,939	1,986
Loss and credit carryforwards	45,351	32,997
Total	51,402	32,048
Deferred income tax liabilities, net	486,428	443,753
Deferred investment tax credits	367	624
Deferred income taxes and investment tax credits	$ 486,795	$ 444,377

We have determined that we are more likely than not to realize all recorded deferred tax assets as of December 31, 2013.

On December 17, 2010, President Obama signed into law the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010, which allows 100% bonus depreciation for qualified property placed in service between September 9, 2010 through December 31, 2011. It also extended the 50% bonus depreciation deduction to qualifying property placed in service through 2012. On January 2, 2013, President Obama signed into law the American Taxpayer Relief Act of 2012, which extended 50% bonus depreciation under §168(k) through 2013 for modified accelerated cost recovery system (MACRS) property with a recovery period of 20 years or less.

The Company estimates that it has net operating loss (NOL) carryforwards of $113.0 million for federal taxes and $113.7 million for Oregon taxes at December 31, 2013. 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 entire NOL carryforwards before they expire in 20 years for federal and 15 years for Oregon.

Uncertain tax positions are accounted for in accordance with accounting standards that require management's assessment of the expected treatment of a tax position taken in a filed tax return, or planned to be taken in a future tax return, that has not been reflected in measuring income tax expense for financial reporting purposes. Until such positions are sustained by the taxing authorities, we would not recognize the tax benefits resulting from such positions and would report the tax effect as a liability in our consolidated balance sheet. As of December 31, 2013, we had no reserves for uncertain tax positions.

As of December 31, 2013, the Company was under examination by the Internal Revenue Service for tax years 2009 through 2011, with resolution expected in 2014. The Company is also subject to examination for tax year 2012.

In 2012 the Company settled the Oregon Department of Revenue examination of tax years 2006 through 2009. This settlement resulted in an additional $0.2 million state tax expense, including interest, but that amount was offset by a corresponding refund claim with the state of California.

Interest and penalties related to any future income tax deficiencies are recorded within income tax expense in the consolidated statements of comprehensive income.

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	2013	2012
Utility plant in service	$2,585,901	$2,435,886
Utility construction work in progress	28,855	46,831
Less: Accumulated depreciation	827,380	789,201
Utility plant, net	1,787,376	1,693,516
Non-utility plant in service	297,330	296,781
Non-utility construction work in progress	6,653	6,510
Less: Accumulated depreciation	28,485	23,195
Non-utility plant, net	275,498	280,096
Total property, plant, and equipment	$2,062,874	$1,973,612

The weighted average depreciation rate was 2.8% for utility assets and 2.2% for non-utility assets in 2013, 2012, and 2011.

Accumulated depreciation does not include the accumulated provision for asset removal costs of $296.3 million and $281.2 million at December 31, 2013 and 2012, respectively. These accrued asset removal costs are reflected on the balance sheets as regulatory liabilities. See Note 2.

11. GAS RESERVES

Our gas reserves are stated at cost, net of regulatory amortization, with the associated deferred tax benefits recorded as liabilities on the balance sheet.

We entered into our agreements with Encana Oil & Gas (USA) Inc. (Encana) to develop and produce physical gas reserves. These agreements are intended to provide long-term gas price protection for our utility customers rather than serving as a source of gas supply. Encana began drilling in 2011 under these agreements, and gas, which is currently being produced from our working interests in these gas fields, is sold by Encana at then prevailing market prices, with revenues from such sales, net of associated production costs, credited to our cost of gas. The cost of gas, including a carrying cost for the net rate base investment, is part of our annual Oregon PGA filing, which allows us to recover our costs through customer rates in a manner previously approved by the OPUC. This transaction acted to hedge the cost of gas for approximately 6% of our gas supplies for the year ended December 31, 2013. The following table outlines our net gas reserves investment at December 31:

In thousands	2013	2012
Gas reserves, current	$ 20,646	$ 14,966
Gas reserves, non-current	140,573	92,179
Less: Accumulated amortization	18,575	7,486
Total gas reserves	142,644	99,659
Less: Deferred taxes on gas reserves	42,117	28,329
Net investment in gas reserves	$ 100,527	$ 71,330

Variable Interest Entity (VIE) Analysis

We concluded that the arrangement with Encana qualifies as a variable interest (VI) as our interest represents a minor portion of total extraction activities. 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	2013	2012
Investments in life insurance policies	$ 51,791	$ 51,439
Investments in gas pipeline joint ventures	14,048	14,216
Other	2,012	2,012
Total other investments	$ 67,851	$ 67,667

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.

Equity Method Investments

Palomar, a wholly-owned subsidiary of PGH, is pursuing the development of a new gas transmission pipeline that would provide an interconnection with our utility distribution system. PGH 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.

VIE Analysis

PGH is a development stage VIE. As of December 31, 2013, there were no changes to our VIE analysis and, as such, we continue to report Palomar under equity method accounting based on the determination that we are not the primary beneficiary of PGH's activities, as defined by the authoritative guidance related to consolidations, due to the fact that we have a 50% share and there are no stipulations that allow disproportionate influence over the entity. Our investment in PGH and Palomar are included in other investments on our balance sheet. Our maximum loss exposure related to PGH is limited to our equity investment balance, less our share of any cash or other assets available to us as a 50% owner.

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. When it is determined that 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, Palomar 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. Palomar 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.

Due to project scope changes in 2011, a portion of the assets were impaired and, as a result, we recorded a pre-tax charge of $1.3 million for our share of these costs at December 31, 2011. There have been no significant changes or impairments to the project since 2011. Our remaining equity investment was not impaired at December 31, 2013 as the fair value of expected cash flows from planned development exceeded our remaining equity investment of $13.4 million at December 31, 2013. 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 $13.2 million based on the current amount of our equity investment, net of cash and working capital at Palomar. We will continue to monitor and update our impairment analysis as required.

13. DERIVATIVE INSTRUMENTS

We enter into financial derivative contracts to meet 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. Our financial derivatives used to meet our utility's natural gas requirements qualify for regulatory accounting deferral.

We enter into these financial derivatives, up to prescribed limits, 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 optimization of our gas portfolio, which are derivatives that do not qualify for hedge accounting or regulatory deferral, but are subject to our regulatory sharing agreement.

Notional Amounts

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

	At December 31,	
In thousands	2013	2012
Natural gas (in therms):		
Financial	389,225	395,820
Physical	552,500	398,250
Foreign exchange	$ 15,002	$ 13,231

PGA

Derivatives entered into by the utility for the procurement or hedging of natural gas for future gas years and prior to our annual PGA filing receive regulatory deferred accounting treatment. Derivative contracts entered into after the annual PGA rate is set for the current gas contract year are subject to our PGA incentive sharing mechanism, which provides for either an 80% or 90% deferral of any gains and losses as regulatory assets or liabilities, with the remaining 20% or 10% recognized in current income. For the current gas year we have selected the 90% deferral option. 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 included in the Company's weighted-average cost of gas (WACOG) in the PGA filing. As of November 1, 2013, we reached our target hedge percentage for the 2013-14 gas year, and these hedge prices were included in the PGA filing 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. Outstanding derivative instruments related to regulated utility operations are deferred in accordance with regulatory accounting standards.

	December 31, 2013		December 31, 2012	
In thousands	Natural gas commodity	Foreign exchange	Natural gas commodity	Foreign exchange
Benefit (expense) to cost of gas	$ 4,985	$ (300)	$ (5,850)	$ 65
Less:				
Amounts deferred to regulatory accounts on balance sheet	(4,964)	300	5,850	(65)
Total gain in pre-tax earnings	$ 21	$ —	$ —	$ —

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.

We realized net losses of $11.0 million and $70.2 million for the years ended December 31, 2013 and 2012, respectively, from the settlement of natural gas financial derivative contracts. These realized losses were recorded as increases to the cost of gas.

Credit Risk Management of Financial Derivatives Instruments

No collateral was posted with or by our counterparties as of December 31, 2013 or 2012. 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 2013 or 2012. 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 financial swap and option contracts outstanding, which reflect unrealized gains of $5.4 million at December 31, 2013, we do not have any collateral demand exposure.

Our financial derivative instruments are subject to master netting arrangements; however, they are presented on a gross basis on the face of 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 when there is a defaulting party or in the event of a credit change due to a merger that affects either party or any other termination event.

If netted by counterparty, our derivative position would result in an asset of $7.2 million and a liability of $2.5 million as of December 31, 2013. As of December 31, 2012, our derivative position would result in an asset of $5.6 million and a liability of $11.4 million.

We are exposed to derivative credit risk primarily through securing pay-fixed natural gas commodity swaps to hedge the risk of price increases for our natural gas purchases 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 in order for them 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 utilize 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 utilize a Monte-Carlo simulation model to estimate the change in credit and liquidity risk from the volatility of natural gas prices. We use the results of the model to establish earnings-at-risk trading limits. Our credit risk for all outstanding financial derivatives at December 31, 2013 currently does not extend beyond March 2016.

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, but we would expect such loss to be eligible for regulatory deferral and rate recovery, subject to prudence review. All of our existing counterparties currently have investment-grade credit ratings.

Fair Value

In accordance with fair value accounting, we include nonperformance 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 techniques 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, 2013. As of December 31, 2013 and 2012, the net fair value was an asset of $4.7 million and a liability of $5.8 million, respectively, using significant other observable, or level 2, inputs. We have used no level 3 inputs in our derivative valuations. We did not have any transfers between level 1 or level 2 during the years ended December 31, 2013 and 2012. 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 $5.1 million, $4.8 million and $5.4 million for the years ended December 31, 2013, 2012 and 2011, respectively. The following table reflects the future minimum lease payments due under non-cancelable leases at December 31, 2013. 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
2014	$ 5,611	$ 462	$ 6,073
2015	5,530	196	5,726
2016	5,510	82	5,592
2017	5,506	12	5,518
2018	2,858	—	2,858
Thereafter	34,836	—	34,836
Total	$ 59,851	$ 752	$ 60,603

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, 2013:

In thousands	Gas Purchase Agreements	Pipeline Capacity Purchase Agreements	Pipeline Capacity Release Agreements
2014	$ 60,692	$ 94,923	$ 3,739
2015	—	77,433	—
2016	—	66,146	—
2017	—	52,084	—
2018	—	42,263	—
Thereafter	—	216,995	—
Total	60,692	549,844	3,739
Less: Amount representing interest	20	113,437	—
Total at present value	$ 60,672	$ 436,407	$ 3,739

Our total payments for fixed charges under capacity purchase agreements were $98.2 million in 2013, $94.3 million in 2012, and $94.2 million in 2011. Included in the amounts were reductions for capacity release sales of $4.5 million for 2013, $4.2 million for 2012, and $3.1 million for 2011. 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

See Note 15 Environmental Matters 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. 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. Unless there is an estimate within a 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 that 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 the 2012 Oregon general rate case, the new SRRM mechanism was approved to recover the Company's deferred environmental costs. The Commission ordered a separate docket to determine the prudence of deferred costs, the allocation of insurance proceeds, and an earnings test that would be applied to past and future deferred costs. In July 2013, all parties filed a settlement agreement with the OPUC to address how to apply the new mechanism. In November, the Commission rejected the settlement and ordered further proceedings. We have established a schedule with parties for 2014 and are working toward resolution of this matter.

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. We annually review all regulatory assets for recoverability and more often if circumstances warrant. If we should determine that 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 determination is made.

In December 2010, NW Natural commenced litigation against certain of its historical liability insurers in Multnomah County Circuit Court, State of Oregon (see Part I, Item 3 "Legal Proceedings"). In the complaint, NW Natural sought damages in excess of $50 million in losses it incurred through the date of the complaint, as well as declaratory relief for additional losses it expects to incur in the future. As of February 6, 2014, we had settled with all defendant insurance companies in this litigation. As a result of this settlement, the Company expects to receive additional payments aggregating approximately $102 million in 2014 related to the settlements. Such payments are to be made in the first and second quarters of 2014. Through December 31, 2013, we have received approximately $48 million. See Note 17 for additional information.

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	2013	2012	2013	2012
Portland Harbor site:				
Gasco/Siltronic Sediments	$ 1,278	$ 2,207	$ 37,954	$ 36,087
Other Portland Harbor	1,766	1,767	3,478	3,160
Gasco Upland site	11,010	18,722	39,508	5,028
Siltronic Upland site	763	637	406	379
Central Service Center site	85	140	248	396
Front Street site	1,274	993	122	—
Oregon Steel Mills	—	—	179	185
Total	$ 16,176	$ 24,466	$ 81,895	$ 45,235

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	2013	2012
Cash paid[(1)]	$ 98,817	$ 71,124
Total regulatory asset deferral[(2)]	148,389	121,144

[(1)] Includes $20.1 million reclassified to utility plant in 2013 associated with the water treatment station of which a portion was paid in 2012.
[(2)] Includes cash paid, remaining liability, and interest, net of insurance reimbursement and amounts reclassified to utility plant for the water treatment station.

PORTLAND HARBOR SITE. The Portland Harbor is an EPA listed Superfund site that is approximately 11 miles long on the Willamette River and is adjacent to NW Natural's Gasco upland and Siltronic upland sites. We have been notified that we are a potentially responsible party to the Superfund site and we have joined with other potentially responsible parties (the Lower Willamette Group or LWG) to develop a Portland Harbor Remedial Investigation/ Feasibility Study (RI/FS). The LWG submitted a draft Feasibility Study (FS) to the Environmental Protection Agency (EPA) in March 2012 that provides a range of remedial costs for the entire Portland Harbor Superfund Site, which includes the Gasco/Siltronic Sediment site, discussed below. The range of costs estimated for various remedial alternatives for the entire Portland Harbor, as provided in the draft FS, is $169 million to $1.8 billion. NW Natural's potential liability is 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 potentially responsible parties. NW Natural is participating in a non-binding allocation process in an effort to settle this potential liability. We manage our liability related to the Superfund site as two distinct remediation projects, the Gasco/Siltronic Sediment 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 upland and

Siltronic upland sites. NW Natural submitted a draft Engineering Evaluation/Cost Analysis (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 range from $39.2 million to $350 million. We have recorded a liability of $39.2 million for the sediment clean-up, which reflects the low end of the EE/CA range, 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. 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 which is performing the RI/FS for the EPA. 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 accrued a liability for these claims which is at the low end of the range of the potential liability and the high end of the range cannot be reasonably estimated. This liability is not included in the range of costs provided in the draft FS for the Portland Harbor.

Gasco upland site. NW Natural owns 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. We manage the Gasco site in two parts, the uplands portion and the groundwater source control action.

In May 2007, we completed a revised Remedial Investigation Report for the uplands portion and submitted it to ODEQ for review. 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 and the high end of the range cannot be reasonably estimated at this time.

In September 2013, we completed construction and placed into service 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 due to the uncertainty associated with the duration of running the water treatment station, which will be highly dependent upon the remedy determined for both the upland portion as well as the final remedy for our Gasco sediment exposure.

On October 28, 2013, the OPUC approved placing $19.0 million of capital costs associated with constructing a water treatment station at our Gasco environmental site into rates beginning November 1, 2013. These amounts are subject to refund, with interest, in the event the Commission determines, through a separate docket, that any of these costs were incurred imprudently. On February 13, 2014, NW Natural filed an all-party stipulation in the proceeding with the OPUC, which if approved would deem Gasco construction costs prudent and would also approve applying $2.5 million of insurance proceeds plus interest to reduce the Gasco costs included in rates beginning November 1, 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 liabilities, and in the case of the Oregon Steel Mills site, pending litigation, liabilities for each of these sites has been recognized at their respective low end of the range of potential liability; the high end of the range could not be reasonably estimated as of December 31, 2013.

Siltronic upland site. Siltronic is the location of a manufactured gas plant formerly owned by NW Natural. 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. Studies for source control investigation have been presented to ODEQ and a final sampling plan required by ODEQ is currently being developed.

Oregon Steel Mills site. See "Legal Proceedings," below.

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, NW Natural does 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 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 that the ultimate disposition of this matter will have a material effect on our financial condition, results of operations or cash flows.

16. REVISION OF PRIOR PERIOD FINANCIAL STATEMENTS

During the first quarter of 2013, we identified an error in the rate used to calculate interest on certain regulatory assets. Accounting standards allow for the capitalization of all or part of an incurred cost that would otherwise be charged to expense if the regulator provides orders that create probable recovery of past costs through future revenues. Historically we had accrued 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. As the equity component of our ROR is not an incurred cost that would otherwise be charged to expense, this portion of the carrying cost should not have been capitalized for financial reporting purposes.

We assessed the materiality of this error on prior period financial statements and concluded it was not material to any prior annual or interim periods; however, the cumulative impact would have been material to the annual and interim periods for 2013, if corrected in 2013. As a result, in accordance with accounting standards, we revised our prior period financial statements as described below to correct this error. The revision had no effect on reported cash flows.

The adjustment impacted years 2003 through 2012 with a cumulative pre-tax decrease over that period of $5.6 million to regulatory assets and other income and expense. The revision decreased net income by $1.1 million and $0.9 million for the years ended December 31, 2012 and 2011, respectively. The cumulative decrease to January 1, 2011 retained earnings was $1.4 million as a result of the revision.

The following table presents the income statement impacts of this revision for the years ended December 31:

	2012			2011		
In thousands, except per share data	Reported Balance	Adjust-ment	Adjusted Balance	Reported Balance	Adjust-ment	Adjusted Balance
Other income and expense, net	$ 4,936	$ (1,777)	$ 3,159	$ 4,523	$ (1,411)	$ 3,112
Income before income taxes	103,959	(1,777)	102,182	107,280	(1,411)	105,869
Income tax expense	44,104	(701)	43,403	43,382	(557)	42,825
Net Income	59,855	(1,076)	58,779	63,898	(854)	63,044
Comprehensive income	58,364	(1,076)	57,288	62,702	(854)	61,848
Basic EPS	2.23	(0.04)	2.19	2.39	(0.03)	2.36
Diluted EPS	2.22	(0.04)	2.18	2.39	(0.03)	2.36

The following table presents the balance sheet impacts of this revision as of December 31:

	2012			2011		
In thousands	Reported Balance	Adjustment	Adjusted Balance	Reported Balance	Adjustment	Adjusted Balance
Non-current assets:						
Regulatory assets	$ 387,888	$ (5,633)	$ 382,255	$ 371,392	$ (3,856)	$ 367,536
Total non-current assets	2,535,054	(5,633)	2,529,421	2,397,885	(3,856)	2,394,029
Total assets	2,818,753	(5,633)	2,813,120	2,746,574	(3,856)	2,742,718
Liabilities and equity:						
Deferred credits and other non-current liabilities:						
Deferred tax liabilities	$ 446,604	$ (2,227)	$ 444,377	$ 413,209	$ (1,526)	$ 411,683
Total deferred credits and other non-current liabilities	1,025,584	(2,227)	1,023,357	975,922	(1,526)	974,396
Equity:						
Retained earnings	385,753	(3,406)	382,347	373,905	(2,330)	371,575
Total equity	733,033	(3,406)	729,627	714,488	(2,330)	712,158
Total liabilities and equity	2,818,753	(5,633)	2,813,120	2,746,574	(3,856)	2,742,718

The following tables present the income statement and balance sheet corrections for the following quarters:

	2012							
	First Quarter		Second Quarter		Third Quarter		Fourth Quarter	
In thousands, except per share data	Reported Balance	Adjusted Balance	Reported Balance	Adjusted Balance	Reported Balance	Adjusted Balance	Reported Balance	Adjusted Balance
Other income and expense, net	$ 1,005	$ 472	$ 921	$ 620	$ 1,710	$ 1,180	$ 1,300	$ 887
Income (loss) before income taxes	68,480	67,947	2,296	1,995	(13,594)	(14,124)	46,777	46,364
Income tax expense (benefit)	27,873	27,663	887	768	(3,036)	(3,245)	18,380	18,217
Net income (loss)	40,607	40,284	1,409	1,227	(10,558)	(10,879)	28,397	28,147
Comprehensive income (loss)	40,773	40,450	1,575	1,393	(10,391)	(10,712)	26,407	26,157
Basic EPS	1.52	1.50	0.05	0.05	(0.39)	(0.41)	1.06	1.05
Diluted EPS	1.51	1.50	0.05	0.05	(0.39)	(0.41)	1.05	1.04
Non-current assets:								
Regulatory assets	$ 368,521	$ 364,132	$ 366,981	$ 362,290	$ 367,692	$ 362,472	$ 387,888	$ 382,255
Total non-current assets	2,416,372	2,411,983	2,448,359	2,443,668	2,492,467	2,487,247	2,535,054	2,529,421
Total assets	2,727,262	2,722,873	2,635,141	2,630,450	2,690,368	2,685,148	2,818,753	2,813,120
Liabilities and equity:								
Deferred credits and other non-current liabilities:								
Deferred tax liabilities	$ 438,486	$ 436,750	$ 440,073	$ 438,217	$ 430,885	$ 428,821	$ 446,604	$ 444,377
Total deferred credits and other non-current liabilities	999,028	997,292	991,007	989,151	985,729	983,665	1,025,584	1,023,357
Equity:								
Retained earnings	402,599	399,946	392,082	389,247	369,584	366,428	385,753	382,347
Total equity	745,971	743,318	737,570	734,735	717,559	714,403	733,033	729,627
Total liabilities and equity	2,727,262	2,722,873	2,635,141	2,630,450	2,690,368	2,685,148	2,818,753	2,813,120

	2011							
	First Quarter		Second Quarter		Third Quarter		Fourth Quarter	
In thousands, except per share data	Reported Balance	Adjusted Balance	Reported Balance	Adjusted Balance	Reported Balance	Adjusted Balance	Reported Balance	Adjusted Balance
Other income and expense, net	$ 1,214	$ 1,291	$ 1,122	$ 779	$ 1,781	$ 1,426	$ 406	$ (384)
Income (loss) before income taxes	68,627	68,704	3,509	3,166	(14,012)	(14,367)	49,156	48,366
Income tax expense (benefit)	27,854	27,884	1,316	1,181	(5,700)	(5,840)	19,912	19,600
Net income (loss)	40,773	40,820	2,193	1,985	(8,312)	(8,527)	29,244	28,766
Comprehensive income (loss)	40,919	40,966	2,339	2,131	(8,166)	(8,381)	27,610	27,132
Basic EPS	1.53	1.53	0.08	0.07	(0.31)	(0.32)	1.09	1.08
Diluted EPS	1.53	1.53	0.08	0.07	(0.31)	(0.32)	1.09	1.07
Non-current assets:								
Regulatory assets	$ 345,452	$ 343,085	$ 326,081	$ 323,371	$ 328,757	$ 325,692	$ 371,392	$ 367,536
Total non-current assets	2,290,848	2,288,481	2,294,100	2,291,390	2,317,293	2,314,228	2,397,885	2,394,029
Total assets	2,571,553	2,569,186	2,521,994	2,519,284	2,567,840	2,564,775	2,746,574	2,742,718
Liabilities and equity:								
Deferred credits and other non-current liabilities:								
Deferred tax liabilities	$ 396,357	$ 395,419	$ 398,825	$ 397,751	$ 394,217	$ 393,003	$ 413,209	$ 411,683
Total deferred credits and other non-current liabilities	873,714	872,776	874,842	873,768	866,927	865,713	975,922	974,396
Equity:								
Retained earnings	385,899	384,470	376,489	374,853	356,574	354,723	373,905	371,575
Total equity	723,228	721,799	714,628	712,992	696,605	694,754	714,488	712,158
Total liabilities and equity	2,571,553	2,569,186	2,521,994	2,519,284	2,567,840	2,564,775	2,746,574	2,742,718

17. SUBSEQUENT EVENT

In December 2010, NW Natural commenced litigation against certain of its historical liability insurers. NW Natural alleged that the defendant insurance companies issued third party liability insurance policies to NW Natural and that the defendants had breached the terms of those policies by failing to reimburse and indemnify NW Natural for liabilities arising from environmental contamination at certain sites caused or alleged to be caused by its historical operations.

NW Natural sought damages in excess of $50 million in losses it had incurred through the date of the complaint, as well as declaratory relief for additional damages it expected to incur in the future. Settlements with certain of the defendant insurance companies resulted in payments received by NW Natural through December 31, 2013 of approximately $48 million.

In January and February 2014, the remaining defendant insurance companies agreed to settle all of NW Natural’s claims. In 2014 the Company expects to receive additional payments aggregating approximately $102 million under settlement agreements signed in 2013 and 2014. Such payments are to be made in the first and second quarters of 2014. As a result of such settlements, the Company anticipates dismissal of the litigation in the second quarter of 2014.

The settlements are recognized in regulatory accounts with the treatment determined through the SRRM. We expect the open regulatory docket regarding SRRM to be resolved during 2014.

