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

AVU-E

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2014)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2014)
Form 3-Q Approved
OMB No.1902-0205
(Expires 05/31/2014)

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

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
Avista Corporation	**End of** 2012/Q4

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

IDENTIFICATION

01 Exact Legal Name of Respondent	02 Year/Period of Report
Avista Corporation	End of 2012/Q4

03 Previous Name and Date of Change *(if name changed during year)*

/ /

04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)*
1411 East Mission Avenue, Spokane, WA 99207

05 Name of Contact Person	06 Title of Contact Person
Christy Burmeister-Smith	VP, Controller, Prin. Acctg

07 Address of Contact Person *(Street, City, State, Zip Code)*
1411 East Mission Avenue, Spokane, WA 99207

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(509) 495-4256	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

01 Name	03 Signature	04 Date Signed *(Mo, Da, Yr)*
Christy Burmeister-Smith	Christy Burmeister-Smith	04/12/2013
02 Title VP, Controller, Prin. Acctg Officer		

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

LIST OF SCHEDULES (Electric Utility)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	N/A
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	N/A
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	N/A
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	N/A
24	Extraordinary Property Losses	230	N/A
25	Unrecovered Plant and Regulatory Study Costs	230	N/A
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254	
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	N/A
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Regional Transmission Service Revenues (Account 457.1)	302	N/A
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310-311	
46	Electric Operation and Maintenance Expenses	320-323	
47	Purchased Power	326-327	
48	Transmission of Electricity for Others	328-330	
49	Transmission of Electricity by ISO/RTOs	331	N/A
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant	336-337	
53	Regulatory Commission Expenses	350-351	
54	Research, Development and Demonstration Activities	352-353	
55	Distribution of Salaries and Wages	354-355	
56	Common Utility Plant and Expenses	356	
57	Amounts included in ISO/RTO Settlement Statements	397	N/A
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	N/A
61	Electric Energy Account	401	
62	Monthly Peaks and Output	401	
63	Steam Electric Generating Plant Statistics	402-403	
64	Hydroelectric Generating Plant Statistics	406-407	
65	Pumped Storage Generating Plant Statistics	408-409	N/A
66	Generating Plant Statistics Pages	410-411	

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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

Stockholders' Reports Check appropriate box:

[X] Two copies will be submitted

[ ] No annual report to stockholders is prepared

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

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.

C. Burmeister-Smith, Vice President, Controller, and Principal Accounting Officer
1411 E. Mission Avenue
Spokane, WA 99207

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

State of Washington, Incorporated March 15, 1889

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

Not Applicable

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

Electric service in the states of Washington, Idaho, and Montana
Natural gas service in the states of Wasington, Idaho, and Oregon

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Avista Capital, Inc.	Parent company to the	100	
2		Company's subsidiaries.		
3				
4	Ecova, Inc.	Provider of utility bill	78.96	Subsidiary of
5		processing, payment and		Avista Capital
6		information services to multi		
7		site customers in North Amer.		
8				
9				
10	Avista Development, Inc.	Maintains an investment	100	Subsidiary of
11		portfolio of real estate and		Avista Capital
12		other investments.		
13				
14	Avista Energy, Inc.	Inactive	100	Subsidiary of
15				Avista Capital
16				
17	Pentzer Corporation	Parent company of Bay Area	100	Subsidiary of
18		Manufacturing and Pentzer		Avista Capital
19		Venture Holdings.		
20				
21	Pentzer Venture Holdings	Inactive	100	Subsidiary of
22				Pentzer Corporation
23				
24	Bay Area Manufacturing	Holding Company	100	Subsidiary of
25				Pentzer Corporation
26				
27	Advanced Manufacturing and Development, Inc.	Performs custom sheet metal	82.95	Subsidiary of

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	dba Metalfx	manufacturing of electronic		Bay Area
2		enclosures, parts and systems		Manufacturing.
3		for the computer, telecom and		
4		medical industries. AM&D		
5		also has a wood products		
6		division.		
7				
8	Spokane Energy, LLC	Owns an electric capactiy	100	Affiliate of
9		contract.		Avista Corp.
10				
11	Avista Capital II	An affiliated business trust	100	Affliate of
12		formed by the Company.		Avista Corp.
13		Issued Pref. Trust Securities		
14				
15	Avista Northwest Resources, LLC	Formed in 2009 to own	100	Affiliate of
16		an interest in a venture		Avista Capital
17		fund investment		
18				
19	Steam Plant Square, LLC	Commercial office and retail	85	Affiliate of
20		leasing.		Avista Development
21				
22	Courtyard Office Center, LLC	Commercial office and retail	100	Affiliate of
23		leasing.		Avista Development
24				
25	Steam Plant Brew Pub, LLC	Restaurant operations	85	Affiliate of Steam
26				Plant Square, LLC
27				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	Chairman of the Board, President	S. L. Morris	
2	and Chief Executive Officer		
3			
4	Senior Vice President and Chief Financial Officer	M. T. Thies	
5			
6	Senior Vice President, General Counsel	M. M. Durkin	
7	and Chief Compliance Officer		
8			
9	Senior Vice President and Corporate Secretary	K. S. Feltes	
10	responsible for Human Resources		
11			
12	Senior Vice President and Environmental	D. P. Vermillion	
13	Compliance Officer		
14			
15	Vice President, Controller and	C. M. Burmeister-Smith	
16	Principal Accounting Officer		
17			
18	Vice President and Chief Information Officer	J. M. Kensok	
19			
20	Vice President, responsible for Energy Delivery	D. F. Kopczynski	
21	and Customer Service (effective 6/2012)		
22			
23	Vice President and Chief Counsel for Regulatory and	D. J. Meyer	
24	Governmental Affairs		
25			
26	Vice President, responsible for State and	K. O. Norwood	
27	Federal Regulations		
28			
29	Vice President and Chief Strategy Officer	R. D. Woodworth	
30			
31	Vice President, responsible for Customer Solutions	J. R. Thackston	
32	(effective 6/2012)		
33			
34	Treasurer	D. C. Thoren	
35			
36	Vice President, Energy Resources	R. L. Storro	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

DIRECTORS

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

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Scott L. Morris**	1411 E Mission Ave., Spokane, WA, 99202
2	(Chairman of the Board, President & CEO)	
3		
4	Erik J. Anderson	3720 Carillon Point, Kirkland, WA 98033
5		
6	Kristianne Blake***	P.O. Box 28338, Spokane, WA 99228
7		
8	Donald C. Burke	16 Ivy Court, Langhorne, PA 19047
9		
10	Rick R. Holley	999 Third Ave., Suite 4300, Seattle, WA 98104
11		
12	John F. Kelly***	P.O. Box 5782, Ketchum, ID 83340
13		
14	Michael L. Noel	11960 W. Six Shooter Rd., Prescott, AZ 86305
15		
16	Heidi B. Stanley	P.O. Box 2884, Spokane, WA 99220
17		
18	R. John Taylor***	111 Main Street, Lewiston, ID 83501
19		
20	Marc F. Racicot	28013 Swan Cove Dr., Big Fork, MT 59911
21		
22	Rebecca A. Klein	611 S. Congress Ave., Suite 125, Austin, TX 78704
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates?

[ ] Yes
[X] No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
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Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?	[ ] Yes [X] No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
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Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s).	Schedule	Column	Line No
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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

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

1. None
2. None
3. None
4. None
5. None
6. Avista Corp. has a committed line of credit with various financial institutions in the total amount of $400.0 million with an expiration date of February 2017. The committed line of credit is secured by non-transferable First Mortgage Bonds of the Company issued to the agent bank that would only become due and payable in the event, and then only to the extent, that the Company defaults on its obligations under the committed line of credit.

Balances outstanding under the Company's revolving committed line of credit were as follows as of December 31, 2012 and December 31, 2011 (dollars in thousands):

	December 31, 2012	December 31, 2011
Balance outstanding at end of period	$52,000	$61,000
Letters of credit outstanding at end of period	$35,885	$29,030

In June 2012, Avista Corp. entered into a bond purchase agreement with certain institutional investors in the private placement market for the purpose of issuing $80.0 million of 4.23 percent First Mortgage Bonds due in 2047. The new First Mortgage Bonds were issued under and in accordance with the Mortgage and Deed of Trust, dated as of June 1, 1939, from the Company to Citibank, N.A., trustee, as amended and supplemented by various supplemental indentures and other instruments. The issuance of the bonds occurred at closing in November 2012. The total net proceeds from the sale of the new bonds were used to repay a portion of the borrowings outstanding under the Company's $400.0 million committed line of credit and for general corporate purposes. The debt issuance was approved by regulatory commissions as follows:WUTC (Docket No. U-111176 Order 02) IPUC (Case No. AVU-U-11-01 Order No. 32338) and the OPUC (Docket UF 4269 Order No. 11-334).

7. On May 10, 2012, the shareholders of Avista Corp. approved an amendment of the Company's Restated Articles of Incorporation and Bylaws to reduce certain shareholder approval requirements to reduce the approval standards for shareholder voting to a "Majority of Votes Cast", where permissible under Washington law, and otherwise to be the lowest threshold permitted by Washington law.
8. Average annual wage increases were 2.4% for non-exempt employees effective February 27, 2012. Average annual wage increases were 2.7% for exempt employees effective February 27, 2012. Officers received average increases of 3.5% effective February 27, 2012. Certain bargaining unit employees received increases of 3.0% effective March 26, 2012.
9. Reference is made to Note 18 of the Notes to Financial Statements.
10. None
11. Reserved
12. See page 123 of this report.
13. Effective June 1, 2012, Avista Corp. appointed Don Kopczynski as Vice President of Operations and Jason Thackston as Vice President of Customer Solutions. Mr. Kopczynski was previously Vice President of Customer Solutions and Mr. Thackston was previously Vice President of Energy Delivery.

14. Proprietary capital is not less than 30 percent.

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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	4,044,184,930	3,876,924,839
3	Construction Work in Progress (107)	200-201	139,513,892	78,182,230
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		4,183,698,822	3,955,107,069
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	1,408,153,972	1,333,212,160
6	Net Utility Plant (Enter Total of line 4 less 5)		2,775,544,850	2,621,894,909
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		2,775,544,850	2,621,894,909
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		6,992,076	6,992,076
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		5,536,702	6,021,869
19	(Less) Accum. Prov. for Depr. and Amort. (122)		921,820	915,043
20	Investments in Associated Companies (123)		12,047,000	12,047,000
21	Investment in Subsidiary Companies (123.1)	224-225	118,714,423	71,971,368
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		16,439,055	18,889,385
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		9,154,874	13,288,292
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		1,092,593	184,929
31	Long-Term Portion of Derivative Assets – Hedges (176)		7,265,426	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		169,328,253	121,487,800
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		2,624,516	945,496
36	Special Deposits (132-134)		2,716,333	22,215,906
37	Working Fund (135)		799,065	861,010
38	Temporary Cash Investments (136)		251,390	60,913
39	Notes Receivable (141)		234,901	283,666
40	Customer Accounts Receivable (142)		159,703,153	173,557,636
41	Other Accounts Receivable (143)		5,188,679	7,943,467
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		4,653,167	4,498,489
43	Notes Receivable from Associated Companies (145)		314,682	0
44	Accounts Receivable from Assoc. Companies (146)		700,835	29,252
45	Fuel Stock (151)	227	4,120,767	4,248,389
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	23,875,397	21,746,205
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	0	0
55	Gas Stored Underground - Current (164.1)		17,276,287	23,609,470
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		16,090,480	16,554,560
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		31,981	85,059
60	Rents Receivable (172)		830,718	1,568,627
61	Accrued Utility Revenues (173)		0	0
62	Miscellaneous Current and Accrued Assets (174)		429,169	254,324
63	Derivative Instrument Assets (175)		5,231,375	1,323,663
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		1,092,593	184,929
65	Derivative Instrument Assets - Hedges (176)		7,265,426	32,408
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		7,265,426	0
67	Total Current and Accrued Assets (Lines 34 through 66)		234,673,968	270,636,633
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		13,532,890	14,332,877
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	559,831,454	524,250,326
73	Prelim. Survey and Investigation Charges (Electric) (183)		3,894,551	4,180,937
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		0	0
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	15,701,369	34,001,379
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		21,635,414	23,830,734
82	Accumulated Deferred Income Taxes (190)	234	148,425,469	153,408,420
83	Unrecovered Purchased Gas Costs (191)		-6,916,577	-12,140,283
84	Total Deferred Debits (lines 69 through 83)		756,104,570	741,864,390
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		3,942,643,717	3,762,875,808

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	end of 2012/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	863,316,222	832,413,930
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		0	0
7	Other Paid-In Capital (208-211)	253	10,942,942	11,686,949
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	-14,977,565	-11,086,811
11	Retained Earnings (215, 215.1, 216)	118-119	377,687,824	364,536,285
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-747,337	-28,386,302
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-6,700,160	-5,636,826
16	Total Proprietary Capital (lines 2 through 15)		1,259,477,056	1,185,700,847
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,336,700,000	1,257,171,208
19	(Less) Reaquired Bonds (222)	256-257	83,700,000	83,700,000
20	Advances from Associated Companies (223)	256-257	51,547,000	51,547,000
21	Other Long-Term Debt (224)	256-257	0	0
22	Unamortized Premium on Long-Term Debt (225)		204,316	213,200
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		1,656,685	1,838,814
24	Total Long-Term Debt (lines 18 through 23)		1,303,094,631	1,223,392,594
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		4,491,191	4,749,777
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		700,447	3,235,000
29	Accumulated Provision for Pensions and Benefits (228.3)		283,984,764	246,176,609
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		26,310,290	40,530,269
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	2,641,867
34	Asset Retirement Obligations (230)		3,167,936	3,512,818
35	Total Other Noncurrent Liabilities (lines 26 through 34)		318,654,628	300,846,340
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		52,000,000	61,000,000
38	Accounts Payable (232)		116,147,642	98,160,779
39	Notes Payable to Associated Companies (233)		598	1,866,383
40	Accounts Payable to Associated Companies (234)		709,623	709,883
41	Customer Deposits (235)		3,323,152	8,868,640
42	Taxes Accrued (236)	262-263	22,309,642	8,292,344
43	Interest Accrued (237)		12,038,698	11,797,709
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	end of 2012/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS) (continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		120,427	104,100
48	Miscellaneous Current and Accrued Liabilities (242)		61,331,657	55,333,088
49	Obligations Under Capital Leases-Current (243)		258,586	224,884
50	Derivative Instrument Liabilities (244)		55,825,491	111,353,644
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		26,310,290	40,530,269
52	Derivative Instrument Liabilities - Hedges (245)		1,433,160	18,895,143
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	2,641,867
54	Total Current and Accrued Liabilities (lines 37 through 53)		299,188,386	333,434,461
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		947,342	947,213
57	Accumulated Deferred Investment Tax Credits (255)	266-267	12,613,058	10,400,886
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	26,169,966	26,584,147
60	Other Regulatory Liabilities (254)	278	55,244,962	20,939,852
61	Unamortized Gain on Reaquired Debt (257)		2,355,118	2,484,655
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		419,216,613	398,500,293
64	Accum. Deferred Income Taxes-Other (283)		245,681,957	259,644,520
65	Total Deferred Credits (lines 56 through 64)		762,229,016	719,501,566
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		3,942,643,717	3,762,875,808

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

STATEMENT OF INCOME

Quarterly
1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable
5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	1,494,227,540	1,617,162,384		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,051,630,004	1,169,781,695		
5	Maintenance Expenses (402)	320-323	61,377,568	57,411,515		
6	Depreciation Expense (403)	336-337	102,188,312	96,771,421		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	12,353,382	11,307,561		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	99,047	99,047		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		5,612,331	3,529,991		
13	(Less) Regulatory Credits (407.4)		24,170,474	19,872,716		
14	Taxes Other Than Income Taxes (408.1)	262-263	83,263,801	83,348,911		
15	Income Taxes - Federal (409.1)	262-263	14,435,558	23,554,951		
16	- Other (409.1)	262-263	379,911	1,264,963		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	35,782,466	29,793,186		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	4,224,555	2,475,028		
19	Investment Tax Credit Adj. - Net (411.4)	266	2,073,106	2,458,952		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,340,800,457	1,456,974,449		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		153,427,083	160,187,935		

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

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

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
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
1,017,916,105	1,053,850,680	476,311,435	563,311,704			2
						3
664,363,922	702,686,156	387,266,082	467,095,539			4
50,481,432	47,524,279	10,896,136	9,887,236			5
83,017,204	78,744,936	19,171,108	18,026,485			6
						7
9,725,903	9,015,875	2,627,479	2,291,686			8
99,047	99,047					9
						10
						11
4,618,160	3,366,279	994,171	163,712			12
22,537,730	17,238,278	1,632,744	2,634,438			13
62,217,029	61,363,417	21,046,772	21,985,494			14
16,824,429	23,647,758	-2,388,871	-92,807			15
432,992	922,947	-53,081	342,016			16
24,012,637	17,702,120	11,769,829	12,091,066			17
4,120,508	2,793,831	104,047	-318,803			18
2,115,166	2,502,656	-42,060	-43,704			19
						20
						21
						22
						23
						24
891,249,683	927,543,361	449,550,774	529,431,088			25
126,666,422	126,307,319	26,760,661	33,880,616			26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		153,427,083	160,187,935		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)		-236	-21,355		
34	(Less) Expenses of Nonutility Operations (417.1)		8,415,859	6,836,563		
35	Nonoperating Rental Income (418)		-2,749	-2,731		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	-1,206,861	9,971,326		
37	Interest and Dividend Income (419)		1,864,293	1,293,357		
38	Allowance for Other Funds Used During Construction (419.1)		4,054,947	2,224,987		
39	Miscellaneous Nonoperating Income (421)					
40	Gain on Disposition of Property (421.1)			31,120		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		-3,706,465	6,660,141		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)			304,717		
45	Donations (426.1)		2,272,123	2,143,177		
46	Life Insurance (426.2)		2,533,552	2,253,671		
47	Penalties (426.3)		15,251	281,762		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,414,338	1,186,022		
49	Other Deductions (426.5)		1,815,326	407,223		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		8,050,590	6,576,572		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	145,213	-2,275		
53	Income Taxes-Federal (409.2)	262-263	106,965	-962,923		
54	Income Taxes-Other (409.2)	262-263	-1,231,456	-349,700		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	-520,718	40,666		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	5,190,742	4,710,550		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-6,690,738	-5,984,782		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		-5,066,317	6,068,351		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		65,281,624	61,400,721		
63	Amort. of Debt Disc. and Expense (428)		447,351	604,805		
64	Amortization of Loss on Reaquired Debt (428.1)		3,364,150	4,021,281		
65	(Less) Amort. of Premium on Debt-Credit (429)		8,883	8,883		
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		885,123	-26,307		
68	Other Interest Expense (431)		2,582,407	2,983,099		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		2,401,072	2,942,302		
70	Net Interest Charges (Total of lines 62 thru 69)		70,150,700	66,032,414		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		78,210,066	100,223,872		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		78,210,066	100,223,872		

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		362,988,164	325,313,182
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				10,509,950
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			10,509,950
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		79,416,927	90,252,546
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31			-68,552,375	(63,736,956)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-68,552,375	(63,736,956)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		2,286,987	649,442
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		376,139,703	362,988,164
	APPROPRIATED RETAINED EARNINGS (Account 215)			

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
39			1,548,121	1,548,121
40				
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)		1,548,121	1,548,121
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		1,548,121	1,548,121
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		377,687,824	364,536,285
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-28,386,302	(24,343,434)
50	Equity in Earnings for Year (Credit) (Account 418.1)		-1,206,861	9,971,326
51	(Less) Dividends Received (Debit)			
52	Equity transactions of subsidiaries		28,845,826	(14,014,194)
53	Balance-End of Year (Total lines 49 thru 52)		-747,337	(28,386,302)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	78,210,066	100,223,872
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	112,091,663	105,727,999
5	Amortization of deferred power and natural gas costs	6,702,266	21,869,528
6	Amortization of debt expense	3,802,618	4,617,203
7	Amortization of investment in exchange power	2,450,031	2,450,030
8	Deferred Income Taxes (Net)	19,589,845	21,115,803
9	Investment Tax Credit Adjustment (Net)	2,212,172	2,558,524
10	Net (Increase) Decrease in Receivables	12,838,942	3,428,347
11	Net (Increase) Decrease in Inventory	4,331,613	-2,737,133
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	31,767,362	-1,250,437
14	Net (Increase) Decrease in Other Regulatory Assets	-4,674,400	10,565,705
15	Net Increase (Decrease) in Other Regulatory Liabilities	-4,241,041	-11,754,169
16	(Less) Allowance for Other Funds Used During Construction	4,054,947	2,224,987
17	(Less) Undistributed Earnings from Subsidiary Companies	-1,206,861	9,971,326
18	Other (provide details in footnote):	17,162,806	-15,689,679
19	Allowance for doubtful accounts	3,973,772	651,650
20	Changes in other non-current assets and liabilities	-7,388,676	-816,072
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	275,980,953	228,764,858
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-268,743,138	-240,025,802
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction		
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-268,743,138	-240,025,802
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38	Federal grant payments received	8,277,036	16,927,752
39	Investments in and Advances to Assoc. and Subsidiary Companies	-19,138,510	-5,482,493
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
54	Changes in other property and investments	4,540,198	-1,754,160
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-275,064,414	-230,334,703
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	80,000,000	85,000,000
62	Preferred Stock		
63	Common Stock	29,078,745	26,462,920
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	109,078,745	111,462,920
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-11,324,884	-195,575
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Debt issuance costs	-763,603	-4,477,097
78	Net Decrease in Short-Term Debt (c)	-9,000,000	-49,000,000
79	Cash paid for settlement of interest rate swap	-18,546,870	-10,557,000
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-68,552,375	-63,736,957
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	891,013	-16,503,709
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	1,807,552	-18,073,554
87			
88	Cash and Cash Equivalents at Beginning of Period	1,867,419	19,940,973
89			
90	Cash and Cash Equivalents at End of period	3,674,971	1,867,419

Schedule Page: 120 Line No.: 18 Column: b

Power and natural gas deferrals	1,704,991
Change in special deposits	9,792,264
Change in other current assets	1,080,222
Non-cash stock compensation	4,549,448
Cash paid for foreign currency hedges	35,881

Schedule Page: 120 Line No.: 18 Column: c

Power and natural gas deferrals	193,076
Change in special deposits	(14,234,011)
Change in other current assets	(5,795,951)
Non-cash stock compensation	4,147,207

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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

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SEE PAGE 123 FOR REQUIRED INFORMATION.