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, 2013

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)	2,396,533,672
4	Property Under Capital Leases	
5	Plant Purchased or Sold	
6	Completed Construction not Classified	174,975,557
7	Experimental Plant Unclassified	
8	TOTAL Utility Plant (Total of lines 3 thru 7)	2,571,509,229
9	Leased to Others	
10	Held for Future Use	264,641
11	Construction Work in Progress	28,855,246
12	Acquisition Adjustments	
13	TOTAL Utility Plant (Total of lines 8 thru 12)	2,600,629,116
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	1,122,660,166
15	Net Utility Plant (Enter Total of line 13 less 14)	1,477,968,950
16	**DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION**	
17	In Service:	
18	Depreciation	1,045,112,838
19	Amortization and Depl. of Producing Natural Gas Land and Land Rights	
20	Amortization. of Underground Storage Land and Land Rights	21,591
21	Amortization. of Other Utility Plant	89,842,331
22	Salvage Work In Progress	-
23	Less Removal Work In Progress	12,316,595
24	TOTAL In Service (Total of lines 18 thru 23)	1,122,660,165
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)	1,122,660,165

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, 2013

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
	2,396,533,672			3
				4
				5
	174,975,557			6
				7
	2,571,509,229			8
				9
	264,641			10
	28,855,246			11
				12
	2,600,629,116			13
	1,122,660,165			14
	1,477,968,950			15
				16
				17
	1,045,112,838			18
				19
	21,591			20
	89,842,331			21
	-			22
	12,316,595			23
	1,122,660,165			24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
	1,122,660,165			35

ACCOUNT SUMMARY BY FUNTIONAL CLASS
NW Natural

Period Beginning: Jan 2013
Period Ending: Dec 2013

Functional Class FERC Plant Account		Beginning Balance	Additions	Retirements	Transfers	Adjustments	Ending Balance
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	58,710,780	5,901,997	0	(33,467)	0	64,579,309
303.2	CUSTOMER INFORMATION SYSTEM	31,868,929	479,239	0	0	0	32,348,168
303.3	INDUSTRIAL & COMMERCIAL BIL	4,146,951	0	0	0	0	4,146,951
303.4	CRMS	1,776,345	273,107	0	0	0	2,049,452
303.5	POWERPLANT SOFTWARE	0	0	0	0	0	0
	Intangible Plant Subtotal	96,587,800	6,654,342	0	(33,467)	0	103,208,675
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 2013
Period Ending: Dec 2013

Functional Class FERC Plant Account		Beginning Balance	Additions	Retirements	Transfers	Adjustments	Ending Balance
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	6,715,064	0	0	0	0	6,715,064
352	WELLS	20,047,076	0	0	0	0	20,047,076
352.1	STORAGE LEASEHOLD & RIGHTS	3,538,491	0	0	0	0	3,538,491
352.2	RESERVOIRS	5,844,618	0	0	0	0	5,844,618
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	28,746,969	781,562	0	0	0	29,528,531
355	MEASURING / REGULATING EQUIPM	6,700,892	0	0	0	0	6,700,892
356	PURIFICATION EQUIPMENT	297,363	0	0	0	0	297,363
357	OTHER EQUIPMENT	1,331,924	0	0	0	0	1,331,924
	Natural Gas Underground Storage Subtotal	86,431,682	781,562	0	0	0	87,213,243
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	128,860	0	(22,303)	0	0	106,557
361.11	STRUCTURES & IMPROVEMENTS	4,540,966	0	0	0	0	4,540,966
361.12	STRUCTURES & IMPROVEMENTS	4,603,395	0	0	0	0	4,603,395
361.2	STRUCTURES & IMPROVEMENTS -	26,757	0	0	0	0	26,757
362.11	GAS HOLDERS - LNG LINNTON	2,690,579	0	0	0	0	2,690,579
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	2,912,136	9,828	0	0	0	2,921,964
363.12	LIQUEFACTION EQUIP - NEWPO	6,951,260	356,851	0	0	0	7,308,111
363.21	VAPORIZING EQUIP - LINNTON	2,629,836	0	0	0	0	2,629,836
363.22	VAPORIZING EQUIP - NEWPORT	3,594,015	0	0	0	0	3,594,015
363.31	COMPRESSOR EQUIP - LINNTON	180,903	0	0	0	0	180,903
363.32	COMPRESSOR EQUIPMENT - NE	300,951	0	0	0	0	300,951
363.41	MEASURING & REGULATING EQU	737,149	0	0	0	0	737,149
363.42	MEASURING & REGULATING EQU	113,414	0	0	0	0	113,414
363.5	CNG REFUELING FACILITIES	1,805,713	123,808	(141,692)	0	0	1,787,828
363.6	LNG REFUELING FACILITIES	739,473	0	0	0	0	739,473
	Local Storage Plant Subtotal	38,369,237	490,486	(163,995)	0	0	38,695,728

ACCOUNT SUMMARY BY FUNTIONAL CLASS
NW Natural

Period Beginning: Jan 2013
Period Ending: Dec 2013

Functional Class / FERC Plant Account		Beginning Balance	Additions	Retirements	Transfers	Adjustments	Ending Balance
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	73,115,823	47,752,702	0	1,102,308	0	121,970,834
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	34,880,570	771	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	3,863,162	106,389	0	0	0	3,969,550
370	COMMUNICATION EQUIPMENT	0	0	0	0	0	0
	Transmission Plant Subtotal	240,702,844	47,859,862	0	1,102,308	0	289,665,013
Distribution Plant							
374.1	LAND	86,775	0	0	0	0	86,775
374.2	LAND RIGHTS	1,863,030	13,382	0	0	0	1,876,412
375	STRUCTURES & IMPROVEMENTS	80,217	0	0	0	0	80,217
376.11	MAINS < 4"	507,675,704	14,325,423	(403,624)	(992,895)	0	520,604,607
376.12	MAINS 4" & >	461,462,135	9,981,007	(506,464)	(102,793)	0	470,833,885
377	COMPRESSOR STATION EQUIPMENT	818,380	151,562	0	0	0	969,942
378	MEASURING & REG EQUIP - GENER	25,300,114	3,391,795	0	(6,620)	0	28,685,290
379	MEASURING & REG EQUIP - GATE	1,883,061	2,011,077	0	0	0	3,894,138
380	SERVICES	634,688,713	24,562,358	(1,699,245)	0	0	657,551,826
381	METERS	76,266,171	3,249,157	(822,151)	0	0	78,693,177
381.1	METERS (ELECTRONIC)	1,788,497	127,112	0	0	0	1,915,609
381.2	ERT (ENCODER RECEIVER TRANS	35,714,127	1,279,512	(500,211)	0	0	36,493,428
382	METER INSTALLATIONS	61,527,311	2,601,756	(2,227,911)	0	0	61,901,156
382.1	METER INSTALLATIONS (ELECTR	625,193	374,204	0	0	0	999,397
382.2	ERT INSTALLATION (ENCODER	9,788,281	0	(101,403)	0	0	9,686,879
383	HOUSE REGULATORS	774,773	340,354	0	0	0	1,115,127

ACCOUNT SUMMARY BY FUNTIONAL CLASS
NW Natural

Period Beginning: Jan 2013
Period Ending: Dec 2013

Functional Class FERC Plant Account		Beginning Balance	Additions	Retirements	Transfers	Adjustments	Ending Balance
386	OTHER PROPERTY ON CUSTOMERS P	0	0	0	0	0	0
387.1	CATHODIC PROTECTION TESTING	154,483	19,376	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	1,820,666,061	62,428,074	(6,261,009)	(1,102,308)	0	1,875,730,818
General Plant							
389	LAND	9,280,364	497,129	(168,218)	0	0	9,609,274
390	STRUCTURES & IMPROVEMENTS	33,884,492	15,836,090	(4,402,376)	0	0	45,318,207
390.1	SOURCE CONTROL PLANT	0	20,942,177	0	0	0	20,942,177
391.1	OFFICE FURNITURE & EQUIPMEN	11,271,409	970,665	(9,497)	(5,183)	0	12,227,394
391.2	COMPUTERS	18,807,546	2,658,917	(1,131,638)	38,650	0	20,373,475
391.3	ON SITE BILLING	938,788	0	0	0	0	938,788
391.4	CUSTOMER INFORMATION SYSTEM	1,387,730	0	0	0	0	1,387,730
392	TRANSPORTATION EQUIPMENT	27,391,614	3,039,049	(1,815,857)	0	0	28,614,806
393	STORES EQUIPMENT	119,406	0	0	0	0	119,406
394	TOOLS - SHOP & GARAGE EQUIPUI	15,322,029	945,553	(320,346)	0	0	15,947,236
395	LABORATORY EQUIPMENT	68,293	0	0	0	0	68,293
396	POWER OPERATED EQUIPMENT	7,678,821	1,306,156	(502,213)	0	0	8,482,763
397	GEN PLANT-COMMUNICATION EQU	98,549	0	0	0	0	98,549
397.1	MOBILE	1,295,887	0	0	0	0	1,295,887
397.2	OTHER THAN MOBILE & TELEMET	1,759,910	9,958	0	0	0	1,769,868
397.3	TELEMETERING - OTHER	4,243,823	194,509	0	0	0	4,438,333
397.4	TELEMETERING - MICROWAVE	2,056,551	177,220	0	0	0	2,233,771
397.5	TELEPHONE EQUIPMENT	2,216,676	3,579	0	0	0	2,220,255
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	61,420	0	0	0	0	61,420
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	138,056,228	46,581,002	(8,350,145)	33,467	0	176,320,553
	Utility Property Grand Total	$2,421,489,050	$164,795,328	($14,775,149)	($0)	$0	$2,571,509,229

ACCOUNT SUMMARY BY FUNTIONAL CLASS
NW Natural

Period Beginning: Jan 2013
Period Ending: Dec 2013

Functional Class / FERC Plant Account		Beginning Balance	Additions	Retirements	Transfers	Adjustments	Ending Balance
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	0	4,989,436
353	LINES	1,649,744	0	0	0	0	1,649,744
354	COMPRESSOR STATION EQUIPMENT	14,629,173	758,547	(700,000)	0	0	14,687,720
355	MEASURING / REGULATING EQUIPM	8,662,242	65,588	0	0	0	8,727,830
357	OTHER EQUIPMENT	63,256	0	0	0	0	63,256
Non Utility	Natural Gas Underground Storage Subtotal	46,935,323	824,134	(700,000)	0	0	47,059,457
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	111,719	0	0	0	0	111,719
Non Utility	General Plant Subtotal	550,458	0	0	0	0	550,458
Non Utility Other							
121.1	NON-UTIL PROP-DOCK	1,956,033	0	(10,000)	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

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ACCOUNT SUMMARY BY FUNTIONAL CLASS
NW Natural

Period Beginning: Jan 2013
Period Ending: Dec 2013

Functional Class FERC Plant Account		Beginning Balance	Additions	Retirements	Transfers	Adjustments	Ending Balance
121.7	NON-UTIL PROP-APPL CENTER	61,113	0	0	0	0	61,113
121.8	NON-UTIL PROP-STORAGE	288,112	0	0	0	0	288,112
Non Utility	Other	5,046,673	0	(10,000)	0	0	5,036,673
	Non Utility Property Grand Total	$61,359,312	$824,134	($710,000)	$0	$0	$61,473,446

Non Utility Property Summary	
Non Utility Property Grand Total	$61,473,446
Gas Stored Underground - St. Helens	3,800,189
Construction Work in Progress Non Utility	6,252,587
Balance Sheet Total for Non Utility Property	$71,526,223

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2013

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 Corp		Pipeline Capacity	50,084,745
3	TMC "Nova and ANG"		Pipeline Capacity	24,251,062
4	Fortis		Pipeline Capacity	8,847,069
5	TransCanada "Gas Trans. NW"		Pipeline Capacity	5,866,781
6	One Pacific Square LLC		Corporate Headquarters Building	4,035,257
7	Tenaska Marketing Ventures		Pipeline Capacity	1,930,650
8	AECO Gas Storage		Pipeline Capacity	727,139
9	Shell Energy		Pipeline Capacity	657,000
10	International Paper		Pipeline Capacity	478,880
11	TC Gas Storage		Pipeline Capacity	468,908
12	Coos County Pipeline		Pipeline Capacity	260,313
13	KB Pipeline	*	Pipeline Capacity	224,258
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42				
43	**Total**			97,832,062

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, 2013

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				
5				
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50				264,641

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, 2013

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	Misc Mains and Service Jobs	9,678,546	3,677,915
2	Mist Underground Storage	8,407,852	3,682,557
3			
4			
5	Other Projects:		
6	Misc IS Projects	5,772,479	4,859,869
7	Newport LNG Readiness	592,602	4,203,874
8	Sherwood Building	55,778	2,473,675
9	Sherwood CNG	1,336,432	98,000
10	Salem Retrofit	506,588	8,418,424
11	Other Projects	2,356,289	3,443,191
12	South of Monmouth Bare Steel	148,680	9,700,000
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45	**Total**	28,855,246	40,557,505

Name of Respondent	This Report is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2013

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, 2013

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 2013

a. Production, Storage, Transmission and Distribution plant	50%
b. Meters	62%
c. General Plant	16%
d. Non-Utility Property	1%

f) Direct assignment of construction overhead capitalized during 2013:
$ 38,473,708

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, 2013

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 Rte Percentage (d)
	(1) Average Short-Term Debt	S	144,072,000			
	(2) Short-Term Interest				s	0.3
	(3) Long-Term Debt	D	701,700,000		d	5.977
	(4) Preferred Stock	P			p	
	(5) Common Equity	C	751,871,513		c	9.5
	(6) Total Capitalization			100.00		
	(7) Average Construction Work in Progress	W	56,415,263			

2.	Gross Rates for Borrowed Funds	s(S/W)+d[(D/(D+P+C))(1-(S/W)]	3.72
3.	Rate for Other Funds	[1-(S/W)] [p(P/(D+P+C)+c(C/(D+P+C)]	7.64
4.	Weighted Average Rate Actually Used for the Year		
	a. Rate for Borrowed Funds -		0.34
	b. Rate for Other Funds -		

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS
NW NATURAL

Period Beginning: Jan 2013
Period Ending: Dec 2013

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	30,218,549	2,430,274	0	0	0	288	0	32,649,111
303.2	CUSTOMER INFORMATION SYSTEM	30,765,849	1,582,318	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	1,441,608	144,819	0	0	0	0	0	1,586,428
303.5	POWERPLANT SOFTWARE	0	0	0	0	0	0	0	0
	Intangible Plant Subtotal	66,572,958	4,157,411	0	0	0	288	0	70,730,657
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

Period Beginning: Jan 2013
Period Ending: Dec 2013

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	19,815	1,776	0	0	0	0	0	21,591
351	STRUCTURES AND IMPROVEMENTS	2,185,725	114,828	0	0	0	0	0	2,300,553
352	WELLS	9,730,639	414,974	0	0	0	0	0	10,145,614
352.1	STORAGE LEASEHOLD & RIGHTS	1,299,739	69,001	0	0	0	0	0	1,368,740
352.2	RESERVOIRS	1,486,747	117,477	0	0	0	0	0	1,604,224
352.3	NON-RECOVERABLE NATURAL GAS	2,835,441	121,089	0	0	0	0	0	2,956,530
353	LINES	2,501,213	134,992	0	0	0	0	0	2,636,205
354	COMPRESSOR STATION EQUIPMENT	13,958,664	781,250	0	0	0	0	0	14,739,914
355	MEASURING / REGULATING EQUIPM	3,661,839	145,424	0	0	0	0	0	3,807,263
356	PURIFICATION EQUIPMENT	195,572	7,375	0	0	0	0	0	202,947
357	OTHER EQUIPMENT	705,911	30,368	0	0	0	0	0	736,279
	Natural Gas Underground Storage Subtotal	38,581,306	1,938,552	0	0	0	0	0	40,519,859
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	1,189,931	246,717	0	0	0	0	0	1,436,648
361.12	STRUCTURES & IMPROVEMENTS	1,967,578	141,623	0	0	0	0	0	2,109,201
361.2	STRUCTURES & IMPROVEMENTS -	9,097	466	0	0	0	0	0	9,562
362.11	GAS HOLDERS - LNG LINNTON	2,072,668	63,229	0	0	0	0	0	2,135,896
362.12	GAS HOLDERS - LNG NEWPORT	4,965,952	157,541	0	0	0	0	0	5,123,493
362.2	GAS HOLDERS - LNG OTHER	1,109	21	0	0	0	0	0	1,130
363.11	LIQUEFACTION EQUIP. - LINN	2,297,431	84,091	0	0	0	0	0	2,381,522
363.12	LIQUEFACTION EQUIP - NEWPO	6,950,208	57,619	0	0	0	0	0	7,007,827
363.21	VAPORIZING EQUIP - LINNTON	2,514,224	36,821	0	0	0	0	0	2,551,046
363.22	VAPORIZING EQUIP - NEWPORT	2,606,816	1,050	0	0	0	0	0	2,607,866
363.31	COMPRESSOR EQUIP - LINNTON	184,247	12,845	0	0	0	0	0	197,092
363.32	COMPRESSOR EQUIPMENT - NE	191,283	14,175	0	0	0	0	0	205,458
363.41	MEASURING & REGULATING EQU	597,210	295	0	0	0	0	0	597,505
363.42	MEASURING & REGULATING EQU	115,812	828	0	0	0	0	0	116,640
363.5	CNG REFUELING FACILITIES	1,724,915	1,733	(141,692)	0	0	0	0	1,584,955
363.6	LNG REFUELING FACILITIES	739,473	0	0	0	0	0	0	739,473
	Local Storage Plant Subtotal	28,127,953	819,054	(141,692)	0	0	0	0	28,805,314
Transmission Plant									
365.1	LAND	0	0	0	0	0	0	0	0
365.2	LAND RIGHTS	1,398,320	122,003	0	0	0	0	0	1,520,323
366.3	STRUCTURES & IMPROVEMENTS -	216,010	20,319	0	0	0	0	0	236,329
367	MAINS	12,236,716	2,620,784	0	0	0	84,891	0	14,942,391
367.21	NORTH MIST TRANSMISSION LI	879,636	50,081	0	0	0	0	0	929,716
367.22	SOUTH MIST TRANSMISSION LI	8,830,433	367,878	0	0	0	0	0	9,198,311
367.23	SOUTH MIST TRANSMISSION LI	9,032,265	931,626	0	0	0	0	0	9,963,892

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS

NW NATURAL

Period Beginning: Jan 2013
Period Ending: Dec 2013

Functional Class FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve
UTILITY									
367.24	11.7M S MIST TRANS LINE	3,462,573	452,505	0	0	0	0	0	3,915,077
367.25	12M NORTH S MIST TRANS	3,364,205	485,973	0	0	0	0	0	3,850,178
367.26	38M NORTH S MIST TRANS	12,551,722	1,774,624	0	0	0	0	0	14,326,346
368	TRANSMISSION COMPRESSOR	(9)	0	0	0	0	0	0	(9)
369	MEASURING & REGULATE STATION	1,021,059	104,801	0	0	0	0	0	1,125,860
370	COMMUNICATION EQUIPMENT	0	0	0	0	0	0	0	0
	Transmission Plant Subtotal	52,992,931	6,930,593	0	0	0	84,891	0	60,008,415
Distribution Plant									
374.1	LAND	0	0	0	0	0	0	0	0
374.2	LAND RIGHTS	856,889	140,039	0	0	0	0	0	996,928
375	STRUCTURES & IMPROVEMENTS	79,768	200	0	0	0	0	0	79,968
376.11	MAINS < 4"	264,187,732	12,882,017	(403,624)	(1,208,352)	14,186	(137,284)	0	275,334,675
376.12	MAINS 4" & >	173,861,030	11,309,469	(506,464)	(620,719)	27,246	53,152	0	184,123,713
377	COMPRESSOR STATION EQUIPMENT	554,124	20,944	0	0	0	0	0	575,068
378	MEASURING & REG EQUIP - GENER	8,961,953	563,738	0	0	0	(758)	0	9,524,933
379	MEASURING & REG EQUIP - GATE	1,271,615	104,182	0	0	0	0	0	1,375,797
380	SERVICES	334,472,055	17,477,027	(1,699,245)	(2,306,446)	0	0	0	347,943,392
381	METERS	18,453,185	1,791,873	(822,151)	0	0	0	0	19,422,907
381.1	METERS (ELECTRONIC)	639,808	263,948	0	0	0	0	0	903,756
381.2	ERT (ENCODER RECEIVER TRANS	10,523,404	2,384,118	(500,211)	0	0	0	0	12,407,311
382	METER INSTALLATIONS	13,347,130	1,467,118	(2,227,911)	0	0	0	0	12,586,338
382.1	METER INSTALLATIONS (ELECTR	525,783	10,148	0	0	0	0	0	535,931
382.2	ERT INSTALLATION (ENCODER	2,788,538	648,339	(101,403)	0	0	0	0	3,335,475
383	HOUSE REGULATORS	65,939	30,412	0	0	0	0	0	96,351
386	OTHER PROPERTY ON CUSTOMERS P	0	0	0	0	0	0	0	0
387.1	CATHODIC PROTECTION TESTING	139,055	129	0	0	0	0	0	139,184
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	830,897,105	49,093,702	(6,261,009)	(4,135,517)	41,432	(84,891)	0	869,550,822
General Plant									
389	LAND	437,351	0	0	0	0	0	0	437,351
390	STRUCTURES & IMPROVEMENTS	8,233,029	407,980	(2,210,278)	0	0	0	0	6,430,732
390.1	SOURCE CONTROL PLANT	0	227,793	0	0	0	0	0	227,793
391.1	OFFICE FURNITURE & EQUIPMEN	6,958,326	903,515	(9,497)	0	0	(288)	0	7,852,057
391.2	COMPUTERS	14,775,421	3,251,736	(1,131,638)	0	0	0	0	16,895,519
391.3	ON SITE BILLING	938,788	0	0	0	0	0	0	938,788
391.4	CUSTOMER INFORMATION SYSTEM	957,549	261,678	0	0	0	0	0	1,219,227
392	TRANSPORTATION EQUIPMENT	8,860,916	1,403,241	(1,815,857)	0	150,375	0	0	8,598,674
393	STORES EQUIPMENT	119,406	0	0	0	0	0	0	119,406
394	TOOLS - SHOP & GARAGE EQUIPUI	7,234,114	1,085,054	(320,346)	0	24,773	0	0	8,023,595
395	LABORATORY EQUIPMENT	68,293	0	0	0	0	0	0	68,293

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS
NW NATURAL

Period Beginning: Jan 2013
Period Ending: Dec 2013

Functional Class / FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve
UTILITY									
396	POWER OPERATED EQUIPMENT	3,685,080	173,359	(502,213)	0	214,520	0	0	3,570,745
397	GEN PLANT-COMMUNICATION EQU	16,281	7,302	0	0	0	0	0	23,584
397.1	MOBILE	1,204,495	8,812	0	0	0	0	0	1,213,307
397.2	OTHER THAN MOBILE & TELEMET	1,667,266	75,555	0	0	0	0	0	1,742,821
397.3	TELEMETERING - OTHER	3,096,638	3,011	0	0	0	0	0	3,099,648
397.4	TELEMETERING - MICROWAVE	1,904,042	23,078	0	0	0	0	0	1,927,120
397.5	TELEPHONE EQUIPMENT	2,077,725	24,948	0	0	0	0	0	2,102,673
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	1,510	525	0	0	0	0	0	2,036
398.3	JANITORIAL EQUIPMENT	15,274	1,908	0	0	0	0	0	17,183
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	62,411,612	7,859,496	(5,989,828)	0	389,667	(288)	0	64,670,658
	Utility Property Grand Total	$1,080,274,900	$70,798,808	($12,392,530)	($4,135,517)	$431,099	($0)	$0	$1,134,976,761

NON UTILITY

Functional Class / FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve
Intangible Plant									
303.1	COMPUTER SOFWARE	$17,130	$7,041	$0	$0	$0	$0	$0	$24,171
303.2	CUSTOMER INFORMATION SYSTEM	25,126	4,275	0	0	0	0	0	29,401
Non Utility	Intangible Plant Subtotal	42,256	11,316	0	0	0	0	0	53,572
Natural Gas Underground Storage									
352	WELLS	2,196,536	350,667	0	0	0	0	0	2,547,203
352.1	STORAGE LEASEHOLD & RIGHTS	122	20	0	0	0	0	0	141
352.2	RESERVOIRS	844,556	97,294	0	0	0	0	0	941,850
353	LINES	219,282	33,993	0	0	0	0	0	253,275
354	COMPRESSOR STATION EQUIPMENT	3,969,922	389,285	(700,000)	0	0	0	0	3,659,207
355	MEASURING / REGULATING EQUIPM	1,313,443	189,161	0	0	0	0	0	1,502,604
357	OTHER EQUIPMENT	4,387	1,442	0	0	0	0	0	5,829
Non Utility	Natural Gas Underground Storage Subtotal	8,548,248	$1,061,862	($700,000)	$0	$0	$0	$0	8,910,110

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS
NW NATURAL

Period Beginning: Jan 2013
Period Ending: Dec 2013

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									
Transmission Plant									
368	TRANSMISSION COMPRESSOR	$1,132,556	238,655	0	0	0	0	0	$1,371,211
Non Utility	Transmission Plant Subtotal	1,132,556	$238,655	$0	$0	$0	$0	$0	$1,371,211
Distribution Plant									
376.12	MAINS 4" & >	129,432	21,270	0	0	0	0	0	150,702
Non Utility	Distribution Plant Subtotal	129,432	$21,270	$0	$0	$0	$0	$0	$150,702
General Plant									
389	LAND	$0	0	0	0	0	0	0	0
390	STRUCTURES & IMPROVEMENTS	17,637	2,033	0	0	0	0	0	19,670
Non Utility	General Plant Subtotal	17,637	2,033	0	0	0	0	0	19,670
Non Utility Other									
121.1	NON-UTIL PROP-DOCK	1,879,228	41,441	(10,000)	0	0	0	0	1,910,669
121.2	NON-UTIL PROP-LAND	0	0	0	0	0	0	0	0
121.3	NON-UTIL PROP-OIL ST	2,204,774	3,360	0	0	0	0	0	2,208,134
121.7	NON-UTIL PROP-APPL CENTER	17,385	4,219	0	0	0	0	0	21,604
121.8	NON-UTIL PROP-STORAGE	(1)	0	0	0	0	0	0	(1)
Non Utility	Other	4,101,384	$49,021	($10,000)	$0	$0	$0	$0	4,140,405
	Non Utility Property Grand Total	$13,971,513	$1,384,157	($710,000)	$0	$0	$0	$0	$14,645,670

TOTAL SUMMARY ALL UTILITY DEPRECIATION RESERVES 12/31/2013

UTILITY			
108010		($26,592,224)	
108011		857,510,453	
108012		10,893,185	
108013		(2,315,075)	
108014		(217,889)	
108015		3,552,466	
108100		295,279,974	
108002		(3,390,863)	
108003		20,564	
108004		236,168	
108666		-	
	SUBTOTAL		$1,134,976,760
ADD:			
108001	REMOVAL WORK IN PROCESS		(12,316,595)
	TOTAL UTILITY DEPRECIATION RESERVES		$1,122,660,165

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS
NW NATURAL

Period Beginning: Jan 2013
Period Ending: Dec 2013

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 NON-UTILITY DEPRECIATION RESERVES								
NON UTILITY								
122026	1,034							
122027	4,212,616							
122028	9,998,774							
122029	(530,297)							
122100	1,014,441							
122002	(50,896)							
TOTAL NON UTILITY DEPRECIATION RESERVES		14,645,670						

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, 2013

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	$ 14,132,362				$ 49,579,995	$ 9,161,076	$ -	$ 72,873,433
2	Gas Delivered to Storage	$ 130,025				$ 34,693,157	$ 1,161,103	$ -	$ 35,972,158
3	Gas Withdrawn from Storage	$ 135,206				$ 41,356,238	$ 1,966,580	$ -	$ 43,458,024
4	Other Debits and Credits	$ -				$ 55,990	$ -	$ -	$ 55,990
5	Balance at End of Year	$ 14,127,181				$ 42,972,904	$ 8,355,599	$ -	$ 65,443,557
6	Dekatherms	6,634,485				10,303,081	1,712,101	-	18,649,667
7	Amount Per Dekatherm	$ 2.13				$ 4.17	$ 4.88	$ -	$ 3.51

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, 2013

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	
2				
3	Account 124			
4				
5	Investment - Encana Gas Reserve - 124045*		92,176,546	7,336,589
6	Amortization of Encana Gas Reserve - 124046*		(7,483,112)	(1,576,521)
7				
8				
9				
10				
11	Investment in Life Insurance (transfer from 186 Deferred Debits) -		51,438,531	4,163,861
12	124100-124109			
13				
14	Investment in Vancouver Land - 124301		1,862,179	-
15				
16				
17				
18	Total Account 124		137,994,144	9,923,929
19				
20				
21				
22				
23	Account 136 Temporary Cash Investments			
24				
25	Marketable Securities - 136002, 136032		89	-
26				
27	OLGA Investment Account - 136100		466,355	2,962,567
28				
29	OLIEE Investment Account - 136104		1,740,136	1,473,614
30				
31	Smart Inv - 136105		88,059	1,187,501
32				
33	Total Account 136		2,294,639	5,623,682
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, 2013

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		1
					2
					3
					4
99,513,135	-	-			5
(9,059,633)	-	-			6
					7
					8
					9
					10
3,811,426	51,790,966	51,790,966			11
					12
					13
-	1,862,179	1,862,179			14
					15
					16
					17
94,264,928	53,653,145	53,653,145	-		18
					19
					20
					21
					22
					23
					24
57	32	32			25
					26
2,853,235	575,687	575,687			27
					28
652,266	2,561,484	2,561,484			29
					30
1,156,180	119,380	119,380			31
					32
4,661,738	3,256,583	3,256,583	-		33
					34
					35
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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, 2013

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		937,212
2	(Short term Financing and Investments)			
3				
4	Northwest Natural Energy LLC	5/26/2009		172,546,876
5	(Holding Company)			
6				
7	Northwest Biogas, LLC	3/23/2009		150,000
8	(Biodigestor Company)			
9				
10	Northwest Energy Corporation	11/1/2001		-
11	(Holding Company)			
12				
13				
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39				
40	TOTAL Cost of Account 123.1		Total	173,634,088

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, 2013

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.
(52,738)	-	884,474		1
				2
				3
(2,289,306)	(3,400,000)	166,857,570		4
				5
				6
-	-	150,000		7
				8
-	145,742,716	145,742,716		9
				10
				11
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				15
				16
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(2,342,044)	142,342,716	313,634,760		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, 2013

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	2,576,846
2	Prepaid Demand Charges	2,044,000
3	Prepaid Taxes	9,266,282
4	Miscellaneous Prepayments	1,750,384
5	TOTAL	15,637,512

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		Balance at End of Year (g)
					Account Charged (e)	Amount (f)	
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		Balance at End of Year (g)
					Account Charged (e)	Amount (f)	
16	None						
17							
18							
19							
20							
21							
22							
23							
24							
25							
26	TOTAL						0

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, 2013

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 TAX LIABILITY	$ 60,253,011	$ (4,070,459)		$ -	56,182,552
4						
5	AMT DEFERRED TAX LIABILITY	(284,366)	(1,495,202)		-	(1,779,568)
6						
7	DEFERRED TAX LIABILITY	$ 59,968,645	$ (5,565,661)		$ -	$ 54,402,984
8						
9	LESS: AMT DEFERRED TAX LIABILITY	284,366	1,495,202		-	1,779,568
10						
11	FAS 109 TAX RATE ADJUSTMENT	-	-		-	-
12						
13	REGULATORY DEFERRED TAX ASSET	$ 60,253,011	$ (4,070,459)		$ -	$ 56,182,552
14	(Page 111 Line 69)					
15						
16						
17						
18						
19						
20						
21						
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32						
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39						
40						
41						
42	TOTAL	$ 60,253,011	$ (4,070,459)		$ -	$ 56,182,552

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, 2013

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	199,934,904	4,633,543		78,713,310	125,855,137
3						
4	Pension Deferral	15,021,903	10,691,367		0	25,713,270
5						
6	Environmental	69,700,592	28,370,271		3	98,070,860
7						
8	Regulatory Receivable - Environmental	56,781,655	10,919,975		11,229,149	56,472,481
9						
10	Deferred Derivative Activity	11,374,000	27,339,000		36,207,000	2,506,000
11						
12	Leasehold Improvements Amortized Over Remaining Life	2,022,444	81,148		527,413	1,576,179
13						
14	AMR Deferral	745,966	3,567,972		3,826,768	487,170
15						
16	Unbilled Revenue	(702,271)	4,744,649		4,649,971	(607,593)
17						
18	Other	(45,306)	18,815,974		18,598,244	172,424
19						
20	OR - Decoupling	17,637,105	22,761,414		29,514,962	10,883,557
21						
22	OR - Deferred Industrial DSM	3,319,757	3,504,333		3,716,270	3,107,820
23						
24	OR - Earnings Test Estimate	(823,218)	871,627		48,413	(4)
25						
26	OR - Gas Inventory Carrying Costs	1,078,883	3,651,693		4,730,576	-
27						
28	OR - Warm	268,277	262,156		897,158	(366,725)
29						
30	OR - Pension Withdrawal	-	7,422,531		-	7,422,531
31						
32	WA - Pension Withdrawal	-	856,924		-	856,924
33						
34	WA - Energy Efficiency	1,942,128	2,723,800		2,289,355	2,376,573
35						
36	WA - Low Income	395,593	911,271		942,280	364,584
37						
38						
39	TOTAL	378,652,412	152,129,648		195,890,872	334,891,188

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, 2013

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	-		
4				
5	Total (Total of lines 2 thru 4)	-		
6				
7	TOTAL Account 190 (Total of lines 5 thru 6)	-		
8	Classification of TOTAL			
9	Federal Income Tax	-		
10	State Income Tax	-		
11	Local Income Tax			

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, 2013

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	7,382,403	7,382,403	3
							4
					7,382,403	7,382,403	5
							6
					7,382,403	7,382,403	7
							8
					5,631,017	5,631,017	9
					1,751,386	1,751,386	10
							11

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, 2013

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				
5				
6				
7				
8				
9				
10				
11				
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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, 2013

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)	
27,075,344	362,873,478					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, 2013

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				
9				
10	Account 212 - Installments Received on Capital Stock			
11				
12	Installments Received Under Employee Purchase Plan			25,350
13	Installments Received Under Dividend Reinvestment Plan			
14	Total Installments Received on Capital Stock (Account 212)			25,350
15				.
16				
17				
18				
19				
20				
21				
22				
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24				
25				
26				
27				
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30				
31				
32				
33				
34				
36				
37				
38				
39	TOTAL			25,350

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, 2013

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		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40	TOTAL	1,649,864

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, 2013

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		
10		
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
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2013

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					
3.542% Series B	Issued by Company	8/19/2013	N/A	N/A	$ 50,000,000
	Total Debt Issued				$ 50,000,000
Common Stock					
Common stock issuance expenses:					
Stock option plan	Issued by Company		N/A	33,800	$ 1,086,849
LTIP	Issued by Company		N/A	5,317	$ 717,252
RSU	Issued by Company		N/A	3,407	$ 162,934
ESPP	Issued by Company		N/A	15,614	$ 617,690
DRIP/OCP	Issued by Company		N/A	100,121	$ 4,377,052
Stock repurchase	Reacquired by Company		N/A	-	$ -
	Total Common Stock			158,259	$ 6,961,777

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, 2013

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		Redeemed	Redeemed
6	8.260% Series B	09-21-2014	10,000,000
7	3.950% Series B	07-15-2014	50,000,000
8	4.700% Series B	06-22-2015	40,000,000
9	5.150% Series B	12-15-2016	25,000,000
10	7.000% Series B	08-01-2017	40,000,000
11	6.600% Series B	03-16-2018	22,000,000
12	8.310% Series B	09-21-2019	10,000,000
13	7.630% Series B	12-09-2019	20,000,000
14	5.370% Series B	02-01-2020	75,000,000
15	9.050% Series A	08-13-2021	10,000,000
16	3.176% Series B	09-15-2021	50,000,000
17	3.542% Series B	08-19-2023	50,000,000
18	5.620% Series B	11-21-2023	40,000,000
19	7.720% Series B	09-01-2025	20,000,000
20	6.520% Series B	12-01-2025	10,000,000
21	7.050% Series B	10-15-2026	20,000,000
22	7.000% Series B	05-21-2027	20,000,000
23	6.650% Series B	11-10-2027	19,700,000
24	6.650% Series B	06-01-2028	10,000,000
25	7.740% Series B	08-29-2030	20,000,000
26	7.850% Series B	09-01-2030	10,000,000
27	5.820% Series B	09-24-2032	30,000,000
28	5.660% Series B	02-25-2033	40,000,000
29	5.250% Series B	06-21-2035	10,000,000
30	4.000% Series	10-31-2042	50,000,000
31			
32			
33			
34			
35			
36			
37	Total First Mortgage Bonds		701,700,000
38			
39	**Account 239**		
40	Less: Debt due with-in one year		(60,000,000)
41			
42			
43			
44			
45			
46			
47			
48			
49	**Account 222 and 223**		
50	None		
51	TOTAL		641,700,000

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, 2013

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
8.260%	826,000			N/A	6
3.950%	1,975,000			N/A	7
4.700%	1,880,000			N/A	8
5.150%	1,287,500			N/A	9
7.000%	2,800,000			N/A	10
6.600%	1,452,000			N/A	11
8.310%	831,000			N/A	12
7.630%	1,526,000			N/A	13
5.370%	4,027,500			N/A	14
9.050%	905,000			N/A	15
3.176%	1,588,000			N/A	16
3.542%	649,906			N/A	17
5.620%	2,248,000			N/A	18
7.720%	1,544,000			N/A	19
6.520%	652,000			N/A	20
7.050%	1,410,000			N/A	21
7.000%	1,400,000			N/A	22
6.650%	1,310,050			N/A	23
6.650%	665,000			N/A	24
7.740%	1,548,000			N/A	25
7.850%	785,000			N/A	26
5.820%	1,746,000			N/A	27
5.660%	2,264,000			N/A	28
5.250%	525,000			N/A	29
4.000%	2,000,000			N/A	30
					31
					32
					33
					34
					35
					36
	37,844,956				37
					38
					39
					40
					41
					42
					43
					44
					45
					46
					47
					48
					49
					50
	37,844,956				51

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, 2013

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	8.260%	[1]	10,000,000	903,369	9/21/1994	9/21/2014
5	3.950%		50,000,000	441,576	7/9/2009	7/15/2014
6	4.700%		40,000,000	341,898	6/21/2005	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			701,700,000	26,118,592		
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.

[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, 2013

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
5,828		3,384	2,444	4
132,456		88,320	44,136	5
82,621		34,188	48,433	6
109,866		27,768	82,098	7
86,075		18,780	67,295	8
55,053		10,572	44,481	9
18,150		2,700	15,450	10
67,559		9,768	57,791	11
7,132,630		986,652	6,145,978	12
32,960		3,840	29,120	13
524,467		60,516	463,951	14
-	638,178	23,399	614,779	15
203,312		18,624	184,688	16
94,544		7,464	87,080	17
38,750		3,000	35,750	18
80,929		5,868	75,061	19
74,044		5,136	68,908	20
80,456		5,424	75,032	21
50,505		3,276	47,229	22
108,454		6,168	102,286	23
54,908		3,108	51,800	24
257,145		13,020	244,125	25
239,822		11,892	227,930	26
73,168		3,264	69,904	27
532,346		17,844	514,502	28
945,848	240,795	235,648	950,995	29
526,221	132,269	262,352	396,138	30
				31
				32
				33
				34
				35
Total 11,608,117	1,011,242	1,871,975	10,747,384	36
				37
				38
				39
	Total above	1,871,975		40
	Less Shelf Registration Expense	(498,000)		41
	Amortization Expense per P&L	1,373,975		42
				43
				44
				45

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, 2013

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	9.8%	11/01/93	24,938,000	(2,170,710)	355,002	271,458
11	9.125%	04/01/98	18,000,000	(1,133,464)	294,484	237,604
12	9.75% (1)	09/29/00	50,000,000	(3,079,332)	1,723,020	1,613,040
13	7.52% (2)	07/01/03	11,000,000	(1,530,079)	828,750	752,250
14	7.50% (3)	07/01/03	4,000,000	(555,971)	301,210	273,408
15	7.25%	08/18/03	20,000,000	(866,800)	469,560	426,214
16						
17						
18						
19						
20						
21						
22						
23						
24						
25	(1) Includes $2,732,588 loss on debt reacquired in 2000 and $346,744 unamortized					
26	loss allocated from the 15.375% Guaranteed Notes.					
27						
28	(2) Includes $489,200 loss on debt reacquired in 2003 and $1,040,879 unamortized					
29	loss allocated from the 9.38% Bonds.					
30						
31	(3) Includes $177,360 loss on debt reacquired in 2003 and $378,611 unamortized					
32	loss allocated from the 9.38% Bonds.					
33						
34						
35						
36						
37						
38	TOTAL				3,972,026	3,573,974

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, 2013

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)**	$ 61,345,475	$ 768,770	$ 61,345,475	$ (52,738)	$ (716,032)
3						
4	TAXABLE INCOME (LOSS) NOT RECORDED ON BOOKS:	-				
5	CONTRIBUTIONS IN AID OF CONSTRUCTION	-		-		
6	OTHER INCOME	2,305,674		2,305,674		
7	INCOME FROM SUBSIDIARIES	-		-		
8						
9	**EXPENSES RECORDED ON BOOKS NOT DEDUCTED ON RETURN:**					
10	ACCRUED VACATION	85,426		85,426		
11	BOND AMORTIZATION	398,052		398,052		
12	DEFERRED DIRECTORS FEES	195,286		195,286		
13	NONDEDUCTIBLE MEALS AND ENTERTAINMENT	691,753		691,753		
14	NONDEDUCTIBLE POLITICAL, SOCIAL AND OTHER	1,077,907		1,077,907		
15	OTHER INCOME	710,521		710,521		
16	PENALTIES	60,839		60,839		
17	SEC. 263A INVENTORY ADJUSTMENTS	1,822,515		1,822,515		
18	PENSION ADJUSTMENTS	3,157,910		3,157,910		
19	DEFERRED COMPENSATION	98,139		98,139		
20	STOCK BASED COMPENSATION	402,454		402,454		
21	INCOME FROM SUBSIDIARIES	83,026		83,026		
22	FEDERAL TAX PROVISION (SEE ANALYSIS BELOW)	35,572,628		36,577,135	(28,397)	(976,110)
23	STATE TAX PROVISION (SEE ANALYSIS BELOW)	6,657,867		6,788,061	(5,957)	(124,237)
24						
25	**BOOK INCOME NOT SUBJECT TO TAX:**					
26	COMPANY OWNED LIFE INSURANCE	2,467,719		2,467,719		
27						
28						
29	**EXPENSES ALLOWABLE FOR TAX NOT ON BOOKS:**					
30	DEPLETION	1,096,744		-		1,096,744
31	REGULATORY REVENUE & COST ADJUSTMENTS	5,649,261		5,649,261		
32	SEC REGULATORY INTEREST	806,996		806,996		
33	BAD DEBT RESERVE	861,974		861,974		
34	DEPREC - EXCESS OF TAX OVER BOOK DEPRECIATION	104,194,481		97,428,627	(80,844)	6,846,699
35	DIVIDENDS PAID TO AN ESOP	763,430		763,430		
36	PREPAID INSURANCE	334,996		334,996		
37	PROPERTY TAX ADJUSTMENT - ACCRUAL TO CASH	140,299		140,299		
38	INTANGIBLE DRILLING COSTS	27,257,057		-		$ 27,257,057
39	REMOVAL COSTS	$ 1,175,000		$ 1,175,000		
40						
41	FEDERAL NET OPERATING LOSS CARRYFORWARD to 2014	(30,082,483)	768,770	6,171,874	(6,248)	(37,016,879)

NORTHWEST NATURAL GAS CO AND SUBSIDIARIES
RECONCILIATION OF BOOK INCOME TO FEDERAL TAXABLE INCOME
TAX PROVISION FOR YEAR ENDED DECEMBER 31, 2013

LINE #			
1	**NET INCOME FOR THE YEAR PER (PAGE 116a)**		**$61,345,475**
2			
3	TAXABLE INCOME (LOSS) NOT RECORDED ON BOOKS:		
4	CONTRIBUTIONS IN AID OF CONSTRUCTION	-	
5	OTHER INCOME	2,305,674	
6	INCOME FROM SUBSIDIARY		
7			2,305,674
8	EXPENSES RECORDED ON BOOKS NOT DEDUCTED ON RETURN:		
9	ACCRUED VACATION	85,426	
10	BOND AMORTIZATION	398,052	
11	DEFERRED DIRECTORS FEES	195,286	
12	NONDEDUCTIBLE MEALS AND ENTERTAINMENT	691,753	
13	NONDEDUCTIBLE POLITICAL, SOCIAL AND OTHER	1,077,907	
14	OTHER INCOME	710,521	
15	PENALTIES	60,839	
16	SEC. 263A INVENTORY ADJUSTMENTS	1,822,515	
17	PENSION ADJUSTMENTS	3,157,910	
18	DEFERRED COMPENSATION	98,139	
19	STOCK BASED COMPENSATION	402,454	
20	INCOME FROM SUBSIDIARY	83,026	
21	FEDERAL TAX PROVISION (SEE ANALYSIS BELOW)	35,572,628	
22	STATE TAX PROVISION (SEE ANALYSIS BELOW)	6,657,867	
23			51,014,324
24	BOOK INCOME NOT SUBJECT TO TAX:		
25	COMPANY OWNED LIFE INSURANCE	2,467,719	
26			2,467,719
27			
28	EXPENSES ALLOWABLE FOR TAX NOT ON BOOKS:		
29	DEPLETION	1,096,744	
30	REGULATORY REVENUE & COST ADJUSTMENTS	5,649,261	
31	SEC REGULATORY INTEREST	806,996	
32	BAD DEBT RESERVE	861,974	
33	DEPREC - EXCESS OF TAX OVER BOOK DEPRECIATION	104,194,481	
34	DIVIDENDS PAID TO AN ESOP	763,430	
35	PREPAID INSURANCE	334,996	
36	PROPERTY TAX ADJUSTMENT - ACCRUAL TO CASH	140,299	
37	INTANGIBLE DRILLING COSTS	27,257,057	
38	REMOVAL COSTS	1,175,000	
39			142,280,238
	FEDERAL NET OPERATING LOSS CARRYFORWARD TO 2014		**(30,082,483)**

NORTHWEST NATURAL GAS CO AND SUBSIDIARIES
RECONCILIATION OF BOOK INCOME TO FEDERAL TAXABLE INCOME
TAX PROVISION FOR YEAR ENDED DECEMBER 31, 2013

LINE #			
1	**TAX COMPUTATION:**		
2			
3	FEDERAL INCOME TAX (BENEFIT) AT STATUTORY RATE		$ -
4	FEDERAL ALTERNATIVE MINIMUM TAX		159,759
5			
6	ADJ: LOW INCOME HOUSING & §29 CREDITS	-	
7	ALTERNATIVE MINIMUM TAX CREDIT	-	
8	FUEL TAX CREDIT (FORM 4136)	-	
9	FOREIGN TAX CREDIT	-	
10			-
11			
12	CURRENT FEDERAL TAX PROVISION CURRENT YEAR - 2013		-
13	PLUS PRIOR PERIOD ADJUSTMENTS		(221,300)
14			
15	**TOTAL FEDERAL CURRENT TAX PROVISION (Pg 261-B2)**		**(61,541)**
16			
17	DEFERRED FEDERAL TAX PROVISION CURRENT YEAR - 2013		36,094,286
18	PLUS PRIOR YEAR PROVISION TO RETURN TRUE UP		(43,385)
19			
20	ADJ: INVESTMENT TAX CREDIT APPLIED	-	
21	DEFERRED ALTERNATIVE MINIMUM TAX	(159,759)	
22	DEFERRED INVESTMENT TAX CREDIT	(256,973)	
23			(416,732)
24	**TOTAL FEDERAL DEFERRED TAX PROVISION (Pg 261-B2)**		**35,634,169**
25			
26	**COMBINED FEDERAL INCOME TAX PROVISION**		**$ 35,572,628**
27			
28			
29	**ALLOCATION OF FEDERAL INCOME TAX PROVISION**		
30			
31	NW NATURAL GAS CO.		
32	OPERATING		$ 32,785,974
33	NON-OPERATING		5,260,313
34	GILL RANCH, LLC		(1,004,657)
35	NW GAS STORAGE, LLC		(437,671)
36	PALOMAR		(16,572)
37	NW ENERGY, LLC		(10,252)
38	TOTAL NW NATURAL GAS CO.		$ 36,577,135
39			
40	NNG FINANCIAL CORPORATION		
41	OPERATING		$ -
42	NON-OPERATING		(28,397)
43	TOTAL NNG FINANCIAL CORPORATION		$ (28,397)
44			
45	NW ENERGY CORPORATION		
46	OPERATING		$ (976,110)
47	NON-OPERATING		-
48	TOTAL NW ENERGY CORPORATION		$ (976,110)
49			
50	**COMBINED FEDERAL INCOME TAX PROVISION**		**$ 35,572,628**
51			
52	COMBINED FEDERAL AND STATE INCOME TAX PROVISION		
53	OPERATING		$ 38,828,622
54	NON-OPERATING		6,162,356
55	NON-OPERATING		(34,354)
56	NW ENERGY CORPORATION		(1,100,347)
57	OTHER SMLLC'S AND PARTNERSHIPS		(1,625,782)
58	PAGES 261-B2 CONTINUED (CURRENT & DEFERRED FEDERAL & STATE)		**$ 42,230,495**

NORTHWEST NATURAL GAS CO AND SUBSIDIARIES
RECONCILIATION OF BOOK INCOME TO STATE TAXABLE INCOME
TAX PROVISION FOR YEAR ENDED DECEMBER 31, 2013

LINE #			
1	**NET INCOME FOR THE YEAR PER (PAGE 116a)**		**$ 61,345,475**
2			
3	TAXABLE INCOME (LOSS) NOT RECORDED ON BOOKS:		
4	CONTRIBUTIONS IN AID OF CONSTRUCTION	-	
5	OTHER INCOME	2,305,674	
6	INCOME FROM SUBSIDIARY	-	
7			2,305,674
8	EXPENSES RECORDED ON BOOKS NOT DEDUCTED ON RETURN:		
9	ACCRUED VACATION	85,426	
10	BOND AMORTIZATION	398,052	
11	DEFERRED DIRECTORS FEES	195,286	
12	NONDEDUCTIBLE MEALS AND ENTERTAINMENT	691,753	
13	NONDEDUCTIBLE POLITICAL, SOCIAL AND OTHER	1,077,907	
14	OTHER INCOME	710,521	
15	PENALTIES	60,839	
16	SEC. 263A INVENTORY ADJUSTMENTS	1,822,515	
17	PENSION ADJUSTMENTS	3,157,910	
18	DEFERRED COMPENSATION	98,139	
19	STOCK BASED COMPENSATION	402,454	
20	INCOME FROM SUBSIDIARY	83,026	
21	FEDERAL TAX PROVISION (SEE ANALYSIS ABOVE)	35,572,628	
22	STATE TAX PROVISION (SEE ANALYSIS BELOW)	6,657,867	
23			51,014,324
24	BOOK INCOME NOT SUBJECT TO TAX:		
25	COMPANY OWNED LIFE INSURANCE	2,467,719	
26			2,467,719
27			
28	EXPENSES ALLOWABLE FOR TAX NOT ON BOOKS:		
29	REGULATORY REVENUE & COST ADJUSTMENTS	5,649,261	
30	SEC REGULATORY INTEREST	806,996	
31	BAD DEBT RESERVE	861,974	
32	DEPREC - EXCESS OF TAX OVER BOOK DEPRECIATION	117,490,242	
33	DIVIDENDS PAID TO AN ESOP	763,430	
34	PREPAID INSURANCE	334,996	
35	PROPERTY TAX ADJUSTMENT - ACCRUAL TO CASH	140,299	
36	INTANGIBLE DRILLING COSTS	27,257,057	
37	REMOVAL COSTS	1,175,000	
38			154,479,254
39	STATE NET OPERATING LOSS CARRYFORWARD TO 2013		**$ (42,281,500)**

NORTHWEST NATURAL GAS CO AND SUBSIDIARIES
RECONCILIATION OF BOOK INCOME TO STATE TAXABLE INCOME
TAX PROVISION FOR YEAR ENDED DECEMBER 31, 2013

LINE #			
1	**<u>TAX COMPUTATION:</u>**		
2			
3	STATE INCOME TAX (BENEFIT)		$ -
4	STATE ALTERNATIVE MINIMUM TAX		-
5			
6	ADJ: LOW INCOME HOUSING & §29 CREDITS	-	
7	ALTERNATIVE MINIMUM TAX CREDIT	-	
8	DEPENDENT CARE TAX CREDIT	-	
9	BUSINESS ENERGY TAX CREDIT	-	
10			-
11			
12	CURRENT STATE TAX PROVISION CURRENT YEAR -2013		-
13	PLUS PRIOR YEAR PROVISION TO RETURN TRUE UP		(10,751)
14			
15	**TOTAL STATE CURRENT TAX PROVISION (Pg 261-B2)**		**(10,751)**
16			
17	DEFERRED STATE TAX PROVISION CURRENT YEAR - 2013		6,637,911
18	PLUS PRIOR YEAR PROVISION TO RETURN TRUE UP		30,707
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)**		**6,668,618**
25			
26	**COMBINED STATE INCOME TAX PROVISION**		**$ 6,657,867**
27			
28			
29	**<u>ALLOCATION OF STATE INCOME TAX PROVISION</u>**		
30			
31	<u>NW NATURAL GAS CO.</u>		
32	OPERATING		$ 6,042,648
33	NON-OPERATING		902,043
34	GILL RANCH, LLC		(77,305)
35	NW GAS STORAGE, LLC		(52,633)
36	PALOMAR		(24,536)
37	NW ENERGY, LLC		(2,156)
38	TOTAL NW NATURAL GAS CO.		$ 6,788,061
39			
40	<u>NNG FINANCIAL CORPORATION</u>		
41	OPERATING		$ -
42	NON-OPERATING		(5,957)
43	TOTAL NNG FINANCIAL CORPORATION		$ (5,957)
44			
45	<u>NW ENERGY CORPORATION</u>		
46	OPERATING		$ (124,237)
47	NON-OPERATING		-
48	TOTAL NW ENERGY CORPORATION		$ (124,237)
49			
50	**COMBINED STATE INCOME TAX PROVISION**		**$ 6,657,867**

NORTHWEST NATURAL GAS COMPANY
RECONCILIATION OF TAX ACCRUAL ACCOUNTS - CURRENT
YEAR ENDED DECEMBER 31, 2013

FEDERAL	Total	2004 ACCRUAL 236.024	2005 ACCRUAL 236.025	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
BALANCE AT 12/31/12 (Page 262)	**$ 2,334,277**	$ -	$ -	$ -	$ -	$ -	$ (16,696)	$ -	$ 54,817	$ 2,296,156	$ -
ACCRUALS	61,541								239,827	(32,658)	(145,628)
PAYMENTS	850,000										850,000
TAX BENEFIT INCLUDED IN	-										
PREMIUM ON COMMON STOCK	-										
OVERPAYMENT APPLIED	-									(2,239,308)	2,239,308
REFUNDS & REFUNDS PENDING	-										
OTHER	(7,494)						16,696			(24,190)	
BALANCE AT 12/31/13 (Page 263)	**$ 3,238,324**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 294,644	$ 0	$ 2,943,680
UTILITY (409-03080)	(221,300)										
NON-UTILITY (409-03070 & 409-03075)	-										
SUBTOTAL	(221,300)										
NNGFC (409-23075)	-										
NW ENERGY CORP (409-33080)	159,759										
GILL RANCH STORAGE (409-43075)	-										
NW GAS STORAGE (409-44001)	-										
NW ENERGY (409-49001)	-										
PALOMAR (409-49003)	-										
ACCRUALS ABOVE (Page 261A&B)	**(61,541)**										
OTHER (CURRENT/DEFERRED RECLASS)	-										
CONSOLIDATED FORM 10-K	**$ (61,541)**										

STATE	Total	2004 ACCRUAL 236.034	2005 ACCRUAL 236.035	2006 ACCRUAL 236.036	2007 ACCRUAL 236.037	2008 ACCRUAL 236.038	2009 ACCRUAL 236.039	2010 ACCRUAL 236.040	2011 ACCRUAL 236.031	2012 ACCRUAL 236.032 & 236.082	2013 ACCRUAL 236.033 & 236.083
BALANCE AT 12/31/12 (Page 262)	**$ 255,436**	$ -	$ -	$ -	$ 209,047	$ -	$ -	$ -	$ -	$ 46,389	$ -
ACCRUALS	10,751										10,751
TAX PAYMENTS	20,000										20,000
TAX BENEFIT INCLUDED IN	-										
PREMIUM ON COMMON STOCK	-										
OVERPAYMENT APPLIED	-										
REFUNDS & REFUNDS PENDING	9,097									19,848	(10,751)
OTHER	-										
BALANCE AT 12/31/13 (Page 263)	**$ 295,284**	$ -	$ -	$ -	$ 209,047	$ -	$ -	$ -	$ -	$ 66,237	$ 20,000
UTILITY (409-03150)	(10,751)										
UTILITY (SB 408) (409-02973)											
NON-UTILITY (409-03135 & 409-03145)											
SUBTOTAL	(10,751)										
NNGFC (409-23145)											
GILL RANCH STORAGE (409-43145)	-										
NW GAS STORAGE (409-44002)	-										
NW ENERGY (409-49002)	-										
PALOMAR (409-49004)	-										
ACCRUALS ABOVE (Page 261A&B)	**(10,751)**										
OTHER (CURRENT/DEFERRED RECLASS)	-										
CONSOLIDATED FORM 10-K	**$ (10,751)**										

NORTHWEST NATURAL GAS COMPANY
RECONCILIATION OF TAX ACCRUAL ACCOUNTS - DEFERRED
YEAR ENDED DECEMBER 31, 2013

FEDERAL	TOTAL	FAS 109 AMT 283.011 & 016	UTILITY REGULATORY 283.021	NON-OPR 283.031,.091	UTILITY DEPREC 283.061	UTILITY OTHER 283.071	STORAGE DEPREC 283.081	283.096, 283.304 283.306
BALANCE AT 12/31/12 (Page 276)	$ (358,554,560)	$ (59,968,644)	$ (6,302,043)	$ 1,038,054	$ (261,233,650)	$ (23,161,537)	$ (13,932,925)	$ 5,006,185
ACCRUALS-NWN (CURRENT YEAR)	(36,518,995)		(2,367,781)	374,945	(31,985,377)	1,881,425	(4,422,206)	
ACCRUALS-NWN (PROVISION TO RETURN)	43,385	32,658	(349,322)	2,214	(1,353,569)	1,710,349	1,054	
ACCRUALS-IRS AUDIT	(239,827)	(239,827)				-		
ACCRUALS-TRUE-UP	(833,009)		(5,519)	(336,811)	95,752	(232,702)	(353,729)	
OTHER	(5)	0	(0)	(2)	(1)	(4)	2	
	(37,548,451)	(207,169)	(2,722,622)	40,346	(33,243,195)	3,359,068	(4,774,879)	-
OFFSET REG ASSET-FAS 109 (Page 232)(OR RATE)	-	0	0	0	0	0	0	0
OFFSET REG ASSET-FAS 109 (Page 232)	4,070,459	4,070,459						
OFFSET OTHER COMPREHENSIVE INCOME (OCI) & PENSION	(1,581,828)							(1,581,828)
TAX SHARING	(3,062,587)					(3,062,587)		
SALE OF PROPERTIES	(2,100,526)				419,237	(2,519,763)		
RECLASSES	1,702,371	1,702,371		(6,853)		-	6,853	
ELIMINATIONS	(976,111)					(976,111)		
OTHER	(200,431)					(200,433)		2
BALANCE AT 12/31/13 (Page 277)	$ (398,251,664)	$ (54,402,983)	$ (9,024,666)	$ 1,071,548	$ (294,057,608)	$ (26,561,363)	$ (18,700,951)	$ 3,424,358