NOTES TO FINANCIAL STATEMENTS

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Business

Avista Corporation (Avista Corp. or the Company) is an energy company engaged in the generation, transmission and distribution of energy, as well as other energy-related businesses. Avista Corp. generates, transmits and distributes electricity in parts of eastern Washington and northern Idaho. In addition, Avista Corp. has electric generating facilities in Montana and northern Oregon. Avista Corp. also provides natural gas distribution service in parts of eastern Washington and northern Idaho, as well as parts of northeastern and southwestern Oregon. Avista Capital, Inc. (Avista Capital), a wholly owned subsidiary of Avista Corp., is the parent company of all of the subsidiary companies, except Spokane Energy, LLC (Spokane Energy). Avista Capital's subsidiaries include Ecova, Inc. (Ecova), a 79.0 percent owned subsidiary as of December 31, 2012. Ecova is a provider of energy efficiency and other facility information and cost management programs and services for multi-site customers and utilities throughout North America.

Basis of Reporting

The financial statements include the assets, liabilities, revenues and expenses of the Company and have been prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America (U.S. GAAP). As required by the FERC, the Company accounts for its investment in majority-owned subsidiaries on the equity method rather than consolidating the assets, liabilities, revenues, and expenses of these subsidiaries, as required by U.S. GAAP. The accompanying financial statements include the Company's proportionate share of utility plant and related operations resulting from its interests in jointly owned plants. In addition, under the requirements of the FERC, there are differences from U.S. GAAP in the presentation of (1) current portion of long-term debt (2) assets and liabilities for cost of removal of assets, (3) assets held for sale, (4) regulatory assets and liabilities, (5) deferred income taxes and (6) comprehensive income.

Use of Estimates

The preparation of the financial statements in conformity with accounting principles generally accepted in the United States of America (U.S. GAAP) requires management to make estimates and assumptions that affect amounts reported in the financial statements. Significant estimates include:

- determining the market value of energy commodity derivative assets and liabilities,
- pension and other postretirement benefit plan obligations,
- contingent liabilities,
- recoverability of regulatory assets, and
- unbilled revenues.

Changes in these estimates and assumptions are considered reasonably possible and may have a material effect on the financial statements and thus actual results could differ from the amounts reported and disclosed herein.

System of Accounts

The accounting records of the Company's utility operations are maintained in accordance with the uniform system of accounts prescribed by the Federal Energy Regulatory Commission (FERC) and adopted by the state regulatory commissions in Washington, Idaho, Montana and Oregon.

Regulation

The Company is subject to state regulation in Washington, Idaho, Montana and Oregon. The Company is also subject to federal regulation primarily by the FERC, as well as various other federal agencies with regulatory oversight of particular aspects of its operations.

Operating Revenues

Revenues related to the sale of energy are recorded when service is rendered or energy is delivered to customers. The determination of the energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, the amount of energy delivered to customers since the date of the last meter reading is estimated and the corresponding unbilled revenue is estimated and recorded.

Accounts receivable includes unbilled energy revenues of the following amounts as of December 31 (dollars in thousands):

	2012	2011
Unbilled accounts receivable	$ 77,298	$ 82,950

Advertising Expenses

The Company expenses advertising costs as incurred. Advertising expenses were not a material portion of the Company's operating expenses in 2012 and 2011.

Depreciation

For utility operations, depreciation expense is estimated by a method of depreciation accounting utilizing composite rates for utility plant. Such rates are designed to provide for retirements of properties at the expiration of their service lives. For utility operations, the ratio of depreciation provisions to average depreciable property was as follows for the years ended December 31:

	2012	2011
Ratio of depreciation to average depreciable property	2.92%	2.92%

The average service lives for the following broad categories of utility plant in service are:

- electric thermal production - 33 years,
- hydroelectric production - 73 years,
- electric transmission - 51 years,
- electric distribution - 38 years, and
- natural gas distribution property - 49 years.

Taxes Other Than Income Taxes

Taxes other than income taxes include state excise taxes, city occupational and franchise taxes, real and personal property taxes and certain other taxes not based on net income. These taxes are generally based on revenues or the value of property. Utility related taxes collected from customers (primarily state excise taxes and city utility taxes) are recorded as operating revenue and expense and totaled the following amounts for the years ended December 31 (dollars in thousands):

	2012	2011
Utility taxes	$ 53,716	$ 55,739

Allowance for Funds Used During Construction

The Allowance for Funds Used During Construction (AFUDC) represents the cost of both the debt and equity funds used to finance utility plant additions during the construction period. As prescribed by regulatory authorities, AFUDC is capitalized as a part of the cost of utility plant and the debt related portion is credited against total interest expense in the Statements of Income. The Company is permitted, under established regulatory rate practices, to recover the capitalized AFUDC, and a reasonable return thereon, through its inclusion in rate base and the provision for depreciation after the related utility plant is placed in service. Cash inflow related to AFUDC does not occur until the related utility plant is placed in service and included in rate base. The effective AFUDC rate was the following for the years ended December 31:

	2012	2011
Effective AFUDC rate	7.62%	7.91%

Income Taxes

A deferred income tax asset or liability is determined based on the enacted tax rates that will be in effect when the differences between the financial statement carrying amounts and tax basis of existing assets and liabilities are expected to be reported in the Company's consolidated income tax returns. The deferred income tax expense for the period is equal to the net change in the deferred income tax asset and liability accounts from the beginning to the end of the period. The effect on deferred income taxes from a change in tax rates is recognized in income in the period that includes the enactment date. Deferred income tax liabilities and regulatory assets are established for income tax benefits flowed through to customers as prescribed by the respective regulatory commissions.

Stock-Based Compensation

Compensation cost relating to share-based payment transactions is recognized in the Company's financial statements based on the fair value of the equity or liability instruments issued and recorded over the requisite service period. See Note 17 for further information.

Cash and Cash Equivalents

For the purposes of the Statements of Cash Flows, the Company considers all temporary investments with a maturity of three months or less when purchased to be cash equivalents.

Allowance for Doubtful Accounts

The Company maintains an allowance for doubtful accounts to provide for estimated and potential losses on accounts receivable. The Company determines the allowance for utility and other customer accounts receivable based on historical write-offs as compared to accounts receivable and operating revenues. Additionally, the Company establishes specific allowances for certain individual accounts.

Utility Plant in Service

The cost of additions to utility plant in service, including an allowance for funds used during construction and replacements of units of property and improvements, is capitalized. The cost of depreciable units of property retired plus the cost of removal less salvage is charged to accumulated depreciation.

Derivative Assets and Liabilities

Derivatives are recorded as either assets or liabilities on the Balance Sheets measured at estimated fair value. In certain defined conditions, a derivative may be specifically designated as a hedge for a particular exposure. The accounting for derivatives depends on the intended use of the derivatives and the resulting designation.

The Washington Utilities and Transportation Commission (UTC) and the Idaho Public Utilities Commission (IPUC) issued accounting orders authorizing Avista Corp. to offset commodity derivative assets or liabilities with a regulatory asset or liability. This accounting treatment is intended to defer the recognition of mark-to-market gains and losses on energy commodity transactions until the period of settlement. The orders provide for Avista Corp. to not recognize the unrealized gain or loss on utility derivative commodity instruments in the Statements of Income. Realized gains or losses are recognized in the period of settlement, subject to approval for recovery through retail rates. Realized gains and losses, subject to regulatory approval, result in adjustments to retail rates through purchased gas cost adjustments, the Energy Recovery Mechanism (ERM) in Washington, the Power Cost Adjustment (PCA) mechanism in Idaho, and periodic general rates cases. Regulatory assets are assessed regularly and are probable for recovery through future rates.

Substantially all forward contracts to purchase or sell power and natural gas are recorded as derivative assets or liabilities at estimated fair value with an offsetting regulatory asset or liability. Contracts that are not considered derivatives are accounted for on the accrual basis until they are settled or realized, unless there is a decline in the fair value of the contract that is determined to be other than temporary.

Fair Value Measurements

Fair value represents the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. Energy commodity derivative assets and liabilities, deferred compensation assets, as well as derivatives related to interest rate swap agreements and foreign currency exchange contracts, are reported at estimated fair value on the Balance Sheets. See Note 15 for the Company's fair value disclosures.

Regulatory Deferred Charges and Credits

The Company prepares its financial statements in accordance with regulatory accounting practices because:

- rates for regulated services are established by or subject to approval by independent third-party regulators,
- the regulated rates are designed to recover the cost of providing the regulated services, and
- in view of demand for the regulated services and the level of competition, it is reasonable to assume that rates can be charged to and collected from customers at levels that will recover costs.

Regulatory accounting practices require that certain costs and/or obligations (such as incurred power and natural gas costs not currently included in rates, but expected to be recovered or refunded in the future) are reflected as deferred charges or credits on the Balance Sheets. These costs and/or obligations are not reflected in the Statements of Income until the period during which matching revenues are recognized. If at some point in the future the Company determines that it no longer meets the criteria for continued application of regulatory accounting practices for all or a portion of its regulated operations, the Company could be:

- required to write off its regulatory assets, and
- precluded from the future deferral of costs not recovered through rates at the time such costs are incurred, even if the Company expected to recover such costs in the future.

See Note 20 for further details of regulatory assets and liabilities.

Investment in Exchange Power-Net

The investment in exchange power represents the Company's previous investment in Washington Public Power Supply System Project 3 (WNP-3), a nuclear project that was terminated prior to completion. Under a settlement agreement with the Bonneville Power Administration in 1985, Avista Corp. began receiving power in 1987, for a 32.5-year period, related to its investment in WNP-3. Through a settlement agreement with the UTC in the Washington jurisdiction, Avista Corp. is amortizing the recoverable portion of its investment in WNP-3 (recorded as investment in exchange power) over a 32.5-year period that began in 1987. For the Idaho jurisdiction, Avista Corp. fully amortized the recoverable portion of its investment in exchange power.

Unamortized Debt Expense

Unamortized debt expense includes debt issuance costs that are amortized over the life of the related debt.

Unamortized Loss on Reacquired Debt

For the Company's Washington regulatory jurisdiction and for any debt repurchases beginning in 2007 in all jurisdictions, premiums paid to repurchase debt are amortized over the remaining life of the original debt that was repurchased or, if new debt is issued in connection with the repurchase, these costs are amortized over the life of the new debt. In the Company's other regulatory jurisdictions, premiums paid to repurchase debt prior to 2007 are being amortized over the average remaining maturity of outstanding debt when no new debt was issued in connection with the debt repurchase. These costs are recovered through retail rates as a component of interest expense.

Contingencies

The Company has unresolved regulatory, legal and tax issues which have inherently uncertain outcomes. The Company accrues a loss contingency if it is probable that a liability has been incurred and the amount of the loss or impairment can be reasonably estimated. The Company also discloses losses that do not meet these conditions for accrual, if there is a reasonable possibility that a loss may be incurred.

NOTE 2. NEW ACCOUNTING STANDARDS

Effective January 1, 2012, the Company adopted Accounting Standards Update (ASU) No. 2011-04, "Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs." This ASU requires enhanced disclosures for fair value measurements, including quantitative analysis of unobservable inputs used in Level 3 fair value measurements. The ASU also clarifies the FASB's intent about the application of existing fair value measurement requirements.

The adoption of this ASU did not have any impact on the Company's financial condition, results of operations and cash flows. See Note 15 for the Company's fair value disclosures.

In February 2013, the FASB issued ASU No. 2013-02, "Comprehensive Income (Topic 220): Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income." This ASU does not change current requirements for reporting net income or other comprehensive income in financial statements; however, it will require entities to disclose the effect on the line items of net income for reclassifications out of accumulated other comprehensive income if the item being reclassified is required to be reclassified in its entirety to net income under U.S. GAAP. For other items that are not required to be reclassified in their entirety to net income under U.S. GAAP, an entity is required to cross-reference other disclosures required under U.S. GAAP to provide additional detail about those items. This ASU is effective for fiscal years beginning after December 15, 2012. The Company does not expect that this ASU will have any material impact on its financial condition, results of operations and cash flows.

In December 2011, the FASB issued ASU No. 2011-11, "Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities." This ASU enhances disclosure requirements about the nature of an entity's right to offset and related arrangements associated with its financial instruments and derivative instruments. ASU No. 2011-11 requires the disclosure of the gross amounts subject to rights of set-off, amounts offset in accordance with the accounting standards followed, and the related net exposure. The Company will be required to adopt this ASU effective January 1, 2013. Adoption of this ASU will require additional disclosures in the Company's financial statements; however, the Company does not expect that this ASU will have any material impact on its financial condition, results of operations and cash flows.

In January 2013, the FASB issued ASU No. 2013-01, "Balance Sheet (Topic 210): Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities." This ASU clarifies which instruments and transactions are subject to the enhanced disclosure requirements of ASU 2011-11 regarding the offsetting of financial assets and liabilities. ASU No. 2013-01 limits the scope of ASU No. 2011-11 to only recognized derivative instruments, repurchase agreements and reverse repurchase agreements, and borrowing and lending securities transactions that are offset in accordance with either ASC 210-20-45 or ASC 815-10-45. The Company will be required to adopt this ASU effective January 1, 2013. The Company does not expect that this ASU will have a material impact on its financial condition, results of operations and cash flows.

NOTE 3. VOLUNTARY SEVERANCE INCENTIVE PROGRAM

On October 22, 2012, Avista Corp. announced a voluntary severance incentive program to reduce the total utility workforce and achieve necessary long-term, sustainable, Company-wide savings, in addition to other cost saving measures.

In general, most regular full and part-time employees of Avista Corp. (not including any of its subsidiaries) who were not covered by a collective bargaining agreement were eligible to participate in the program. Based on the response to the program by interested employees and the approvals by Company management, the program resulted in the termination of 55, or approximately 6 percent, of the eligible 919 non-union employees, and the total severance costs under the program were $7.3 million (pre-tax). The total severance costs are made up of the severance payments and the related payroll taxes and employee benefit costs. Approximately 50 percent of the applicants to the program were approved for termination by Company management. The long-term operating and maintenance cost savings under the program are expected to exceed the severance costs of the program and the expected payback period for the severance costs will be approximately 1.4 years.

Each participant in the program was entitled to receive severance pay in an amount calculated by reference to the participant's years of service and base pay as of December 31, 2012. In no event did the amount of severance pay exceed 78 weeks of a participant's base pay.

All terminations under the voluntary severance incentive program were completed by December 31, 2012. The cost of the program was recognized as expense during the fourth quarter of 2012 and severance pay was distributed in a single lump sum cash payment to each participant during January 2013.

NOTE 4. ECOVA ACQUISITIONS

The acquisition of Cadence Network in July 2008 was funded by issuing additional Ecova common stock. Under the transaction agreement, the previous owners of Cadence Network had a right to have their shares of Ecova common stock redeemed by Ecova during July 2011 or July 2012 if their investment in Ecova was not liquidated through either an initial public offering or sale of the business to a third party. These redemption rights were not exercised and expired effective July 31, 2012. As such, this redeemable noncontrolling interest was reclassified to equity effective July 31, 2012. Additionally, certain minority shareholders and option holders of Ecova have the right to put their shares back to Ecova at their discretion during an annual put window. Stock options and other outstanding redeemable stock are valued at their maximum redemption amount which is equal to their intrinsic value (fair value less exercise price).

In January 2011, Ecova acquired substantially all of the assets and liabilities of Building Knowledge Networks, LLC (BKN), a Seattle-based real-time building energy management services provider.

On November 30, 2011, Ecova acquired all of the capital stock of Prenova, Inc. (Prenova), an Atlanta-based energy management company.

On January 31, 2012, Ecova acquired all of the capital stock of LPB Energy Management (LPB), a Dallas, Texas-based energy management company.

NOTE 5. DERIVATIVES AND RISK MANAGEMENT

Energy Commodity Derivatives

Avista Corp. is exposed to market risks relating to changes in electricity and natural gas commodity prices and certain other fuel prices. Market risk is, in general, the risk of fluctuation in the market price of the commodity being traded and is influenced primarily by supply and demand. Market risk includes the fluctuation in the market price of associated derivative commodity instruments. Avista Corp. utilizes derivative instruments, such as forwards, futures, swaps and options in order to manage the various risks relating to these commodity price exposures. The Company has an energy resources risk policy and control procedures to manage these risks. The Company's Risk Management Committee establishes the Company's energy resources risk policy and monitors compliance. The Risk Management Committee is comprised of certain Company officers and other members of management. The Audit Committee of the Company's Board of Directors periodically reviews and discusses enterprise risk management processes, and it focuses on the Company's material financial and accounting risk exposures and the steps management has undertaken to control them.

As part of the its resource procurement and management operations in the electric business, Avista Corp. engages in an ongoing process of resource optimization, which involves the economic selection from available energy resources to serve Avista Corp.'s load obligations and the use of these resources to capture available economic value. Avista Corp. transacts in wholesale markets by selling and purchasing electric capacity and energy, fuel for electric generation, and derivative contracts related to capacity, energy and fuel. Such transactions are part of the process of matching resources with our load obligations and hedging the related financial risks. These transactions range from terms of intra-hour up to multiple years.

Avista Corp. makes continuing projections of:

- electric loads at various points in time (ranging from intra-hour to multiple years) based on, among other things, estimates of customer usage and weather, historical data and contract terms, and
- resource availability at these points in time based on, among other things, fuel choices and fuel markets, estimates of streamflows, availability of generating units, historic and forward market information, contract terms, and experience.

On the basis of these projections, we make purchases and sales of electric capacity and energy, fuel for electric generation, and related derivative instruments to match expected resources to expected electric load requirements and reduce our exposure to electricity (or fuel) market price changes. Resource optimization involves generating plant dispatch and scheduling available resources and also includes transactions such as:

- purchasing fuel for generation,
- when economical, selling fuel and substituting wholesale electric purchases, and
- other wholesale transactions to capture the value of generation and transmission resources and fuel delivery capacity contracts.

Avista Corp.'s optimization process includes entering into hedging transactions to manage risks. Transactions include both physical energy contracts and related derivative instruments.

As part of its resource procurement and management of its natural gas business, Avista Corp. makes continuing projections of its natural gas loads and assesses available natural gas resources including natural gas storage availability. Natural gas resource planning typically includes peak requirements, low and average monthly requirements and delivery constraints from natural gas supply locations to Avista Corp.'s distribution system. However, daily variations in natural gas demand can be significantly different than monthly demand projections. On the basis of these projections, Avista Corp. plans and executes a series of transactions to hedge a significant portion of its projected natural gas requirements through forward market transactions and derivative instruments. These transactions may extend as much as four natural gas operating years (November through October) into the future. Avista Corp. also leaves a significant portion of its natural gas supply requirements unhedged for purchase in short-term and spot markets.

Natural gas resource optimization activities include:

- wholesale market sales of surplus natural gas supplies,
- optimization of interstate pipeline transportation capacity not needed to serve daily load, and
- purchases and sales of natural gas to optimize use of storage capacity.

The following table presents the underlying energy commodity derivative volumes as of December 31, 2012 that are expected to settle in each respective year (in thousands of MWhs and mmBTUs):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical (1) MWH	Financial (1) MWH	Physical mmBTUs	Financial mmBTUs	Physical MWH	Financial MWH	Physical mmBTUs	Financial mmBTUs
2013	713	3,365	18,523	88,391	264	2,712	7,252	91,962
2014	397	801	6,394	55,407	377	1,844	1,786	33,623
2015	379	614	3,390	42,930	286	982	—	35,575
2016	367	—	1,365	455	287	—	—	—
2017	366	—	—	—	286	—	—	—
Thereafter	583	—	—	—	443	—	—	—

(1) Physical transactions represent commodity transactions where Avista will take delivery of either electricity or natural gas and financial transactions represent derivative instruments with no physical delivery, such as futures, swaps, options, or forward contracts.

The above electric and natural gas derivative contracts will be included in either power supply costs or natural gas supply costs during the period they settle and will be included in the various recovery mechanisms (ERM, PCA, and PGAs), or in the general rate case process, and are expected to eventually be collected through retail rates from customers.

Foreign Currency Exchange Contracts

A significant portion of Avista Corp.'s natural gas supply (including fuel for power generation) is obtained from Canadian sources. Most of those transactions are executed in U.S. dollars, which avoids foreign currency risk. A portion of Avista Corp.'s short-term natural gas transactions and long-term Canadian transportation contracts are committed based on Canadian currency prices and settled within sixty days with U.S. dollars. Avista Corp. economically hedges a portion of the foreign currency risk by purchasing Canadian currency contracts when such commodity transactions are initiated. This risk has not had a material effect on the Company's financial condition, results of operations or cash flows and these differences in cost related to currency fluctuations were included with natural gas supply costs for ratemaking. The following table summarizes the foreign currency hedges that the Company has entered into as of December 31 (dollars in thousands):

	2012	2011
Number of contracts	20	28
Notional amount (in United States dollars)	$ 12,621	$ 7,033
Notional amount (in Canadian dollars)	12,502	7,192

Interest Rate Swap Agreements

Avista Corp. hedges a portion of its interest rate risk with financial derivative instruments, which may include interest rate swaps and U.S. Treasury lock agreements. These interest rate swap agreements are considered economic hedges against fluctuations in future cash flows associated with anticipated debt issuances.