PAGE 276 UTILITY DEBITS 410 (03005 & 33006)	54,436,869
PAGE 276 UTILITY CREDITS 411 (03015 & 33016)	(22,148,732)
PAGE 277 NON UTILITY DEBITS 410 (03000 & 03020)	5,697,882
PAGE 277 NON UTILITY CREDITS 411 (03020)	(437,569)
	37,548,450
CORP 5000, DEFERRED ITC (411-03100 & 03115)	(256,973)
CORP 2000 NNGFC DEFERREDS (410-23020)	(28,397)
CORP 3500 NWN GAS RESERVES DEFERREDS (410-33005 & 411-33015)	(159,759)
GILL RANCH STORAGE DEFERREDS (410-42977 & 411-42980)	(1,004,657)
NW GAS STORAGE DEFERREDS (411-44980)	(437,671)
NW ENERGY DEFERREDS (410-49053 & 411-49053)	(10,252)
PALOMAR DEFERREDS	(16,572)
TOTAL FEDERAL DEFERRED TAX (Page 261A&B)	35,634,169
OTHER	-
CONSOLIDATED FORM 10-K	$ 35,634,169

STATE	TOTAL	NOL CARRYOVER 283.017	UTILITY REGULATORY 283.022	NON-OPR 283.032,.092	UTILITY DEPREC 283.062	UTILITY OTHER 283.072,.300	STORAGE DEPREC 283.082	283.097, 283.305 283.307
BALANCE AT 12/31/12 (Page 276)	$ (60,146,047)	$ -	$ (1,336,000)	$ 164,530	$ (51,481,110)	$ (5,602,388)	$ (2,909,325)	$ 1,018,245
ACCRUALS-NWN (CURRENT YEAR)	(7,521,827)		(386,398)	78,653	(7,082,247)	795,817	(927,651)	
ACCRUALS-NWN (PROVISION TO RETURN)	(30,707)		(80,822)	710	(339,235)	391,654	(3,014)	
ACCRUALS-OREGON AUDIT	-							
ACCRUALS-TRUE-UP	720,966		20,402	719	176,902	574,406	(51,463)	
OTHER	362				2	360		
	(6,831,206)	-	(446,818)	80,082	(7,244,579)	1,762,237	(982,128)	-
OFFSET REG ASSET-FAS 109 (Page 232)(OR RATE)	-							
OFFSET OTHER COMPREHENSIVE	-							
INCOME (OCI) & PENSION	(331,021)							(331,021)
CREDIT UTILIZED	(19,848)					(19,848)		
TAX SHARING	(48,774)					(48,774)		
SALE OF PROPERTIES	(436,102)				87,095	(523,197)		
RECLASSES	-			(1,448)			1,448	
ELIMINATIONS	(124,237)					(124,237)		
OTHER	(41,890)		1	0	(4)	(41,889)	2	0
BALANCE AT 12/31/13 (Page 235 & 277)	$ (67,979,123)	$ -	$ (1,782,818)	$ 243,165	$ (58,638,598)	$ (4,598,095)	$ (3,890,002)	$ 687,224

PAGE 276 UTILITY DEBITS 410 (02985)	7,733,092
PAGE 276 UTILITY CREDITS 411 (02980)	(1,803,930)
PAGE 277 NON UTILITY DEBITS 410 (03027 & 03140)	994,797
PAGE 277 NON UTILITY CREDITS 411 (02990)	(92,754)
	6,831,205
CORP 2000 NNGFC DEFERREDS (410-23140)	(5,957)
NW ENERGY CORP DEFERREDS (410-32985 & 411-32980)	-
GILL RANCH STORAGE DEFERREDS (410-42053 & 411-42053)	(77,305)
NW GAS STORAGE DEFERREDS (411-44053)	(52,633)
NW ENERGY DEFERREDS (410-49980)	(2,156)
PALOMAR DEFERREDS	(24,536)
TOTAL STATE DEFERRED TAX (Page 261A&B)	6,668,618
OTHER	-
CONSOLIDATED FORM 10-K	$ 6,668,618

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, 2013

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)	(2,334,277)	
2				
3		Payroll - FICA & Medicare	844,401	
4		Payroll - Unemployment	1,705	
5		Payroll - Severance	44,636	
6		Diesel and Gasoline Tax		
7		Other - U.S. Dept. of Transportation	-	
8				
9		Miscellaneous	-	
10				
11		Total Federal	(1,443,535)	-
12				
13				
14	**Oregon Tax:**	Corporate Excise (see Page 261-B2 Cont)	(217,331)	
15		Payroll - Transit Authority	123,066	
16		Payroll - Unemployment	27,162	
17		Payroll - Workers Compensation	-	
18				
19		Real & Personal Property - Accrued		
20		Real & Personal Property - Prepaid		9,087,676
21				
22		Regulatory Commission Fee	-	
23		Vehicle Licence Fee & Fuel Use Tax	-	
24				
25				
26		Other - State Department of Energy	-	
27		Other - State Department of Energy (pre-certification)	-	
28		Other - State of Oregon Department of Transportation	-	
29		Other - State Vehicle Fuel Use Tax	-	
30		Other - State Corporate Registration	-	
31		Other - Payroll Underaccrual	-	
32		Other - Storage Property Tax Reclassification	-	
33		Miscellaneous	-	
34				
35		Total State of Oregon	(67,103)	9,087,676
36				
37				
38				
39				
40	TOTAL		(1,510,638)	9,087,676

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, 2013

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.
(61,541)	850,000	7,494	(3,238,324)		1
					2
6,765,932	6,303,492	(1)	1,306,840		3
48,188	49,242	-	651		4
		(23,418)	21,218		5
	(12,265)	23,418	35,683		6
48,230	48,230	-	-		7
-	-		-		8
			-		9
20,220	20,220				10
6,821,029	7,258,919	7,493	(1,873,932)	-	11
					12
					13
-	-	189,199	(28,132)		14
527,298	520,287	-	130,077		15
881,459	894,831	-	13,790		16
-	-		-		17
	-		-		18
18,368,352	18,368,352		-		19
653,866	832,472			9,266,282	20
	-		-		21
1,620,845	1,620,845		-		22
-	-		-		23
	-		-		24
	-		-		25
516,104	516,104		-		26
145,471	145,471		-		27
8,042	8,042		-		28
-	-		-		29
-	-		-		30
-	-		-		31
(653,866)	(653,866)		-		32
100,000	100,000		-		33
-	-				34
22,167,571	22,352,538	189,199	115,735	9,266,282	35
					36
					37
					38
					39
28,988,600	29,611,457	196,692	(1,758,197)	9,266,282	40

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

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	250	-
4	Real & Personal Property	1,631,288	-
5	Regulatory Commission	-	-
6	Utility Tax	328,896	-
7			
8	Other	-	-
9	Miscellaneous	-	-
10	Total State of Washington	1,960,434	-
11			
12	**California Tax:**		
13	Corporate Income		
14	Franchise	(38,105)	-
15	Other		-
16			
17	Total State of California	(38,105)	-
18			
19	**Local Oregon Tax:**		
20	City & County business licenses & income tax	(178,578)	-
21	Franchise	6,871,045	-
22	Property taxes	-	-
23	Other	-	-
24	Miscellaneous	-	-
25	Total Local State of Oregon Tax Expense	6,692,467	-
26			
27	**Local Washington Tax:**		
28	City & County business licenses & income tax	-	-
29	Franchise	-	-
30	Property taxes	-	-
31	Other	-	-
32			
33	Total Local State of Washington Tax Expense	-	-
34			
35	**Local California Tax:**		
36	Franchise	-	-
37	Other	-	-
38		-	-
39	Total Local State of California Tax Expense	-	-
40			
41	TOTAL	7,104,158	9,087,676

Page 113, Line 43 7,104,158

Name of Respondent	This Report Is:	Date of Report	Year of Report
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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)	Prepaid Taxes (Incl. in Account 165) (h)	Line No.
					1
81,541	81,541	-	-		2
4,760	4,873	-	137		3
1,769,317	1,731,010	-	1,669,595		4
139,859	139,859	-	-		5
2,933,635	2,804,904	-	457,627		6
		-			7
23,604	23,604	-	-		8
-	-	-	-		9
4,952,716	4,785,791	-	2,127,359	-	10
		-			11
		-			12
					13
(10,751)	20,000	(198,295)	(267,151)		14
15,790	15,790	-	-		15
		-			16
5,039	35,790	(198,295)	- (267,151)	-	17
					18
					19
100	(99)	-	(178,379)		20
16,068,118	15,599,815	-	7,339,348		21
-	-	-	-		22
-	-	-	-		23
-	-	-	-		24
16,068,218	15,599,716	-	7,160,969	-	25
					26
		-	-		27
-		-	-		28
-	-	-	-		29
-	-	-	-		30
-	-	-	-		31
					32
-	-	-	-	-	33
					34
					35
-	-	-	-		36
1,646,538	1,646,538	-	-		37
128,143	128,143	-	-		38
1,774,681	1,774,681	-	-	-	39
					40
51,789,254	51,807,435	(1,603)	7,262,980	9,266,282	41

89,945,874	SAP query of GL 503800	Page 113, Line 43	7,262,980
(41,060,519)	SAP query of GL 410-411		
2,774,128	Capitalized payroll taxes		
129,770	Vehicle taxes and B&O taxes		
51,789,254	Total taxes charged, above		

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
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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	**Federal Tax:**			
2	Corporate Income - NW Natural Corporation	(221,300)	-	-
3	Corporate Income - NNG Financial Corporation	-	-	-
4	Corporate Income - NW Energy Corporation	-	-	-
5				
6	Payroll - FICA & Medicare	4,484,650	2,119,919	-
7	Payroll - Unemployment	31,940	15,098	-
8	Payroll - Severance		-	-
9	Diesel and Gasoline Tax	-	-	-
10	Other - U.S. Dept. of Transportation	-	-	-
11		-	-	-
12	Miscellaneous	-	-	-
13				
14	Total Federal Tax Expense	4,295,290	2,135,017	-
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	TOTAL	4,295,290	2,135,017	-

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, 2013

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	-	409-23075	-	NNG Financial Corporation (current only)
4	-	409-33080	159,759	NW Energy Corporation (current only)
5				
6	-	236051	161,364	Payroll Clearing
7	-	236051	1,149	Payroll Clearing
8				
9	-	165012	48,230	Vehicle Fuel Tax & Taxes & Licenses
10	-		-	
11	-			
12	-	408-23185	20,220	Fees & Permits
13				
14	-		390,722	
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	-		390,722	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
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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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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	-	-	-
3	Corporate Income - NNG Financial Corporation	-	-	-
4	Corporate Income - NW Energy Corporation	-	-	-
5				
6	Payroll - Transit Authority	349,508	165,214	-
7	Payroll - Unemployment	584,256	276,181	-
8	Payroll - Workers Compensation	-	-	-
9				
10	Real & Personal Property - Accrued	18,368,351		-
11	Real & Personal Property - Prepaid	-	-	-
12	Real & Personal - Other	(653,866)	-	-
13	Regulatory Commission Fee	1,620,845	-	-
14	Vehicle Licence Fee	-	-	-
15				
16				
17	Other - State Department of Energy	516,104	-	-
18	Other - State Department of Energy (pre-certification)	145,471		
19	Other - State of Oregon Department of Transportation	8,042	-	-
20	Other - State Vehicle Fuel Use Tax	-	-	-
21	Other - State Corporate Registration	-	-	-
22	Other - Payroll underaccrual	-		
23	Other - Storage Property Tax Reclassification	-	-	653,866
24	Other - State Excise Tax	100,000		
25	Miscellaneous		-	-
26				
27				
28				
29				
30				
31				
32				
33				
34	Total Oregon Tax	21,038,711	441,395	653,866
35				
36				
37				
38				
39				
40	TOTAL	21,038,711	441,395	653,866

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, 2013

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.
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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	-	409-23145	-	NNG Financial Corporation (current only)
4	-		-	GRS, NWGS, Palomar and NW Energy (current only)
5				
6	-	236051	12,576	Payroll Clearing
7	-	236051	21,022	Payroll Clearing
8	-		-	
9				
10	-		-	
11	-		-	
12				
13	-		-	
14	-	165012	-	Vehicle taxes & licenses
15	-			
16				
17	-		-	
18	-		-	
19	-		-	
20	-		-	
21	-		-	
22	-		-	
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33	-		33,598	
34				
35				
36				
37				
38				
39				
40	-		33,598	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
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TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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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	-	81,541	-
3	Payroll - Unemployment	3,155	1,492	-
4	Real & Personal Property	1,769,317	-	-
5	Regulatory Commission	139,859	-	-
6	Utility Tax (franchise tax)	2,933,635	-	-
7				
8	Other	23,604	-	-
9	Miscellaneous			
10				
11				
12	Total State of Washington Tax Expense	4,869,570	83,032	-
13				
14	**California State:**			
15	Corporate Income	(10,751)		
16	Franchise Tax	2,400		
17				
18				
19				
20				
21				
22				
23				
24	Total State of California Tax Expense	(8,351)	-	-
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40	TOTAL	4,861,219	83,032	-

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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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.
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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	-		-	B&O taxes
3	-	236051	114	Payroll Clearing
4	-		-	
5	-		-	
6	-		-	
7				
8	-		-	
9				
10	-		-	
11				
12	-		114	
13				
14				
15				
16			13,390	GRS, Gas Storage, NW Energy Franchise Tax
17				
18				
19				
20				
21				
22				
23				
24	-		13,390	
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40	-		13,504	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
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TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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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				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18	**Local Oregon:**			
19	City & County business licenses & income tax	100	-	-
20	Franchise	16,068,118	-	-
21	Property taxes	-	-	-
22	Other	-	-	-
23				
24	Total Local State of Oregon Tax Expense	16,068,218	-	-
25				
26	**Local Washington:**			
27	City & County business licenses & income tax	-	-	-
28	Franchise		-	-
29	Property taxes	-		
30	Other	-		
31				
32	Total Local State of Washington Tax Expense	-	-	-
33				
34	**Local California:**			
35	Franchise	-	-	-
36	Property taxes			
37	Other	-	-	
38				
39	Total Local State of California Tax Expense	-	-	-
40				
41	TOTAL	46,263,438	2,659,444	653,866

Pg 114, Line 14	46,495,489	Pg 116, Line 52	653,866
Pg 114, Line 15	(221,300)	Pg 116, Line 53	
Pg 114, Line 16	(10,751)	Pg 116, Line 54	
	46,263,438		653,866

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, 2013

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).
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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				
12				
13				
14				
15				
16				
17				
18				
19	-		-	
20	-			
21	-		-	
22	-		-	
23			-	Miscellaneous
24	-		-	
25				
26				
27	-		-	
28	-		-	
29				
30				
31				
32	-		-	
33				
34	-		-	
35	-			
36		408-43185	1,646,476	Property Tax
37		408-44180	128,206	Miscellaneous
38				
39	-		1,774,682	
40				
41	-		2,212,505	

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, 2013

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	Margin Sharing	12,340,247
2	Public Purpose	5,532,731
3	Property Sales Credit	3,063,312
4	Workers Compensation Claims	1,339,482
5	OLGA Surcharge	1,161,467
6	Deferred Revenue - Appliance Center	290,614
7	Other items, each less than $250,000	517,262
8		
9		
10		
11		
12		
13		
14		
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31		
32		
33		
34	TOTAL	24,245,115

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, 2013

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	-		-	8,279,454	8,279,454
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
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35						
36						
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39						
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41						
42						
43						
44						
45						
46						
47						
48	**Total**	-		-	8,279,454	8,279,454

Name of Report	This Report is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A resubmission	(Mo, Da, Yr)	Dec. 31, 2013

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, 2013

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, 2013

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	59,968,644	239,827	32,658
3.02	Revenue & Cost Gas Adjustments	7,638,044	3,038,972	395,313
3.03	Deferred Depreciation - Federal	261,233,650	37,235,681	3,992,487
3.04	Deferred Income Taxes - Other (Includes SB 408)	28,763,925	14,317,903	19,439,207
3.05	Deferred Depreciation - State	51,481,110	8,279,509	1,034,928
4.01	Other	(1)	1	-
4.02	Other - reclass		(941,932)	(941,932)
5	Total (Total of Lines 2 Thru 4)	409,085,372	62,169,961	23,952,661
6	Other (Specify) Non - Utility	15,639,665	-	-
6.01	Other Comprehensive Income - Federal	(5,006,186)	-	-
6.02	Other Comprehensive Income - State	(1,018,245)	-	-
7	**TOTAL (Acct 283) (Total of lines 5 thru 6) (Page 113)**	**418,700,606**	**62,169,961**	**23,952,661**
8	Classification of TOTAL			
9	Federal Income Tax	358,554,560	54,436,869	22,148,732
10	State Income Tax	60,146,046	7,733,092	1,803,930
11	Local Income Tax			
		418,700,606 Page 113, Line 65	62,169,961 Page 114, Line 17	23,952,662 Page 114, Line 18

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, 2013

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					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Acct. No. (g)	Amount (h)	Acct. No. (i)	Amount (j)	Balance at End of Year Page 114 (k)	Line No.
							1
							2
							3
-	-			186016	5,772,830	54,402,983	3.01
-	-					10,281,704	3.02
-	-			186221	419,237	294,057,607	3.03
-	-	186221	7,516,838			31,159,459	3.04
-	-			186221	87,095	58,638,596	3.05
-	-				2	(2)	4.01
	-	190100, 190102	7,382,403			7,382,403	4.02
-			14,899,241		6,279,164	455,922,749	5
6,692,679	530,323					21,802,021	6
-	-	218000	1,581,828			(3,424,358)	6.01
-	-	218000	331,021			(687,224)	6.02
6,692,679	530,323		16,812,090		6,279,164	**473,613,188**	7
							8
5,697,882	437,569		13,971,738		6,192,067	403,882,681	9
994,797	92,754		2,840,351		87,095	69,730,507	10
							11

6,692,679	530,323	473,613,188
Page 116, Line 55	Page 116, Line 56	Page 113, Line 65

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, 2013

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	Year of Report
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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.
723,920,455	706,138,822	723,920,455	706,138,822	76,576,465	73,226,373	1
						2
2,281,999	2,473,001	2,281,999	2,473,001			3
1,435,964	1,341,639	1,435,964	1,341,639			4
	-	-				5
	-	-				6
15,898,199	15,674,791	15,898,199	15,674,791	38,078,608	37,939,247	7
						8
						9
						10
						11
279,204	279,744	279,204	279,744			12
						13
2,368,021	(7,615,577)	2,368,021	(7,615,577)			14
746,183,842	718,292,420	746,183,842	718,292,420			15
-	-	-	-			16
746,183,842	718,292,420	746,183,842	718,292,420			17

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
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OTHER GAS REVENUES (ACCOUNT 495)

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

Line No.	Description of Transaction (a)	Revenues (in dollars) (b)
1	Unbilled Revenue	4,666,718
2	Interstate Storage Credit	8,440,296
3	Decoupling	8,411,182
4	Decoupling Amortization	(15,647,287)
5	Washington Amortizations	(952,643)
6	Oregon Amortizations	(1,328,556)
7	WA Great Program	(477,548)
8	Working Gas	(980,352)
9	Gain on Property Sales	814,317
10	Warm Deferrals	(635,003)
11	Other (Misc Gas Revenues, Priority Sched Fee, etc)	56,897
12		
13		
14		
15		
16		
17		
18	TOTAL	2,368,021

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, 2013

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, 2013

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
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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)	-	-

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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	4,996,113	3,658,267
71	802 Natural Gas Gasoline Plant Outlet Purchases		
72	803 Natural Gas Transmission Line Purchases		
73	804 Natural Gas City Gate Purchases	369,337,000	360,382,022
74	804.1 Liquefied Natural Gas Purchases		
75	805 Other Gas Purchases		
76	(Less) 805.1 Purchases Gas Cost Adjustments	(8,332,916)	(19,887,355)
77	TOTAL Purchased Gas (Total of Lines 68 thru 76)	366,000,197	344,152,934
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)	-	-

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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	43,240,811	31,882,876
87	(Less) 808.2 Gas Delivered to Storage-Credit	(35,806,301)	(20,368,425)
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	(137,119)	(332,105)
94	TOTAL Gas Used in Utility Operations-Credit (lines 91 thru 93)	(137,119)	(332,105)
95	813 Other Gas Supply Expenses		
96	TOTAL Other Gas Supply Exp. (Total of lines 77, 78, 85, 86-89,	373,297,588	355,335,280
	94, 95)		
97	TOTAL Production Expenses (Total of lines 3, 30, 58, 65, 96)	373,297,588	355,335,280
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	308,626	264,205
104	817 Lines Expenses		
105	818 Compressor Station Fuel and Power	431,285	438,761
106	819 Compressor Station Fuel and Power	-	-
107	820 Measuring and Regulating Station Expenses	1,290,763	1,344,804
108	821 Purification Expenses	23,724	49,469
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)	2,054,398	2,097,239

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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	195,165	176,617
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)	195,165	176,617
125	TOTAL Underground Storage Expenses (lines 114 and 124)	2,249,563	2,273,856
126	B. Other Storage Expenses		
127	Operation		
128	840 Operation supervision and Engineering	64,651	62,385
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)	64,651	62,385
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)	64,651	62,385

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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	1,437,338	1,625,071
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	(35,832)	(68,566)
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)	1,401,506	1,556,505
166	Maintenance		
167	847.1 Maintenance Supervision and Engineering		
168	847.2 Maintenance of Structures and Improvements	324,292	301,503
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)	324,292	301,503
176	TOTAL Liquefied Nat Gas Terminaling and Proc Exp (Total of lines 165 & 175)	1,725,798	1,858,008
177	TOTAL Natural Gas Storage (Total of lines 125, 146, and 176)	4,040,012	4,194,249

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, 2013

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	660,645	205,118
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)	660,645	205,118
192	Maintenance		
193	861 Maintenance Supervision and Engineering		
194	862 Maintenance of Structures and Improvements		
195	863 Maintenance of Mains	12,435	(43,943)
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)	12,435	(43,943)
201	TOTAL Transmission Expenses (Total of lines 191 and 200)	673,080	161,175
202	4. DISTRIBUTION EXPENSES		
203	Operation		
204	870 Operation Supervision and Engineering	1,749,595	1,769,895
205	871 Distribution Load Dispatching		
206	872 Compressor Station Labor and Expenses		
207	873 Compressor Station Fuel and Power		

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, 2013

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	6,858,543	6,571,560
209	875 Measuring and Regulating Station Expenses-General	88,810	69,475
210	876 Measuring and Regulating Station Expenses-Industrial		
211	877 Measuring and Regulating Station Expenses-City Gas	539,114	432,560
	Check Station		
212	878 Meter and House Regulator Expenses	5,192,411	4,395,961
213	879 Customer Installations Expenses	4,155,624	3,982,514
214	880 Other Expenses	1,393,057	976,228
215	881 Rents	196,340	178,040
216	TOTAL Operations (Total of lines 204 thru 215)	20,173,494	18,376,233
217	Maintenance		
218	885 Maintenance Supervision and Engineering	2,487,028	518,462
219	886 Maintenance of Structures and Improvements		
220	887 Maintenance of Mains	2,198,045	2,289,460
221	888 Maintenance of Compressor Station Equipment		
222	889 Maintenance of Measuring & Regulating Station Equipment	962,482	818,291
	-General		
223	890 Maintenance of Meas. and Reg. Station Equipment-Industrial		
224	891 Maintenance of Meas & Reg Station Equip-City Gate	73,334	75,041
	Check Station		
225	892 Maintenance of Services	1,491,692	1,323,392
226	893 Maintenance of Meters and House Regulators	1,700,472	1,991,434
227	894 Maintenance of Other Equipment	21,269	23,326
228	TOTAL Maintenance (Total of lines 218 thru 227)	8,934,322	7,039,406
229	TOTAL Distribution Expenses (Total of lines 216 and 228)	29,107,816	25,415,639
230	5. CUSTOMER ACCOUNTS EXPENSES		
231	Operation		
232	901 Supervision	1,130,600	1,068,662
233	902 Meter Reading Expenses	552,946	490,541
234	903 Customer Records and Collection Expenses	14,496,480	14,042,543

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, 2013

GAS OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account	Amount for Current Year	Amount for Previous Year
	(a)	(b)	(c)
235	904 Uncollectible Accounts	198,531	1,130,774
236	905 Miscellaneous Customer Accounts Expenses		
237	TOTAL Customer Accounts Expenses (Total of lines 232-236)	16,378,557	16,732,520
238	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSE		
239	Operation		
240	907 Supervision	22,472	220,435
	908 Customer Assistance Expense	530,954	2,369,063
242	909 Informational and Instructional Expenses	1,158,387	1,441,371
243	910 Miscellaneous Customer Service and Informational Expenses	109,819	127,981
244	TOTAL Customer Service & Information Expenses	1,821,632	4,158,850
	(Total of lines 240 thru 243)		
245	7. SALES EXPENSES		
246	Operation		
247	911 Supervision	135,728	236,187
248	912 Demonstration and Selling Expenses	2,218,063	1,847,865
249	913 Advertising Expenses	250,572	238,527
250	916 Miscellaneous Sales Expenses	107	80
251	TOTAL Sales Expenses (Total of lines 247 thru 250)	2,604,470	2,322,659
252	8. ADMINISTRATIVE AND GENERAL EXPENSES		
253	Operation		
254	920 Administrative and General Salaries	23,418,801	16,728,391
255	921 Office Supplies and Expenses	14,523,003	11,289,730
256	(Less) 922 Administrative Expenses Transferred - Credit	(15,355,207)	(14,683,290)
257	923 Outside Services Employed	7,251,718	7,016,072
258	924 Property Insurance	2,608,454	2,428,848
259	925 Injuries and Damages	13,351	1,004,092
260	926 Employee Pensions and Benefits	31,327,470	34,120,542
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	2,426,438	2,431,741
266	931 Rents	4,654,170	4,531,602
267	TOTAL Operation (Total of lines 254 thru 266)	70,868,198	64,867,728
268	Maintenance		
269	935 Maintenance of General Plant	3,410,779	3,623,520
270	TOTAL Administrative and General Expenses (Total of	74,278,977	68,491,248
	lines 267 and 269)		
271	TOTAL Gas O & M Expenses (Total of lines 97,177,201,229,237	502,202,132	476,811,620
	,244,251,and 270)		

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, 2013

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	93,458	207,000		
7	Storage Plants	Inventory	233,695		Included in the Cost of Inventory	
8	Total		327,153	207,000		
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45	**Total**		327,153	207,000		

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, 2013

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)	850,269
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)	92,419
4		
5	Other expenses (2966)	12,161
6		
7	Director's Fees and Expenses (4320)	1,356,070
8		
9	Annual Meeting (4290)	115,519
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40	TOTAL	2,426,438

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS
NW NATURAL

Period Beginning: Jan 2013
Period Ending: Dec 2013

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	30,218,549	2,430,274	0	0	0	288	0	32,649,111
303.2	CUSTOMER INFORMATION SYSTEM	30,765,849	1,582,318	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	1,441,608	144,819	0	0	0	0	0	1,586,428
303.5	POWERPLANT SOFTWARE	0	0	0	0	0	0	0	0
	Intangible Plant Subtotal	66,572,958	4,157,411	0	0	0	288	0	70,730,657
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
Natural Gas Underground Storage									
350.1	LAND	0	0	0	0	0	0	0	0
350.2	RIGHTS-OF-WAY	19,815	1,776	0	0	0	0	0	21,591
351	STRUCTURES AND IMPROVEMENTS	2,185,725	114,828	0	0	0	0	0	2,300,553
352	WELLS	9,730,639	414,974	0	0	0	0	0	10,145,614