The following table summarizes the interest rate swaps that the Company has entered into as of December 31 (dollars in thousands):

	2012	2011
Number of contracts	—	3
Notional amount	$ —	$ 75,000
Mandatory cash settlement date	—	July 2012
Number of contracts	2	2
Notional amount	$ 85,000	$ 85,000
Mandatory cash settlement date	June 2013	June 2013
Number of contracts	2	—
Notional amount	$ 50,000	$ —
Mandatory cash settlement date	October 2014	—
Number of contracts	1	—
Notional amount	$ 25,000	$ —
Mandatory cash settlement date	October 2015	—

In May 2012, the Company cash settled interest rate swap contracts (notional amount of $75.0 million) and paid a total of $18.5 million. The interest rate swap contracts were settled in connection with the pricing of $80.0 million of First Mortgage Bonds. In September 2011, the Company cash settled interest rate swap contracts (notional amount of $85.0 million) and paid a total of $10.6 million. The interest rate swap contracts were settled in connection with the pricing of $85.0 million of First Mortgage Bonds.

Upon settlement of the interest rate swaps, the regulatory asset or liability (included as part of long-term debt) is amortized as a component of interest expense over the life of the forecasted interest payments.

Derivative Instruments Summary

The following table presents the fair values and locations of derivative instruments recorded on the Balance Sheet as of December 31, 2012 (in thousands):

		Fair Value			
Derivative	Balance Sheet Location	Asset	Liability	Collateral Netting	Net Asset (Liability)
Foreign currency contracts	Derivative instrument liabilities –Hedges	$ 7	$ (34)	$ —	$ (27)
Interest rate contracts	Derivative instrument liabilities -Hedges	—	(1,406)	—	(1,406)
Interest rate contracts	Long-term portion of derivative instrument assets -Hedges	7,265	—	—	7,265
Commodity contracts	Derivative instrument assets current	10,772	(6,633)	—	4,139
Commodity contracts	Long-term portion of derivative assets	18,779	(17,686)	—	1,093
Commodity contracts	Derivative instrument liabilities current	50,227	(89,449)	9,707	(29,515)
Commodity contracts	Long-term portion of derivative liabilities	2,247	(28,558)	—	(26,311)
Total derivative instruments recorded on the balance sheet		$ 89,297	$ (143,766)	$ 9,707	$ (44,762)

The following table presents the fair values and locations of derivative instruments recorded on the Balance Sheet as of December 31, 2011 (in thousands):

Derivative	Balance Sheet Location	Fair Value Asset	Fair Value Liability	Fair Value Net Asset (Liability)
Foreign currency contracts	Derivative instrument assets –Hedges	$ 32	$ —	$ 32
Interest rate contracts	Derivative instrument liabilities –Hedges	—	(16,253)	(16,253)
Interest rate contracts	Long-term portion of derivative instrument liabilities - Hedges	—	(2,642)	(2,642)
Commodity contracts	Derivative instrument assets current	1,618	(479)	1,139
Commodity contracts	Long-term portion of derivative assets	185	—	185
Commodity contracts	Derivative instrument liabilities current	40,090	(110,914)	(70,824)
Commodity contracts	Long-term portion of derivative instrument liabilities	44,308	(84,838)	(40,530)
Total derivative instruments recorded on the balance sheet		$ 86,233	$ (215,126)	$ (128,893)

Exposure to Demands for Collateral

The Company's derivative contracts often require collateral (in the form of cash or letters of credit) or other credit enhancements, or reductions or terminations of a portion of the contract through cash settlement, in the event of a downgrade in the Company's credit ratings or changes in market prices. In periods of price volatility, the level of exposure can change significantly. As a result, sudden and significant demands may be made against the Company's credit facilities and cash. The Company actively monitors the exposure to possible collateral calls and takes steps to mitigate capital requirements. As of December 31, 2012, the Company had cash deposited as collateral of $10.1 million and letters of credit of $28.1 million outstanding related to its energy derivative contracts. The Balance Sheet at December 31, 2012 reflects the offsetting of $9.7 million of cash collateral against net derivative positions where a legal right of offset exists.

Certain of the Company's derivative instruments contain provisions that require the Company to maintain an investment grade credit rating from the major credit rating agencies. If the Company's credit ratings were to fall below "investment grade," it would be in violation of these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing collateralization on derivative instruments in net liability positions. The aggregate fair value of all derivative instruments with credit-risk-related contingent features that are in a liability position as of December 31, 2012 was $35.9 million. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2012, the Company could be required to post $25.8 million of additional collateral to its counterparties.

Credit Risk

Credit risk relates to the potential losses that the Company would incur as a result of non-performance by counterparties of their contractual obligations to deliver energy or make financial settlements. The Company often extends credit to counterparties and customers and is exposed to the risk that it may not be able to collect amounts owed to the Company. Credit risk includes potential counterparty default due to circumstances:

- relating directly to it,
- caused by market price changes, and
- relating to other market participants that have a direct or indirect relationship with such counterparty.

Changes in market prices may dramatically alter the size of credit risk with counterparties, even when conservative credit limits are established. Should a counterparty fail to perform, the Company may be required to honor the underlying commitment or to replace existing contracts with contracts at then-current market prices.

We enter into bilateral transactions between Avista and various counterparties. We also trade energy and related derivative instruments through clearinghouse exchanges.

The Company seeks to mitigate bilateral credit risk by:

- entering into bilateral contracts that specify credit terms and protections against default,

- applying credit limits and duration criteria to existing and prospective counterparties,
- actively monitoring current credit exposures,
- asserting our collateral rights with counterparties,
- carrying out transaction settlements timely and effectively, and
- conducting transactions on exchanges with fully collateralized clearing arrangements that significantly reduce counterparty default risk.

The Company's credit policy includes an evaluation of the financial condition of counterparties. Credit risk management includes collateral requirements or other credit enhancements, such as letters of credit or parent company guarantees. The Company enters into various agreements that address credit risks including standardized agreements that allow for the netting or offsetting of positive and negative exposures.

The Company has concentrations of suppliers and customers in the electric and natural gas industries including:

- electric and natural gas utilities,
- electric generators and transmission providers,
- natural gas producers and pipelines,
- financial institutions including commodity clearing exchanges and related parties, and
- energy marketing and trading companies.

In addition, the Company has concentrations of credit risk related to geographic location as it operates in the western United States and western Canada. These concentrations of counterparties and concentrations of geographic location may impact the Company's overall exposure to credit risk because the counterparties may be similarly affected by changes in conditions.

The Company maintains credit support agreements with certain counterparties and margin calls are periodically made and/or received. Margin calls are triggered when exposures exceed contractual limits or when there are changes in a counterparty's creditworthiness. Price movements in electricity and natural gas can generate exposure levels in excess of these contractual limits. Negotiating for collateral in the form of cash, letters of credit, or performance guarantees is common industry practice.

NOTE 6. JOINTLY OWNED ELECTRIC FACILITIES

The Company has a 15 percent ownership interest in a twin-unit coal-fired generating facility, the Colstrip Generating Project (Colstrip) located in southeastern Montana, and provides financing for its ownership interest in the project. The Company's share of related fuel costs as well as operating expenses for plant in service are included in the corresponding accounts in the Statements of Income. The Company's share of utility plant in service for Colstrip and accumulated depreciation were as follows as of December 31 (dollars in thousands):

	2012	2011
Utility plant in service	$ 344,958	$ 342,539
Accumulated depreciation	(234,126)	(225,746)

NOTE 7. ASSET RETIREMENT OBLIGATIONS

The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the associated costs of the asset retirement obligation are capitalized as part of the carrying amount of the related long-lived asset. The liability is accreted to its present value each period and the related capitalized costs are depreciated over the useful life of the related asset. Upon retirement of the asset, the Company either settles the retirement obligation for its recorded amount or incurs a gain or loss. The Company records regulatory assets and liabilities for the difference between asset retirement costs currently recovered in rates and asset retirement obligations recorded since asset retirement costs are recovered through rates charged to customers. The regulatory assets do not earn a return.

Specifically, the Company has recorded liabilities for future asset retirement obligations to:

- restore ponds at Colstrip,
- cap a landfill at the Kettle Falls Plant,
- remove plant and restore the land at the Coyote Springs 2 site at the termination of the land lease,
- remove asbestos at the corporate office building, and
- dispose of PCBs in certain transformers.

Due to an inability to estimate a range of settlement dates, the Company cannot estimate a liability for the:

- removal and disposal of certain transmission and distribution assets, and
- abandonment and decommissioning of certain hydroelectric generation and natural gas storage facilities.

The following table documents the changes in the Company's asset retirement obligation during the years ended December 31 (dollars in thousands):

	2012	2011
Asset retirement obligation at beginning of year	$ 3,513	$ 3,887
New liability recognized	—	—
Liability settled	(559)	(612)
Accretion expense	214	238
Asset retirement obligation at end of year	$ 3,168	$ 3,513

NOTE 8. PENSION PLANS AND OTHER POSTRETIREMENT BENEFIT PLANS

The Company has a defined benefit pension plan covering substantially all regular full-time employees at Avista Corp. Individual benefits under this plan are based upon the employee's years of service, date of hire and average compensation as specified in the plan. The Company's funding policy is to contribute at least the minimum amounts that are required to be funded under the Employee Retirement Income Security Act, but not more than the maximum amounts that are currently deductible for income tax purposes. The Company contributed $44 million in cash to the pension plan in 2012 and $26 million in 2011. The Company expects to contribute $44 million in cash to the pension plan in 2013.

The Company also has a Supplemental Executive Retirement Plan (SERP) that provides additional pension benefits to executive officers of the Company. The SERP is intended to provide benefits to executive officers whose benefits under the pension plan are reduced due to the application of Section 415 of the Internal Revenue Code of 1986 and the deferral of salary under deferred compensation plans. The liability and expense for this plan are included as pension benefits in the tables included in this Note.

The Company expects that benefit payments under the pension plan and the SERP will total (dollars in thousands):

	2013	2014	2015	2016	2017	Total 2018-2022
Expected benefit payments	$ 24,504	$ 24,280	$ 25,434	$ 26,567	$ 27,797	$ 162,488

The expected long-term rate of return on plan assets is based on past performance and economic forecasts for the types of investments held by the plan. In selecting a discount rate, the Company considers yield rates for highly rated corporate bond portfolios with maturities similar to that of the expected term of pension benefits.

The Company provides certain health care and life insurance benefits for substantially all of its retired employees. The Company accrues the estimated cost of postretirement benefit obligations during the years that employees provide services. The Company elected to amortize the transition obligation of $34.5 million over a period of 20 years, beginning in 1993.

The Company has a Health Reimbursement Arrangement to provide employees with tax-advantaged funds to pay for allowable medical expenses upon retirement. The amount earned by the employee is fixed on the retirement date based on the employee's years of service and the ending salary. The liability and expense of this plan are included as other postretirement benefits.

The Company provides death benefits to beneficiaries of executive officers who die during their term of office or after retirement. Under the plan, an executive officer's designated beneficiary will receive a payment equal to twice the executive officer's annual base salary at the time of death (or if death occurs after retirement, a payment equal to twice the executive officer's total annual pension benefit). The liability and expense for this plan are included as other postretirement benefits.

The Company expects that benefit payments under other postretirement benefit plans will total (dollars in thousands):

	2013	2014	2015	2016	2017	Total 2018-2022
Expected benefit payments	$ 6,099	$ 6,160	$ 6,261	$ 6,389	$ 6,571	$ 36,342

The Company expects to contribute $6.1 million to other postretirement benefit plans in 2013, representing expected benefit payments to be paid during the year. The Company uses a December 31 measurement date for its pension and other postretirement benefit plans.

The following table sets forth the pension and other postretirement benefit plan disclosures as of December 31, 2012 and 2011 and the components of net periodic benefit costs for the years ended December 31, 2012 and 2011 (dollars in thousands):

	Pension Benefits 2012	Pension Benefits 2011	Other Post-retirement Benefits 2012	Other Post-retirement Benefits 2011
Change in benefit obligation:				
Benefit obligation as of beginning of year	$ 494,192	$ 433,491	$ 104,730	$ 60,339
Service cost	15,551	12,936	2,804	1,805
Interest cost	24,349	24,134	5,056	4,126
Actuarial loss	72,170	44,148	24,543	42,476
Transfer of accrued vacation	—	—	336	450
Benefits paid	(21,643)	(20,517)	(4,928)	(4,466)
Benefit obligation as of end of year	$ 584,619	$ 494,192	$ 132,541	$ 104,730
Change in plan assets:				
Fair value of plan assets as of beginning of year	$ 328,150	$ 306,712	$ 22,455	$ 22,875
Actual return on plan assets	54,318	14,705	2,833	(420)
Employer contributions	44,000	26,000	—	—
Benefits paid	(20,407)	(19,267)	—	—
Fair value of plan assets as of end of year	$ 406,061	$ 328,150	$ 25,288	$ 22,455
Funded status	$ (178,558)	$ (166,042)	$ (107,253)	$ (82,275)
Unrecognized net actuarial loss	223,308	192,883	94,202	76,187
Unrecognized prior service cost	319	665	(856)	(1,005)
Unrecognized net transition obligation	—	—	—	505
Prepaid (accrued) benefit cost	45,069	27,506	(13,907)	(6,588)
Additional liability	(223,627)	(193,548)	(93,346)	(75,687)
Accrued benefit liability	$ (178,558)	$ (166,042)	$ (107,253)	$ (82,275)
Accumulated pension benefit obligation	$ 505,695	$ 429,135	—	—
Accumulated postretirement benefit obligation:				
For retirees			$ 49,232	$ 39,470
For fully eligible employees			$ 35,570	$ 29,597
For other participants			$ 47,739	$ 35,663
Included in accumulated comprehensive loss (income) (net of tax):				
Unrecognized net transition obligation	$ —	$ —	$ —	$ 328
Unrecognized prior service cost	207	433	(556)	(653)
Unrecognized net actuarial loss	145,150	125,374	61,231	49,522
Total	145,357	125,807	60,675	49,197
Less regulatory asset	(138,184)	(119,360)	(60,981)	(49,873)
Accumulated other comprehensive loss (income)	$ 7,173	$ 6,447	$ (306)	$ (676)

	Pension Benefits 2012	Pension Benefits 2011	Other Post-retirement Benefits 2012	Other Post-retirement Benefits 2011
Weighted average assumptions as of December 31:				
Discount rate for benefit obligation	4.15%	5.04%	4.15%	4.98%
Discount rate for annual expense	5.04%	5.68%	4.98%	5.53%
Expected long-term return on plan assets	6.95%	7.40%	6.55%	7.00%
Rate of compensation increase	4.89%	4.87%		
Medical cost trend pre-age 65 – initial			7.00%	7.50%
Medical cost trend pre-age 65 – ultimate			5.00%	5.00%
Ultimate medical cost trend year pre-age 65			2019	2017
Medical cost trend post-age 65 – initial			7.50%	8.00%
Medical cost trend post-age 65 – ultimate			5.00%	6.00%

Ultimate medical cost trend year post-age 65	2021	2018

	Pension Benefits		Other Postretirement Benefits	
	2012	2011	2012	2011
Components of net periodic benefit cost:				
Service cost	$ 15,551	$ 12,936	$ 2,804	$ 1,805
Interest cost	24,349	24,134	5,056	4,126
Expected return on plan assets	(23,810)	(23,115)	(1,471)	(1,601)
Transition obligation recognition	—	—	505	505
Amortization of prior service cost	346	475	(149)	(149)
Net loss recognition	11,637	9,493	5,020	3,458
Net periodic benefit cost	$ 28,073	$ 23,923	$ 11,765	$ 8,144

Plan Assets

The Finance Committee of the Company's Board of Directors approves investment policies, objectives and strategies that seek an appropriate return for the pension plan and other postretirement benefit plans and reviews and approves changes to the investment and funding policies.

The Company has contracted with investment consultants who are responsible for managing/monitoring the individual investment managers. The investment managers' performance and related individual fund performance is periodically reviewed by an internal benefits committee and by the Finance Committee to monitor compliance with investment policy objectives and strategies.

Pension plan assets are invested primarily in marketable debt and equity securities. Pension plan assets may also be invested in real estate, absolute return, venture capital/private equity and commodity funds. In seeking to obtain the desired return to fund the pension plan, the investment consultant recommends allocation percentages by asset classes. These recommendations are reviewed by the internal benefits committee, which then recommends their adoption by the Finance Committee. The Finance Committee has established target investment allocation percentages by asset classes as indicated in the table below:

	2012	2011
Equity securities	51%	51%
Debt securities	31%	31%
Real estate	5%	5%
Absolute return	10%	10%
Other	3%	3%

The market-related value of pension plan assets invested in debt and equity securities was based primarily on fair value (market prices). The fair value of investment securities traded on a national securities exchange is determined based on the last reported sales price; securities traded in the over-the-counter market are valued at the last reported bid price. Investment securities for which market prices are not readily available or for which market prices do not represent the value at the time of pricing, are fair-valued by the investment manager based upon other inputs (including valuations of securities that are comparable in coupon, rating, maturity and industry). Investments in common/collective trust funds are presented at estimated fair value, which is determined based on the unit value of the fund. Unit value is determined by an independent trustee, which sponsors the fund, by dividing the fund's net assets by its units outstanding at the valuation date. The fair value of the closely held investments and partnership interests is based upon the allocated share of the fair value of the underlying assets as well as the allocated share of the undistributed profits and losses, including realized and unrealized gains and losses.

The market-related value of pension plan assets invested in real estate was determined by the investment manager based on three basic approaches:

- properties are externally appraised on an annual basis by independent appraisers, additional appraisals may be performed as warranted by specific asset or market conditions,
- property valuations are reviewed quarterly and adjusted as necessary, and
- loans are reflected at fair value.

The market-related value of pension plan assets was determined as of December 31, 2012 and 2011.

The following table discloses by level within the fair value hierarchy (see Note 15 for a description of the fair value hierarchy) of the pension plan's assets measured and reported as of December 31, 2012 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Mutual funds:				
Fixed income securities	$ 83,037	$ —	$ —	$ 83,037
U.S. equity securities	135,436	—	—	135,436
International equity securities	79,448	—	—	79,448
Absolute return (1)	20,764	—	—	20,764
Commodities (2)	8,258	—	—	8,258
Common/collective trusts:				
Fixed income securities	—	43,107	—	43,107
Real estate	—	—	17,596	17,596
Partnership/closely held investments:				
Absolute return (1)	—	—	17,755	17,755
Private equity funds (3)	—	—	660	660
Total	$ 326,943	$ 43,107	$ 36,011	$ 406,061

The following table discloses by level within the fair value hierarchy (see Note 15 for a description of the fair value hierarchy) of the pension plan's assets measured and reported as of December 31, 2011 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ —	$ 7,550	$ —	$ 7,550
Mutual funds:				
Fixed income securities	76,486	—	—	76,486
U.S. equity securities	102,790	—	—	102,790
International equity securities	52,241	—	—	52,241
Absolute return (1)	16,121	—	—	16,121
Commodities (2)	6,526	—	—	6,526
Common/collective trusts:				
Fixed income securities	—	27,774	—	27,774
U.S. equity securities	—	12,669	—	12,669
Real estate	—	—	8,598	8,598
Partnership/closely held investments:				
Absolute return (1)	—	—	16,587	16,587
Private equity funds (3)	—	—	808	808
Total	$ 254,164	$ 47,993	$ 25,993	$ 328,150

(1) This category invests in multiple strategies to diversify risk and reduce volatility. The strategies include: (a) event driven, relative value, convertible, and fixed income arbitrage, (b) distressed investments, (c) long/short equity and fixed income, and (d) market neutral strategies.

(2) The fund primarily invests in derivatives linked to commodity indices to gain exposure to the commodity markets. The fund manager fully collateralizes these positions with debt securities.

(3) This category includes private equity funds that invest primarily in U.S. companies.

The table below discloses the summary of changes in the fair value of the pension plan's Level 3 assets for the year ended December 31, 2012 (dollars in thousands):

	Common/collective trusts	Partnership/closely held investments	
	Real estate	Absolute return	Private equity funds
Balance, as of January 1, 2012	$ 8,598	$ 16,587	$ 808
Realized gains	411	—	108
Unrealized gains (losses)	1,087	1,168	80
Purchases (sales), net	7,500	—	(336)
Balance, as of December 31, 2012	$ 17,596	$ 17,755	$ 660

The table below discloses the summary of changes in the fair value of the pension plan's Level 3 assets for the year ended December 31, 2011 (dollars in thousands):

	Common/collective trusts		Partnership/closely held investments	
	Absolute return	Real estate	Absolute return	Private equity funds
Balance, as of January 1, 2011	$ 95	$ 423	$ 16,917	$ 1,272
Realized gains (losses)	(748)	22	—	373
Unrealized gains (losses)	746	1,098	(330)	(218)
Purchases (sales), net	(93)	7,055	—	(619)
Balance, as of December 31, 2011	$ —	$ 8,598	$ 16,587	$ 808

The market-related value of other postretirement plan assets invested in debt and equity securities was based primarily on fair value (market prices). The fair value of investment securities traded on a national securities exchange is determined based on the last reported sales price; securities traded in the over-the-counter market are valued at the last reported bid price. Investment securities for which market prices are not readily available or for which market prices do not represent the value at the time of pricing, are fair-valued by the investment manager based upon other inputs (including valuations of securities that are comparable in coupon, rating, maturity and industry). The target asset allocation was 62 percent equity securities and 38 percent debt securities in 2012 and 2011.

The market-related value of other postretirement plan assets was determined as of December 31, 2012 and 2011.