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS

NW NATURAL

Period Beginning: Jan 2013
Period Ending: Dec 2013

Functional Class FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve
UTILITY									
352.1	STORAGE LEASEHOLD & RIGHTS	1,299,739	69,001	0	0	0	0	0	1,368,740
352.2	RESERVOIRS	1,486,747	117,477	0	0	0	0	0	1,604,224
352.3	NON-RECOVERABLE NATURAL GAS	2,835,441	121,089	0	0	0	0	0	2,956,530
353	LINES	2,501,213	134,992	0	0	0	0	0	2,636,205
354	COMPRESSOR STATION EQUIPMENT	13,958,664	781,250	0	0	0	0	0	14,739,914
355	MEASURING / REGULATING EQUIPM	3,661,839	145,424	0	0	0	0	0	3,807,263
356	PURIFICATION EQUIPMENT	195,572	7,375	0	0	0	0	0	202,947
357	OTHER EQUIPMENT	705,911	30,368	0	0	0	0	0	736,279
	Natural Gas Underground Storage Subtotal	38,581,306	1,938,552	0	0	0	0	0	40,519,859
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	1,189,931	246,717	0	0	0	0	0	1,436,648
361.12	STRUCTURES & IMPROVEMENTS	1,967,578	141,623	0	0	0	0	0	2,109,201
361.2	STRUCTURES & IMPROVEMENTS -	9,097	466	0	0	0	0	0	9,562
362.11	GAS HOLDERS - LNG LINNTON	2,072,668	63,229	0	0	0	0	0	2,135,896
362.12	GAS HOLDERS - LNG NEWPORT	4,965,952	157,541	0	0	0	0	0	5,123,493
362.2	GAS HOLDERS - LNG OTHER	1,109	21	0	0	0	0	0	1,130
363.11	LIQUEFACTION EQUIP. - LINN	2,297,431	84,091	0	0	0	0	0	2,381,522
363.12	LIQUEFACTION EQUIP - NEWPO	6,950,208	57,619	0	0	0	0	0	7,007,827
363.21	VAPORIZING EQUIP - LINNTON	2,514,224	36,821	0	0	0	0	0	2,551,046
363.22	VAPORIZING EQUIP - NEWPORT	2,606,816	1,050	0	0	0	0	0	2,607,866
363.31	COMPRESSOR EQUIP - LINNTON	184,247	12,845	0	0	0	0	0	197,092
363.32	COMPRESSOR EQUIPMENT - NE	191,283	14,175	0	0	0	0	0	205,458
363.41	MEASURING & REGULATING EQU	597,210	295	0	0	0	0	0	597,505
363.42	MEASURING & REGULATING EQU	115,812	828	0	0	0	0	0	116,640
363.5	CNG REFUELING FACILITIES	1,724,915	1,733	(141,692)	0	0	0	0	1,584,955
363.6	LNG REFUELING FACILITIES	739,473	0	0	0	0	0	0	739,473
	Local Storage Plant Subtotal	28,127,953	819,054	(141,692)	0	0	0	0	28,805,314
Transmission Plant									
365.1	LAND	0	0	0	0	0	0	0	0
365.2	LAND RIGHTS	1,398,320	122,003	0	0	0	0	0	1,520,323
366.3	STRUCTURES & IMPROVEMENTS -	216,010	20,319	0	0	0	0	0	236,329
367	MAINS	12,236,716	2,620,784	0	0	0	84,891	0	14,942,391
367.21	NORTH MIST TRANSMISSION LI	879,636	50,081	0	0	0	0	0	929,716
367.22	SOUTH MIST TRANSMISSION LI	8,830,433	367,878	0	0	0	0	0	9,198,311
367.23	SOUTH MIST TRANSMISSION LI	9,032,265	931,626	0	0	0	0	0	9,963,892
367.24	11.7M S MIST TRANS LINE	3,462,573	452,505	0	0	0	0	0	3,915,077
367.25	12M NORTH S MIST TRANS	3,364,205	485,973	0	0	0	0	0	3,850,178
367.26	38M NORTH S MIST TRANS	12,551,722	1,774,624	0	0	0	0	0	14,326,346

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS

NW NATURAL

Period Beginning: Jan 2013
Period Ending: Dec 2013

Functional Class FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve
UTILITY									
368	TRANSMISSION COMPRESSOR	(9)	0	0	0	0	0	0	(9)
369	MEASURING & REGULATE STATION	1,021,059	104,801	0	0	0	0	0	1,125,860
370	COMMUNICATION EQUIPMENT	0	0	0	0	0	0	0	0
	Transmission Plant Subtotal	52,992,931	6,930,593	0	0	0	84,891	0	60,008,415
Distribution Plant									
374.1	LAND	0	0	0	0	0	0	0	0
374.2	LAND RIGHTS	856,889	140,039	0	0	0	0	0	996,928
375	STRUCTURES & IMPROVEMENTS	79,768	200	0	0	0	0	0	79,968
376.11	MAINS < 4"	264,187,732	12,882,017	(403,624)	(1,208,352)	14,186	(137,284)	0	275,334,675
376.12	MAINS 4" & >	173,861,030	11,309,469	(506,464)	(620,719)	27,246	53,152	0	184,123,713
377	COMPRESSOR STATION EQUIPMENT	554,124	20,944	0	0	0	0	0	575,068
378	MEASURING & REG EQUIP - GENER	8,961,953	563,738	0	0	0	(758)	0	9,524,933
379	MEASURING & REG EQUIP - GATE	1,271,615	104,182	0	0	0	0	0	1,375,797
380	SERVICES	334,472,055	17,477,027	(1,699,245)	(2,306,446)	0	0	0	347,943,392
381	METERS	18,453,185	1,791,873	(822,151)	0	0	0	0	19,422,907
381.1	METERS (ELECTRONIC)	639,808	263,948	0	0	0	0	0	903,756
381.2	ERT (ENCODER RECEIVER TRANS	10,523,404	2,384,118	(500,211)	0	0	0	0	12,407,311
382	METER INSTALLATIONS	13,347,130	1,467,118	(2,227,911)	0	0	0	0	12,586,338
382.1	METER INSTALLATIONS (ELECTR	525,783	10,148	0	0	0	0	0	535,931
382.2	ERT INSTALLATION (ENCODER	2,788,538	648,339	(101,403)	0	0	0	0	3,335,475
383	HOUSE REGULATORS	65,939	30,412	0	0	0	0	0	96,351
386	OTHER PROPERTY ON CUSTOMERS P	0	0	0	0	0	0	0	0
387.1	CATHODIC PROTECTION TESTING	139,055	129	0	0	0	0	0	139,184
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	830,897,105	49,093,702	(6,261,009)	(4,135,517)	41,432	(84,891)	0	869,550,822
General Plant									
389	LAND	437,351	0	0	0	0	0	0	437,351
390	STRUCTURES & IMPROVEMENTS	8,233,029	407,980	(2,210,278)	0	0	0	0	6,430,732
390.1	SOURCE CONTROL PLANT	0	227,793	0	0	0	0	0	
391.1	OFFICE FURNITURE & EQUIPMEN	6,958,326	903,515	(9,497)	0	0	(288)	0	7,852,057
391.2	COMPUTERS	14,775,421	3,251,736	(1,131,638)	0	0	0	0	16,895,519
391.3	ON SITE BILLING	938,788	0	0	0	0	0	0	938,788
391.4	CUSTOMER INFORMATION SYSTEM	957,549	261,678	0	0	0	0	0	1,219,227
392	TRANSPORTATION EQUIPMENT	8,860,916	1,403,241	(1,815,857)	0	150,375	0	0	8,598,674
393	STORES EQUIPMENT	119,406	0	0	0	0	0	0	119,406
394	TOOLS - SHOP & GARAGE EQUIPUI	7,234,114	1,085,054	(320,346)	0	24,773	0	0	8,023,595
395	LABORATORY EQUIPMENT	68,293	0	0	0	0	0	0	68,293
396	POWER OPERATED EQUIPMENT	3,685,080	173,359	(502,213)	0	214,520	0	0	3,570,745
397	GEN PLANT-COMMUNICATION EQU	16,281	7,302	0	0	0	0	0	23,584
397.1	MOBILE	1,204,495	8,812	0	0	0	0	0	1,213,307
397.2	OTHER THAN MOBILE & TELEMET	1,667,266	75,555	0	0	0	0	0	1,742,821
397.3	TELEMETERING - OTHER	3,096,638	3,011	0	0	0	0	0	3,099,648
397.4	TELEMETERING - MICROWAVE	1,904,042	23,078	0	0	0	0	0	1,927,120

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS
NW NATURAL

Period Beginning: Jan 2013
Period Ending: Dec 2013

Functional Class FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve
UTILITY									
397.5	TELEPHONE EQUIPMENT	2,077,725	24,948	0	0	0	0	0	2,102,673
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	1,510	525	0	0	0	0	0	2,036
398.3	JANITORIAL EQUIPMENT	15,274	1,908	0	0	0	0	0	17,183
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	62,411,612	7,859,496	(5,989,828)	0	389,667	(288)	0	64,442,865
	Utility Property Grand Total	$1,080,274,901	$70,798,808	($12,392,530)	($4,135,517)	$431,099	($0)	$0	$1,134,748,967

NON UTILITY

Functional Class FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve
Intangible Plant									
303.1	COMPUTER SOFWARE	$17,130	$7,041	$0	$0	$0	$0	$0	$ 24,171
303.2	CUSTOMER INFORMATION SYSTEM	25,126	4,275	0	0	0	0	0	29,401
Non Utility	Intangible Plant Subtotal	42,256	11,316	0	0	0	0	0	53,572
Natural Gas Underground Storage									
352	WELLS	2,196,536	350,667	0	0	0	0	0	2,547,203
352.1	STORAGE LEASEHOLD & RIGHTS	122	20	0	0	0	0	0	141
352.2	RESERVOIRS	844,556	97,294	0	0	0	0	0	941,850
353	LINES	219,282	33,993	0	0	0	0	0	253,275
354	COMPRESSOR STATION EQUIPMENT	3,969,922	389,285	(700,000)	0	0	0	0	3,659,207
355	MEASURING / REGULATING EQUIPM	1,313,443	189,161	0	0	0	0	0	1,502,604
357	OTHER EQUIPMENT	4,387	1,442	0	0	0	0	0	5,829
Non Utility	Natural Gas Underground Storage Subtotal	8,548,248	1,061,862	(700,000)	0	0	0	0	8,910,110
Transmission Plant									
368	TRANSMISSION COMPRESSOR	1,132,556	238,655	0	0	0	0	0	1,371,211
Non Utility	Transmission Plant Subtotal	1,132,556	238,655	0	0	0	0	0	1,371,211
Distribution Plant									
376.12	MAINS 4" & >	129,432	21,270	0	0	0	0	0	150,702
Non Utility	Distribution Plant Subtotal	129,432	21,270	0	0	0	0	0	150,702

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS

NW NATURAL

Period Beginning: Jan 2013
Period Ending: Dec 2013

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									
General Plant									
389	LAND	0	0	0	0	0	0	0	0
390	STRUCTURES & IMPROVEMENTS	17,637	2,033	0	0	0	0	0	19,670
Non Utility	General Plant Subtotal	17,637	2,033	0	0	0	0	0	19,670
Non Utility Other									
121.1	NON-UTIL PROP-DOCK	1,879,228	41,441	(10,000)	0	0	0	0	1,910,669
121.2	NON-UTIL PROP-LAND	0	0	0	0	0	0	0	0
121.3	NON-UTIL PROP-OIL ST	2,204,774	3,360	0	0	0	0	0	2,208,134
121.7	NON-UTIL PROP-APPL CENTER	17,385	4,219	0	0	0	0	0	21,604
121.8	NON-UTIL PROP-STORAGE	(1)	0	0	0	0	0	0	(1)
Non Utility	Other	4,101,384	49,021	(10,000)	0	0	0	0	4,140,405
	Non Utility Property Grand Total	$13,971,513	$1,384,157	($710,000)	$0	$0	$0	$0	$14,645,670

TOTAL SUMMARY ALL UTILITY DEPRECIATION RESERVES 12/31/2013

UTILITY		
108010	($26,592,224)	
108011	857,510,453	
108012	10,893,185	
108013	(2,315,075)	
108014	(217,889)	
108015	3,552,466	
108100	295,279,974	
108002	(3,390,863)	
108003	20,564	
108004	236,168	
108666	-	
SUBTOTAL		$1,134,976,760
ADD:		
108001 REMOVAL WORK IN PROCESS		(12,316,595)
TOTAL UTILITY DEPRECIATION RESERVES		1,122,660,165

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS
NW NATURAL

Period Beginning: Jan 2013
Period Ending: Dec 2013

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 NON-UTILITY DEPRECIATION RESERVES								
NON UTILITY								
122026	1,034							
122027	4,212,616							
122028	9,998,774							
122029	(530,297)							
122100	1,014,441							
122002	(50,896)							
TOTAL NON UTILITY DEPRECIATION RESERVES		14,645,670						

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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	87,213	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			

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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	1,204,736
3	Account 426.2	Insurance Benefits	(2,467,719)
4	Account 426.3	Penalties - Internal Revenue	60,840
5	Account 426.4	Civic, Political and Related Activities (426.31-426.33 & 426.41-426.45)	1,056,330
6	Account 426.5	Other Deductions (426.05, 426.50-426.52)	279,469
7	Account 426.6	Diversification (426.60)	-
8			
9		Total Account 425 & 426	133,656
10			
11	Account 430	Interest on Debt to Associated Companies	-
12	Account 431	Other Interest Expense	
13		Notes Payable (431.1)	440,306
14		Miscellaneous (431.2-431.5)	1,233,081
15			
16		Total Account 430 & 431	1,673,387
17			
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REGULATORY COMMISSION EXPENSES (Account 928)

1. Report below details of regulatory commission expenses incurred during the current year (or in previous years, if being amortized) relating to formal cases before a 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 (UM180)	NONE	0	0	NONE
8					
9					
10	**WASHINGTON UTILITIES & TRANSPORTATION COMMISSION:**				
11					
12	REGULATORY ISSUES	NONE	0	0	NONE
13					
14	LEAST COST PLANNING (UG10149)	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					
25					
26					
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40					
41					
42					
43	TOTAL		0	0	

Northwest Natural does not track expenses by formal regulatory cases.

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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
							24
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		0					43

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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	5,687,243
2	Pensions - other	3,379,826
3	Post-retirement benefits other than pensions (PBOP)	1,888,151
4	Post-employment benefit plans	-
5	Other Benefits	20,372,250
6		
7		
8		
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36		
37	**Total**	31,327,470

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DISTRIBUTION OF SALARIES AND WAGES

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

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

Line No.	Classification (a)	Direct Payroll Distribution (b)	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	1,662,654	238,378	1,901,032
32	Transmission	467,717	82,711	550,428
33	Distribution	13,837,116	2,470,684	16,307,800
34	Customer Accounts	8,457,663	1,241,461	9,699,124
35	Customer Service and Informational	1,401,082	199,200	1,600,282
36	Sales	1,122,914	159,634	1,282,548
37	Administrative and General	17,402,214	2,475,753	19,877,967
38	TOTAL Operation (Total of lines 28 thru 37)	44,351,360	6,867,821	51,219,181
39	Maintenance			
40	Production - Manufactured Gas			
41	Production - Natural Gas			
42	Other Gas Supply			
43	Storage, LNG Terminaling and Processing	284,725	41,521	326,246
44	Transmission	1,194,925	170,081	1,365,006
45	Distribution	6,580,348	1,098,843	7,679,191
46	Administrative and General	1,143,464	181,386	1,324,850
47	TOTAL Maint. (Total of lines 40 thru 46)	9,203,462	1,491,831	10,695,293

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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)	1,947,379	279,899	2,227,278
54	Transmission (Total of lines 32 and 44)	1,662,642	252,792	1,915,434
55	Distribution (Total of lines 33 and 45)	20,417,464	3,569,527	23,986,991
56	Customer Accounts (Total of line 34)	8,457,663	1,241,461	9,699,124
57	Customer Service and Informational (Total of line 35)	1,401,082	199,200	1,600,282
58	Sales (Total of line 36)	1,122,914	159,634	1,282,548
59	Administrative and General (Total of lines 37 and 46)	18,545,678	2,657,139	21,202,817
60	TOTAL Operation and Maintenance (Total of lines 50 thru 59)	53,554,822	8,359,652	61,914,474
61	Other Utility Departments			
62	Operation and Maintenance			
63	TOTAL All Utility Dept. (Total of lines 25,60, and 62)	53,554,822	8,359,652	61,914,474
64	Utility Plant			
65	Construction (By Utility Departments)			
66	Electric Plant			
67	Gas Plant	24,810,715	3,957,307	28,768,022
68	Other			
69	TOTAL Construction (Total of lines 66 thru 68)	24,810,715	3,957,307	28,768,022
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	834,606	-	834,606
75.02	Governmental	268,874	376,535	645,409
75.03	Acct Rec-NNG Financial Corporation	394	-	394
75.04	Acct Rec-Palomar	-	-	-
75.05	Acct Rec-Gill Ranch	-	-	-
75.06	Acct Rec-PGE Joint Meter Reading	108,280	-	108,280
75.07	Storage Business	452,244	-	452,244
75.08	Other Accounts Receivable	-	32,519	32,519
75.11				
75.12				
75.13				
75.14				
75.15				
75.16				
75.17				
75.18				
75.19				
76	TOTAL Other Accounts	1,664,399	409,054	2,073,453
77	TOTAL SALARIES AND WAGES	80,029,936	12,726,013	92,755,949

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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	13,166,359
2	SEVENSON ENVIRONMENTAL	12,849,158
3	COLORADO STRUCTURES INC	12,620,423
4	BROTHERS PIPELINE CORP	5,261,350
5	ANCHOR QEA LLC	5,188,793
6	K & L GATES LLP	4,078,241
7	THE HDD CO INC	2,321,163
8	MARSH USA INC	2,299,555
9	LOCATING INC	2,087,061
10	BROTHERTON CORP	2,077,326
11	K & D SERVICES OF OREGON	1,998,549
12	ITRON INC	1,666,621
13	ADVANCE ENGINEERING CORP	1,544,290
14	ACTIVE TELESOURCE INC	1,506,132
15	HENKELS & MCCOY INC	1,446,263
16	ADVANTEL INC	1,410,241
17	COURTNEY & SON INC	1,087,951
18	PRICEWATERHOUSECOOPERS LLP	986,207
19	CREATIVE MEDIA DEVELOPMENT INC	878,773
20	OREGON WASHINGTON LABORATORIES	856,360
21	D.P. NICOLI INC	822,867
22	ONLINE ENTERPRISES INC	815,814
23	WOODRUFF-SAWYER & COMPANY	815,214
24	PEARL LEGAL GROUP PC	780,620
25	DELL MARKETING LP	768,411
26	GEOENGINEERS INC	738,303
27	RAIMORE CONSTRUCTION LLC	712,738
28	MEARS/CPG LLC	707,401
29	WILLBROS ENGINEERS (US) LLC	692,159
30	MCDOWELL RACKNER & GIBSON PC	608,046
31	MICROSOFT LICENSING GP	576,186
32	STOEL RIVES LLP	495,071
33	MSN COMMUNICATIONS INC	494,305
34	URS CORPORATION AMERICAS	477,943
35	FISHNET SECURITY INC	477,168
36	HAHN AND ASSOCIATES INC	472,523
37	SURVEYS & ANALYSIS INC	461,961
38	AMERICAN GAS ASSOCIATION	438,254
39	SOLAR TURBINES INC	431,389
40	CORPORATE ENVIRONMENTAL	421,116
41	THOMAS N SNAIR	404,421
42	ALASKA CONTINENTAL PIPELINE	392,549
43	G A W INC	386,665
44	ALIXPARTNERS LLP	347,103
45	LOWER WILLAMETTE GROUP	341,484
46	STANDARD UTILITY CONTRACTORS	336,217
47	OPERATIONS TECHNOLOGY	335,000
48	MULVANNYG2 ARCHITECTURE CORP	326,312
49	C-2 UTILITY CONTRACTORS LLC	317,192
50	SAP INDUSTRIES INC	313,878
51	FES INVESTMENTS INC	300,356
52	CENVEO GRAPHIC ARTS CENTER	288,566
53	ENVIRONMENTAL PROTECTION AGNCY	286,711
54	APEX DIRECTIONAL DRILLING LLC	279,119
55	AIMS/PVIC	278,560
56	HEWITT ASSOCIATES LLC	275,216
57	MOODY'S INVESTORS SERVICE INC	271,500
58	PIPETEL TECHNOLOGIES INC	269,000
	TOTAL	93,288,154

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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	None			
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	Goods or Services Provided for Affiliated Company			
21				
22	Shared services agreement - payroll	NW Energy LLC	426-49505	20,700
23	Shared services agreement - overhead	NW Energy LLC	426-49505	5,692
24				
25				
26				
27	Shared services agreement - payroll	NW Natural Gas Storage LLC	421-61505	27,092
28	Shared services agreement - overhead	NW Natural Gas Storage LLC	921-01505	7,450
29				
30				
31				
32	Shared services agreement - payroll	Gill Ranch	Various	234,880
33	Shared services agreement - overhead	Gill Ranch	922-02476	130,682
34				
35				
36				
37	Shared services agreement - payroll	Shared Services Transferred to NWN Gas Storage	421-61505	190,401
38	Shared services agreement - overhead	Shared Services Transferred to NWN Gas Storage	Various	52,211
39				
40	TOTAL			669,108

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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:	4	15,400	29,528,531
2	Miller Station, Mist, Oregon			
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	1,989,802
8	(Fuel used is natural gas)			
9				
10				
11				
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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
7,267		187,600	4,036	1	12/8/2013	2
						3
						4
						5
2,442		635	37	2	1/2/2013	6
-		-	-	N/A	N/A	7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
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						24
						25
						26
						27
						28
		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

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GAS STORAGE PROJECTS

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

Line No.	Item (a)	Gas Belonging to Respondent (Dth) (b)	Gas Belonging to Others (Dth) (c)	Total Amount (Dth) (d)
	STORAGE OPERATIONS (in Dth)			
1	Gas Delivered to Storage			
2	January	509,351		509,351
3	February	126,263		126,263
4	March	550,194		550,194
5	April	453,854		453,854
6	May	857,431		857,431
7	June	891,584		891,584
8	July	1,500,729		1,500,729
9	August	1,759,686		1,759,686
10	September	1,038,835		1,038,835
11	October	1,084,196		1,084,196
12	November	1,257,775		1,257,775
13	December	673,233		673,233
14	TOTAL (Total of Lines 2 Thru 13)	10,703,131		10,703,131
15	Gas Withdrawn from Storage			
16	January	1,501,988		1,501,988
17	February	1,329,140		1,329,140
18	March	354,313		354,313
19	April	2,134,909		2,134,909
20	May	477,850		477,850
21	June	17,551		17,551
22	July	65,328		65,328
23	August	27,446		27,446
24	September	28,590		28,590
25	October	400,735		400,735
26	November	728,228		728,228
27	December	4,623,486		4,623,486
28	TOTAL (Total of lines 16 thru 27)	11,689,564		11,689,564

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

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, 2013

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	12,015,182
2	Cushion Gas (Including Native Gas)	6,634,485
3	Total Gas in Reservoir (Total of Line 1 and 2)	18,649,667
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)	358,716
8	Date of Maximum Days' Withdrawal	12/08/13
9	LNG Terminal Companies (in Dth) (Two wholly owned, one shared)	3
10	Number of Tanks	3
11	Capacity of Tanks	2,222,100
12	LNG Volumes	
13	Received at "Ship Rail"	0
14	Transferred to Tanks	301,842
15	Withdrawn from Tanks	374,948
16	"Boil Off" Vaporization Loss	0

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, 2013

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		639.6
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*	**	76.7
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
NORTHWEST NATURAL GAS COMPANY	X An Original A Resubmission		Dec. 31, 2013

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	13,784,996		No
2	Newport, OR	LNG	100,000	22,248,517	Yes	
3	Mist, OR	underground	520,000	87,213,243	Yes	
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, 2013

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)		76,423,733
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	38,078,607
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	11,689,564
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)		126,191,904
16	**GAS DELIVERED**		
17	Gas Sales (Accounts 480-495)		76,576,465
18	Deliveries of Gas Gathered for Others (Account 489.1)	303	0
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	38,078,607
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	10,703,131
26	Gas Used for Compressor Station Fuel	331	187,600
27	Other Deliveries (Specify) Co Use	331	139,553
28	Total Deliveries (Total of lines 17 thru 27)		125,685,356
29	**GAS UNACCOUNTED FOR**		
30	Production System Losses		
31	Gathering System Losses		
32	Transmission System Losses		
33	Distribution System Losses		506,548
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)		506,548
37	Total Deliveries & Unaccounted for (Total of lines 28 and 36)		126,191,904

NORTHWEST NATURAL GAS COMPANY

Washington Supplement to FERC Form 2

December 31, 2013

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, 2013

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	$ 451,076,405	$ 437,056,221	$ 49,122,448	$ 46,985,552
4	COMMERCIAL SALES	218,920,249	213,777,756	19,945,569	19,330,408
5	INDUSTRIAL SALES	53,923,801	55,304,845	3,240,107	3,721,585
6	OTHER SALES				
7	SALES FOR RESALE				
8	TRANSPORTATION OF GAS OF OTHERS	15,898,199	15,674,791	1,814,923	1,663,531
9	OTHER OPERATING REVENUES	6,365,188	(3,521,192)	(134,580)	(1,746,627)
10					
11	TOTAL GAS SERVICE REVENUES	$ 746,183,842	$ 718,292,421	$ 73,988,467	$ 69,954,449
12					
13	THERMS OF GAS SOLD-TRANSPORTED				
14					
15	RESIDENTIAL SALES	414,314,598	395,247,444	46,680,915	44,145,350
16	COMMERCIAL SALES	250,046,069	242,826,001	20,727,712	19,789,530
17	INDUSTRIAL SALES	93,673,355	94,456,570	4,611,634	5,324,195
18	OTHER SALES (UNBILLED)	7,730,628	(266,286)	925,117	102,631
19	SALES FOR RESALE				
20	TRANSPORTATION OF GAS OF OTHERS	380,786,075	379,392,465	18,850,614	17,659,260
21					
22	TOTAL THERMS OF GAS SOLD-TRANSPORTED	1,146,550,725	1,111,656,194	91,795,992	87,020,966
23					
24	AVERAGE NUMBER OF GAS CUSTOMERS PER MONTH				
25					
26	RESIDENTIAL SALES	625,017	618,535	66,242	65,038
27	COMMERCIAL SALES	64,470	63,284	5,976	5,646
28	INDUSTRIAL SALES	709	722	45	46
29	OTHER SALES				
30	SALES FOR RESALE				
31	TRANSPORTATION OF GAS OF OTHERS	212	203	19	18
32					
33					
	TRANS. & DISTRN. MAINS - FEET (END OF YEAR)	74,410,533	74,072,518	9,119,472	9,013,750
35	NO. OF METERS IN SERV. & HELD IN RESERVE (AVE.)	785,846	776,473	76,092	74,244
36	AVERAGE B.T.U. CONTENT PER CU. FT.	1,027.7	1,026.8	1,028.7	1,026.9

[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, 2013

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

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, 2013

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
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INFORMATION NOT AVAILABLE
SEE FERC ANNUAL REPORT

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, 2013

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

(Next Page is 200)