The following table discloses by level within the fair value hierarchy (see Note 15 for a description of the fair value hierarchy) of other postretirement plan assets measured and reported as of December 31, 2012 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ —	$ 6	$ —	$ 6
Mutual funds:				
Fixed income securities	9,314	—	—	9,314
U.S. equity securities	10,266	—	—	10,266
International equity securities	5,702	—	—	5,702
Total	$ 25,282	$ 6	$ —	$ 25,288

The following table discloses by level within the fair value hierarchy (see Note 15 for a description of the fair value hierarchy) of other postretirement plan assets measured and reported as of December 31, 2011 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ —	$ 86	$ —	$ 86
Mutual funds:				
Fixed income securities	8,683	—	—	8,683
U.S. equity securities	7,278	—	—	7,278
International equity securities	4,766	—	—	4,766
U.S. equity securities	1,569	—	—	1,569
Other	73	—	—	73
Total	$ 22,369	$ 86	$ —	$ 22,455

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point increase in the assumed health care cost trend rate for each year would increase the accumulated postretirement benefit obligation as of December 31, 2012 by $20.8 million and the service and interest cost by $1.4 million. A one-percentage-point decrease in the assumed health care cost trend rate for each year would decrease the accumulated postretirement benefit obligation as of December 31, 2012 by $16.7 million and the service and interest cost by $1.1 million.

The Company has a salary deferral 401(k) plans that is a defined contribution plan and cover substantially all employees. Employees can make contributions to their respective accounts in the plan on a pre-tax basis up to the maximum amount permitted by law. The Company matches a portion of the salary deferred by each participant according to the schedule in the plan.

Employer matching contributions were as follows for the years ended December 31 (dollars in thousands):

	2012	2011
Employer 401(k) matching contributions	$ 5,813	$ 5,452

The Company has an Executive Deferral Plan. This plan allows executive officers and other key employees the opportunity to defer until the earlier of their retirement, termination, disability or death, up to 75 percent of their base salary and/or up to 100 percent of their incentive payments. Deferred compensation funds are held by the Company in a Rabbi Trust. There were deferred compensation assets and corresponding deferred compensation liabilities on the Balance Sheets of the following amounts as of December 31 (dollars in thousands):

	2012	2011
Deferred compensation assets and liabilities	$ 8,806	$ 8,653

NOTE 9. ACCOUNTING FOR INCOME TAXES

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes and tax credit carryforwards. As of December 31, 2012, the Company had $13.9 million of state tax credit carryforwards. State tax credits expire from 2015 to 2025. The Company recognizes the effect of state tax credits generated from utility plant as they are utilized.

The realization of deferred income tax assets is dependent upon the ability to generate taxable income in future periods. The Company evaluated available evidence supporting the realization of its deferred income tax assets and determined it is more likely than not that deferred income tax assets will be realized.

The Company and its eligible subsidiaries file consolidated federal income tax returns. The Company also files state income tax returns in certain jurisdictions, including Idaho, Oregon and Montana. Subsidiaries are charged or credited with the tax effects of their operations on a stand-alone basis. The Internal Revenue Service (IRS) has completed its examination of all tax years through 2009 and all issues were resolved related to these years. The IRS has not completed an examination of the Company's 2010 through 2011 federal income tax returns. The Company does not believe that any open tax years for federal or state income taxes could result in any adjustments that would be significant to the financial statements.

The Company did not incur any penalties on income tax positions in 2012 or 2011.

The Company had net regulatory assets related to the probable recovery of certain deferred income tax liabilities from customers through future rates as of December 31 (dollars in thousands):

	2012	2011
Regulatory assets for deferred income taxes	$ 79,406	$ 84,576

NOTE 10. ENERGY PURCHASE CONTRACTS

Avista Corp. has contracts for the purchase of fuel for thermal generation, natural gas for resale and various agreements for the purchase or exchange of electric energy with other entities. The termination dates of the contracts range from one month to the year 2055. Total expenses for power purchased, natural gas purchased, fuel for generation and other fuel costs were as follows for the years ended December 31 (dollars in thousands):

	2012	2011
Utility power resources	$ 523,416	$ 557,619

The following table details Avista Corp.'s future contractual commitments for power resources (including transmission contracts) and natural gas resources (including transportation contracts) (dollars in thousands):

	2013	2014	2015	2016	2017	Thereafter	Total
Power resources	$ 196,877	$ 132,378	$ 118,054	$ 117,779	$ 116,580	$ 1,025,941	$ 1,707,609
Natural gas resources	109,406	96,092	77,688	60,104	51,950	678,042	1,073,282
Total	$ 306,283	$ 228,470	$ 195,742	$ 177,883	$ 168,530	$ 1,703,983	$ 2,780,891

These energy purchase contracts were entered into as part of Avista Corp.'s obligation to serve its retail electric and natural gas customers' energy requirements. As a result, these costs are recovered either through base retail rates or adjustments to retail rates as part of the power and natural gas cost deferral and recovery mechanisms.

In addition, Avista Corp. has operational agreements, settlements and other contractual obligations for its generation, transmission and distribution facilities. The following table details future contractual commitments for these agreements (dollars in thousands):

	2013	2014	2015	2016	2017	Thereafter	Total
Contractual obligations	$ 30,913	$ 31,732	$ 29,259	$ 35,844	$ 27,708	$ 230,453	$ 385,909

Avista Corp. has fixed contracts with certain Public Utility Districts (PUD) to purchase portions of the output of certain generating facilities. Although Avista Corp. has no investment in the PUD generating facilities, the fixed contracts obligate Avista Corp. to pay certain minimum amounts (based in part on the debt service requirements of the PUD) whether or not the facilities are operating.

Expenses under these PUD contracts were as follows for the years ended December 31 (dollars in thousands):

	2012	2011
PUD contract costs	$ 8,436	$ 10,533

Information as of December 31, 2012 pertaining to these PUD contracts is summarized in the following table (dollars in thousands):

	Company's Current Share of					
	Output	Kilowatt	Annual	Debt Service Costs (1)	Bonds	Expiration
Douglas County PUD:						
Wells Project	3.4%	24,048	2,716	874	3,117	2018
Grant County PUD:						
Priest Rapids and Wanapum Projects	3.3%	65,800	5,717	2,425	30,655	2055
Totals		89,848	$ 8,433	$ 3,299	$ 33,772	

(1) The annual costs will change in proportion to the percentage of output allocated to Avista Corp. in a particular year. Amounts represent the operating costs for 2012. Debt service costs are included in annual costs.

The estimated aggregate amounts of required minimum payments (Avista Corp.'s share of existing debt service costs) under these PUD contracts are as follows (dollars in thousands):

	2013	2014	2015	2016	2017	Thereafter	Total
Minimum payments	$ 3,348	$ 3,332	$ 3,223	$ 3,222	$ 3,220	$ 42,988	$ 59,333

In addition, Avista Corp. will be required to pay its proportionate share of the variable operating expenses of these projects.

NOTE 11. NOTES PAYABLE

Avista Corp. has a committed line of credit with various financial institutions in the total amount of $400.0 million with an expiration date of February 2017.

The committed line of credit is secured by non-transferable First Mortgage Bonds of the Company issued to the agent bank that would only become due and payable in the event, and then only to the extent, that the Company defaults on its obligations under the committed line of credit.

The committed line of credit agreement contains customary covenants and default provisions. The credit agreement has a covenant which does not permit the ratio of "consolidated total debt" to "consolidated total capitalization" of Avista Corp. to be greater than 65 percent at any time. As of December 31, 2012, the Company was in compliance with this covenant.

Balances outstanding and interest rates of borrowings (excluding letters of credit) under the Company's revolving committed lines of credit were as follows as of December 31 (dollars in thousands):

	2012	2011
Balance outstanding at end of period	$ 52,000	$ 61,000
Letters of credit outstanding at end of period	$ 35,885	$ 29,030
Average interest rate at end of period	1.12%	1.12%

NOTE 12. BONDS

The following details bonds outstanding as of December 31 (dollars in thousands):

Maturity Year	Description	Interest Rate	2012	2011
2012	Secured Medium-Term Notes	7.37%	$ —	$ 7,000
2013	First Mortgage Bonds	1.68%	50,000	50,000

2018	First Mortgage Bonds	5.95%	250,000	250,000
2018	Secured Medium-Term Notes	7.39%-7.45%	22,500	22,500
2019	First Mortgage Bonds	5.45%	90,000	90,000
2020	First Mortgage Bonds	3.89%	52,000	52,000
2022	First Mortgage Bonds	5.13%	250,000	250,000
2023	Secured Medium-Term Notes	7.18%-7.54%	13,500	13,500
2028	Secured Medium-Term Notes	6.37%	25,000	25,000
2032	Secured Pollution Control Bonds (1)	(1)	66,700	66,700
2034	Secured Pollution Control Bonds (2)	(2)	17,000	17,000
2035	First Mortgage Bonds	6.25%	150,000	150,000
2037	First Mortgage Bonds	5.70%	150,000	150,000
2040	First Mortgage Bonds	5.55%	35,000	35,000
2041	First Mortgage Bonds	4.45%	85,000	85,000
2047	First Mortgage Bonds (3)	4.23%	80,000	—
	Total secured bonds		1,336,700	1,263,700
2023	Unsecured Pollution Control Bonds	6.00%	—	4,100
	Settled interest rate swaps		(27,900)	(10,629)
	Secured Pollution Control Bonds held by Avista Corporation (1) (2)		(83,700)	(83,700)
	Total bonds		$ 1,225,100	$ 1,173,471

(1) In December 2010, $66.7 million of the City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) due 2032, which had been held by Avista Corp. since 2008, were refunded by a new bond issue (Series 2010A). The new bonds were not offered to the public and were purchased by Avista Corp. due to market conditions. The Company expects that at a later date, subject to market conditions, these bonds may be remarketed to unaffiliated investors. So long as Avista Corp. is the holder of these bonds, the bonds will not be reflected as an asset or a liability on Avista Corp.'s Balance Sheet.

(2) In December 2010, $17.0 million of the City of Forsyth, Montana Pollution Control Revenue Refunding Bonds, (Avista Corporation Colstrip Project) due 2034, which had been held by Avista Corp. since 2009, were refunded by a new bond issue (Series 2010B). The new bonds were not offered to the public and were purchased by Avista Corp. due to market conditions. The Company expects that at a later date, subject to market conditions, the bonds may be remarketed to unaffiliated investors. So long as Avista Corp. is the holder of these bonds, the bonds will not be reflected as an asset or a liability on Avista Corp.'s Balance Sheet.

(3) In November 2012, the Company issued $80.0 million of 4.23 percent First Mortgage Bonds due in 2047.

The following table details future long-term debt maturities including advances from associated companies (see Note 13) (dollars in thousands):

	2013	2014	2015	2016	2017	Thereafter	Total
Debt maturities	$ 50,000	$ —	$ —	$ —	$ —	$ 1,254,547	$ 1,304,547

Substantially all utility properties owned by the Company are subject to the lien of the Company's mortgage indenture. Under the Mortgage and Deed of Trust securing the Company's First Mortgage Bonds (including Secured Medium-Term Notes), the Company may issue additional First Mortgage Bonds in an aggregate principal amount equal to the sum of: 1) 66-2/3 percent of the cost or fair value (whichever is lower) of property additions which have not previously been made the basis of any application under the Mortgage, or 2) an equal principal amount of retired First Mortgage Bonds which have not previously been made the basis of any application under the Mortgage, or 3) deposit of cash. However, the Company may not issue any additional First Mortgage Bonds (with certain exceptions in the case of bonds issued on the basis of retired bonds) unless the Company's "net earnings" (as defined in the Mortgage) for any period of 12 consecutive calendar months out of the preceding 18 calendar months were at least twice the annual interest requirements on all mortgage securities at the time outstanding, including the First Mortgage Bonds to be issued, and on all indebtedness of prior rank. As of December 31, 2012, property additions and retired bonds would have allowed, and the net earnings test would not have prohibited the issuance of $640.1 million in aggregate principal amount of additional First Mortgage Bonds.

See Note 11 for information regarding First Mortgage Bonds issued to secure the Company's obligations under its committed line of credit agreement.

NOTE 13. ADVANCES FROM ASSOCIATED COMPANIES

In 1997, the Company issued Floating Rate Junior Subordinated Deferrable Interest Debentures, Series B, with a principal amount of $51.5 million to Avista Capital II, an affiliated business trust formed by the Company. Avista Capital II issued $50.0 million of Preferred Trust Securities with a floating distribution rate of LIBOR plus 0.875 percent, calculated and reset quarterly. The distribution rates paid were as follows during the years ended December 31:

	2012	2011
Low distribution rate	1.19%	1.13%
High distribution rate	1.40	1.40
Distribution rate at the end of the year	1.19	1.40

Concurrent with the issuance of the Preferred Trust Securities, Avista Capital II issued $1.5 million of Common Trust Securities to the Company. These debt securities may be redeemed at the option of Avista Capital II on or after June 1, 2007 and mature on June 1, 2037. In December 2000, the Company purchased $10.0 million of these Preferred Trust Securities.

The Company owns 100 percent of Avista Capital II and has solely and unconditionally guaranteed the payment of distributions on, and redemption price and liquidation amount for, the Preferred Trust Securities to the extent that Avista Capital II has funds available for such payments from the respective debt securities. Upon maturity or prior redemption of such debt securities, the Preferred Trust Securities will be mandatorily redeemed.

NOTE 14. LEASES

The Company has multiple lease arrangements involving various assets, with minimum terms ranging from 1 to forty-five years. Rental expense under operating leases was as follows for the years ended December 31 (dollars in thousands):

	2012	2011
Rental expense	$ 3,274	$ 2,853

Future minimum lease payments required under operating leases having initial or remaining noncancelable lease terms in excess of one year as of December 31 were as follows (dollars in thousands):

	2013	2014	2015	2016	2017	Thereafter	Total
Minimum payments required	$ 1,749	$ 1,517	$ 498	$ 162	$ 148	$ 2,712	$ 6,786

NOTE 15. FAIR VALUE

The carrying values of cash and cash equivalents, special deposits, accounts and notes receivable, accounts payable and notes payable are reasonable estimates of their fair values. Bonds and advances from associated companies are reported at carrying value on the Balance Sheets.

The following table sets forth the carrying value and estimated fair value of the Company's financial instruments not reported at estimated fair value on the Balance Sheets as of December 31 (dollars in thousands):

	2012		2011	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Bonds (Level 2)	$ 951,000	$ 1,164,639	$ 962,100	$ 1,135,536
Bonds (Level 3)	302,000	320,892	222,000	234,226
Advances from associated companies (Level 3)	51,547	43,686	51,547	43,810

These estimates of fair value were primarily based on available market information.

The fair value hierarchy prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement).

The three levels of the fair value hierarchy are defined as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities. Active markets are those in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

Level 3 – Pricing inputs include significant inputs that are generally unobservable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value.

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. The determination of the fair values incorporates various factors that not only include the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits and letters of credit), but also the impact of Avista Corp.'s nonperformance risk on its liabilities.

The following table discloses by level within the fair value hierarchy the Company's assets and liabilities measured and reported on the Balance Sheets as of December 31, 2012 and 2011 at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting (1)	Total
December 31, 2012					
Assets:					
Energy commodity derivatives	$ —	$ 81,640	$ —	$ (76,408)	$ 5,232
Level 3 energy commodity derivatives:					
Power exchange agreements	—	—	385	(385)	—
Foreign currency derivatives	—	7	—	(7)	—
Interest rate swaps	—	7,265	—	—	7,265
Deferred compensation assets:					
Fixed income securities	2,010	—	—	—	2,010
Equity securities	5,955	—	—	—	5,955
Total	$ 7,965	$ 88,912	$ 385	$ (76,800)	$ 20,462
Liabilities:					
Energy commodity derivatives	$ —	$ 119,390	$ —	$ (86,115)	$ 33,275
Level 3 energy commodity derivatives:					
Natural gas exchange agreements	—	—	2,379	—	2,379
Power exchange agreements	—	—	19,077	(385)	18,692
Power option agreements	—	—	1,480	—	1,480
Foreign currency derivatives	—	34	—	(7)	27
Interest rate swaps	—	1,406	—	—	1,406
Total	$ —	$ 120,830	$ 22,936	$ (86,507)	$ 57,259

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting (1)	Total
December 31, 2011					
Assets:					
Energy commodity derivatives	$ —	$ 80,571	$ —	$ (79,247)	$ 1,324
Level 3 energy commodity derivatives:					
Natural gas exchange agreements	—	—	956	(956)	—
Power exchange agreements	—	—	4,674	(4,674)	—
Foreign currency derivatives	—	32	—	—	32
Deferred compensation assets:					
Fixed income securities	2,116	—	—	—	2,116
Equity securities	5,252	—	—	—	5,252
Total	$ 7,368	$ 80,603	$ 5,630	$ (84,877)	$ 8,724
Liabilities:					
Energy commodity derivatives	$ —	$ 177,743	$ —	$ (79,247)	$ 98,496
Level 3 energy commodity derivatives:					
Natural gas exchange agreements	—	—	2,644	(956)	1,688
Power exchange agreements	—	—	14,584	(4,674)	9,910
Power option agreements	—	—	1,260	—	1,260
Interest rate swaps	—	18,895	—	—	18,895
Total	$ —	$ 196,638	$ 18,488	$ (84,877)	$ 130,249

(1) The Company is permitted to net derivative assets and derivative liabilities with the same counterparty when a legally enforceable master netting agreement exists. In addition, the Company nets derivative assets and derivative liabilities against any payables and receivables for cash collateral held or placed with these same counterparties.

Avista Corp. enters into forward contracts to purchase or sell a specified amount of energy at a specified time, or during a specified period, in the future. These contracts are entered into as part of Avista Corp.'s management of loads and resources and certain contracts are considered derivative instruments. The difference between the amount of derivative assets and liabilities disclosed in respective levels and the amount of derivative assets and liabilities disclosed on the Balance Sheets is due to netting arrangements with certain counterparties. The Company uses quoted market prices and forward price curves to estimate the fair value of utility derivative commodity instruments included in Level 2. In particular, electric derivative valuations are performed using broker quotes, adjusted for periods in between quotable periods. Natural gas derivative valuations are estimated using New York Mercantile Exchange (NYMEX) pricing for similar instruments, adjusted for basin differences, using broker quotes. Where observable inputs are available for substantially the full term of the contract, the derivative asset or liability is included in Level 2.

Deferred compensation assets and liabilities represent funds held by the Company in a Rabbi Trust for an executive deferral plan. These funds consist of actively traded equity and bond funds with quoted prices in active markets. The balance disclosed in the table above excludes cash and cash equivalents of $0.8 million as of December 31, 2012 and $1.3 million as of December 31, 2011.

Level 3 Fair Value

For power exchange agreements, the Company compares the Level 2 brokered quotes and forward price curves described above to an internally developed forward price which is based on the average operating and maintenance (O&M) charges from four surrogate nuclear power plants around the country for the current year. Because the nuclear power plant O&M charges are only known for one year, all forward years are estimated assuming an annual escalation. In addition to the forward price being estimated using unobservable inputs, the Company also estimates the volumes of the transactions that will take place in the future based on historical average transaction volumes per delivery year (November to April). Significant increases or decreases in any of these inputs in isolation would result in a significantly higher or lower fair value measurement. Generally, a change in the current year O&M charges for the surrogate plants is accompanied by a directionally similar change in O&M charges in future years. There is generally not a correlation between external market prices and the O&M charges used to develop the internal forward price.

For power commodity option agreements, the Company uses the Black-Scholes-Merton valuation model to estimate the fair value, and this model includes significant inputs not observable or corroborated in the market. These inputs include 1) the strike price (which is an internally derived price based on a combination of generation plant heat rate factors, natural gas market pricing, delivery and other O&M charges, 2) estimated delivery volumes for years beyond 2013, and 3) volatility rates for periods beyond January 2016. Significant increases or decreases in any of these inputs in isolation would result in a significantly higher or lower fair value measurement. Generally, changes in overall commodity market prices and volatility rates are accompanied by directionally similar changes in the strike price and volatility assumptions used in the calculation.

For natural gas commodity exchange agreements, the Company uses the same Level 2 brokered quotes described above; however, the Company also estimates the purchase and sales volumes (within contractual limits) as well as the timing of those transactions. Changing the timing of volume estimates changes the timing of purchases and sales, impacting which brokered quote is used. Because the brokered quotes can vary significantly from period to period, the unobservable estimates of the timing and volume of transactions can have a significant impact on the calculated fair value. The Company currently estimates volumes and timing of transactions based on a most likely scenario using historical data. Historically, the timing and volume of transactions have not been highly correlated with market prices and market volatility.

The following table presents the quantitative information which was used to estimate the fair values of the Level 3 assets and liabilities above as of December 31, 2012 (dollars in thousands):

	Fair Value (Net) at December 31, 2012	Valuation Technique	Unobservable Input	Range
Power exchange agreements	$ (18,692)	Surrogate facility pricing	O&M charges	$30.49-$53.82/MWh (1)
			Escalation factor	5% - 2013 to 2015
				3% - 2016 to 2019
			Transaction volumes	365,619 - 379,156 MWhs
Power option agreements	(1,480)	Black-Scholes-Merton	Strike price	$52.61/MWh - 2013
				$76.63/MWh - 2019
			Delivery volumes	128,491 - 287,147 MWhs
			Volatility rates	0.20 (2)
Natural gas exchange agreements	(2,379)	Internally derived weighted average cost of gas	Forward purchase prices	$3.19 - $3.38/mmBTU
			Forward sales prices	$3.29 - $4.46/mmBTU
			Purchase volumes	135,000 - 465,000 mmBTUs
			Sales volumes	140,010 - 620,000 mmBTUs

(1) The average O&M charges for 2012 were $40.87 per MWh.
(2) The estimated volatility rate of 0.20 is compared to actual quoted volatility rates of 0.33 for 2012 to 0.21 in January 2016.

Avista Corp.'s risk management team and accounting team are responsible for developing the valuation methods described above and both groups report to the Chief Financial Officer. The valuation methods, the significant inputs, and the resulting fair values described above are reviewed on at least a quarterly basis by the risk management team and the accounting team to ensure they provide a reasonable estimate of fair value each reporting period.

The following table presents activity for energy commodity derivative assets (liabilities) measured at fair value using significant unobservable inputs (Level 3) for the years ended December 31 (dollars in thousands):

	Natural Gas Exchange Agreements	Power Exchange Agreements	Power Option	Total
Year ended December 31, 2012:				
Balance as of January 1, 2012	$ (1,688)	$ (9,910)	$ (1,260)	$ (12,858)
Total gains or losses (realized/unrealized):				
Included in net income	—	—	—	—
Included in other comprehensive income	—	—	—	—
Included in regulatory assets/liabilities (1)	343	(15,236)	(220)	(15,113)
Purchases	—	—	—	—
Issuance	—	—	—	—
Settlements	(1,034)	6,454	—	5,420
Transfers to/from other categories	—	—	—	—
Ending balance as of December 31, 2012	$ (2,379)	$ (18,692)	$ (1,480)	$ (22,551)
Year ended December 31, 2011:				
Balance as of January 1, 2011	$ —	$ 15,793	$ (2,334)	$ 13,459
Total gains or losses (realized/unrealized):				
Included in net income	—	—	—	—
Included in other comprehensive income	—	—	—	—
Included in regulatory assets/liabilities (1)	2,621	(28,571)	1,074	(24,876)
Purchases	—	—	—	—
Issuance	—	—	—	—
Settlements	95	2,868	—	2,963
Transfers from other categories (2)	(4,404)	—	—	(4,404)
Ending balance as of December 31, 2011	$ (1,688)	$ (9,910)	$ (1,260)	$ (12,858)

(1) The UTC and the IPUC issued accounting orders authorizing Avista Corp. to offset commodity derivative assets or liabilities with a regulatory asset or liability. This accounting treatment is intended to defer the recognition of mark-to-market gains and losses on energy commodity transactions until the period of settlement. The orders provide for Avista Corp. to not recognize the unrealized gain or loss on utility derivative commodity instruments in the Statements of Income. Realized gains or losses are recognized in the period of settlement, subject to approval for recovery through retail rates. Realized gains and losses, subject to regulatory approval, result in adjustments to retail rates through purchased gas cost adjustments, the ERM in Washington, the PCA mechanism in Idaho, and periodic general rates cases.

(2) A derivative contract was reclassified from Level 2 to Level 3 during 2011 due to a particular unobservable input becoming more significant to the fair value measurement. There were not any reclassifications between Level 1 and Level 2. The Company's policy is to reclassify identified items as of the end of the reporting period.

NOTE 16. COMMON STOCK

The Company has a Direct Stock Purchase and Dividend Reinvestment Plan under which the Company's shareholders may automatically reinvest their dividends and make optional cash payments for the purchase of the Company's common stock at current market value.

The payment of dividends on common stock is restricted by provisions of certain covenants applicable to preferred stock contained in the Company's Articles of Incorporation, as amended.

In August 2012, the Company entered into two sales agency agreements under which the Company may sell up to 2,726,390 shares of its common stock from time to time. As of December 31, 2012, the Company had 1,795,199 shares available to be issued under these agreements.

Shares issued under sales agency agreements were as follows in the year ended December 31:

	2012	2011
Shares issued under sales agency agreement	931,191	807,000

The Company has 10 million authorized shares of preferred stock. The Company did not have any preferred stock outstanding as of December 31, 2012 and 2011.

NOTE 17. STOCK COMPENSATION PLANS

Avista Corp.

1998 Plan

In 1998, the Company adopted, and shareholders approved, the Long-Term Incentive Plan (1998 Plan). Under the 1998 Plan, certain key employees, officers and non-employee directors of the Company and its subsidiaries may be granted stock options, stock appreciation rights, stock awards (including restricted stock) and other stock-based awards and dividend equivalent rights. The Company has available a maximum of 4.5 million shares of its common stock for grant under the 1998 Plan. As of December 31, 2012, 0.7 million shares were remaining for grant under this plan.

2000 Plan

In 2000, the Company adopted a Non-Officer Employee Long-Term Incentive Plan (2000 Plan), which was not required to be approved by shareholders. The provisions of the 2000 Plan are essentially the same as those under the 1998 Plan, except for the exclusion of non-employee directors and executive officers of the Company. The Company has available a maximum of 2.5 million shares of its common stock for grant under the 2000 Plan. However, the Company currently does not plan to issue any further options or securities under the 2000 Plan. As of December 31, 2012, 1.9 million shares were remaining for grant under this plan.

Stock Compensation

The Company records compensation cost relating to share-based payment transactions in the financial statements based on the fair value of the equity or liability instruments issued. The Company recorded stock-based compensation expense (included in other operating expenses) and income tax benefits in the Statements of Income of the following amounts for the years ended December 31 (dollars in thousands):

	2012	2011
Stock-based compensation expense	$ 5,792	$ 5,756
Income tax benefits	2,027	2,014

Stock Options

The following summarizes stock options activity under the 1998 Plan and the 2000 Plan for the years ended December 31:

	2012	2011
Number of shares under stock options:		
Options outstanding at beginning of year	92,499	201,674
Options granted	—	—
Options exercised	(89,499)	(107,575)
Options canceled	—	(1,600)
Options outstanding and exercisable at end of year	3,000	92,499
Weighted average exercise price:		
Options exercised	$ 10.63	$ 12.25
Options canceled	$ —	$ 11.80
Options outstanding and exercisable at end of year	$ 12.41	$ 10.69
Cash received from options exercised (in thousands)	$ 951	$ 1,318
Intrinsic value of options exercised (in thousands)	$ 1,349	$ 1,279
Intrinsic value of options outstanding (in thousands)	$ 35	$ 1,393

Information for options outstanding and exercisable as of December 31, 2012 is as follows:

Exercise Price	Number	Weighted Average Exercise Price	Weighted Average Remaining Life (in years)
$12.41	3,000	12.41	0.35

As of December 31, 2012 and 2011, the Company's stock options were fully vested and expensed.

Restricted Shares

Restricted share awards vest in equal thirds each year over a three-year period and are payable in Avista Corp. common stock at the end of each year if the service condition is met. In addition to the service condition, the Company must meet a return on equity target in order for the CEO's restricted shares to vest. During the vesting period, employees are entitled to dividend equivalents which are paid when dividends on the Company's common stock are declared. Restricted stock is valued at the close of market of the Company's common stock on the grant date. The weighted average remaining vesting period for the Company's restricted shares outstanding as of December 31, 2012 was 0.7 years. The following table summarizes restricted stock activity for the years ended December 31:

	2012	2011
Unvested shares at beginning of year	93,482	84,134
Shares granted	70,281	50,618
Shares canceled	(790)	(431)
Shares vested	(45,855)	(40,839)
Unvested shares at end of year	117,118	93,482
Weighted average fair value at grant date	$ 25.83	$ 23.06
Unrecognized compensation expense at end of year (in thousands)	$ 1,428	$ 932
Intrinsic value, unvested shares at end of year (in thousands)	$ 2,824	$ 2,407
Intrinsic value, shares vested during the year (in thousands)	$ 1,173	$ 934

Performance Shares

Performance share awards vest after a period of three years and are payable in cash or Avista Corp. common stock at the end of the three-year period. Performance share awards entitle the recipients to dividend equivalent rights, are subject to forfeiture under certain circumstances, and are subject to meeting specific performance conditions. Based on the attainment of the performance condition, the amount of cash paid or common stock issued will range from 0 to 150 percent of the performance shares granted for grants prior to 2011 and 0 to 200 percent for grants in 2011 and after, depending on the change in the value of the Company's common stock relative to an external benchmark. Dividend equivalent rights are accumulated and paid out only on shares that eventually vest.

Performance share awards entitle the grantee to shares of common stock or cash payable once the service condition is satisfied. Based on attainment of the performance condition, grantees may receive 0 to 150 percent of the original shares granted for grants prior to 2011 and 0 to 200 percent for shares granted in 2011 and after. The performance condition used is the Company's Total Shareholder Return performance over a three-year period as compared against other utilities; this is considered a market-based condition. Performance shares may be settled in common stock or cash at the discretion of the Company. Historically, the Company has settled these awards through issuance of stock and intends to continue this practice. These awards vest at the end of the three-year period. Performance shares are equity awards with a market-based condition, which results in the compensation cost for these awards being recognized over the requisite service period, provided that the requisite service period is rendered, regardless of when, if ever, the market condition is satisfied.

The Company measures (at the grant date) the estimated fair value of performance shares awarded. The fair value of each performance share award was estimated on the date of grant using a statistical model that incorporates the probability of meeting performance targets based on historical returns relative to a peer group. Expected volatility was based on the historical volatility of Avista Corp. common stock over a three-year period. The expected term of the performance shares is three years based on the performance cycle. The risk-free interest rate was based on the U.S. Treasury yield at the time of grant. The compensation expense on these awards will only be adjusted for changes in forfeitures.

The following summarizes the weighted average assumptions used to determine the fair value of performance shares and related compensation expense as well as the resulting estimated fair value of performance shares granted:

	2012	2011
Risk-free interest rate	0.3%	1.2%
Expected life, in years	3	3
Expected volatility	22.7%	26.9%
Dividend yield	4.5%	4.7%
Weighted average grant date fair value (per share)	$ 26.06	$ 20.79

The fair value includes both performance shares and dividend equivalent rights.

The following summarizes performance share activity:

	2012	2011
Opening balance of unvested performance shares	351,345	325,700
Performance shares granted	181,000	184,600
Performance shares canceled	(4,544)	(2,177)
Performance shares vested	(168,101)	(156,778)
Ending balance of unvested performance shares	359,700	351,345
Intrinsic value of unvested performance shares (in thousands)	$ 8,672	$ 9,047
Unrecognized compensation expense (in thousands)	$ 3,800	$ 2,991

The weighted average remaining vesting period for the Company's performance shares outstanding as of December 31, 2012 was 1.5 years. Unrecognized compensation expense as of December 31, 2012 will be recognized during 2013. The following summarizes the impact of the market condition on the vested performance shares:

	2012	2011
Performance shares vested	168,101	156,778
Impact of market condition on shares vested	(168,101)	(15,678)
Shares of common stock earned	—	141,100
Intrinsic value of common stock earned (in thousands)	$ —	$ 3,633

Shares earned under this plan are distributed to participants in the quarter following vesting.

Outstanding performance share awards include a dividend component that is paid in cash. This component of the performance share grants is accounted for as a liability award. These liability awards are revalued on a quarterly basis taking into account the number of awards outstanding, historical dividend rate, and the change in the value of the Company's common stock relative to an external benchmark. Over the life of these awards, the cumulative amount of compensation expense recognized will match the actual cash paid. As of December 31, 2012 and 2011, the Company had recognized compensation expense and a liability of $0.7 million and $1.0 million related to the dividend component of performance share grants.

NOTE 18. COMMITMENTS AND CONTINGENCIES

In the course of its business, the Company becomes involved in various claims, controversies, disputes and other contingent matters, including the items described in this Note. Some of these claims, controversies, disputes and other contingent matters involve litigation or other contested proceedings. For all such matters, the Company intends to vigorously protect and defend its interests and pursue its rights. However, no assurance can be given as to the ultimate outcome of any particular matter because litigation and other contested proceedings are inherently subject to numerous uncertainties. For matters that affect Avista Corp.'s operations, the Company intends to seek, to the extent appropriate, recovery of incurred costs through the ratemaking process.

Federal Energy Regulatory Commission Inquiry

In April 2004, the Federal Energy Regulatory Commission (FERC) approved the contested Agreement in Resolution of Section 206 Proceeding (Agreement in Resolution) between Avista Corp., Avista Energy and the FERC's Trial Staff which stated that there was: (1) no evidence that any executives or employees of Avista Corp. or Avista Energy knowingly engaged in or facilitated any improper trading strategy during 2000 and 2001; (2) no evidence that Avista Corp. or Avista Energy engaged in any efforts to manipulate the western energy markets during 2000 and 2001; and (3) no finding that Avista Corp. or Avista Energy withheld relevant information from the FERC's inquiry into the western energy markets for 2000 and 2001 (Trading Investigation). The Attorney General of the State of California (California AG), the California Electricity Oversight Board, and the City of Tacoma, Washington (City of Tacoma) challenged the FERC's decisions approving the Agreement in Resolution, which are now pending before the United States Court of Appeals for the Ninth Circuit (Ninth Circuit). In May 2004, the FERC provided notice that Avista Energy was no longer subject to an investigation reviewing certain bids above $250 per MW in the short-term energy markets operated by the California Independent System Operator (CalISO) and the California Power Exchange (CalPX) from May 1, 2000 to October 2, 2000 (Bidding Investigation). That matter is also pending before the Ninth Circuit, after the California AG, Pacific Gas & Electric (PG&E), Southern California Edison Company (SCE) and the California Public Utilities Commission (CPUC) filed petitions for review in 2005.

Based on the FERC's order approving the Agreement in Resolution in the Trading Investigation and order denying rehearing requests, the Company does not expect that this proceeding will have any material effect on its financial condition, results of operations or cash flows. Furthermore, based on information currently known to the Company regarding the Bidding Investigation and the fact that the FERC Staff did not find any evidence of manipulative behavior, the Company does not expect that this matter will have a material effect on its financial condition, results of operations or cash flows.

California Refund Proceeding

In July 2001, the FERC ordered an evidentiary hearing to determine the amount of refunds due to California energy buyers for purchases made in the spot markets operated by the CalISO and the CalPX during the period from October 2, 2000 to June 20, 2001 (Refund Period). Proposed refunds are based on the calculation of mitigated market clearing prices for each hour. The FERC ruled that if the refunds required by the formula would cause a seller to recover less than its actual costs for the Refund Period, sellers may document these costs and limit their refund liability commensurately. In September 2005, Avista Energy submitted its cost filing claim pursuant to the FERC's August 2005 order. The filing was initially accepted by the FERC, but in March 2011, the FERC ordered Avista Energy to remove any return on equity in a compliance filing with the CalISO, which Avista Energy did in April 2011. A challenge to Avista Energy's cost filing by the California AG, the CPUC, PG&E and SCE was denied in July 2011 as a collateral attack on the FERC's prior orders accepting Avista Energy's cost filing. In July 2011, the California AG, the CPUC, PG&E and SCE filed a petition for review of the FERC's orders regarding Avista Energy's cost filing with the Ninth Circuit.

The 2001 bankruptcy of PG&E resulted in a default on its payment obligations to the CalPX. As a result, Avista Energy has not been paid for all of its energy sales during the Refund Period. Those funds are now in escrow accounts and will not be released until the FERC issues an order directing such release in the California refund proceeding. The CalISO continues to work on its compliance filing for the Refund Period, which will show "who owes what to whom." In July 2011, the FERC accepted the preparatory rerun compliance filings by the CalPX and CalISO, and responded to the CalPX request for guidance on issues related to completing the final determination of "who owes what to whom." The FERC directed both the CalISO and the CalPX to prepare and submit to the FERC their final refund rerun compliance filings. The FERC's order also directs the CalPX to pay past due principal amounts to governmental entities. In February 2012, the FERC denied the challenges made to the July 2011 order by the California AG, the CPUC, PG&E and SCE. As of September 30, 2012, Avista Energy's accounts receivable outstanding related to defaulting parties in California were fully offset by reserves for uncollected amounts and funds collected from the defaulting parties.

In August 2006, the Ninth Circuit upheld October 2, 2000 as the refund effective date for the FPA section 206 refund proceeding, but remanded to the FERC its decision not to consider an FPA section 309 remedy for tariff violations prior to that date. In an order issued in May 2011, the FERC clarified the issues set for hearing for the period May 1, 2000 - October 1, 2000 (Summer Period): (1) which market practices and behaviors constitute a violation of the then-current CalISO, CalPX, and individual seller's tariffs and FERC orders; (2) whether any of the sellers named as respondents in this proceeding engaged in those tariff violations; and (3) whether any such tariff violations affected the market clearing price. The FERC reiterated that the California Parties are expected to be very specific when presenting their arguments and evidence, and that general claims would not suffice. The FERC also gave the California Parties an opportunity to show that exchange transactions with the CalISO during the Refund Period were not just and reasonable. Avista Energy has one exchange transaction with the CalISO. The California AG, the CPUC, PG&E and SCE filed for rehearing of the FERC's May 2011 order, arguing that it improperly denies them a market-wide remedy for the pre-refund period. That request for rehearing was denied in an order issued by FERC on November 2, 2012. The California AG, the CPUC, PG&E and SCE filed a petition for review of the May 2011 and November 2012 orders with the Ninth Circuit on November 7, 2012.

A FERC hearing commenced on April 11, 2012 and concluded on July 19, 2012. On August 27, 2012, the Presiding Administrative Law Judge issued a partial initial decision granting Avista Corp.'s motion for summary disposition, based on the stipulation by the

California Parties that there are no allegations of tariff violations made against Avista Corp. in this proceeding and therefore no tariff violations by Avista Corp. that affected the market clearing price in any hour during the Summer Period. On November 2, 2012, FERC issued an order affirming the partial initial decision and dismissing Avista Corp. from the proceeding, thereby terminating all claims against Avista Corp. for the Summer Period. In the same order, FERC also held that a market-wide remedy would not be appropriate with regard to any respondent during the Summer Period. FERC stated that it is clear that the Ninth Circuit did not mandate a specific remedy on remand and, instead, left it to the FERC's discretion to determine which remedy would be appropriate. On December 3, 2012, the California Parties filed a request for clarification and rehearing of the November 2, 2012 order. On February 15, 2013, the Administrative Law Judge issued an initial decision finding that certain Respondents committed various tariff and other violations that affected the market clearing price in the California organized markets during the Summer Period. The tariff violations identified for Avista Energy are type II and III bidding violations; false export violations; and selling ancillary services without market-based rate authority. The initial decision did not discuss evidence offered by Avista Energy, on an hour by hour basis, rebutting the alleged violations and Avista Energy is currently preparing briefs on exceptions which will identify these errors. With respect to Avista Energy's one exchange transaction with the CalISO during the Refund Period, the judge made no findings with respect to the justness and reasonableness of that transaction, but nonetheless determined that Avista Energy owed approximately $0.2 million in refunds with regard to the transaction.

Because the resolution of the California refund proceeding remains uncertain, legal counsel cannot express an opinion on the extent of the Company's liability, if any. However, based on information currently known, the Company does not expect that the refunds ultimately ordered for the Refund Period would result in a material loss. In the event that the Commission does not overturn the legal and factual errors in the February 15, 2013 initial decision, the Company does not expect that the refunds ultimately ordered for that period would result in a material loss either. This is primarily due to the fact that the FERC orders have stated that any refunds will be netted against unpaid amounts owed to the respective parties and the Company does not believe that refunds would exceed unpaid amounts owed to the Company.

Pacific Northwest Refund Proceeding

In July 2001, the FERC initiated a preliminary evidentiary hearing to develop a factual record as to whether prices for spot market sales of wholesale energy in the Pacific Northwest between December 25, 2000 and June 20, 2001 were just and reasonable. In June 2003, the FERC terminated the Pacific Northwest refund proceedings, after finding that the equities do not justify the imposition of refunds. In August 2007, the Ninth Circuit found that the FERC, in denying the request for refunds, had failed to take into account new evidence of market manipulation in the California energy market and its potential ties to the Pacific Northwest energy market and that such failure was arbitrary and capricious and, accordingly, remanded the case to the FERC, stating that the FERC's findings must be reevaluated in light of the evidence. In addition, the Ninth Circuit concluded that the FERC abused its discretion in denying potential relief for transactions involving energy that was purchased by the California Energy Resources Scheduling (CERS) in the Pacific Northwest and ultimately consumed in California. The Ninth Circuit expressly declined to direct the FERC to grant refunds. The Ninth Circuit denied petitions for rehearing by various parties, and remanded the case to the FERC in April 2009.

On October 3, 2011, the FERC issued an Order on Remand, finding that, in light of the Ninth Circuit's remand order, additional procedures are needed to address possible unlawful activity that may have influenced prices in the Pacific Northwest spot market during the period from December 25, 2000 through June 20, 2001. The Order establishes an evidentiary, trial-type hearing before an Administrative Law Judge (ALJ), and reopens the record to permit parties to present evidence of unlawful market activity during the relevant period. The Order also allows participants to supplement the record with additional evidence on CERS transactions in the Pacific Northwest spot market from January 18, 2001 to June 20, 2001. The Order states that parties seeking refunds must submit evidence demonstrating that specific unlawful market activity occurred, and must demonstrate that such activity directly affected negotiations with respect to the specific contract rate about which they complain. Simply alleging a general link between the dysfunctional spot market in California and the Pacific Northwest spot market will not be sufficient to establish a causal connection between a particular seller's alleged unlawful activities and the specific contract negotiations at issue. Claimants filed notice of their claims on August 17, 2012, and they filed their direct testimony on September 21, 2012. Respondents' filed their answering testimony on December 17, 2012 and staff filed its answering testimony on February 5, 2013. Respondents' cross-answering testimony is due February 22, 2013 and claimants' rebuttal testimony is due March 12, 2013. The hearing is scheduled to begin on April 15, 2013. On July 11, 2012, Avista Energy and Avista Corp. filed settlements of all issues in this docket with regard to the claims made by the City of Tacoma. On September 21, 2012, and September 26, 2012, the FERC issued orders approving the settlements between the City of Tacoma and Avista Corp. and Avista Energy, respectively, thus terminating those claims. The two remaining direct claimants against Avista Corp. and Avista Energy in this proceeding are the City of Seattle, Washington, and the California Attorney General (on behalf of CERS).