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, 2013

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)	203,262,701
4	Property Under Capital Leases	
5	Plant Purchased or Sold	
6	Completed Construction not Classified	7,380,397
7	Experimental Plant Unclassified	
8	TOTAL Utility Plant (Total of lines 3 thru 7)	210,643,098
9	Leased to Others	
10	Held for Future Use	0
11	Construction Work in Progress	532,126
12	Acquisition Adjustments	
13	TOTAL Utility Plant (Total of lines 8 thru 12)	211,175,224
14	Accum. Prov. for Depr., Amort., & Depl.	88,890,664
15	Net Utility Plant (Total of line 13 less 14)	122,284,560
16	**DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION**	
17	In Service:	
18	Depreciation	87,546,683
19	Amort. and Depl. of Producing Natural Gas Land and Land Rights	
20	Amort. of Underground Storage Land and Land Rights	0
21	Amort. of Other Utility Plant	1,959,811
22	Salvage Work In Progress	0
23	Less Removal Work in Progress	615,830
24	TOTAL in Service (Total of lines 18 thru 23)	88,890,664
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)	88,890,664

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, 2013

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
	203,262,701			3
	0			4
	0			5
	7,380,397			6
				7
	210,643,098			8
				9
	0			10
	532,126			11
				12
	211,175,224			13
	88,890,664			14
	122,284,560			15
				16
				17
	87,546,683			18
				19
	0			20
	1,959,811			21
	0			22
	615,830			23
	88,890,664			24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
	88,890,664			35

(Next page is 204)

ACCOUNT SUMMARY BY FUNTIONAL CLASS
NW Natural

Period Beginning: Jan 2013
Period Ending: Dec 2013

Functional Class FERC Plant Account		Beginning Balance	Additions	Retirements	Transfers	Adjustments	Ending Balance
Intangible Plant							
301	ORGANIZATION	$322	$0	$0	$0	$0	$322
302	FRANCHISES & CONSENTS	125	0	0	0	0	125
303.1	COMPUTER SOFTWARE	72,938	(72,938)	0	0	0	0
303.2	CUSTOMER INFORMATION SYSTEM	1,898,028	(38,165)	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	1,971,413	(111,103)	0	0	0	1,860,310
Transmission Plant							
367	MAINS	772,600	196,002	0	0	0	968,602
	Transmission Plant Subtotal	772,600	196,002	0	0	0	968,602
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"	63,209,541	1,387,904	(38,287)	1,730,154	0	66,289,313
376.12	MAINS 4" & >	58,182,185	1,976,602	(29,243)	(1,318,506)	0	58,811,038
378	MEASURING & REG EQUIP - GENER	1,095,611	39,263	0	0	0	1,134,874
379	MEASURING & REG EQUIP - GATE	600,840	3,977	0	0	0	604,817
380	SERVICES	54,470,138	2,538,613	(30,142)	0	0	56,978,608
381	METERS	9,043,450	345,418	7,586	0	0	9,396,454
381.2	ERT (ENCODER RECEIVER TRANS	6,141,878	126,256	(52,907)	0	0	6,215,227
382	METER INSTALLATIONS	6,026,980	264,544	(177,378)	0	0	6,114,146
382.2	ERT INSTALLATION (ENCODER	968,424	0	(6,653)	0	0	961,771
383	HOUSE REGULATORS	34,826	951	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	199,869,416	6,683,528	(327,025)	411,649	0	206,637,568

ACCOUNT SUMMARY BY FUNTIONAL CLASS
NW Natural

Period Beginning: Jan 2013
Period Ending: Dec 2013

Functional Class / FERC Plant Account		Beginning Balance	Additions	Retirements	Transfers	Adjustments	Ending Balance
General Plant							
389	LAND	0	0	0	0	0	0
390	STRUCTURES & IMPROVEMENTS	0	0	0	0	0	0
391.1	OFFICE FURNITURE & EQUIPMEN	37,151	0	0	0	0	37,151
391.4	CUSTOMER INFORMATION SYSTEM	79,339	0	0	0	0	79,339
392	TRANSPORTATION EQUIPMENT	680,623	0	(11,160)	0	0	669,464
394	TOOLS - SHOP AND GARAGE EQUIPMENT	84,311	0	0	0	0	84,311
396	POWER OPERATED EQUIPMENT	220,704	0	(29,323)	0	0	191,381
397.3	TELEMETERING - OTHER	101,081	0	0	0	0	101,081
397.5	TELEPHONE EQUIPMENT	9,164	0	0	0	0	9,164
398.4	INSTALLED IN LEASED BUILDINGS	4,727	0	0	0	0	4,727
	General Plant Subtotal	1,217,101	0	(40,483)	0	0	1,176,618
	Washington Utility Property Grand Total	$203,830,530	$6,768,427	($367,507)	$411,649	$0	$210,643,098

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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, 2013

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				
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42				0
43				

(Next Page is 216)

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, 2013

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	Misc Mains and Service Jobs	532,126	367,792
2			
3			
4			
5			
6			
7			
8			
9			
10			
11			
12			
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39			
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41			
42			
43			
44			
45	**Total**	532,126	367,792

(Next Page is 218)

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, 2013

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 Rte Percentage (d)
	(1) Average Short-Term Debt	S	144,072,000			
	(2) Short-Term Interest				s	0.3
	(3) Long-Term Debt	D	701,700,000		d	5.977
	(4) Preferred Stock	P			p	
	(5) Common Equity	C	751,871,513		c	9.5
	(6) Total Capitalization			100.00		
	(7) Average Construction Work in Progress	W	56,415,263			

2.	Gross Rates for Borrowed Funds s(S/W)+d[(D/(D+P+C))(1-(S/W)]	3.72
3.	Rate for Other Funds [1-(S/W)][p(P/(D+P+C))+c(C/(D+P+C))]	7.64
4.	Weighted Average Rate Actually Used for the Year a. Rate for Borrowed Funds - b. Rate for Other Funds -	0.34

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 2013

a.	Production , Storage, Transmission and Distribution plant	50%
b.	Meters	62%
c.	General Plant	16%
d.	Non – Utility Property	1%

f) Direct assignment of construction overhead capitalized during 2013:
$ 38,473,708

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 2013
Period Ending: Dec 2013

Functional Class / FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve
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	2,227	917	0	0	0	0	0	3,144
303.2	CUSTOMER INFORMATION SYSTEM	1,622,903	240,170	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	1,625,130	241,087	0	0	0	0	0	1,866,216
Transmission Plant									
367	MAINS	45,150	18,650	0	0	0	0	0	63,800
	Transmission Plant Subtotal	45,150	18,650	0	0	0	0	0	63,800
Distribution Plant									
374.1	LAND	0	0	0	0	0	0	0	0
374.2	LAND RIGHTS	12,180	2,076	0	0	0	0	0	14,256
375	STRUCTURES & IMPROVEMENTS	30,845	0	0	0	0	0	0	30,845
376.11	MAINS < 4"	28,953,193	1,688,803	(38,287)	(113,371)	0	60,542	0	30,550,881
376.12	MAINS 4" & >	19,759,538	1,429,276	(29,243)	(49,672)	0	(48,661)	0	21,061,238
378	MEASURING & REG EQUIP - GENER	409,079	24,855	0	0	0	0	0	433,934
379	MEASURING & REG EQUIP - GATE	550,564	26,631	0	0	0	0	0	577,195
380	SERVICES	25,647,680	1,505,592	(30,142)	(69,150)	0	0	0	27,053,979
381	METERS	1,865,913	214,110	7,586	0	0	0	0	2,087,609
381.2	ERT (ENCODER RECEIVER TRANS	2,433,118	409,193	(52,907)	0	0	0	0	2,789,404
382	METER INSTALLATIONS	1,692,504	144,144	(177,378)	0	0	0	0	1,659,270
382.2	ERT INSTALLATION (ENCODER	384,795	64,246	(6,653)	0	0	0	0	442,388
383	HOUSE REGULATORS	3,789	1,039	0	0	0	0	0	4,828
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	81,769,828	5,509,964	(327,025)	(232,193)	0	11,881	0	86,732,455

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS
NW Natural

Period Beginning: Jan 2013
Period Ending: Dec 2013

Functional Class FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve
General Plant									
389	LAND	0	0	0	0	0	0	0	0
390	STRUCTURES & IMPROVEMENTS	0	0	0	0	0	0	0	0
391.1	OFFICE FURNITURE & EQUIPMEN	33,967	2,961	0	0	0	0	0	36,928
391.4	CUSTOMER INFORMATION SYSTEM	79,339	0	0	0	0	0	0	79,339
392	TRANSPORTATION EQUIPMENT	517,687	38,224	(11,160)	0	0	0	0	544,751
394	TOOLS AND EQUIPMENT	3,872	5,893	0	0	0	0	0	9,765
396	POWER OPERATED EQUIPMENT	167,147	5,460	(29,323)	0	0	0	0	143,285
397.3	TELEMETERING - OTHER	15,994	71	0	0	0	0	0	16,065
397.5	TELEPHONE EQUIPMENT	9,164	0	0	0	0	0	0	9,164
398.4	INSTALLED IN LEASED BUILDINGS	4,727	0	0	0	0	0	0	4,727
	General Plant Subtotal	831,897	52,609	(40,483)	0	0	0	0	844,023
	Washington Utility Property Grand Total	$84,272,003	$5,822,310	($367,507)	($232,193)	$0	$11,881	$0	$89,506,494

TOTAL SUMMARY WASHINGTON UTILITY DEPRECIATION RESERVES 12/31/2013

WASHINGTON		
108010	($797,767)	
108011	63,065,633	
108012	532,448	
108013	(12,303)	
108014	-	
108015	143,285	
108100	26,575,198	
		$89,506,494
ADD:		
108001 REMOVAL WORK IN PROCESS		(615,830)
TOTAL WASHINGTON UTILITY DEPRECIATION		$88,890,664

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, 2013

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.

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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, 2013

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

(Next page is 274)

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, 2013

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

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, 2013

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.
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Acct. No. (g)	Amount (h)	Acct. No. (i)	Amount (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

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, 2013

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

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, 2013

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

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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, 2013

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	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2013

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.
72,308,124	70,037,545	72,308,124	70,037,545	7,294,538	6,936,171	1
						2
105,449	122,398	105,449	122,398			3
130,515	147,316	130,515	147,316			4
	-	-				5
	-	-				6
1,814,923	1,663,531	1,814,923	1,663,531	1,885,061	1,765,926	7
						8
						9
						10
						11
18,136	19,013	18,136	19,013			12
						13
(388,680)	(2,035,354)	(388,680)	(2,035,354)			14
73,988,467	69,954,449	73,988,467	69,954,449			15
						16
73,988,467	69,954,449	73,988,467	69,954,449			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, 2013

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	UNBILLED REVENUE AND OTHER	(388,680)
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25	TOTAL	(388,680)

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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, 2013

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

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, 2013

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

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, 2013

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

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, 2013

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

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, 2013

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

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, 2013

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

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, 2013

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

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, 2013

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

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, 2013

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, 2013

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	Account Charged	Natural Gas		Manufactured Gas	
			Gas Used (Dth)	Amount of Credit (in dollars)	Gas Used (Dth)	Amount of Credit (in dollars)
	(a)	(b)	(c)	(d)	(d)	(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						
10						
11						
12						
13						
14						
15	**NONE**					
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45	**Total**					

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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, 2013

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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24	**SEE FERC ANNUAL REPORT**	
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40	TOTAL	

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS
NW Natural

Period Beginning: Jan 2013
Period Ending: Dec 2013

Functional Class / FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve
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	2,227	917	0	0	0	0	0	3,144
303.2	CUSTOMER INFORMATION SYSTEM	1,622,903	240,170	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	1,625,130	241,087	0	0	0	0	0	1,866,216
Transmission Plant									
367	MAINS	45,150	18,650	0	0	0	0	0	63,800
	Transmission Plant Subtotal	45,150	18,650	0	0	0	0	0	63,800
Distribution Plant									
374.1	LAND	0	0	0	0	0	0	0	0
374.2	LAND RIGHTS	12,180	2,076	0	0	0	0	0	14,256
375	STRUCTURES & IMPROVEMENTS	30,845	0	0	0	0	0	0	30,845
376.11	MAINS < 4"	28,953,193	1,688,803	(38,287)	(113,371)	0	60,542	0	30,550,881
376.12	MAINS 4" & >	19,759,538	1,429,276	(29,243)	(49,672)	0	(48,661)	0	21,061,238
378	MEASURING & REG EQUIP - GENER	409,079	24,855	0	0	0	0	0	433,934
379	MEASURING & REG EQUIP - GATE	550,564	26,631	0	0	0	0	0	577,195
380	SERVICES	25,647,680	1,505,592	(30,142)	(69,150)	0	0	0	27,053,979
381	METERS	1,865,913	214,110	7,586	0	0	0	0	2,087,609
381.2	ERT (ENCODER RECEIVER TRANS	2,433,118	409,193	(52,907)	0	0	0	0	2,789,404
382	METER INSTALLATIONS	1,692,504	144,144	(177,378)	0	0	0	0	1,659,270
382.2	ERT INSTALLATION (ENCODER	384,795	64,246	(6,653)	0	0	0	0	442,388
383	HOUSE REGULATORS	3,789	1,039	0	0	0	0	0	4,828
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	81,769,828	5,509,964	(327,025)	(232,193)	0	11,881	0	86,732,455
General Plant									
389	LAND	0	0	0	0	0	0	0	0
390	STRUCTURES & IMPROVEMENTS	0	0	0	0	0	0	0	0
391.1	OFFICE FURNITURE & EQUIPMEN	33,967	2,961	0	0	0	0	0	36,928
391.4	CUSTOMER INFORMATION SYSTEM	79,339	0	0	0	0	0	0	79,339
392	TRANSPORTATION EQUIPMENT	517,687	38,224	(11,160)	0	0	0	0	544,751
394	TOOLS AND EQUIPMENT	3,872	5,893	0	0	0	0	0	9,765
396	POWER OPERATED EQUIPMENT	167,147	5,460	(29,323)	0	0	0	0	143,285
397.3	TELEMETERING - OTHER	15,994	71	0	0	0	0	0	16,065
397.5	TELEPHONE EQUIPMENT	9,164	0	0	0	0	0	0	9,164
398.4	INSTALLED IN LEASED BUILDINGS	4,727	0	0	0	0	0	0	4,727
	General Plant Subtotal	831,897	52,609	(40,483)	0	0	0	0	844,023
	Washington Utility Property Grand Total	$84,272,003	$5,822,310	($367,507)	($232,193)	$0	$11,881	$0	$89,506,494

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS
NW Natural

Period Beginning: Jan 2013
Period Ending: Dec 2013

Functional Class FERC Plant Account	Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve
Washington Utility Property Grand Total	$84,272,003	$5,822,310	($367,507)	($232,193)	$0	$11,881	$0	$89,506,494

TOTAL SUMMARY WASHINGTON UTILITY DEPRECIATION RESERVES 12/31/2013

WASHINGTON		
108010	($797,767)	
108011	63,065,633	
108012	532,448	
108013	(12,303)	
108015	143,285	
108100	26,575,198	
SUBTOTAL		$89,506,494
ADD:		
108001 REMOVAL WORK IN PROCESS		(615,830)
TOTAL WASHINGTON UTILITY DEPRECIATION		$88,890,664

Name of Respondent	This Report is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2013

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			
8.03			
8.04			
8.05			
8.06			
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	NONE		

(Next Page is 340)

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, 2013

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	
17		
18		
19		
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28	**SEE FERC ANNUAL REPORT**	
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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, 2013

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					
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SEE FERC ANNUAL REPORT

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, 2013

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, or 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
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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, 2013

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			

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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, 2013

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			

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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, 2013

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			
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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, 2013

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				
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25				

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, 2013

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						
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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"	13,007		44	12,963
2	High Pressure	6"	371,257	1,113		372,370
3	High Pressure	8"	320,308	386		320,694
4	High Pressure	10"	462,473		113	462,360
5	High Pressure	12"	1,084,343	47,634		1,131,977
6	High Pressure	16"	558,346		125	558,221
7	High Pressure	20"	71,721		12	71,709
8	High Pressure	24"	464,770	154		464,924
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31						
32						
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34						
	TOTALS		3,346,225	49,287	294	3,395,218

* 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"	0	5	0	5
2	High Pressure	6"	0	100	0	100
3	High Pressure	8"	17,837	101	0	17,938
4						
5						
6						
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	TOTALS		17,837	206	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"	18,512,241	138,891	149,741	18,501,391
7	High Pressure	2"	37,827,942	319,163	55,231	38,091,874
8	High Pressure	3"	160,355	0	29	160,326
9	High Pressure	4"	9,826,693	39,802	15,944	9,850,551
10	High Pressure	6"	2,914,211	4,318	24,777	2,893,752
11	High Pressure	Over 6"	1,484,851	33,977	1,407	1,517,421
12						
13						
14						
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32						
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34						
	TOTALS		70,726,293	536,151	247,129	71,015,315

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"	1,001,815	15,323	7,306	1,009,832
2	High Pressure	2"	5,989,409	84,651	4,757	6,069,303
3	High Pressure	3"	44,300	0	0	44,300
4	High Pressure	4"	1,417,546	13,060	5,672	1,424,934
5	High Pressure	6"	400,560	10,337	0	410,897
6	High Pressure	Over 6"	142,283	0	120	142,163
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	TOTALS		8,995,913	123,371	17,855	9,101,429

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"	630,616	7,425	1846	636,195	-
2	HP, LP	1"	52,956	985	285	53,656	-
3	HP, LP	1 1/4"	5,261	0	10	5,251	-
4	HP, LP	2"	4,274	35	34	4,275	-
5	HP, LP	3"	49	0	0	49	-
6	HP, LP	4"	485	5	12	478	-
7	HP, LP	6"	18	0	0	18	-
8	HP, LP	Over 6"	14	0	0	14	-
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
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24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
	TOTALS		693,673	8,450	2,187	699,936	

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"	60,813	1,284	76	62,021	-
2	HP	1"	4,985	144	20	5,109	-
3	HP	1 1/4"	10	0	0	10	-
4	HP	2"	251	2	1	252	-
5	HP	4"	32	1	5	28	-
6	HP, LP	6"	8	0	0	8	-
7	HP, LP	Over 6"	0	0	0	0	-
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
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21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
	TOTALS		66,099	1,431	102	67,428	

NORTHWEST NATURAL GAS COMPANY
CUSTOMER METERS
SYSTEM 2013

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	17		2	15
23	1.5M TC	Rotary	Roots	1,500	22		2	20
24	1.5M ID	Rotary	Roots	1,500	58		4	54
26	R2M9	Rotary	Roots	2,000	1			1
32	3M125	Rotary	Roots	3,000	12	1		13
33	RS3M TC	Rotary	Roots	3,000	8		1	7
34	RS3M ID	Rotary	Roots	3,000	23		2	21
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	9	1		10
43	RS5M TC	Rotary	Roots	5,000	19			19
44	RS5M ID	Rotary	Roots	5,000	71		3	68
52	7M125	Rotary	Roots	7,000	5	1		6
53	RS7M TC	Rotary	Roots	7,000	27			27
54	RS7M ID	Rotary	Roots	7,000	36		1	35
64	RS11 ID	Rotary	Roots	11,000	67		2	65
65	RS11 TC ID	Rotary	Roots	11,000	1			1
73	RS16 ID	Rotary	Roots	16,000	8		1	7
83	RS23 ID	Rotary	Roots	23,000	34		9	25
93	RS38 ID	Rotary	Roots	38,000	16			16
95	RS56 ID	Rotary	Roots	56,000	5		2	3
120	R175	Diaphragm	Rockwell	175	53,869		650	53,219
125	R200	Diaphragm	Rockwell	200	21,691		263	21,428
130	A175	Diaphragm	American	175	86,519	1	745	85,775
140	S175	Diaphragm	Sprague	175	24,303		291	24,012
260	Misc.	Various	Various	Various	3			3
270	1000A	Diaphragm	Schlemberger	1,000	196		18	178
272	1000A	Diaphragm	Actaris	1,000	77		18	59
300	1600 ID	Diaphragm	Rockwell	800	3			3
305	1600 TC ID	Diaphragm	Rockwell	800	7			7
310	RW3M ID	Diaphragm	Rockwell	1,450	58		1	57
315	RW3M TC ID	Diaphragm	Rockwell	1,450	38		3	35
320	RW5M ID	Diaphragm	Rockwell	2,500	39			39
325	RW5M TC ID	Diaphragm	Rockwell	2,500	47			47
390	1400 ID	Diaphragm	American	1,400	205		4	201
395	1400 TC ID	Diaphragm	American	1,400	10			10
400	2300 ID	Diaphragm	American	2,300	148		5	143
410	AL5M	Diaphragm	American	5,000	79		4	75
411	DU5M	Diaphragm	American	5,000	1			1
415	AL5M	Diaphragm	American	5,000	9			9
450	400A	Diaphragm	Schlemberger	400	1,566		34	1,532
452	400A	Diaphragm	Actaris	400	696		11	685
470	A425	Diaphragm	American	425	2,477		152	2,325
471	AL425	Diaphragm	American	425	2,864		57	2,807
472	A425	Diaphragm	American	425	2,933		86	2,847
475	AL-630	Diaphragm	American	630	7,417	1,600	46	8,971
480	A800 ID	Diaphragm	American	800	1,025	1	88	938
485	A800 TC ID	Diaphragm	American	800	1,069		170	899
486	A800	Diaphragm	American	800	7			7
490	S305	Diaphragm	Sprague	305	4			4
500	AL1M ID	Diaphragm	American	1,000	490		28	462
502	AL 1000	Diaphragm	American	1,000	370		10	360
505	AL1M TC ID	Diaphragm	American	1,000	558		29	529
507	AL 1000	Diaphragm	American	1,000	3,702	421	32	4,091
510	R310	Diaphragm	Rockwell	310	3,895		319	3,576
515	R315	Diaphragm	Rockwell	315	182		7	175
520	R415	Diaphragm	Rockwell	415	4,869		456	4,413
530	RW1M ID	Diaphragm	Rockwell	1,000	21		4	17
535	RW1M TC ID	Diaphragm	Rockwell	1,000	10			10

NORTHWEST NATURAL GAS COMPANY
CUSTOMER METERS
SYSTEM 2013

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	602		76	526
545	R750 TC ID	Diaphragm	Rockwell	750	61			61
555	A310	Diaphragm	American	310	1,384		43	1,341
560	A250	Diaphragm	American	250	148,749	2	682	148,069
561	AC250	Diaphragm	American	250	123,484	15,418	2,462	136,440
565	RX250	Diaphragm	American	250	1,130		1	1,129
570	R275	Diaphragm	Rockwell	275	103,391	1	320	103,072
572	275	Diaphragm	Invensys	275	49,586	1	297	49,290
575	G2	Diaphragm	Westinghouse	200	18			18
580	SPRM	D+Reg	Sprague	175	486			486
585	S250	Diaphragm	Sprague	250	27,193		204	26,989
590	S250	Diaphragm	Lancaster	250	23,005		209	22,796
595	METRIS 250	Diaphragm	Schlemberger	250	14,062		470	13,592
613	8C	Rotary	Roots	800	44			44
616	8C175TQM	Rotary	Roots	800	30		1	29
617	8C175TQM	Rotary	Dresser/Roots	800	56	3		59
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	279		19	260
623	1.5M	Rotary	Roots	1,500	25		1	24
625	15C175TQM	Rotary	Dresser/Roots	1,500	231	5		236
626	15CTQM	Rotary	Roots	1,500	589	4	1	592
632	3M	Rotary	Roots	3,000	349	9	4	354
633	RS3M	Rotary	Roots	3,000	114		1	113
636	5M175TQM	Rotary	Roots	3,000	1,045	19		1,064
637	3M175TQM	Rotary	Dresser/Roots	3,000	678	12	1	689
638	3M1480B3-HPC	Rotary	Dresser/Roots	3,000	4			4
642	5M	Rotary	Roots	5,000	233	10		243
643	RS5M TC	Rotary	Roots	5,000	132		1	131
644	5M175	Rotary	Roots	5,000	15		1	14
645	5M125	Rotary	Roots	5,000	3			3
646	5M175TQM	Rotary	Roots	5,000	704	5	1	708
647	5M175TQM	Rotary	Dresser/Roots	5,000	376	7		383
652	7M	Rotary	Roots	7,000	132		1	131
653	RS7M	Rotary	Roots	7,000	58	1		59
654	7M175	Rotary	Roots	7,000	34			34
655	7M175TQM	Rotary	Dresser/Roots	7,000	160	2		162
656	7M175TQM	Rotary	Roots	7,000	253	4		257
657	7M175TQM	Rotary	Roots	7,000	90			90
662	11M	Rotary	Roots	11,000	7	1		8
663	RS11	Rotary	Roots	11,000	44			44
664	RS11 ID	Rotary	Roots	11,000	47		3	44
665	RS11	Rotary	Roots	11,000	16			16
666	11M175TQM	Rotary	Roots	11,000	357	4		361
667	11M175TQM	Rotary	Roots	11,000	4			4
668	11M175TQM	Rotary	Dresser/Roots	11,000	1			1
672	16M	Rotary	Roots	16,000	3		1	2
673	16M175	Rotary	Roots	16,000	60		8	52
674	RS16 TC ID	Rotary	Roots	16,000	21		1	20
675	RS16 TC	Rotary	Roots	16,000	48		1	47
676	16M175TQM	Rotary	Roots	16,000	200	3		203
686	23M125TQM	Rotary	Roots	23,000	14	1	1	14
690	23M232TQM	Rotary	Dresser/Roots	23,000	40	3		43
696	38M125TQM	Rotary	Roots	23,000	22	1		23
698	56M175TQM	Rotary	Dresser/Roots	56,000	1			1
702	RT18	Turbine	Rockwell	38,000	1			1
703	RT18	Turbine	Rockwell	18,000	35		4	31
708	RT60	Turbine	Rockwell	30,000	22		4	18
709	RT60	Turbine	Rockwell	60,000	11		6	5
711	T140	Turbine	Rockwell	60,000	1			1
713	T140	Turbine	Rockwell	60,000	2		1	1
714	T140	Turbine	Rockwell	140,000	1		1	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 2013

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	2			2
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	1	6		7
804	5M125e	Rotary	Dresser/Roots	5,000	1	7		8
805	7M125e	Rotary	Dresser/Roots	7,000	2	1		3
806	11M125e	Rotary	Dresser/Roots	11,000	1	3	1	3
813	3M175e	Rotary	Dresser/Roots	3,000	6	4		10
814	5M175e	Rotary	Dresser/Roots	5,000	3	6		9
815	7M175e	Rotary	Dresser/Roots	7,000	4	3		7
816	11M175e	Rotary	Dresser/Roots	11,000	4	3	1	6
817	16M175e	Rotary	Dresser/Roots	16,000	1	2	2	1
822	15c175TQMe	Rotary	Dresser/Roots	1,500	24	43		67
823	3M175TQMe	Rotary	Dresser/Roots	3,000	75	71		146
824	5M175TQMe	Rotary	Dresser/Roots	5,000	30	27		57
825	7M175TQMe	Rotary	Dresser/Roots	7,000	35	26		61
826	11M175TQMe	Rotary	Dresser/Roots	11,000	53	16		69
827	16M175TQMe	Rotary	Dresser/Roots	16,000	22	4		26
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				776,473	17,764	8,391	785,846

NORTHWEST NATURAL GAS COMPANY
CUSTOMER METERS
WASHINGTON 2013

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	6			6
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		2
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	5		2	3
93	RS38 ID	Rotary	Roots	38,000	1			1
120	R175	Diaphragm	Rockwell	175	3,011		33	2,978
125	R200	Diaphragm	Rockwell	200	778		40	738
130	A175	Diaphragm	American	175	3,715		34	3,681
140	S175	Diaphragm	Sprague	175	1,142		14	1,128
260	Misc.	Various	Various	Various	1			1
270	1000A	Diaphragm	Schlumberger	1,000	9		1	8
272	1000A	Diaphragm	Actaris	1,000	5		3	2
300	1600 ID	Diaphragm	Rockwell	800	1			1
310	RW3M ID	Diaphragm	Rockwell	1,450	1			1
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	19			19
400	2300 ID	Diaphragm	American	2,300	10			10
410	AL5M	Diaphragm	American	5,000	14		1	13
450	400A	Diaphragm	Schlumberger	400	149		1	148
452	400A	Diaphragm	Actaris	400	77		2	75
470	A425	Diaphragm	American	425	152		18	134
471	AL425	Diaphragm	American	425	262		2	260
472	A425	Diaphragm	American	425	231		20	211
475	AL-630	Diaphragm	American	630	509	173	4	678
480	A800 ID	Diaphragm	American	800	94	1	10	85
485	A800 TC ID	Diaphragm	American	800	74		20	54
486	A800	Diaphragm	American	800	3			3
500	AL1M ID	Diaphragm	American	1,000	45		2	43
502	AL 1000	Diaphragm	American	1,000	26			26
505	AL1M TC ID	Diaphragm	American	1,000	26		1	25
507	AL 1000	Diaphragm	American	1,000	321	52	2	371
510	R310	Diaphragm	Rockwell	310	179		28	151
515	R315	Diaphragm	Rockwell	315	7		1	6
520	R415	Diaphragm	Rockwell	415	327		46	281
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	57		9	48
545	R750 TC ID	Diaphragm	Rockwell	750	3			3
555	AL 310	Diaphragm	American	310	100		8	92
560	A250	Diaphragm	American	250	17,109		52	17,057
561	AC250	Diaphragm	American	250	14,561	2,446	350	16,657