Both Avista Corp. and Avista Energy were buyers and sellers of energy in the Pacific Northwest energy market during the period between December 25, 2000 and June 20, 2001 and, are subject to potential claims in this proceeding, and if refunds are ordered by the FERC with regard to any particular contract, could be liable to make payments. The Company cannot predict the outcome of this proceeding or the amount of any refunds that Avista Corp. or Avista Energy could be ordered to make. Therefore, the Company cannot predict the potential impact the outcome of this matter could ultimately have on the Company's results of operations, financial condition or cash flows.

California Attorney General Complaint (the "Lockyer Complaint")

In May 2002, the FERC conditionally dismissed a complaint filed in March 2002 by the California AG that alleged violations of the FPA by the FERC and all sellers (including Avista Corp. and its subsidiaries) of electric power and energy into California. The complaint alleged that the FERC's adoption and implementation of market-based rate authority was flawed and, as a result, individual sellers should refund the difference between the rate charged and a just and reasonable rate. In May 2002, the FERC issued an order dismissing the complaint. In September 2004, the Ninth Circuit upheld the FERC's market-based rate authority, but held that the FERC erred in ruling that it lacked authority to order refunds for violations of its reporting requirement. The Court remanded the case for further proceedings.

In March 2008, the FERC issued an order establishing a trial-type hearing to address "whether any individual public utility seller's violation of the FERC's market-based rate quarterly reporting requirement led to an unjust and unreasonable rate for that particular seller in California during the 2000-2001 period." Purchasers in the California markets were given the opportunity to present evidence that "any seller that violated the quarterly reporting requirement failed to disclose an increased market share sufficient to give it the ability to exercise market power and thus cause its market-based rates to be unjust and unreasonable." In March 2010, the Presiding ALJ granted the motions for summary disposition and found that a hearing was "unnecessary" because the California AG, CPUC, PG&E and SCE "failed to apply the appropriate test to determine market power during the relevant time period." The judge determined that "[w]ithout a proper showing of market power, the California Parties failed to establish a prima facie case." In May 2011, the FERC affirmed "in all respects" the ALJ's decision. In June 2011, the California AG, CPUC, PG&E and SCE filed for rehearing of that order. Those rehearing requests were denied by the FERC on June 13, 2012. On June 20, 2012, the California AG, CPUC, PG&E and SCE filed a petition for review of the FERC's order with the Ninth Circuit. On February 6, 2013, the California AG, CPUC, PG&E, and SCE filed an unopposed motion with the Ninth Circuit, requesting that a briefing schedule be established, such that petitioners' joint opening brief would be due May 17, 2013; respondents' answering brief would be due July 16, 2013; respondent-intervenors' joint brief would be due August 6, 2013; and petitioners' optional joint reply brief would be due September 10, 2013.

Based on information currently known to the Company's management, the Company does not expect that this matter will have a material effect on its financial condition, results of operations or cash flows.

Colstrip Generating Project Complaint

In March 2007, two families that own property near the holding ponds from Units 3 & 4 of the Colstrip Generating Project (Colstrip) filed a complaint against the owners of Colstrip and Hydrometrics, Inc. in Montana District Court. Avista Corp. owns a 15 percent interest in Units 3 & 4 of Colstrip. The plaintiffs alleged that the holding ponds and remediation activities adversely impacted their property. They alleged contamination, decrease in water tables, reduced flow of streams on their property and other similar impacts to their property. They also sought punitive damages, attorney's fees, an order by the court to remove certain ponds, and the forfeiture of profits earned from the generation of Colstrip. In September 2010, the owners of Colstrip filed a motion with the court to enforce a settlement agreement that would resolve all issues between the parties. In October 2011 the court issued an order which enforces the settlement agreement. The plaintiffs subsequently appealed the court's decision and, on December 31, 2012, the Montana Supreme Court issued its decision, holding that the District Court properly granted the motion to enforce the settlement agreement. A petition for rehearing before the Supreme Court was denied on February 5, 2013. Under the settlement, Avista Corp.'s portion of payment (which was accrued in 2010) to the plaintiffs was not material to its financial condition, results of operations or cash flows.

Sierra Club and Montana Environmental Information Center Notice

On July 30, 2012, Avista Corp. received a Notice of Intent to Sue for violations of the Clean Air Act at Colstrip Steam Electric Station (Notice) from counsel on behalf of the Sierra Club and the Montana Environmental Information Center (MEIC), an Amended Notice was received on September 4, 2012, and a Second Amended Notice was received on October 1, 2012. A "supplemental" Notice was received on December 4, 2012. The Notice, Amended Notice, Second Amended Notice and Supplemental Notice were all addressed to the Owner or Managing Agent of Colstrip, and to the other Colstrip co-owners: PPL Montana, Puget Sound Energy, Portland General Electric Company, NorthWestern Energy and PacifiCorp. The Notice alleges certain violations of the Clean Air Act, including the New Source Review, Title V and opacity requirements. The Amended Notice alleges additional opacity violations at Colstrip, and the Second Amended Notice alleges additional Title V allegations. All three notices state that Sierra Club and MEIC will request a United States District Court to impose injunctive relief and civil penalties, require a beneficial environmental project in the areas affected by the alleged air pollution and require reimbursement of Sierra Club's and MEIC's costs of litigation and attorney's fees. Under the Clean Air Act, lawsuits cannot be filed until 60 days after the applicable notice date. Avista Corp. is evaluating the allegations set forth in the Notice, Amended Notice and Second Amended Notice and Supplemental Notice, and cannot at this time predict the outcome of this matter.

Harbor Oil Inc. Site

Avista Corp. used Harbor Oil Inc. (Harbor Oil) for the recycling of waste oil and non-PCB transformer oil in the late 1980s and early 1990s. In June 2005, the Environmental Protection Agency (EPA) Region 10 provided notification to Avista Corp. and several other parties, as customers of Harbor Oil, that the EPA had determined that hazardous substances were released at the Harbor Oil site in Portland, Oregon and that Avista Corp. and several other parties may be liable for investigation and cleanup of the site under the Comprehensive Environmental Response, Compensation, and Liability Act, commonly referred to as the federal "Superfund" law, which provides for joint and several liability. The initial indication from the EPA is that the site may be contaminated with PCBs, petroleum hydrocarbons, chlorinated solvents and heavy metals. Six potentially responsible parties, including Avista Corp., signed an Administrative Order on Consent with the EPA on May 31, 2007 to conduct a remedial investigation and feasibility study (RI/FS). The draft final RI/FS was submitted to the EPA in December 2011 and was accepted as pre-final in March 2012. The EPA issued a notice of its plan to make a finding of No Further Action in November 2012. Should the EPA make a No Further Action determination, the EPA stated it would then propose removal of the site from the National Priority List. Based on the review of its records related to Harbor Oil, the Company does not believe it is a significant contributor to this potential environmental contamination based on the small volume of waste oil it delivered to the Harbor Oil site. As such, the Company does not expect that this matter will have a material effect on its financial condition, results of operations or cash flows. The Company has expensed its share of the RI/FS ($0.5 million) for this matter.

Spokane River Licensing

The Company owns and operates six hydroelectric plants on the Spokane River. Five of these (Long Lake, Nine Mile, Upper Falls, Monroe Street, and Post Falls) are regulated under one 50-year FERC license issued in June 2009 and are referred to as the Spokane River Project. The sixth, Little Falls, is operated under separate Congressional authority and is not licensed by the FERC. The license incorporated the 4(e) conditions that were included in the December 2008 Settlement Agreement with the United States Department of Interior and the Coeur d'Alene Tribe, as well as the mandatory conditions that were agreed to in the Idaho 401 Water Quality Certifications and in the amended Washington 401 Water Quality Certification.

As part of the Settlement Agreement with the Washington Department of Ecology (Ecology), the Company has participated in the Total Maximum Daily Load (TMDL) process for the Spokane River and Lake Spokane, the reservoir created by Long Lake Dam. On May 20, 2010, the EPA approved the TMDL and on May 27, 2010, Ecology filed an amended 401 Water Quality Certification with the FERC for inclusion into the license. The amended 401 Water Quality Certification includes the Company's level of responsibility, as defined in the TMDL, for low dissolved oxygen levels in Lake Spokane. The Company submitted a draft Water Quality Attainment Plan for Dissolved Oxygen to Ecology in May 2012 and this was approved by Ecology in September 2012. This plan was subsequently approved by the FERC. The Company will begin to implement this plan, and management believes costs will not be material. On July 16, 2010, the City of Post Falls and the Hayden Area Regional Sewer Board filed an appeal with the United States District Court for the District of Idaho with respect to the EPA's approval of the TMDL. The Company, the City of Coeur d'Alene, Kaiser Aluminum and the Spokane River Keeper subsequently moved to intervene in the appeal. In September 2011, the EPA issued a stay to the litigation that will be in effect until either the permits are issued and all appeals and challenges are complete or the court lifts the stay. The stay is still in effect.

The IPUC and the UTC approved the recovery of licensing costs through the general rate case settlements in 2009. The Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to implementing the license for the Spokane River Project.

Cabinet Gorge Total Dissolved Gas Abatement Plan

Dissolved atmospheric gas levels in the Clark Fork River exceed state of Idaho and federal water quality standards downstream of the Cabinet Gorge Hydroelectric Generating Project (Cabinet Gorge) during periods when excess river flows must be diverted over the spillway. Under the terms of the Clark Fork Settlement Agreement as incorporated in Avista Corp.'s FERC license for the Clark Fork Project, Avista Corp. has worked in consultation with agencies, tribes and other stakeholders to address this issue. In the second quarter of 2011, the Company completed preliminary feasibility assessments for several alternative abatement measures. In 2012, Avista Corp., with the approval of the Clark Fork Management Committee (created under the Clark Fork Settlement Agreement), moved forward to test one of the alternatives by constructing a spill crest modification on a single spill gate. The modification will be tested in 2013 to evaluate whether this approach will provide significant TDG reduction, and whether it could be applied to other spill gates. The Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to this issue.

Fish Passage at Cabinet Gorge and Noxon Rapids

In 1999, the USFWS listed bull trout as threatened under the Endangered Species Act. The Clark Fork Settlement Agreement describes programs intended to help restore bull trout populations in the project area. Using the concept of adaptive management and working closely with the USFWS, the Company evaluated the feasibility of fish passage at Cabinet Gorge and Noxon Rapids. The results of these studies led, in part, to the decision to move forward with development of permanent facilities, among other bull trout enhancement efforts. As of the end of 2012, fishway design for Cabinet Gorge was still being finalized. Construction cost estimates and schedules will be developed in 2013. Fishway design for Noxon Rapids has also been initiated, and is still in early stages.

In January 2010, the USFWS revised its 2005 designation of critical habitat for the bull trout to include the lower Clark Fork River as critical habitat. The Company believes its ongoing efforts through the Clark Fork Settlement Agreement continue to effectively address issues related to bull trout. The Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to fish passage at Cabinet Gorge and Noxon Rapids.

Aluminum Recycling Site

In October 2009, the Company (through its subsidiary Pentzer Venture Holdings II, Inc. (Pentzer)) received notice from Ecology proposing to find Pentzer liable for a release of hazardous substances under the Model Toxics Control Act, under Washington state law. Pentzer owns property that adjoins land owned by the Union Pacific Railroad (UPR). UPR leased their property to operators of a facility designated by Ecology as "Aluminum Recycling - Trentwood." Operators of the UPR property maintained piles of aluminum dross, which designate as a state-only dangerous waste in Washington State. In the course of its business, the operators placed a portion of the aluminum dross pile on the property owned by Pentzer. Pentzer does not believe it is a contributor to any environmental contamination associated with the dross pile, and submitted a response to Ecology's proposed findings in November 2009. In December 2009, Pentzer received notice from Ecology that it had been designated as a potentially liable party for any hazardous substances located on this site. UPR completed a Remedial Investigation/Feasibility Study during 2011, which was approved by Ecology in 2012. Based on information currently known to the Company's management, the Company does not expect this issue will have a material effect on its financial condition, results of operations or cash flows.

Collective Bargaining Agreements

The Company's collective bargaining agreement with the International Brotherhood of Electrical Workers represents approximately 45 percent of all of Avista Corp.'s employees. The agreement with the local union in Washington and Idaho representing the majority (approximately 90 percent) of the bargaining unit employees expires in March 2014. Two local agreements in Oregon, which cover approximately 50 employees, expire in March 2014.

Other Contingencies

In the normal course of business, the Company has various other legal claims and contingent matters outstanding. The Company believes that any ultimate liability arising from these actions will not have a material impact on its financial condition, results of operations or cash flows. It is possible that a change could occur in the Company's estimates of the probability or amount of a liability being incurred. Such a change, should it occur, could be significant.

The Company routinely assesses, based on studies, expert analyses and legal reviews, its contingencies, obligations and commitments for remediation of contaminated sites, including assessments of ranges and probabilities of recoveries from other responsible parties who either have or have not agreed to a settlement as well as recoveries from insurance carriers. The Company's policy is to accrue and charge to current expense identified exposures related to environmental remediation sites based on estimates of investigation, cleanup and monitoring costs to be incurred. For matters that affect Avista Corp.'s operations, the Company seeks, to the extent appropriate, recovery of incurred costs through the ratemaking process.

The Company has potential liabilities under the Endangered Species Act for species of fish that have either already been added to the endangered species list, listed as "threatened" or petitioned for listing. Thus far, measures adopted and implemented have had minimal impact on the Company. However, the Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to this issue.

Under the federal licenses for its hydroelectric projects, the Company is obligated to protect its property rights, including water rights. The state of Montana is examining the status of all water right claims within state boundaries. Claims within the Clark Fork River basin could adversely affect the energy production of the Company's Cabinet Gorge and Noxon Rapids hydroelectric facilities. The state of Idaho has initiated adjudication in northern Idaho, which will ultimately include the lower Clark Fork River, the Spokane River and the Coeur d'Alene basin. In addition, the state of Washington has indicated an interest in initiating adjudication for the Spokane River basin in the next several years. The Company is and will continue to be a participant in these adjudication processes. The complexity of such adjudications makes each unlikely to be concluded in the foreseeable future. As such, it is not possible for the Company to estimate the impact of any outcome at this time.

NOTE 19. INFORMATION SERVICES CONTRACTS

The Company has information services contracts that expire at various times through 2018. The largest of these contracts provides for increases due to changes in the cost of living index and further provides flexibility in the annual obligation from year-to-year subject to a three-year true-up cycle. Total payments under these contracts were as follows for the years ended December 31 (dollars in thousands):

	2012	2011
Information service contract payments	$ 13,221	$ 13,038

The majority of the costs are included in other operating expenses in the Statements of Income. The following table details minimum future contractual commitments for these agreements (dollars in thousands):

	2013	2014	2015	2016	2017	Thereafter	Total
Contractual obligations	$ 11,175	$ 9,400	$ 8,700	$ 8,700	$ 8,600	$ 900	$ 47,475

NOTE 20. REGULATORY MATTERS

Power Cost Deferrals and Recovery Mechanisms

Deferred power supply costs are recorded as a deferred charge on the Balance Sheets for future prudence review and recovery through retail rates. The power supply costs deferred include certain differences between actual net power supply costs incurred by Avista Corp. and the costs included in base retail rates. This difference in net power supply costs primarily results from changes in:

- short-term wholesale market prices and sales and purchase volumes,
- the level of hydroelectric generation,
- the level of thermal generation (including changes in fuel prices), and
- retail loads.

In Washington, the Energy Recovery Mechanism (ERM) allows Avista Corp. to periodically increase or decrease electric rates with UTC approval to reflect changes in power supply costs. The ERM is an accounting method used to track certain differences between actual net power supply costs, net of the margin on wholesale sales and sales of fuel, and the amount included in base retail rates for Washington customers. In the 2010 Washington general rate case settlement, the parties agreed that there would be no deferrals under the ERM for 2010. Deferrals under the ERM resumed in 2011. Total net deferred power costs under the ERM were a liability of $22.2 million as of December 31, 2012, and this balance represents the customer portion of the deferred power costs. As part of the approved Washington general rate case settlement filed on October 19, 2012 and approved on December 26, 2012, during 2013 a one-year credit of $4.4 million would be returned to electric customers from the existing ERM deferral balance so the net average electric rate increase to customers in 2013 would be 2.0 percent. Additionally, during 2014 a one-year credit of $9.0 million would be returned to electric customers from the then-existing ERM deferral balance, if such funds are available, so the net average electric rate increase to customers effective January 1, 2014 would be 2.0 percent. The credits to customers from the ERM balances would not impact the Company's net income.

Under the ERM, the Company absorbs the cost or receives the benefit from the initial amount of power supply costs in excess of or below the level in retail rates, which is referred to as the deadband. The annual (calendar year) deadband amount is currently $4.0 million. The Company will incur the cost of, or receive the benefit from, 100 percent of this initial power supply cost variance. The Company shares annual power supply cost variances between $4.0 million and $10.0 million with its customers. There is a 50 percent customers/50 percent Company sharing ratio when actual power supply expenses are higher (surcharge to customers) than the amount included in base retail rates within this band. There is a 75 percent customers/25 percent Company sharing ratio when actual power supply expenses are lower (rebate to customers) than the amount included in base retail rates within this band. To the extent that the annual power supply cost variance from the amount included in base rates exceeds $10.0 million, 90 percent of the cost variance is deferred for future surcharge or rebate. The Company absorbs or receives the benefit in power supply costs of the remaining 10 percent of the annual variance beyond $10.0 million without affecting current or future customer rates.

The following is a summary of the ERM:

Annual Power Supply Cost Variability	Deferred for Future Surcharge or Rebate to Customers	Expense or Benefit
within +/- $0 to $4 million (deadband)	0%	100%
higher by $4 million to $10 million	50%	50%
lower by $4 million to $10 million	75%	25%
higher or lower by over $10 million	90%	10%

As part of the 2012 Washington general rate case settlement, the proposed modifications to the ERM deadband and other sharing bands that were included in the original April 2012 general rate case filing were not agreed to and the ERM will continue unchanged. However, the trigger point at which rates will change under the ERM was modified to be $30 million rather than the current 10 percent of base revenues (approximately $45 million) under the mechanism.

Avista Corp. has a Power Cost Adjustment (PCA) mechanism in Idaho that allows it to modify electric rates on October 1 of each year with Idaho Public Utilities Commission (IPUC) approval. Under the PCA mechanism, Avista Corp. defers 90 percent of the difference between certain actual net power supply expenses and the amount included in base retail rates for its Idaho customers. These annual

October 1 rate adjustments recover or rebate power costs deferred during the preceding July-June twelve-month period. Total net power supply costs deferred under the PCA mechanism were a regulatory liability of $5.1 million as of December 31, 2012 and $0.7 million as of December 31, 2011.

Natural Gas Cost Deferrals and Recovery Mechanisms

Avista Corp. files a purchased gas cost adjustment (PGA) in all three states it serves to adjust natural gas rates for: 1) estimated commodity and pipeline transportation costs to serve natural gas customers for the coming year, and 2) the difference between actual and estimated commodity and transportation costs for the prior year. These annual PGA filings in Washington and Idaho provide for the deferral, and recovery or refund, of 100 percent of the difference between actual and estimated commodity and pipeline transportation costs, subject to applicable regulatory review. The annual PGA filing in Oregon provides for deferral, and recovery or refund, of 100 percent of the difference between actual and estimated pipeline transportation costs and commodity costs that are fixed through hedge transactions. Commodity costs that are not hedged for Oregon customers are subject to a sharing mechanism whereby Avista Corp. defers, and recovers or refunds, 90 percent of the difference between these actual and estimated costs. Total net deferred natural gas costs to be refunded to customers were a liability of $6.9 million as of December 31, 2012 and $12.1 million as of December 31, 2011.

Washington General Rate Cases

In December 2011, the UTC approved a settlement agreement in the Company's electric and natural gas general rate cases filed in May 2011. As agreed to in the settlement agreement, base electric rates for the Company's Washington customers increased by an average of 4.6 percent, which is designed to increase annual revenues by $20.0 million. Base natural gas rates for the Company's Washington customers increased by an average of 2.4 percent, which is designed to increase annual revenues by $3.75 million. The new electric and natural gas rates became effective on January 1, 2012.

As part of the settlement agreement, the Company agreed to not file a general rate case in Washington prior to April 1, 2012.

The settlement agreement also provides for the deferral of certain generation plant maintenance costs. In order to address the variability in year-to-year maintenance costs, beginning in 2011, the Company is deferring changes in maintenance costs related to its Coyote Spring 2 natural gas-fired generation plant and its 15 percent ownership interest in Units 3 & 4 of the Colstrip generation plant. The Company compares actual, non-fuel, maintenance expenses for the Coyote Springs 2 and Colstrip plants with the amount of baseline maintenance expenses used to establish base retail rates, and defers the difference. The deferral occurred annually, with no carrying charge, with deferred costs being amortized over a four-year period, beginning in January of the year following the period costs are deferred. The amount of expense to be requested for recovery in future general rate cases would be the actual maintenance expense recorded in the test period, less any amount deferred during the test period, plus the amortization of previously deferred costs. Total net deferred costs under this mechanism in Washington were a regulatory asset of $4.0 million as of December 31, 2012 compared to a regulatory liability of $0.5 million as of December 31, 2011.

As part of the settlement agreement in October 2012 to the Company's latest general rate case discussed in further detail below, the parties have agreed that the maintenance cost deferral mechanism on these generation plants will terminate on December 31, 2012, with the four-year amortization of the 2011 and 2012 deferrals to conclude in 2015 and 2016, respectively.