NORTHWEST NATURAL GAS COMPANY
CUSTOMER METERS
WASHINGTON 2013

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	14,533		31	14,502
572	275	Diaphragm	Invensys	275	7,173		28	7,145
580	SPRM	D+Reg	Sprague	175	8			8
585	S250	Diaphragm	Sprague	250	3,773		46	3,727
590	S250	Diaphragm	Lancaster	250	2,852		23	2,829
595	METRIS 250	Diaphragm	Schlumberger	250	2,032		19	2,013
613	8C	Rotary	Roots	800	1			1
616	8C175TQM	Rotory	Dresser/Roots	800	5			5
617	8C175TQM	Rotary	Dresser/Roots	800	7	1		8
622	1.5M	Rotary	Roots	1,500	19		3	16
623	1.5M	Rotary	Roots	1,500	1			1
625	15C175TQM	Rotary	Dresser/Roots	1,500	18	2		20
626	15CTQM	Rotary	Roots	1,500	55	1		56
632	3M	Rotary	Roots	3,000	33			33
633	RS3M	Rotary	Roots	3,000	12			12
636	5M175TQM	Rotary	Roots	3,000	96	1		97
637	3M175TQM	Rotary	Dresser/Roots	3,000	64			64
642	5M	Rotary	Roots	5,000	28			28
643	RS5M TC	Rotary	Roots	5,000	12			12
644	3M175TQS	Rotary	Roots	5,000	13			13
646	5M175TQM	Rotary	Roots	5,000	65	1		66
647	5M175TQM	Rotary	Dresser/Roots	5,000	45	1		46
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	29			29
696	38M125TQM	Rotary	Roots	38,000	8			8
803	3M125e	Rotary	Dresser/Roots	3,000	1			1
805	7M125e	Rotary	Dresser/Roots	7,000	1			1
814	5M175e	Rotary	Dresser/Roots	5,000	0	1		1
822	15c175TQMe	Rotary	Dresser/Roots	1,500	3	7		10
823	3M175TQMe	Rotary	Dresser/Roots	3,000	7	6		13
824	5M175TQMe	Rotary	Dresser/Roots	5,000	2	2		4
825	7M175TQMe	Rotary	Dresser/Roots	7,000	4	4		8
826	11M175TQMe	Rotary	Dresser/Roots	11,000	2	2		4
827	16M175TQMe	Rotary	Dresser/Roots	16,000	1			1
	TOTALS				74,244	2,702	854	76,092

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, 2013

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 (a)	Ref. Page No. (b)	Amount of Dth (c)
1	Name of System		
2	**GAS RECEIVED**		
3	Gas Purchases (Accounts 800-805)		
4	Gas of Others Received for Gathering (Account 489.1)		9,024,562
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	1,885,061
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.?)		10,909,623
16	**GAS DELIVERED**		
17	Gas Sales (Accounts 480-484)		7,202,026
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	1,885,061
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		92,512
28	Total Deliveries (Total of lines 17 thru 27)		9,179,599
29	**GAS UNACCOUNTED FOR**		
30	Production System Losses		
31	Gathering System Losses		
32	Transmission System Losses		
33	Distribution System Losses		1,730,024
34	Storage System Losses		
35	Other Losses (Specify)		
36	Total Unaccounted for (Total of lines 30 thru 35)		1,730,024
37	Total Deliveries & Unaccounted for (Total of lines 28 and 36)		10,909,623

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, 2013

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	513,500	921.1	N/A	7%	Market Adj. + Perf
2	David H. Anderson*	385,833	921.1	N/A	5%	Promotion
3	Stephen P. Feltz**	284,500	921.1	N/A	23%	Promotion
4	Margaret D. Kirkpatrick	292,500	921.1	N/A	3%	Market Adj. + Perf
5	Lea Anne Doolittle	266,667	921.1	N/A	3%	Market Adj. + Perf
6	J. Keith White	241,833	921.1	N/A	3%	Market Adj. + Perf
7	David R. Williams	227,833	921.1	N/A	3%	Market Adj. + Perf
8	Grant M. Yoshihara	227,833	921.1	N/A	3%	Market Adj. + Perf
9	C. Alex Miller***	208,333	921.1	N/A	7%	Promotion
10	MardiLyn Saathoff	231,667	921.1	N/A	8%	Market Adj. + Perf
11	Brody J. Wilson****	162,280	921.1	N/A	NA	Promotion

(1) Salary amounts do not include bonuses paid to executives

*Promoted to Executive Vice President Operations and Regulation effective 2/28/2013
**Promoted to Senior Vice President and Chief Financial Officer effective 2/28/2013
***Promoted to Treasurer and retains Vice President of Regulation position effective 2/28/2013
****Promoted to Controller effective 9/26/2013

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	469	42,349,482
11	Bargaining Unit	612	39,231,144
13	Total	1,081	81,580,626

(2) Salaries and wages do not include bonuses paid

NORTHWEST NATURAL GAS COMPANY

Oregon Supplement to FERC Form 2

December 31, 2013

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

INDEX

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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, 2013

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

Name of Respondent	This Report is:	Date of Report	Year of Report
	(1) X An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) A Resubmission		Dec. 31, 2013

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	401,953,956	390,070,669
3	481 Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 6)	198,974,681	194,447,348
5	Large (or Ind.) (See instr. 6)	50,683,694	51,583,260
6	482 Other Sales to Public Authorities		
7	484 Interdepartmental Sales		
8	TOTAL Sales to Ultimate Consumers	651,612,331	636,101,277
9	483 Sales for Resale		
10	TOTAL Nat. Gas Service Revenues	651,612,331	636,101,277
11	Revenues from Manufactured Gas		
12	TOTAL Gas Service Revenues	651,612,331	636,101,277
13	OTHER OPERATING REVENUES		
14	485 Intercompany Transfers		
15	487 Late Payment Charge	2,176,550	2,350,603
16	488 Misc. Service Revenues	1,294,879	1,382,129
17	489 Rev. From Trans. of Gas of Others	14,083,276	14,011,260
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	261,068	260,731
22	494 Interdepartmental Rents		
23	495 Other Gas Revenues	2,767,272	(5,768,029)
24	TOTAL Other Operating Revenues	20,583,045	12,236,694
25	TOTAL Gas Operating Revenues	672,195,376	648,337,971
26	(Less) 496 Provision for Rate Refunds		
27	TOTAL Gas Operating Revenues Net of Provision for refund	672,195,376	648,337,971
28	Dist. Type Sales by State (Incl. Main Line Sales to Resid. and Comm. Custrs.)	600,928,637	584,518,017
29	Main Line Industrial Sales (Incl. Main Line Sales to Pub. Authorities)	50,683,694	51,583,260
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))	651,612,331	636,101,277

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, 2013

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
37,129,903	35,123,723	558,775	553,497	2
				3
23,235,303	22,251,048	58,456	57,606	4
8,916,721	8,915,431	899	894	5
				6
				7
69,281,927	66,290,202	618,130	611,997	8
				9
69,281,927	66,290,202	618,130	611,997	10
				11
				12
				13
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69,281,927				27
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69,281,927				33

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
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STATE OF OREGON - INTERDEPARTMENTAL SALES - NATURAL GAS (Account 484

Report particulars concerning sales of natural gas included in Account 484

LINE NO.	DEPARTMENT AND BASIS OF CHARGES (a)	POINT OF DELIVERY (b)	MCF (14.73 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		161,732
	2. Other	Communication	99,336	
		Totals	99,336	161,732

Name of Respondent	This Report is:	Date of Report	Year of Report
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STATE OF OREGON - ALLOCATED GAS OPERATION AND MAINTENANCE EXPENSES

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		
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 Northwest Natural Gas Company	This Report is: X An Original A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 2013

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			
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9	**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, 2013

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		
65	TOTAL Exploration and Development (Total of lines 61 thru 64)	**INFORMATION NOT AVAILABLE**	
	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 Northwest Natural Gas Company	This Report is: X An Original A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 2013

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		
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 Northwest Natural Gas Company	This Report is: X An Original A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 2013

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		
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		

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, 2013

STATE OF OREGON - ALLOCATED GAS OPERATION AND MAINTENANCE EXPENSES

Line No.	Account (a)	Current Year (b)	Previous Year (c)
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		
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		
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		

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, 2013

STATE OF OREGON - ALLOCATED GAS OPERATION AND MAINTENANCE EXPENSES

Line No.	Account (a)	Current Year (b)	Previous Year (c)
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	INFORMATION NOT AVAILABLE	
256	(Less) 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	(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			
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, 2013

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	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2013

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

Line No.	KIND OF TAX (a)	AMOUNT (b)
	SEE FERC ANNUAL REPORT	
	TOTAL (Must agree with page 1, line 11)	

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, 2013

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	
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
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 (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2013

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	
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
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20		
21		
22		
23		
24		
25		
26		
27	State Tax Net Income	
28	Show Computation of Tax:	
	SEE FERC ANNUAL REPORT PAGE 262-C	

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, 2013

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 Northwest Natural Gas Company	This Report is: X An Original A Resubmission	Date of Repo (Mo, Da, Yr)	Year of Report Dec. 31, 2013

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					
AMOUNTS DEBITED ACCOUNT 410.2 (e)	AMOUNTS CREDITED ACCOUNT 411.2 (f)	DEBITS ACCT. NO. (g)	DEBITS AMOUNT (h)	CREDITS ACCT. NO. (i)	CREDITS 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
							22

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, 2013

STATE OF OREGON - ALLOCATED ACCUMULATED DEFERRED INCOME TAXES

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, 2013

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	AMOUNTS CREDITED ACCOUNT 411.2	ACCT. NO.	AMOUNT	ACCT. NO.	AMOUNT	BALANCE END OF YEAR	Line No.
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
							15
							16
							17
							18
							19
							20
							21

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, 2013

STATE OF OREGON - ALLOCATED ACCUMULATED DEFERRED INCOME TAXES

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, 2013

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					
		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

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, 2013

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	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2013

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
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							21
							22
							23

SEE FERC ANNUAL REPORT
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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, 2013

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	Year of Report
Northwest Natural Gas Company	(1) X An Original (2) A Resubmission	(Mo, Da, Yr)	Dec. 31, 2013

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 (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	(1) X An Original (2) A Resubmission		Dec. 31, 2013

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)	2,193,270,971		2,193,270,971			
4	Property Under Capital Leases						
5	Plant Purchased or Sold						
6	Completed Construction not Classified	167,595,160		167,595,160			
7	Experimental Plant Unclassified						
8	TOTAL (Enter total of lines 3 thru 7)	2,360,866,131		2,360,866,131			
9	Leased to Others						
10	Held for Future Use	264,641		264,641			
11	Construction Work in Progress	28,323,120		28,323,120			
12	Acquisition Adjustments						
13	TOTAL Utility Plant (Enter total of lines 8 thru 12)	2,389,453,892		2,389,453,892			
14	Accum. Prov. for Depr., Amort., & Depl.	1,033,769,502		1,033,769,502			
15	Net Utility Plant (Line 13 less 14)	1,355,684,390		1,355,684,390			
16	**DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION**						
17	In Service:						
18	Depreciation	914,536,914		914,536,914			
19	Amort. and Depl. of Producing Natural Gas Land and Land Rights			0			
20	Amort. of Underground Storage Land and Land Rights	19,815		19,815			
21	Amort. of Other Utility Plant	81,446,168		81,446,168			
21.01	Salvage Work In Progress	0		0			
21.02	Less Removal Work in Progress	10,187,147		10,187,147			
22	TOTAL in Service (Lines 18 thru 21)	985,815,750		985,815,750			
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)	985,815,750		985,815,750			

ACCOUNT SUMMARY BY FUNTIONAL CLASS
NW Natural

Period Beginning: Jan 2013
Period Ending: Dec 2013

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	58,637,842	5,974,935	0	(33,467)	0	64,579,309
303.2	CUSTOMER INFORMATION SYSTEM	29,970,901	517,403	0	0	0	30,488,305
303.3	INDUSTRIAL & COMMERCIAL BIL	4,146,951	0	0	0	0	4,146,951
303.4	CRMS	1,776,345	273,107	0	0	0	2,049,451
303.5	POWERPLANT SOFTWARE	0	0	0	0	0	0
	Intangible Plant Subtotal	94,616,387	6,765,445	0	(33,467)	0	101,348,365
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 2013
Period Ending: Dec 2013

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	6,715,064	0	0	0	0	6,715,064
352	WELLS	20,047,076	0	0	0	0	20,047,076
352.1	STORAGE LEASEHOLD & RIGHTS	3,538,491	0	0	0	0	3,538,491
352.2	RESERVOIRS	5,844,618	0	0	0	0	5,844,618
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	28,746,969	781,562	0	0	0	29,528,531
355	MEASURING / REGULATING EQUIPM	6,700,892	0	0	0	0	6,700,892
356	PURIFICATION EQUIPMENT	297,363	0	0	0	0	297,363
357	OTHER EQUIPMENT	1,331,924	0	0	0	0	1,331,924
	Natural Gas Underground Storage Subtotal	86,431,682	781,562	0	0	0	87,213,243
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	128,860	0	(22,303)	0	0	106,557
361.11	STRUCTURES & IMPROVEMENTS	4,540,966	0	0	0	0	4,540,966
361.12	STRUCTURES & IMPROVEMENTS	4,603,395	0	0	0	0	4,603,395
361.2	STRUCTURES & IMPROVEMENTS -	26,757	0	0	0	0	26,757
362.11	GAS HOLDERS - LNG LINNTON	2,690,579	0	0	0	0	2,690,579
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	2,912,136	9,828	0	0	0	2,921,964
363.12	LIQUEFACTION EQUIP - NEWPO	6,951,260	356,851	0	0	0	7,308,111
363.21	VAPORIZING EQUIP - LINNTON	2,629,836	0	0	0	0	2,629,836
363.22	VAPORIZING EQUIP - NEWPORT	3,594,015	0	0	0	0	3,594,015
363.31	COMPRESSOR EQUIP - LINNTON	180,903	0	0	0	0	180,903
363.32	COMPRESSOR EQUIPMENT - NE	300,951	0	0	0	0	300,951
363.41	MEASURING & REGULATING EQU	737,149	0	0	0	0	737,149
363.42	MEASURING & REGULATING EQU	113,414	0	0	0	0	113,414
363.5	CNG REFUELING FACILITIES	1,805,713	123,808	(141,692)	0	0	1,787,828
363.6	LNG REFUELING FACILITIES	739,473	0	0	0	0	739,473
	Local Storage Plant Subtotal	38,369,237	490,486	(163,995)	0	0	38,695,728

ACCOUNT SUMMARY BY FUNTIONAL CLASS
NW Natural

Period Beginning: Jan 2013
Period Ending: Dec 2013

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	72,343,223	47,556,700	0	1,102,308	0	121,002,232
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	34,880,570	771	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	3,863,162	106,389	0	0	0	3,969,550
370	COMMUNICATION EQUIPMENT	0	0	0	0	0	0
	Transmission Plant Subtotal	239,930,244	47,663,860	0	1,102,308	0	288,696,411
Distribution Plant							
374.1	LAND	76,386	0	0	0	0	76,386
374.2	LAND RIGHTS	1,835,351	13,382	0	0	0	1,848,733
375	STRUCTURES & IMPROVEMENTS	49,372	0	0	0	0	49,372
376.11	MAINS < 4"	444,575,092	12,937,518	(365,338)	(2,723,049)	0	454,424,224
376.12	MAINS 4" & >	403,177,351	8,004,405	(477,221)	1,215,712	0	411,920,247
377	COMPRESSOR STATION EQUIPMENT	818,380	151,562	0	0	0	969,942
378	MEASURING & REG EQUIP - GENER	24,203,400	3,352,532	0	(6,620)	0	27,549,313
379	MEASURING & REG EQUIP - GATE	1,282,221	2,007,100	0	0	0	3,289,321
380	SERVICES	580,212,245	22,023,745	(1,669,103)	0	0	600,566,888
381	METERS	67,222,721	2,903,738	(829,737)	0	0	69,296,722
381.1	METERS (ELECTRONIC)	1,788,497	127,112	0	0	0	1,915,609
381.2	ERT (ENCODER RECEIVER TRANS	29,572,249	1,153,255	(447,304)	0	0	30,278,200
382	METER INSTALLATIONS	55,501,434	2,337,213	(2,050,533)	0	0	55,788,114
382.1	METER INSTALLATIONS (ELECTR	625,193	374,204	0	0	0	999,397
382.2	ERT INSTALLATION (ENCODER	8,819,857	0	(94,750)	0	0	8,725,108
383	HOUSE REGULATORS	739,947	339,403	0	0	0	1,079,350
386	OTHER PROPERTY ON CUSTOMERS P	0	0	0	0	0	0
387.1	CATHODIC PROTECTION TESTING	154,483	19,376	0	0	0	173,859

ACCOUNT SUMMARY BY FUNTIONAL CLASS
NW Natural

Period Beginning: Jan 2013
Period Ending: Dec 2013

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	1,620,796,645	55,744,546	(5,933,985)	(1,513,957)	0	1,669,093,250
General Plant							
389	LAND	9,280,364	497,129	(168,218)	0	0	9,609,274
390	STRUCTURES & IMPROVEMENTS	33,884,492	15,836,090	(4,402,376)	0	0	45,318,207
390.1	SOURCE CONTROL FACILITY	0	20,942,177	0	0	0	20,942,177
391.1	OFFICE FURNITURE & EQUIPMEN	11,234,258	970,665	(9,497)	(5,183)	0	12,190,243
391.2	COMPUTERS	18,807,546	2,658,917	(1,131,638)	38,650	0	20,373,475
391.3	ON SITE BILLING	938,788	0	0	0	0	938,788
391.4	CUSTOMER INFORMATION SYSTEM	1,308,391	0	0	0	0	1,308,391
392	TRANSPORTATION EQUIPMENT	26,710,991	3,039,049	(1,804,698)	0	0	27,945,343
393	STORES EQUIPMENT	119,406	0	0	0	0	119,406
394	TOOLS - SHOP & GARAGE EQUIPUI	15,237,718	945,553	(320,346)	0	0	15,862,925
395	LABORATORY EQUIPMENT	68,293	0	0	0	0	68,293
396	POWER OPERATED EQUIPMENT	7,458,117	1,306,156	(472,890)	0	0	8,291,382
397	GEN PLANT-COMMUNICATION EQU	98,549	0	0	0	0	98,549
397.1	MOBILE	1,295,887	0	0	0	0	1,295,887
397.2	OTHER THAN MOBILE & TELEMET	1,759,910	9,958	0	0	0	1,769,868
397.3	TELEMETERING - OTHER	4,142,742	194,509	0	0	0	4,337,251
397.4	TELEMETERING - MICROWAVE	2,056,551	177,220	0	0	0	2,233,771
397.5	TELEPHONE EQUIPMENT	2,207,512	3,579	0	0	0	2,211,091
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	61,420	0	0	0	0	61,420
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	136,839,127	46,581,002	(8,309,662)	33,467	0	175,143,934
	Oregon Utility Property Grand Total	$2,217,658,520	$158,026,901	($14,407,642)	($411,649)	$0	$2,360,866,130

ACCOUNT SUMMARY BY FUNTIONAL CLASS
NW Natural

Period Beginning: Jan 2013
Period Ending: Dec 2013

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	0	4,989,436
353	LINES	1,649,744	0	0	0	0	1,649,744
354	COMPRESSOR STATION EQUIPMENT	14,629,173	758,547	(700,000)	0	0	14,687,720
355	MEASURING / REGULATING EQUIPM	8,662,242	65,588	0	0	0	8,727,830
357	OTHER EQUIPMENT	63,256	0	0	0	0	63,256
Non Utility	Natural Gas Underground Storage Subtotal	46,935,323	824,134	(700,000)	0	0	47,059,457
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	111,719	0	0	0	0	111,719
Non Utility	General Plant Subtotal	550,458	0	0	0	0	550,458
Non Utility Other							
121.1	NON-UTIL PROP-DOCK	1,956,033	0	(10,000)	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 2013
Period Ending: Dec 2013

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	0	0	0	288,112
Non Utility	Other	5,046,673	0	(10,000)	0	0	5,036,673
	Oregon Non Utility Property Grand Total	$61,359,312	$824,134	($710,000)	$0	$0	$61,473,446

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, 2013

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				
6				
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39				
40	TOTALS			264,641

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, 2013

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	Misc Mains and Service Jobs	9,146,420	3,310,124
2	Mist Underground Storage	8,407,852	3,682,557
3	Other Projects:		
4	Misc IS Projects	5,772,479	4,859,869
5	Newport LNG Readiness	592,602	4,203,874
6	Sherwood Building	55,778	2,473,675
7	Sherwood CNG	1,336,432	97,999
8	Salem Retrofit	506,588	8,418,424
9	Other Projects	2,356,289	3,443,191
10	South of Monmouth Bare Steel	148,680	9,700,000
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45	**Total**	28,323,120	40,189,713

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS
NW Natural

Period Beginning: Jan 2013
Period Ending: Dec 2013

Functional Class / FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve
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	30,216,322	2,429,357	0	0	0	288	0	32,645,967
303.2	CUSTOMER INFORMATION SYSTEM	29,142,946	1,342,149	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	1,441,608	144,819	0	0	0	0	0	1,586,428
303.5	POWERPLANT SOFTWARE	0	0		0	0	0	0	0
	Intangible Plant Subtotal	64,947,828	3,916,325	0	0	0	288	0	68,864,441
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
Natural Gas Underground Storage									
350.1	LAND	0	0	0	0	0	0	0	0
350.2	RIGHTS-OF-WAY	19,815	1,776	0	0	0	0	0	21,591

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS
NW Natural

Period Beginning: Jan 2013
Period Ending: Dec 2013

Functional Class FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve
351	STRUCTURES AND IMPROVEMENTS	2,185,725	114,828	0	0	0	0	0	2,300,553
352	WELLS	9,730,639	414,974	0	0	0	0	0	10,145,614
352.1	STORAGE LEASEHOLD & RIGHTS	1,299,739	69,001	0	0	0	0	0	1,368,740
352.2	RESERVOIRS	1,486,747	117,477	0	0	0	0	0	1,604,224
352.3	NON-RECOVERABLE NATURAL GAS	2,835,441	121,089	0	0	0	0	0	2,956,530
353	LINES	2,501,213	134,992	0	0	0	0	0	2,636,205
354	COMPRESSOR STATION EQUIPMENT	13,958,664	781,250	0	0	0	0	0	14,739,914
355	MEASURING / REGULATING EQUIPM	3,661,839	145,424	0	0	0	0	0	3,807,263
356	PURIFICATION EQUIPMENT	195,572	7,375	0	0	0	0	0	202,947
357	OTHER EQUIPMENT	705,911	30,368	0	0	0	0	0	736,279
	Natural Gas Underground Storage Subtotal	38,581,306	1,938,552	0	0	0	0	0	40,519,859
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	1,189,931	246,717	0	0	0	0	0	1,436,648
361.12	STRUCTURES & IMPROVEMENTS	1,967,578	141,623	0	0	0	0	0	2,109,201
361.2	STRUCTURES & IMPROVEMENTS -	9,097	466	0	0	0	0	0	9,562
362.11	GAS HOLDERS - LNG LINNTON	2,072,668	63,229	0	0	0	0	0	2,135,896
362.12	GAS HOLDERS - LNG NEWPORT	4,965,952	157,541	0	0	0	0	0	5,123,493
362.2	GAS HOLDERS - LNG OTHER	1,109	21	0	0	0	0	0	1,130
363.11	LIQUEFACTION EQUIP. - LINN	2,297,431	84,091	0	0	0	0	0	2,381,522
363.12	LIQUEFACTION EQUIP - NEWPO	6,950,208	57,619	0	0	0	0	0	7,007,827
363.21	VAPORIZING EQUIP - LINNTON	2,514,224	36,821	0	0	0	0	0	2,551,046
363.22	VAPORIZING EQUIP - NEWPORT	2,606,816	1,050	0	0	0	0	0	2,607,866
363.31	COMPRESSOR EQUIP - LINNTON	184,247	12,845	0	0	0	0	0	197,092
363.32	COMPRESSOR EQUIPMENT - NE	191,283	14,175	0	0	0	0	0	205,458
363.41	MEASURING & REGULATING EQU	597,210	295	0	0	0	0	0	597,505
363.42	MEASURING & REGULATING EQU	115,812	828	0	0	0	0	0	116,640
363.5	CNG REFUELING FACILITIES	1,724,915	1,733	(141,692)	0	0	0	0	1,584,955
363.6	LNG REFUELING FACILITIES	739,473	0	0	0	0	0	0	739,473
	Local Storage Plant Subtotal	28,127,953	819,054	(141,692)	0	0	0	0	28,805,314
Transmission Plant									
365.1	LAND	0	0	0	0	0	0	0	0
365.2	LAND RIGHTS	1,398,320	122,003	0	0	0	0	0	1,520,323
366.3	STRUCTURES & IMPROVEMENTS -	216,010	20,319	0	0	0	0	0	236,329
367	MAINS	12,191,566	2,602,133	0	0	0	84,891	0	14,878,590
367.21	NORTH MIST TRANSMISSION LI	879,636	50,081	0	0	0	0	0	929,716
367.22	SOUTH MIST TRANSMISSION LI	8,830,433	367,878	0	0	0	0	0	9,198,311