In December 2012, the UTC approved a settlement agreement in the Company's electric and natural gas general rate cases filed in April 2012. As agreed to in the settlement, effective January 1, 2013, base rates for Washington electric customers increased by an overall 3.0 percent (designed to increase annual revenues by $13.6 million), and base rates for Washington natural gas customers increased by an overall 3.6 percent (designed to increase annual revenues by $5.3 million). The settling parties agree that a one-year credit of $4.4 million will be returned to electric customers from the existing ERM deferral balance so the net average electric rate increase impact to the Company's customers in 2013 will be 2.0 percent. The credit to customers from the ERM balance will not impact the Company's earnings.

The settlement also provided that, effective January 1, 2014, the Company will implement temporary base rate increases for Washington electric customers by an overall 3.0 percent (designed to increase annual revenues by $14.0 million), and for Washington natural gas customers by an overall 0.9 percent (designed to increase annual revenues by $1.4 million). The settling parties agree that a one-year credit of $9.0 million will be returned to electric customers from the then-existing ERM deferral balance, if such funds are available, so the net average electric rate increase to customers effective January 1, 2014 would be 2.0 percent. The credit to customers from the ERM balance will not impact the Company's earnings.

The UTC order approving the settlement agreement included certain conditions. The new retail rates to become effective January 1, 2014 will be temporary rates, and on January 1, 2015 electric and natural gas base rates will revert back to 2013 levels absent any intervening action from the UTC. The settlement agreement also states that the Company will not file a general rate case in Washington that would cause an increase in base retail rates before January 1, 2015. The Company could, however, make a filing prior to January 2015, but new rates resulting from the filing would not take effect prior to January 1, 2015. This does not preclude the Company from filing annual rate adjustments such as the PGA.

In addition, in its Order, the UTC found that much of the approved base rate increases are justified by the planned capital expenditures necessary to upgrade and maintain the Company's utility facilities. If these capital projects are not completed to a level that was contemplated in the original settlement agreement, this could result in base rates which are considered too high by the UTC. As a result, Avista Corp. must file capital expenditure progress reports with the UTC on a periodic basis so that the UTC can monitor the capital expenditures and ensure they are in line with those contemplated in the settlement agreement.

The settlement agreement provides for an authorized return on equity of 9.8 percent and an equity ratio of 47.0 percent, resulting in an overall return on rate base of 7.64 percent.

Idaho General Rate Cases

In September 2011, the IPUC approved a settlement agreement in the Company's general rate case filed in July 2011. The new electric and natural gas rates became effective on October 1, 2011. As agreed to in the settlement agreement, base electric rates for the Company's Idaho customers increased by an average of 1.1 percent, which was designed to increase annual revenues by $2.8 million. Base natural gas rates for the Company's Idaho customers increased by an average of 1.6 percent, which was designed to increase annual revenues by $1.1 million.

As part of the settlement agreement, the Company agreed to not seek to make effective a change in base electric or natural gas rates prior to April 1, 2013, by means of a general rate case filing. This does not preclude the Company from filing annual rate adjustments such as the PCA and the PGA.

The settlement agreement also provides for the deferral of certain generation plant operation and maintenance costs. In order to address the variability in year-to-year operation and maintenance costs, beginning in 2011, the Company is deferring changes in operation and maintenance costs related to the Coyote Spring 2 natural gas-fired generation plant and its 15 percent ownership interest in Units 3 & 4 of the Colstrip generation plant. The Company compares actual, non-fuel, operation and maintenance expenses for the Coyote Springs 2 and Colstrip plants with the amount of expenses authorized for recovery in base rates in the applicable deferral year, and defers the difference from that currently authorized. The deferral occurs annually, with no carrying charge, with deferred costs being amortized over a three-year period, beginning in January of the year following the period costs are deferred. The amount of expense to be requested for recovery in future general rate cases will be the actual operation and maintenance expense recorded in the test period, less any amount deferred during the test period, plus the amortization of previously deferred costs. Total net deferred costs under this mechanism in Idaho were regulatory assets of $2.3 million as of December 31, 2012 and $0.1 million as of December 31, 2011.

On October 11, 2012, the Company filed electric and natural gas general rate cases with the IPUC. The Company requested an overall increase in electric rates of 4.6 percent and an overall increase in natural gas rates of 7.2 percent. The filings were designed to increase annual electric revenues by $11.4 million and increase annual natural gas revenues by $4.6 million. The Company's requests were based on a proposed overall rate of return of 8.46 percent, with a common equity ratio of 50 percent and a 10.9 percent return on equity.

On February 6, 2013, Avista Corp. and certain other parties filed a settlement agreement with the IPUC with respect to Avista Corp.'s electric and natural gas general rate cases. Parties to the settlement agreement include the staff of the IPUC, Clearwater Paper Corporation, Idaho Forest Group, LLC, the Idaho Conservation League, and the Company. Community Action Partnership Association of Idaho (CAPAI), a low-income customer advocacy group, and the Snake River Alliance did not join in the settlement agreement. However, on February 20, 2013 the Snake River Alliance provided a letter to the IPUC supporting the settlement agreement. This settlement agreement is subject to approval by the IPUC and would conclude the proceedings related the general rate requests filed by the Company on October 11, 2012. New rates would be implemented in two phases: April 1, 2013 and October 1, 2013.

The settlement agreement proposes that, effective April 1, 2013, Avista Corp. would be authorized to implement a base rate increase for Idaho natural gas customers of 4.9 percent (designed to increase annual revenues by $3.1 million). There would be no change in base electric rates on April 1, 2013. However, the settlement agreement would provide for the recovery of the costs of the Palouse Wind Project through the Power Cost Adjustment mechanism beginning April 1, 2013.

The settlement agreement also proposes that, effective October 1, 2013, Avista Corp. would be authorized to implement a base rate increase for Idaho natural gas customers of 2.0 percent (designed to increase annual revenues by $1.3 million). A credit resulting from deferred natural gas costs of $1.6 million would be returned to the Company's Idaho natural gas customers from October 1, 2013 through December 31, 2014, so the net annual average natural gas rate increase to natural gas customers effective October 1, 2013 would be 0.3 percent.

Further, the settlement proposes that, effective October 1, 2013, Avista Corp. would be authorized to implement a base rate increase for Idaho electric customers of 3.1 percent (designed to increase annual revenues by $7.8 million). A $3.9 million credit resulting from a payment to be made to Avista Corp. by the Bonneville Power Administration relating to its prior use of Avista Corp.'s transmission system would be returned to Idaho electric customers from October 1, 2013 through December 31, 2014, so the net annual average electric rate increase to electric customers effective October 1, 2013 would be 1.9 percent.

The $1.6 million credit to Idaho natural gas customers and the $3.9 million credit to Idaho electric customers would not impact the Company's net income.

Also included in the settlement agreement is a provision that Avista Corp. may file a general rate case in Idaho in 2014; however, new rates resulting from the filing would not take effect prior to January 1, 2015.

The settlement agreement provides for an authorized return on equity of 9.8 percent and an equity ratio of 50.0 percent.

The settlement also includes an after-the-fact earnings test for 2013 and 2014, such that if Avista Corp., on a consolidated basis for electric and natural gas operations in Idaho, earns more than a 9.8 percent return on equity, Avista Corp. would refund to customers 50 percent of any earnings above the 9.8 percent.

Oregon General Rate Cases

In March 2011, the OPUC approved an all-party settlement stipulation in the Company's general rate case that was filed in September 2010. The settlement provides for an overall rate increase of 3.1 percent for the Company's Oregon customers, designed to increase annual revenues by $3.0 million. Part of the rate increase became effective March 15, 2011, with the remaining increase effective June 1, 2011. An additional rate adjustment designed to increase revenues by $0.6 million will occur on June 1, 2012 to recover capital costs associated with certain reinforcement and replacement projects upon a demonstration that such projects are complete and the costs were prudently incurred.

On January 1, 2013, Avista Corp. purchased the Klamath Falls Lateral (Lateral), a 15-mile, 6-inch natural gas transmission pipeline from Williams Northwest Pipeline (Williams). The Klamath Falls Lateral interconnects with another interstate pipeline, Gas Transmission Northwest, to transport natural gas to serve Avista Corp.'s customers in Klamath Falls, Oregon. The purchase price was approximately $2.3 million and will save Oregon customers approximately $1.4 million annually as Avista Corp. will be able to reduce its contracted natural gas transportation requirements from Williams. In Order No. 12-429, the OPUC approved the Company's request to recover from customers the revenue requirement associated with the purchase of the Lateral, which is approximately $0.5 million annually. This approval will provide a return of and a return on Avista Corp.'s investment in the lateral. While the OPUC approved the recovery of the revenue requirement, it will not determine whether the purchase of the Lateral was prudent until the Company's next Oregon general rate case.

NOTE 21. SUPPLEMENTAL CASH FLOW INFORMATION (in thousands)

	2012	2011
Cash paid for interest	$68,508	$63,876
Cash paid for income taxes	$6,631	$16,631

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

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

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

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year		(4,325,953)		
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value	134,046	(1,444,919)		
4	Total (lines 2 and 3)	134,046	(1,444,919)		
5	Balance of Account 219 at End of Preceding Quarter/Year	134,046	(5,770,872)		
6	Balance of Account 219 at Beginning of Current Year	134,046	(5,770,872)		
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	(290,263)			
8	Current Quarter/Year to Date Changes in Fair Value	323,478	(1,096,549)		
9	Total (lines 7 and 8)	33,215	(1,096,549)		
10	Balance of Account 219 at End of Current Quarter/Year	167,261	(6,867,421)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1			(4,325,953)		
2					
3			(1,310,873)		
4			(1,310,873)	100,223,872	98,912,999
5			(5,636,826)		
6			(5,636,826)		
7			(290,263)		
8			(773,071)		
9			(1,063,334)	78,210,066	77,146,732
10			(6,700,160)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

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

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

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	4,032,753,211	3,033,013,660
4	Property Under Capital Leases	6,442,348	
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	4,039,195,559	3,033,013,660
9	Leased to Others		
10	Held for Future Use	4,989,371	4,773,791
11	Construction Work in Progress	139,513,892	80,205,686
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	4,183,698,822	3,117,993,137
14	Accum Prov for Depr, Amort, & Depl	1,408,153,972	1,075,820,044
15	Net Utility Plant (13 less 14)	2,775,544,850	2,042,173,093
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	1,375,661,341	1,065,032,018
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	32,492,631	10,788,026
22	Total In Service (18 thru 21)	1,408,153,972	1,075,820,044
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	1,408,153,972	1,075,820,044

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
777,111,352				222,628,199	3
858,865				5,583,483	4
					5
					6
					7
777,970,217				228,211,682	8
					9
215,580					10
18,296,122				41,012,084	11
					12
796,481,919				269,223,766	13
269,742,834				62,591,094	14
526,739,085				206,632,672	15
					16
					17
268,498,775				42,130,548	18
					19
					20
1,244,059				20,460,546	21
269,742,834				62,591,094	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
269,742,834				62,591,094	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

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

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents	44,651,922	
4	(303) Miscellaneous Intangible Plant	4,288,270	1,241,064
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	48,940,192	1,241,064
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	2,230,395	1,257,906
9	(311) Structures and Improvements	125,680,440	543,106
10	(312) Boiler Plant Equipment	162,508,052	2,464,583
11	(313) Engines and Engine-Driven Generators	6,770	
12	(314) Turbogenerator Units	51,256,394	1,093,319
13	(315) Accessory Electric Equipment	27,093,815	670,237
14	(316) Misc. Power Plant Equipment	15,902,021	42,254
15	(317) Asset Retirement Costs for Steam Production	585,275	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	385,263,162	6,071,405
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	57,332,232	1,251,728
28	(331) Structures and Improvements	43,273,610	1,011,269
29	(332) Reservoirs, Dams, and Waterways	122,714,977	786,507
30	(333) Water Wheels, Turbines, and Generators	155,527,371	7,791,074
31	(334) Accessory Electric Equipment	33,962,255	49,351
32	(335) Misc. Power PLant Equipment	8,036,326	91,016
33	(336) Roads, Railroads, and Bridges	1,999,563	21,193
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	422,846,334	11,002,138
36	D. Other Production Plant		
37	(340) Land and Land Rights	905,167	
38	(341) Structures and Improvements	16,487,922	93,638
39	(342) Fuel Holders, Products, and Accessories	21,163,536	5,442
40	(343) Prime Movers	21,876,781	1,843,247
41	(344) Generators	196,822,105	4,289,082
42	(345) Accessory Electric Equipment	16,928,460	205,367
43	(346) Misc. Power Plant Equipment	1,625,721	138,176
44	(347) Asset Retirement Costs for Other Production	351,683	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	276,161,375	6,574,952
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,084,270,871	23,648,495

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
					2
			44,651,922		3
519,618			5,009,716		4
519,618			49,661,638		5
					6
					7
			3,488,301		8
2,539			126,221,007		9
936,177			164,036,458		10
			6,770		11
22,114			52,327,599		12
1,601,785			26,162,267		13
2,914			15,941,361		14
			585,275		15
2,565,529			388,769,038		16
					17
					18
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					22
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					24
					25
					26
		-632,879	57,951,081		27
16,405			44,268,474		28
		632,879	124,134,363		29
266,410		-7,554	163,044,481		30
6,648		7,554	34,012,512		31
			8,127,342		32
			2,020,756		33
					34
289,463			433,559,009		35
					36
			905,167		37
			16,581,560		38
			21,168,978		39
31,469			23,688,559		40
2,248,555			198,862,632		41
21,829			17,111,998		42
44,370			1,719,527		43
			351,683		44
2,346,223			280,390,104		45
5,201,215			1,102,718,151		46

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	19,251,651	-520,364
49	(352) Structures and Improvements	16,777,512	388,452
50	(353) Station Equipment	203,280,704	10,655,521
51	(354) Towers and Fixtures	17,120,820	2,111
52	(355) Poles and Fixtures	145,612,293	9,529,788
53	(356) Overhead Conductors and Devices	112,615,430	4,196,717
54	(357) Underground Conduit	2,605,488	
55	(358) Underground Conductors and Devices	2,330,072	
56	(359) Roads and Trails	1,872,246	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	521,466,216	24,252,225
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	6,437,090	297,959
61	(361) Structures and Improvements	17,668,762	420,768
62	(362) Station Equipment	105,536,110	7,751,957
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	244,062,954	18,823,738
65	(365) Overhead Conductors and Devices	163,385,669	11,104,061
66	(366) Underground Conduit	82,309,152	3,487,069
67	(367) Underground Conductors and Devices	136,552,448	5,826,387
68	(368) Line Transformers	191,749,400	10,579,855
69	(369) Services	123,632,342	9,205,427
70	(370) Meters	47,867,798	704,058
71	(371) Installations on Customer Premises		
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	34,636,469	1,882,383
74	(374) Asset Retirement Costs for Distribution Plant	129,707	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,153,967,901	70,083,662
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	385,053	
87	(390) Structures and Improvements	5,729,823	507,001
88	(391) Office Furniture and Equipment	3,250,957	4,985,599
89	(392) Transportation Equipment	16,507,978	1,870,394
90	(393) Stores Equipment	395,329	
91	(394) Tools, Shop and Garage Equipment	3,198,301	96,267
92	(395) Laboratory Equipment	1,047,345	
93	(396) Power Operated Equipment	34,614,512	4,132,769
94	(397) Communication Equipment	43,997,759	4,963,790
95	(398) Miscellaneous Equipment	13,156	17,355
96	SUBTOTAL (Enter Total of lines 86 thru 95)	109,140,213	16,573,175
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant		
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	109,140,213	16,573,175
100	TOTAL (Accounts 101 and 106)	2,917,785,393	135,798,621
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	2,917,785,393	135,798,621

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
			18,731,287		48
61,592			17,104,372		49
714,052			213,222,173		50
			17,122,931		51
364,024		19,819	154,797,876		52
48,436		3,905	116,767,616		53
			2,605,488		54
			2,330,072		55
			1,872,246		56
					57
1,188,104		23,724	544,554,061		58
					59
			6,735,049		60
119,427			17,970,103		61
1,949,860			111,338,207		62
					63
1,551,487			261,335,205		64
738,288			173,751,442		65
118,111			85,678,110		66
730,080			141,648,755		67
3,356,824			198,972,431		68
189,219			132,648,550		69
606,236			47,965,620		70
					71
					72
133,382			36,385,470		73
			129,707		74
9,492,914			1,214,558,649		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			385,053		86
387		-7,034	6,229,403		87
366,554			7,870,002		88
769,988			17,608,384		89
			395,329		90
108,629			3,185,939		91
127,321			920,024		92
2,705,607			36,041,674		93
106,707			48,854,842		94
			30,511		95
4,185,193		-7,034	121,521,161		96
					97
					98
4,185,193		-7,034	121,521,161		99
20,587,044		16,690	3,033,013,660		100
					101
					102
					103
20,587,044		16,690	3,033,013,660		104

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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ELECTRIC 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 $250,000 or more. Group other items of property held for future use.
2. For property having an original cost of $250,000 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	Land and Rights:			
2				
3				
4	Distribution Plant Land, Spokane, Washington	Oct 2008	Unknown	1,623,321
5	Distribution UG Plant Land, Spokane, Washington	Dec 2010	Unknown	216,314
6	Transmission Plant Land, Spokane, Washington	Dec 2010	Unknown	193,587
7	Transmission Plant Land, Moscow, Idaho	March 2011	Unknown	126,640
8	Distribution Plant Land, Spokane, Washington	March 2011	Unknown	540,307
9	Distribution Plant Land, Spokane, Washington	Oct 2011	Unknown	414,073
10	Transmission Plant Land, Spokane, Washington	Dec 2011	Unknown	1,143,033
11	Distribution Plant Land, Spokane, Washington	Dec 2011	Unknown	250,489
12	Other Production Plant Land, Spokane, Washington	Dec 2011	Unknown	40,896
13	Distribution Plant Land, Deary, Idaho	June 2012	Unknown	72,367
14	Transmission Plant Land, Thornton, Washington	Aug 2012	Unknown	1,383
15	Distribution Plant Land, Spokane, Washington	Oct 2012	Unknown	151,381
16				
17				
18				
19				
20				
21	Other Property:			
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47	Total			4,773,791

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Clark Fork Implementation PME Agreement	11,710,072
2	Nine Mile Redevelopment	10,630,643
3	Moscow 230kV Sub - Rebuild 230kV Yard	7,976,641
4	Transportation Equipment	5,832,360
5	CS2 LTSA Capital Add	5,033,681
6	Post Falls Intake Gare Replacement	4,519,054
7	Spokane River Implementation PME Agreement	4,281,265
8	Little Falls Powerhouse Redevelopment	3,294,285
9	Regulating Hydro	2,699,572
10	High Voltage Protection Upgrade	2,117,502
11	Productivity Initiative	1,917,613
12	Wood Pole Management Program	1,782,756
13	Spokane Smart Circuit	1,780,637
14	Blue Creek 115kV Rebuild	1,140,231
15	Line Ratings Mitigation Project	1,105,744
16	Minor Projects Under $1,000,000	13,322,506
17		
18	Research Development and Demonstration:	
19	SGDP Pullman Smard Grid Demonstration Project	1,061,124
20		
21		
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43	TOTAL	80,205,686

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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	1,012,217,392	1,012,217,392		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense				
4	(403.1) Depreciation Expense for Asset Retirement Costs	74,527,789	74,527,789		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	1,106,873	1,106,873		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	-275,172	-275,172		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	75,359,490	75,359,490		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	20,061,843	20,061,843		
13	Cost of Removal	1,075,876	1,075,876		
14	Salvage (Credit)	972,119	972,119		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	20,165,600	20,165,600		
16	Other Debit or Cr. Items (Describe, details in footnote):	-2,379,264	-2,379,264		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	1,065,032,018	1,065,032,018		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	272,295,483	272,295,483		
21	Nuclear Production				
22	Hydraulic Production-Conventional	115,896,200	115,896,200		
23	Hydraulic Production-Pumped Storage				
24	Other Production	76,241,054	76,241,054		
25	Transmission	183,292,936	183,292,936		
26	Distribution	368,105,672	368,105,672		
27	Regional Transmission and Market Operation				
28	General	49,200,673	49,200,673		
29	TOTAL (Enter Total of lines 20 thru 28)	1,065,032,018	1,065,032,018		

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

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

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1				
2	Avista Capital - Common Stock	1997		170,053,827
3	Avista Capital - Equity in Earnings			-101,447,380
4	OCI Investment in Subs			134,045
5	Avista Capital - Other Changes in Net Investment			3,230,876
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41				
42	Total Cost of Account 123.1 $ 0		TOTAL	71,971,368

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues form investments, including such revenues form securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
	46,675,006	216,728,833		2
-1,206,861		-102,654,241		3
	33,216	167,261		4
	1,241,694	4,472,570		5
				6
				7
				8
				9
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-1,206,861	47,949,916	118,714,423		42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

MATERIALS AND SUPPLIES

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

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	4,248,389	4,120,767	(1)
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	15,450,514	16,046,143	(1)
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	2,354,732	2,645,483	(1)
8	Transmission Plant (Estimated)	48,245	54,922	(1)
9	Distribution Plant (Estimated)	216,491	264,561	(1)
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	3,676,223	4,864,288	(1),(2)
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	21,746,205	23,875,397	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)			
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	25,994,594	27,996,164	

Schedule Page: 227 Line No.: 1 Column: d

(1) Electric
(2) Gas

Schedule Page: 227 Line No.: 5 Column: d

Footnote Linked. See note on 227, Row: 1, col/item:

Schedule Page: 227 Line No.: 7 Column: d

Footnote Linked. See note on 227, Row: 1, col/item:

Schedule Page: 227 Line No.: 8 Column: d

Footnote Linked. See note on 227, Row: 1, col/item:

Schedule Page: 227 Line No.: 9 Column: d

Footnote Linked. See note on 227, Row: 1, col/item:

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

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	Lancaster L&L Interconnect	24,709	186200		
3					
4					
5					
6					
7					
8					
9					
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19					
20					
21	**Generation Studies**				
22	AVA Noxon Upgrade	40,214	186200		
23	AVA Nine Mile Upgrade	209	186200		
24	Rattlesnake Flat Interconnect	9,347	186200		
25	Horizon Wind Interconnect	61,845	186200		
26	Nighthawk LLC Interconnect	3,914	186200		
27	Palouse Wind Phase II	110	186200		
28	Deep Creek Hydro Interconnect	327	186200		
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Schedule Page: 231 Line No.: 2 Column: a

Total charges incurred life to date.