Period Beginning: Jan 2013
Period Ending: Dec 2013

Functional Class FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve
367.23	SOUTH MIST TRANSMISSION LI	9,032,265	931,626	0	0	0	0	0	9,963,892
367.24	11.7M S MIST TRANS LINE	3,462,573	452,505	0	0	0	0	0	3,915,077
367.25	12M NORTH S MIST TRANS	3,364,205	485,973	0	0	0	0	0	3,850,178
367.26	38M NORTH S MIST TRANS	12,551,722	1,774,624	0	0	0	0	0	14,326,346
368	TRANSMISSION COMPRESSOR	(9)	0	0	0	0	0	0	(9)
369	MEASURING & REGULATE STATION	1,021,059	104,801	0	0	0	0	0	1,125,860
370	COMMUNICATION EQUIPMENT	0	0	0	0	0	0	0	0
	Transmission Plant Subtotal	52,947,782	6,911,942	0	0	0	84,891	0	59,944,615
Distribution Plant									
374.1	LAND	0	0	0	0	0	0	0	0
374.2	LAND RIGHTS	844,710	137,963	0	0	0	0	0	982,673
375	STRUCTURES & IMPROVEMENTS	48,923	200	0	0	0	0	0	49,123
376.11	MAINS < 4"	235,234,539	11,193,618	(365,338)	(1,094,981)	14,186	(198,230)	0	244,783,794
376.12	MAINS 4" & >	154,101,491	9,880,193	(477,221)	(571,047)	27,246	101,813	0	163,062,475
377	COMPRESSOR STATION EQUIPMENT	554,124	20,944	0	0	0	0	0	575,068
378	MEASURING & REG EQUIP - GENER	8,552,874	538,883	0	0	0	(758)	0	9,090,999
379	MEASURING & REG EQUIP - GATE	721,051	77,551	0	0	0	0	0	798,602
380	SERVICES	308,824,376	15,971,436	(1,669,103)	(2,237,296)	0	0	0	320,889,413
381	METERS	16,587,273	1,577,762	(829,737)	0	0	0	0	17,335,298
381.1	METERS (ELECTRONIC)	639,808	263,948	0	0	0	0	0	903,756
381.2	ERT (ENCODER RECEIVER TRANS	8,090,286	1,974,925	(447,304)	0	0	0	0	9,617,907
382	METER INSTALLATIONS	11,654,626	1,322,975	(2,050,533)	0	0	0	0	10,927,068
382.1	METER INSTALLATIONS (ELECTR	525,783	10,148	0	0	0	0	0	535,931
382.2	ERT INSTALLATION (ENCODER	2,403,743	584,093	(94,750)	0	0	0	0	2,893,087
383	HOUSE REGULATORS	62,150	29,373	0	0	0	0	0	91,523
386	OTHER PROPERTY ON CUSTOMERS P	0	0	0	0	0	0	0	0
387.1	CATHODIC PROTECTION TESTING	139,055	129	0	0	0	0	0	139,184
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	749,127,277	43,584,142	(5,933,985)	(3,903,324)	41,432	(97,175)	0	782,818,367
General Plant									
389	LAND	437,351	0	0	0	0	0	0	437,351
390	STRUCTURES & IMPROVEMENTS	8,233,029	407,980	(2,210,278)	0	0	0	0	6,430,732
390.1	SOURCE CONTROL FACILITY	0	227,793	0	0	0	0	0	227,793
391.1	OFFICE FURNITURE & EQUIPMEN	6,924,359	900,555	(9,497)	0	0	(288)	0	7,815,129
391.2	COMPUTERS	14,775,421	3,251,736	(1,131,638)	0	0	0	0	16,895,519
391.3	ON SITE BILLING	938,788	0	0	0	0	0	0	938,788
391.4	CUSTOMER INFORMATION SYSTEM	878,210	261,678	0	0	0	0	0	1,139,888
392	TRANSPORTATION EQUIPMENT	8,343,229	1,365,017	(1,804,698)	0	150,375	0	0	8,053,923
393	STORES EQUIPMENT	119,406	0	0	0	0	0	0	119,406

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS
NW Natural

Period Beginning: Jan 2013
Period Ending: Dec 2013

Functional Class FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve
394	TOOLS - SHOP & GARAGE EQUIPUI	7,230,242	1,079,161	(320,346)	0	24,773	0	0	8,013,830
395	LABORATORY EQUIPMENT	68,293	0	0	0	0	0	0	68,293
396	POWER OPERATED EQUIPMENT	3,517,933	167,899	(472,890)	0	214,520	0	0	3,427,461
397	GEN PLANT-COMMUNICATION EQU	16,281	7,302	0	0	0	0	0	23,584
397.1	MOBILE	1,204,495	8,812	0	0	0	0	0	1,213,307
397.2	OTHER THAN MOBILE & TELEMET	1,667,266	75,555	0	0	0	0	0	1,742,821
397.3	TELEMETERING - OTHER	3,080,644	2,940	0	0	0	0	0	3,083,584
397.4	TELEMETERING - MICROWAVE	1,904,042	23,078	0	0	0	0	0	1,927,120
397.5	TELEPHONE EQUIPMENT	2,068,561	24,948	0	0	0	0	0	2,093,509
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	1,510	525	0	0	0	0	0	2,036
398.3	JANITORIAL EQUIPMENT	15,274	1,908	0	0	0	0	0	17,183
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	61,579,715	7,806,887	(5,949,346)	0	389,667	(288)	0	63,826,635
	Utility Property Grand Total	$996,002,897	$64,976,902	($12,025,023)	($3,903,324)	$431,099	($12,285)	$0	$1,045,470,266

NON UTILITY

Functional Class FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve
Intangible Plant									
303.1	COMPUTER SOFWARE	$17,130	$7,041	$0	$0	$0	$0	$0	24,171
303.2	CUSTOMER INFORMATION SYSTEM	25,126	4,275	0	0	0	0	0	29,401
Non Utility	Intangible Plant Subtotal	42,256	11,316	0	0	0	0	0	53,572
Natural Gas Underground Storage									
352	WELLS	2,196,536	350,667	0	0	0	0	0	2,547,203
352.1	STORAGE LEASEHOLD & RIGHTS	122	20	0	0	0	0	0	141
352.2	RESERVOIRS	844,556	97,294	0	0	0	0	0	941,850
353	LINES	219,282	33,993	0	0	0	0	0	253,275
354	COMPRESSOR STATION EQUIPMENT	3,969,922	389,285	(700,000)	0	0	0	0	3,659,207
355	MEASURING / REGULATING EQUIPM	1,313,443	189,161	0	0	0	0	0	1,502,604
357	OTHER EQUIPMENT	4,387	1,442	0	0	0	0	0	5,829
Non Utility	Natural Gas Underground Storage Subtotal	8,548,248	1,061,862	(700,000)	0	0	0	0	8,910,110

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS
NW Natural

Period Beginning: Jan 2013
Period Ending: Dec 2013

Functional Class / FERC Plant Account		Beginning Reserve	Provision	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Loss/(Gain)	Ending Reserve
Transmission Plant									
368	TRANSMISSION COMPRESSOR	1,132,556	238,655	0	0	0	0	0	1,371,211
Non Utility	Transmission Plant Subtotal	1,132,556	238,655	0	0	0	0	0	1,371,211
Distribution Plant									
376.12	MAINS 4" & >	129,432	21,270	0	0	0	0	0	150,702
Non Utility	Distribution Plant Subtotal	129,432	21,270	0	0	0	0	0	150,702
General Plant									
389	LAND	0	0	0	0	0	0	0	0
390	STRUCTURES & IMPROVEMENTS	17,637	2,033	0	0	0	0	0	19,670
Non Utility	General Plant Subtotal	17,637	2,033	0	0	0	0	0	19,670
Non Utility Other									
121.1	NON-UTIL PROP-DOCK	1,879,228	41,441	(10,000)	0	0	0	0	1,910,669
121.2	NON-UTIL PROP-LAND	0	0	0	0	0	0	0	0
121.3	NON-UTIL PROP-OIL ST	2,204,774	3,360	0	0	0	0	0	2,208,134
121.7	NON-UTIL PROP-APPL CENTER	17,385	4,219	0	0	0	0	0	21,604
121.8	NON-UTIL PROP-STORAGE	(1)	0	0	0	0	0	0	(1)
Non Utility	Other	4,101,384	49,021	(10,000)	0	0	0	0	4,140,405
	Non Utility Property Grand Total	$13,971,513	$1,384,157	($710,000)	$0	$0	$0	$0	$14,645,670

RESERVE BALANCES AND ACTIVITY BY FUNCTIONAL CLASS
NW Natural

Period Beginning: Jan 2013
Period Ending: Dec 2013

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 OREGON UTILITY DEPRECIATION RESERVES 12/31/2013									
OREGON									
108010	($25,794,457)								
108011	794,444,821								
108012	10,360,736								
108013	(2,302,772)								
108014	(217,889)								
108015	3,409,182								
108100	268,704,777								
108002	(3,390,863)								
108003	20,564								
108004	236,168								
108666	-								
SUBTOTAL		$1,045,470,266							
ADD:									
108001 REMOVAL WORK IN PROCESS		11,700,765							
TOTAL OREGON UTILITY DEPRECIATION		1,057,171,031							
TOTAL SUMMARY OREGON NON-UTILITY RESERVES DEPRECIATION									
122027	4,212,616								
122028	9,998,774								
122100	1,014,441								
122002	(50,896)								
122029	(530,297)								
122026	1,034								
TOTAL OREGON NON UTILITY DEPRECIATION		14,645,670							

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, 2013

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, 2013

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, 2013

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, 2013

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						
77	TOTAL Nat. Gas Storage & Proc. Plant	INFORMATION NOT AVAILABLE					
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, 2013

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, 2013

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)
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12	**INFORMATION NOT AVAILABLE**			
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49				
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, 2013

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)
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11	**INFORMATION NOT AVAILABLE**		
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44	TOTALS		

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, 2013

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				
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, 2013

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, 2013

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:

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

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

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

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

Column (g) - 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.

Column (h) - In some cases, two or more lines will be required to report a purchase, as when two or more rates are being paid under the same contract, or when purchases under the same rate schedule are charged to more than one account. If for such reasons the producer rate schedule or non-jurisdictional purchase contract appears on more than one line, enter a numerical code (selected by the respondent) in Column (h) to so indicate. Once established, the same numerical suffix is to be used for all subsequent-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).

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

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

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

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

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

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission	(Mo, Da, Yr)	Dec. 31, 2013

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			
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9			
10	**SEE FERC ANNUAL REPORT**		
11			
12			
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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, 2013

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						8
										9
										10
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										51

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, 2013

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		93,458	207,000			
9	Storage Plants		233,695	Included in the Cost of Inventory			
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25	TOTAL		327,153	207,000	0.63		

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, 2013

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		634,809
8	(c.) Gasoline Plants		
9	(d.) Transmission Line		
10	(e.) City Gate Under FERC Rate Schedules		66,764,362
11	(f.) LNG		
12	(g.) Other		
13	TOTAL, Gas Purchased (Enter Total of lines 7 thru 13)		67,399,171
14	Gas of Others Received for Transportation		36,193,546
15	Receipts of Respondents' Gas Transported or Compressed by Others		0
16	Exchange Gas Received		
17	Gas Withdrawn from Underground Storage	*	6,104,842
18	Gas Received from LNG Storage		325,836
19	Gas Received from LNG Processing		
20	Other Receipts (Specify)		
21	TOTAL Receipts (Enter Total of lines 2 thru 5, 13, and 14 thru 20)		110,023,395

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, 2013

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)
22	**GAS DELIVERED**		
23	Natural Gas Sales		
24	Field Sales		
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		
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		8,906,172
39	(ii) Other Distribution System Sales		59,695,204
40	TOTAL, Distribution System Sales (Lines 38 + 39)		68,601,376
41	Unbilled Therms		680,551
42	TOTAL SALES (Enter Total of lines 29, 36, 40, and 41)		69,281,927
43	Deliveries of Gas Transported or Compressed for:		
44	(a.) Other Interstate Pipeline Companies		
45	(b.) Others - Transportation		36,193,546
46	TOTAL, Gas Transported or Compressed for Others (Enter Total of lines 44 and 45)		36,193,546
47	Deliveries of Respondent's Gas for Trans. or Compression by Others		
48	Exchange Gas Delivered		
49	Natural Gas Used by Respondent		-
50	Natural Gas Delivered to Underground Storage	*	4,435,908
51	Natural Gas Delivered to LNG Storage		276,192
52	Natural Gas Delivered to LNG Processing	331	327,153
53	Natural Gas for Franchise Requirements		
54	Other Deliveries (Specify): FIK		
55	TOTAL SALES & OTHER DELIVERIES (Lines 42, 46, 47 thru 54)		110,514,726
56	**UNACCOUNTED FOR**		
57	Production System Losses		
58	Storage Losses: Mist Gas Loss		
59	Transmission System Losses		0
60	Distribution System Losses		(491,331)
61	Other Losses (Leakage)		
62	TOTAL Unaccounted for (Enter Total of lines 57 thru 61)		(491,331)
63	TOTAL SALES, OTHER DELIVERIES, AND UNACCOUNTED FOR (Enter Total of lines 55 and 62)		110,023,395

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, 2013
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			

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, 2013

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 (Mo, Da, Yr)	Year of Report
Northwest Natural Gas Company	X An Original A Resubmission		Dec. 31, 2013

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	AOI PAC	426-04935	5,000
2	CITIZENS FOR HILLSBORO SCHOOLS	426-04935	1,000
3	CITIZENS FOR SCHOOL SUPPORT	426-04935	5,000
4	CITIZENS FOR SCHOOLS	426-04935	2,500
5	COMMITTEE FOR SAFE	426-04935	10,000
6	NATIONAL CONFERENCE OF STATE LEGISL	426-04935	5,000
7	OTHER < $1,000	426-04935	10,068
8	Total 426-04935	Total	38,568
9			
10			
11	NATURAL GAS POLITICAL COMMITTEE	426-04955	130,000
12	Total 426-04955	Total	130,000
13			
14			
15	INTERNAL LOBBY AND INTERNAL RESOURCES	426-04950	273,062
16	GROW OREGON	426-04950	15,000
17	OTHER < $1,000	426-04950	623
18	Total 426-04950	Total	288,685
19			
20			
21			
22			
23		Total	457,253

Name of Respondent	This Report Is:	Date of Report	Year of Report
	(1) X An Original	(Mo, Da, Yr)	
Northwest Natural Gas Company	(2) A Resubmission		Dec. 31, 2013

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, 2012			
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 & 922-02476	365,561	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	-	N/A
10	State income tax expense (benefit) - see FERC Form 2 p. 263C	409-43145	-	N/A
11	**Total of transactions with affiliated party**		365,561	
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	166,857,570	N/A
17	Shared Services Agreement - see FERC Form 2 p. 358	421-61505, 421-61510,	26,392	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	-	N/A
20	**State income tax expense (benefit) - see FERC Form 2 p. 263C**	409-49002	-	N/A
21	Total of transactions with affiliated party		166,883,962	
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	421-61505, 421-61510,	277,154	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	-	N/A
28	**State income tax expense (benefit) - see FERC Form 2 p. 263C**	409-44002	-	N/A
29	Total of transactions with affiliated party		277,154	
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	884,474	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	-	N/A
37	**State income tax expense (benefit) - see FERC Form 2 p. 263C**	409-23145	-	N/A
38	Total of transactions with affiliated party		1,108,732	
39				
40	Name of Affiliated Party: Northwest Biogas, LLC			
41	**NW Biogas LLC Investment**	123.1	150,000	N/A
42	**Total of transactions with affiliated party**		150,000	
43				
44	Name of Affiliated Party: Northwest Energy Corporation			
45	**Northwest Energy Corp Investment**	123.1	145,742,716	N/A
46	Total of transactions with affiliated party		145,742,716	
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	159,759	N/A
51	Total of transactions with affiliated party		159,759	
52				
53	**Total of transactions with all affiliated parties**		314,687,884	N/A

NORTHWEST NATURAL
DONATIONS FOR THE YEAR ENDED DECEMBER 31, 2013

DESCRIPTION		AMOUNT ASSIGNED TO OREGON	AMOUNT ASSIGNED TO WASHINGTON
UNITED WAY OF THE COLUMBIA-WILLAMETTE	$	121,400.00	20,000.00
OREGON COMMUNITY FOUNDATION		74,433.00	
FRESHWATER TRUST		70,000.00	
CAMP FIRE USA		37,411.00	
BIG BROTHERS BIG SISTERS NORTHWEST		36,072.00	
ENVIRONMENTAL FEDERATION OF OREGON		26,000.00	
WORK FOR ART		24,000.00	
DUCK ATHLETIC FUND		22,898.00	
OREGON ZOO FOUNDATION		22,500.00	
AMERICAN RED CROSS-OREGON TRAIL CHAPTEF		17,500.00	2,000.00
OREGON FOOD BANK INC		17,200.00	
SELF ENHANCEMENT INC		16,000.00	
FRIENDS OF THE MOUNTED PATROL		15,985.00	
BLACK UNITED FUND		15,700.00	
PORTLAND CENTER STAGE		15,000.00	
OREGON STATE UNIVERSITY FOUNDATION		14,400.00	
URBAN LEAGUE OF PORTLAND		14,000.00	
MERCY CORPS INTERNATIONAL		12,000.00	
BLANCHET HOUSE OR HOSPITALITY		11,000.00	
PORTLAND COMMUNITY COLLEGE FOUNDATION		10,624.00	
AUDUBON SOCIETY OF PORTLAND		10,436.00	
FOREST PARK CONSERVANCY		10,300.00	
STAND FOR CHILDREN		10,300.00	
LIBRARY FOUNDATION		10,000.00	
LITERARY ARTS INC		10,000.00	
OREGON ALLIANCE OF INDEPENDENT COLLEGES		10,000.00	
OREGON SYMPHONY ASSOCIATION		10,000.00	
PORTLAND CLASSICAL CHINESE GARDEN		10,000.00	
PORTLAND OPERA ASSOCIATION INC		10,000.00	
VERNONIA SCHOOL DISTRICT		10,000.00	
CENTRAL CITY CONCERN		9,000.00	
GRANTMAKERS OF OREGON		8,719.00	
PSU FOUNDATION		8,250.00	
FRIENDS OF OUTDOOR SCHOOL		8,000.00	
LEGACY EMANUEL CHILDREN'S HOSPITAL		7,500.00	
SCHOOLHOUSE SUPPLIES INC		7,500.00	
VOLUNTEERS OF AMERICA		7,500.00	
DE LA SALLE NORTH CATHOLIC		7,313.00	
CASA FOR CHILDREN		6,685.00	
TUALATIN RIVERKEEPERS		6,500.00	
SMART		6,050.00	
LIFEWORKS NORTHWEST		6,011.00	
PORTLAND SCHOOLS FOUNDATION		6,000.00	
UNITED WAY OF COLUMBIA COUNTY		6,000.00	
UNITED WAY OF LINN COUNTY		6,000.00	
OREGON CHILDREN'S THEATRE		5,850.00	
MEDICAL TEAMS INTERNATIONAL		5,685.00	

NORTHWEST NATURAL
DONATIONS FOR THE YEAR ENDED DECEMBER 31, 2013

DESCRIPTION	AMOUNT ASSIGNED TO OREGON	AMOUNT ASSIGNED TO WASHINGTON
FRIENDS OF TREES	5,600.00	
UNIVERSITY OF OREGON FOUNDATION	5,574.00	
GUIDE DOGS FOR THE BLIND INC	5,500.00	
SOLV	5,500.00	
IMPACT NORTHWEST	5,185.00	
SHARE EMERGENCY HOUSING	2,000.00	3,185.00
OPEN MEADOW ALTERNATIVE SCHOOLS INC	5,168.00	
AMERICAN CANCER SOCIETY'S CAMP OF UKANDU	5,000.00	
ASSOCIATED OREGON INDUSTRIES FOUNDATION	5,000.00	
CASCADE AIDS PROJECT	5,000.00	
CASH OREGON	5,000.00	
CHILDREN'S CENTER OR CLACKAMAS	5,000.00	
CHILDREN'S INSTITUTE	5,000.00	
COMMUNITY ACTION OF WASHINGTON COUNTY	5,000.00	
COMMUNITY DEVELOPMENT CORPORATION OF C	5,000.00	
COMMUNITY TRANSITIONAL SCHOOL	5,000.00	
DRESS FOR SUCCESS OF OREGON INC	5,000.00	
FORT VANCOUVER NATIONAL TRUST		5,000.00
FRIENDS OF THE CHILDREN		5,000.00
I HAVE A DREAM OREGON FOUNDATION	5,000.00	
INCIGHT COMPANY	5,000.00	
JAPANESE GARDEN SOCIETY	5,000.00	
LOWER COLUMBIA RIVER ESTUARY PARTNERSHI	5,000.00	
NATURE CONSERVANCY	5,000.00	
OREGON HISTORICAL SOCIETY	5,000.00	
OREGON MUSEUM OF SCIENCE AND INDUSTRY	5,000.00	
PORTLAND ART MUSEUM	5,000.00	
SATURDAY ACADEMY	4,500.00	
JUNIOR ACHIEVEMENT	4,450.00	
BOYS AND GIRLS CLUB OF PORTLAND	4,000.00	
FORT VANCOUVER REGIONAL LIBRARY FOUNDATION		4,000.00
P:EARMENTOR	3,500.00	
UNITED WAY OF THE COLUMBIA GORGE	3,500.00	
BOYS AND GIRLS CLUB OF SALEM	3,000.00	
CASA OF LINN COUNTY	3,000.00	
OREGON BURN CENTER AT EMANUEL	3,000.00	
OREGON COLLEGE OF ORIENTAL MEDICINE	3,000.00	
OREGON PARTNERSHIP DBA LINES FOR LINE	3,000.00	
PORTLAND INSTITUTE FOR CONTEMPORARY ART	3,000.00	
UNITED WAY OF MID-WILLAMETTE	3,000.00	
COMMUNITY WAREHOUSE	2,750.00	
YWCA CLARK COUNTY		2,750.00
BASIC RIGHTS EDUCATION FUND	2,500.00	
BRADLEY-ANGLE HOUSE	2,500.00	
CATHOLIC CHARITIES	2500	
CHILDREN'S CHARITY GOLF TOURNAMENT	2,500.00	
COMMUNITY FOUNDATION FOR SOUTHWEST WASHINGTON		2,500.00

NORTHWEST NATURAL
DONATIONS FOR THE YEAR ENDED DECEMBER 31, 2013

DESCRIPTION	AMOUNT ASSIGNED TO OREGON	AMOUNT ASSIGNED TO WASHINGTON
DOUGY CENTER	2,500.00	
HABITAT FOR HUMANITY - WILLAMETTE WEST	2,500.00	
HUMAN ACCESS PROJECT	2,500.00	
JESUIT HIGH SCHOOL	2,500.00	
JEWISH FEDERATION OF GREATER PORTLAND	2,500.00	
JOIN: A CENTER FOR INVOLVEMENT	2,500.00	
MOLLY'S FUND FIGHTING LUPUS	2,500.00	
NAYA FAMILY CENTER	2,500.00	
OREGON AREA JEWISH COMMITTEE	2,500.00	
OREGON BALLET THEATRE	2,500.00	
OREGON HEALTH AND SCIENCE FOUNDATION	2,500.00	
OREGON MENTORS	2,500.00	
OREGON WWII MEMORIAL FOUNDATION	2,500.00	
PORTLAND FESTIVAL SYMPHONY	2,500.00	
PSU FOUNDATION - SCHOOL OF BUSINESS ADM	2,500.00	
PSU FOUNDATION - SIMON BENSON AWARDS	2,500.00	
REAP INC	2,500.00	
VIRGINIA GARCIA MEMORIAL FOUNDATION	2,500.00	
WASHINGTON GORGE ACTION PROGRAMS		2,500.00
WORDSTOCK	2,500.00	
FISH FOOD BANK	2,000.00	
FRIENDS OF THE RIDGEFIELD NATIONAL WILDLIF	2,000.00	
INNOVATION PARTNERSHIP	2,000.00	
MAYOR'S CHARITY BALL IN MCMINNVILLE	2,000.00	
NEIGHBORHOOD HOUSE INC	2,000.00	
NORTHWEST HOUSING ALTERNATIVES	2,000.00	
PSU FOUNDATION - SAIL	2,000.00	
RURAL DEVELOPMENT INITIATIVES INC	2,000.00	
SALEM-KEIZER EDUCATION FOUNDATION	2,000.00	
UNITED WAY OF BENTON AND LINCOLN COUNTIE	2,000.00	
CITIZENS CRIME COMMISSION	1,900.00	
OREGON HEAT	1,685.00	
FENCES FOR FIDO	1,600.00	
GIRLS INC OF NORTHWEST OREGON	1,600.00	
JAPAN-AMERICA SOCIETY OF OREGON	1,600.00	
OFFICE OF THE GOVERNOR	1,500.00	
PORTLAND PUBLIC SCHOOLS FOUNDATION	1,500.00	
SERENDIPITY CENTER INC	1,500.00	
SISTERS OF THE ROAD CAFE	1,500.00	
STREET ROOTS	1,500.00	
UNION GOSPEL MISSION	1,500.00	
YMCA OF COLUMBIA-WILLAMETTE	1,500.00	
UNITED WAY OF SOUTHWESTERN OREGON	1,400.00	
AMERICAN DIABETES ASSOCIATION	1,350.00	
SUNSHINE DIVISION	1,343.00	
TRAUMA INTERVENTION PROGRAM OF PORTLAN	1,343.00	
THEODORE ROOSEVELT WOMEN'S SCHOLARSHII	1,300.00	

NORTHWEST NATURAL
DONATIONS FOR THE YEAR ENDED DECEMBER 31, 2013

DESCRIPTION	AMOUNT ASSIGNED TO OREGON	AMOUNT ASSIGNED TO WASHINGTON
CONCORDIA UNIVERSITY FOUNDATION	1,250.00	0.00
GEORGE FOX UNIVERSITY	1,250.00	0.00
LEUKEMIA & LYMPHOA SOCIETY	1,200.00	0.00
WALK & KNOCK	-	1,200.00
OPEN ARMS INTERNATIONAL INC	1,013.00	0.00
1000 FRIENDS OF OREGON	1,000.00	0.00
ANIMAL AID INC	1,000.00	0.00
ASIAN AMERICAN YOUTH LEADERSHIP CONFERE	1,000.00	0.00
CAMPAIGN FOR EQUAL JUSTICE	1,000.00	0.00
CHILDREN'S ADVOCACY CENTER	1,000.00	0.00
CHILDREN'S TRUST FUND OF OREGON	1,000.00	0.00
DAVID DOUGLAS FOUNDATION	1,000.00	0.00
FAMILY BUILDING BLOCKS	1,000.00	0.00
FRIENDLY HOUSE INC	1,000.00	0.00
INNOVATIVE SERVICES NW	-	1,000.00
LEWIS & CLARK	1,000.00	0.00
LINCOLN COUNTY FOOD SHARE	1,000.00	0.00
MACDONALD CENTER	1,000.00	0.00
NEIGHBORS FOR KIDS	1,000.00	0.00
OUR MILITARY KIDS INC	1,000.00	0.00
REVOLUTION CHURCH	1,000.00	0.00
SMART IN THE SOUTH VALLEY	1,000.00	0.00
UNITED WAY OF CLATSOP COUNTY	1,000.00	0.00
UNITED WAY OF LANE COUNTY	1,000.00	0.00
VERNONIA EDUCATION FOUNDATION	1,000.00	0.00
VIETNAMESE COMMUNITY OF OREGON	1,000.00	0.00
Under 1K	34,567.00	2,042.00
Grand Total	$ 1,144,350.00	$ 51,177.00
Total of Donations > $1,000	1,109,783.00	49,135.00
Various Charities < $1,000	34,567.00	2,042.00
Total Donations	$ 1,144,350.00	$ 51,177.00

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, 2013

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	President and Chief Executive Officer	Gregg S. Kantor	513,500	513,500
2	Executive Vice President Operations and Regulation	David H. Anderson*	385,833	385,833
2	Senior Vice President and Chief Financial Officer	Stephen P. Feltz**	284,500	284,500
3	Senior Vice President and General Counsel	Margaret D. Kirkpatrick	292,500	292,500
4	Senior Vice President	Lea Anne Doolittle	266,667	266,667
5	Vice President	J. Keith White	241,833	241,833
6	Vice President	David R. Williams	227,833	227,833
7	Vice President	Grant M. Yoshihara	227,833	227,833
8	Vice President and Treasurer	C. Alex Miller***	208,333	208,333
9	Chief Governance Officer and Corp. Secretary	MardiLyn Saathoff	231,667	231,667
10	Controller	Brody J. Wilson****	162,280	162,280

*Promoted to Executive Vice President Operations and Regulation effective 2/28/2013
**Promoted to Senior Vice President and Chief Financial Officer effective 2/28/2013
***Promoted to Treasurer and retains Vice President of Regulation position effective 2/28/2013
****Promoted to Controller effective 9/26/2013

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, 2013

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 for 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 arrangement (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, 2013

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

Oregon Production Statistics (Dths)	
Gas Produced	
Gas Purchased	67,399,171
Total Receipts	67,399,171
Gas Sales	68,601,376
Gas Used by Company	327,153
Gas Delivered to LNG Storage - Net	(1,718,578)
Losses & billing Delay	189,220
Total Disbursements	67,399,171
Oregon Revenue by Service Class	
Residential	$ 404,236,581
Commercial & Industrial	
Firm	222,455,503
Interruptible	28,620,638
Transportation	14,083,276
Total	$ 669,395,998
Gas Sold in Therms (Oregon)	
Residential	371,299,035
Commercial & Industrial	
Firm	263,360,215
Interruptible	58,160,023
Transportation	361,935,461
Total	1,054,754,734
Average Number of Oregon Customers	
Residential	558,775
Commercial & Industrial	
Firm	58,985
Interruptible	137
Transportation	233
Total	618,130