Schedule Page: 231 Line No.: 22 Column: a

Total charges incurred life to date.

Schedule Page: 231 Line No.: 23 Column: a

Total charges incurred life to date.

Schedule Page: 231 Line No.: 24 Column: a

Total charges incurred life to date.

Schedule Page: 231 Line No.: 25 Column: a

Total charges incurred life to date.

Schedule Page: 231 Line No.: 26 Column: a

Total charges incurred life to date.

Schedule Page: 231 Line No.: 27 Column: a

Total charges incurred life to date.

Schedule Page: 231 Line No.: 28 Column: a

Total charges incurred life to date.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter /Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Regulatory Asset FAS 106	472,752		407	472,752	
2	Reg Asset Post Ret Liab	260,358,633	46,049,036			306,407,669
3	Regulatory Asset FAS109 Utility Plant	70,616,515		283	5,151,910	65,464,605
4	Regulatory Asset Lancaster Generation	5,326,667		407	1,360,000	3,966,667
5	Regulatory Asset FAS109 DSIT Non Plant	1,762,314		283	97,548	1,664,766
6	Regulatory Asset FAS109 DFIT State Tax Cr	6,669,689	794,495			7,464,184
7	Regulatory Asset FAS109 WNP3	5,653,819		283	737,482	4,916,337
8	Regulatory Asset Roseburg/Medford	142,470	122,541			265,011
9	Regulatory Asset- Spokane River Relicense	701,098		407	78,736	622,362
10	Regulatory Asset- Spokane River PM&E	649,198		557	73,312	575,886
11	Regulatory Asset- Lake CDA Fund	9,648,664		407	211,065	9,437,599
12	Regulatory Asset- Lake CDA IPA Fund	2,000,000				2,000,000
13	Reg Assets- Decouplings Surcharge	190,282		407	182,958	7,324
14	Regulatory Asset ID DSIT Amort	70,934		407	70,934	
15	Regulatory Asset RTO Deposits- ID					
16	Regulatory Asset BPA Residential Exchange	104,636	436,169			540,805
17	Regulatory Asset ERM Approved					
18	Regulatory Asset- CNC Transmission	735,906		407	252,637	483,269
19	DEF CS2 & COLSTRIP	143,226	6,685,420	407	516,251	6,312,395
20	LiDAR O&M REG DEF	337,879	249,379			587,258
21	ID Wind Gen AFUDC	358,264	11,109			369,373
22	Regulatory Asset Wartsila Units	1,089,605		407	337,788	751,817
23	MTM St Regulatory Asset	69,684,643		244	34,603,118	35,081,525
24	MTM Lt Regulatory Asset	40,345,338		244	15,127,641	25,217,697
25	Regulatory Asset FAS143 Asset Retirement Obligation	2,717,489		230	318,644	2,398,845
26	Reg Asset AN- CDA Lake Settlement	39,186,540		407	1,559,332	37,627,208
27	Reg Asset WA-CDA Lake Settlement	1,356,388		407	152,118	1,204,270
28	Regulatory Asset Workers Comp	2,623,100		242	344,422	2,278,678
29	CS2 Lev Ret	1,250,099		407	340,600	909,499
30	Regulatory Asset ID PCA Deferral 2	2,017,929		557	2,017,929	
31	Regulatory Asset ID PCA Deferral 3	(2,762,169)	2,762,168			-1
32	DSM Asset	798,418	2,578,599	242	798,418	2,578,599
33	SWAPS ON FMBS		40,697,807	254		40,697,807
34						
35						
36						
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42						
43						
44	**TOTAL :**	524,250,326	100,386,723		64,805,595	559,831,454

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1						
2	Colstrip Common Fac.	1,110,999				1,110,999
3	Regulatory Asset-Decoupling def	-19,852	19,852			
4						
5	Regulatory Asset-Mt lease pym	1,713,249		540	360,684	1,352,565
6	Regulatory Asset-Mt lease pymt	3,383,112		540	676,632	2,706,480
7	Colstrip Common Fac.	2,355,642				2,355,642
8	Prepaid airplane Lease LT	466,025		931	147,166	318,859
9	Misc DD- airplane lease	90,181	12,556			102,737
10	Plant Allocation of clearing jr	1,140,273	2,444,223			3,584,496
11	Misc DD- IR Swaps	18,895,143		245	18,895,143	
12	Misc Error Suspense	5,225		var	342,205	-336,980
13	Renewable Energy-Cert Fees	174,000		557	9,156	164,844
14	Nez Perce Settlement	165,961		557	5,212	160,749
15	Long Term Note Rec acct	209,469		143	204,050	5,419
16	Reg Asset ID-Lake Cdal	271,030		506	30,974	240,056
17	Misc Deffered debits/WA REC DEF			var	277,010	-277,010
18	ID Panhandle Forest Use Permit	181,017				181,017
19	Credit Union Labor and Exp	25,762	9,248			35,010
20	Outdoor Lghtng Greenbelt Pathwy	65,248	32,979			98,227
21	Horizon Wind Interco	61,845				61,845
22	Insurance Recvy CDA Lake	320,932		var	320,932	
23	KF Water Rights Supply	1,179,357		310	1,178,588	769
24	Reclass Idaho Clk Fork Relic	452,846		537	265,896	186,950
25	Reclass misc def debits		357,784			357,784
26	Misc Work Orders <$50,000	-149,432	275,641			126,209
27	Subsidiary Billings	42,452	135,814			178,266
28	"Null" Projects directly to 186	15,197				15,197
29	Conservation					
30	Regulatory Assets Consv	-200	200			
31	Regulatory Assets Consv	1,845,898		var	185,185	1,660,713
32						
33	Optional Wind Power			909	186,231	-186,231
34						
35						
36	Misc Deffered Debits/Res Acctg		1,577,531			1,577,531
37	Deff Palouse Wind %ThorntonSW			557	80,774	-80,774
38						
39						
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41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	34,001,379				15,701,369

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2		9,302,194	6,261,068
3			
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	9,302,194	6,261,068
9	Gas		
10		1,056,690	2,161,932
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15	1,056,690	2,161,932
17	Other	143,049,536	140,002,469
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	153,408,420	148,425,469

Notes

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

CAPITAL STOCKS (Account 201 and 204)

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

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Account 201 - Common Stock Issued			
2	No Par Value	200,000,000		
3	Restricted shares			
4	Total Common	200,000,000		
5				
6				
7	Account 204 - Preferred Stock Issued	10,000,000		
8				
9				
10	Cumulative			
11				
12				
13	Total Preferred	10,000,000		
14				
15				
16				
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

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

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
59,812,796	863,316,222			117,118	3,025,158	2
						3
59,812,796	863,316,222			117,118	3,025,158	4
						5
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

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. Add more columns for any account if deemed necessary. 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 brief explanation of the origin and purpose of each donation.

(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which 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 which, 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	Equity transactions of subsidiaries	10,942,942
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40	TOTAL	10,942,942

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Common Stock - no par	-14,977,565
2		
3		
4		
5		
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18		
19		
20		
21		
22	TOTAL	-14,977,565

Schedule Page: 254 Line No.: 1 Column: b

Capital Stock expense activity, 2012

Beginning Balance:	$(11,086,811)
Issuance of Common Stock:	558,210
Tax Benefit - Options Exercised:	34,614
Excess Tax Benefits on Stock Comp:	1,230,724
Stock compensation accrual:	**(5,714,302)**
Ending Balance:	$(14,977,565)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	FMBS - SERIES A - 7.53% DUE 05/05/2023	5,500,000	42,712
2	FMBS - SERIES A - 7.54% DUE 5/05/2023	1,000,000	7,766
3	FMBS - SERIES A - 7.39% DUE 5/11/2018	7,000,000	54,364
4	FMBS - SERIES A - 7.45% DUE 6/11/2018	15,500,000	170,597
5	FMBS - SERIES A - 7.18% DUE 8/11/2023	7,000,000	54,364
6	ADVANCE ASSOCIATED-AVISTA CAPITAL II (ToPRS)	51,547,000	1,296,086
7	FMBS - 6.37% SERIES C	25,000,000	158,304
8	FMBS - 5.45% SERIES	90,000,000	1,432,081
9	FMBS - 6.25% SERIES	150,000,000	2,180,435
10	FMBS - 5.70% SERIES	150,000,000	4,924,304
11	FMBS - 5.95% SERIES	250,000,000	3,081,419
12	FMBS - 5.125% SERIES	250,000,000	2,859,788
13	COLSTRIP 2010A PCRBs DUE 2032	66,700,000	
14	COLSTRIP 2010B PCRBs DUE 2034	17,000,000	
15	FMBS - 1.68% SERIES	50,000,000	305,790
16	FMBS - 3.89% SERIES	52,000,000	383,338
17	FMBS - 5.55% SERIES	35,000,000	258,834
18			
19	SERIES C SET UP		666,169
20	4.45% SERIES DUE 12-14-2041	85,000,000	692,722
21	4.23% SERIES DUE 11-29-2047	80,000,000	725,635
22	KETTLE FALLS P C REV BONDS DUE 14	4,100,000	
23	FMBS - SERIES A - 7.37% DUE 5/10/2012	7,000,000	
24			
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	1,399,347,000	19,294,708

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

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
05-06-1993	05-05-2023	05-06-1993	05-05-2023	5,500,000	414,150	1
05-07-1993	05-05-2023	05-07-1993	05-05-2023	1,000,000	75,400	2
05-11-1993	05-11-2018	05-11-1993	05-11-2018	7,000,000	517,300	3
06-09-1993	06-11-2018	06-09-1993	06-11-2018	15,500,000	1,154,750	4
08-12-1993	08-11-2023	08-12-1993	08-11-2023	7,000,000	502,600	5
06-03-1997	06-01-2037	06-03-1997	06-01-2037	51,547,000	541,503	6
06-19-1998	06-19-2028	06-19-1998	06-19-2028	25,000,000	1,592,500	7
11-18-2004	12-01-2019	11-18-2004	12-01-2019	90,000,000	4,905,000	8
11-17-2005	12-01-2035	11-17-2005	12-01-2035	150,000,000	9,375,000	9
12-15-2006	07-01-2037	12-15-2006	07-01-2037	150,000,000	8,550,000	10
04-02-2008	06-01-2018	04-02-2008	06-01-2018	250,000,000	14,875,000	11
09-22-2009	04-01-2022	09-22-2009	04-01-2022	250,000,000	12,812,500	12
12-15-2010	10-1-2032	12-15-2010	10-1-2032	66,700,000	309,043	13
12-15-2010	3-1-2034	12-15-2010	3-1-2034	17,000,000	78,766	14
12-30-2010	12-30-2013	12-30-2010	12-30-2013	50,000,000	840,000	15
12-20-2010	12-20-2020	12-20-2010	12-20-2020	52,000,000	2,022,800	16
12-20-2010	12-20-2040	12-20-2010	12-20-2040	35,000,000	1,942,500	17
						18
6-15-1998	6-15-2013	6-15-1998	6-15-2013			19
12-14-2011	12-14-2041	12-14-2011	12-14-2041	85,000,000	3,782,500	20
11-30-2012	11-29-2047	11-30-2012	11-29-2047	80,000,000	291,400	21
7-29-1993	12-01-2023	7-29-1993	12-01-2023		120,950	22
5-10-1993	5-10-2012	05-10-1993	05-10-2012		214,958	23
						24
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				1,388,247,000	64,918,620	33

Schedule Page: 256 Line No.: 6 Column: a

Upon issuance Avista Capital II isued $1.5 million of Common Trust Securities to the Company. In December 2000, the Company purchased $10.0 million of these Preferred Trust Securities. The interest for the year disclosed in column (i)reflects the net amount of interest owed to third parties.

Schedule Page: 256 Line No.: 13 Column: b

The Company reacquired this debt in 2010. These bonds have not been retired or canceled; the Company plans, based on liquidity needs and market conditions, to remarket these bonds at a future date.

Schedule Page: 256 Line No.: 13 Column: c

The Company reaquired these bonds in 2010.

Schedule Page: 256 Line No.: 14 Column: b

The Company reacquired this debt in 2010. These bonds have not been retired or canceled; the Company plans, based on liquidity needs and market conditions, to remarket these bonds at a future date.

Schedule Page: 256 Line No.: 14 Column: c

The Company reaquired these bonds in 2010.

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

The new issuance is based on the following state commission orders:

1. Order of the Washington Utilities and Transportation Commission entered July 13, 2011, as amended on August 24, 2011 in Docket No. U-111176;
2. Order of the Idaho Public Utilities Commission, Order No. 32338, entered August 25, 2011;
3. Order of the Public Utility Commission of Oregon, Order No. 11334, entered August 26, 2011;

Order of the Public Service Commission of the State of Montana, Default Order No. 4535

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

Expenses may change as invoices related to this issuance become known.

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

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

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	78,210,066
2		
3		
4	Taxable Income Not Reported on Books	
5		3,398,971
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		124,136,767
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		14,239,687
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		-205,058,564
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	61,262,765
28	Show Computation of Tax:	
29	State Tax	379,911
30	Federal Tax Net Income less state tax	61,642,676
31		
32	Federal Tax @ 35%	21,574,937
33		
34	Prior Year & Misc True Ups	-8,077,924
35	Cabinet Gorge Tax Credits	-200,441
36	Total Federal Expense	13,311,067
37		
38		
39		
40		
41		
42		
43		
44		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	FEDERAL:					
2	Income Tax 2009	-118,190			-118,190	
3	Income Tax 2010	142,150		6,913,541	1,370,785	-6,552,932
4	Income Tax 2011	-9,963,974		-2,571,551	-11,352,573	5,321,340
5	Income Tax (Current)			16,441,880	15,012,803	
6	Retained Earnings					
7	Prior Retained Earnings	-1,392,676				
8	Prior Retained Earnings	-3,302,066				1,231,592
9	Current Retained Earnings			-1,994,624		
10	Total Federal	-14,634,756		18,789,246	4,912,825	
11						
12	STATE OF WASHINGTON:					
13	Property Tax (2010)	-3,193		-8	660	3,861
14	Property Tax (2011)	9,704,000		171,510	9,871,649	-3,861
15	Property Tax (2012)			10,622,012		
16	Excise Tax (2010)	-22,495				
17	Excise Tax (2011)	2,585,031		-17,932	2,567,100	
18	Excise Tax (2012)			24,039,256	21,712,032	
19	Natural Gas Use Tax	12,729		10,947	14,885	-8,181
20	Municipal Occupation Tax	3,123,004		22,227,744	22,808,413	
21	Sales & Use Tax (2006)	-8,173				
22	Sales & Use Tax (2011)	186,525			186,514	
23	Sales & Use Tax (2012)			566,682	511,779	
24	Motor Vehicle Tax (2012)			5,473	5,473	
25	Total Washington	15,577,428		57,625,684	57,678,505	-8,181
26						
27	STATE OF IDAHO:					
28	Income Tax (2010)	-4,633				
29	Income Tax (2011)	258,945		-129,632	-6,327	
30	Income Tax (2012)			377,042	400,000	
31	Property Tax (2009)	1,647		-1,640	7	
32	Property Tax (2010)	-3,870		3,870		
33	Property Tax (2011)	2,631,938		-36,462	2,595,476	
34	Property Tax (2012)			6,179,245	2,902,249	
35	Motor Vehicle Tax (2012)			570	570	
36	Sales & Use Tax (2005)	436				
37	Sales & Use Tax (2011)	42,032			42,032	
38	Sales & Use Tax (2012)			134,186	132,017	
39	Irrigation Credits (2011)					
40	KWH Tax (2010)	1		1	2	
41	TOTAL	8,292,344		103,605,888	89,588,591	-1

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
						2
-868,026		-73,728			6,987,269	3
4,138,388		-1,292,964			-1,278,587	4
1,429,077		19,284,594			-2,842,713	5
						6
-1,392,676						7
-2,070,474						8
-1,994,624					-1,994,624	9
-758,335		17,917,902			871,345	10
						11
						12
					-8	13
		145,116			26,394	14
10,622,012		8,493,012			2,129,000	15
-22,495						16
		-20,384			2,452	17
2,327,224		18,386,314			5,652,942	18
610		3,578			7,369	19
2,542,334		16,405,423			5,822,321	20
-8,173						21
12						22
54,903					566,682	23
					5,473	24
15,516,427		43,413,059			14,212,625	25
						26
						27
-4,633						28
135,640		-103,706			-25,926	29
-22,958		388,842			-11,800	30
		-1,640				31
		4,316			-446	32
		-76,485			40,023	33
3,276,997		5,064,040			1,115,205	34
					570	35
436						36
						37
2,169					134,186	38
						39
		1				40
22,309,642		80,567,923			23,037,967	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	KWH Tax (2011)	20,705		264	20,969	
2	KWH Tax (2012)			399,680	364,000	
3	Franchise Tax (2010)	-15,507				15,507
4	Franchise Tax (2011)	1,629,882			1,614,375	-15,507
5	Franchise Tax (2012)			4,318,446	2,837,684	
6	Total Idaho	4,561,576		11,245,570	10,903,054	
7						
8	STATE OF MONTANA:					
9	Income Tax (2010)	-171,969			-179,683	
10	Income Tax (2011)	489,040		-99,269		
11	Income Tax (2012)			252,779	225,000	
12	Property Tax (2011)	3,454,233		965	3,455,198	
13	Property Tax (2012)			7,219,743	3,619,369	
14	Colstrip Generation Tax			3,048	3,048	
15	KWH Tax (2011)	267,607			267,608	
16	KWH Tax (2012)			1,137,780	858,252	
17	Motor Vehicle Tax (2012)			1,819	1,819	
18	Consumer Council Tax	6		50	21	
19	Public Commission Tax	10		138	35	
20	Total Montana	4,038,927		8,517,053	8,250,667	
21						
22	STATE OF OREGON:					
23	Income Tax (2007)	-230,262				230,262
24	Income Tax (2010)	91,318				-230,262
25	Income Tax (2011)	386,749		-379,351		
26	Income Tax (2012)			356,742	125,000	
27	Property Tax (2010)	-1,791,031		1,894,942		-103,911
28	Property Tax (2011)	-95,501		1,973,371	1,927,159	49,289
29	Property Tax (2012)				2,030,655	54,622
30	Motor Vehicle Tax (2012)			2,057	2,057	
31	BETC Credit (2010 and Prior)	1,448				
32	BETC Credit (2011)	-365,909				
33	BETC Credit (2012)			-18,696		
34	Glendale Regulatory Cr. 2008	-210,889				
35	Glendate Regulatory Cr. 2009	70,289				
36	Franchise Tax (2010)	25,602			24,921	
37	Franchise Tax (2011)	903,082			876,166	
38	Franchise Tax (2012)			3,672,794	2,924,589	
39	Total Oregon	-1,215,104		7,501,859	7,910,547	
40						
41	TOTAL	8,292,344		103,605,888	89,588,591	-1

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
		264				1
35,680		399,680				2
						3
						4
1,480,762		3,150,983			1,167,463	5
4,904,093		8,826,295			2,419,275	6
						7
						8
7,714						9
389,771		-99,269				10
27,779		252,779				11
		965				12
3,600,374		7,219,743				13
		3,048				14
						15
279,528		1,137,780				16
					1,819	17
34		50				18
113		138				19
4,305,313		8,515,234			1,819	20
						21
						22
						23
-138,944						24
7,398		-94,838			-284,513	25
231,742		89,184			267,558	26
		1,004,911			890,031	27
		896,176			1,077,196	28
-1,976,033						29
					2,057	30
1,448						31
-365,909						32
-18,696					-18,696	33
-210,889						34
70,289						35
681						36
26,916						37
748,205					3,672,794	38
-1,623,792		1,895,433			5,606,427	39
						40
22,309,642		80,567,923			23,037,967	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	STATE OF CALIFORNIA:					
2	Income Tax (2010)	-800			-800	
3	Income Tax (2011)	-7,925		1,600		
4	Income Tax (2012)				1,600	
5	Total California	-8,725		1,600	800	
6						
7	MISCELLANEOUS STATES:					
8	Income Tax (2011)					
9	Income Tax (2012)					-1
10	Total Misc States					-1
11						
12	COUNTY & MUNICIPAL					
13	WA Renewable Energy	-561		-103,659	-103,659	
14	Misc.	-26,441		28,535	35,852	8,181
15	Total County	-27,002		-75,124	-67,807	8,181
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
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30						
31						
32						
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34						
35						
36						
37						
38						
39						
40						
41	TOTAL	8,292,344		103,605,888	89,588,591	-1

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (I) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
						2
-6,325					1,600	3
-1,600						4
-7,925					1,600	5
						6
						7
						8
-1						9
-1						10
						11
						12
-561					-103,659	13
-25,577					28,535	14
-26,138					-75,124	15
						16
						17
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22,309,642		80,567,923			23,037,967	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year: Account No. (c)	Deferred for Year: Amount (d)	Allocations to Current Year's Income: Account No. (e)	Allocations to Current Year's Income: Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%						
6		10,166,406	411	2,254,232			
7							
8	TOTAL	10,166,406		2,254,232			
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Gas Propertry (100%	234,480			411	42,060	
11							
12	TOTAL PROPERTY	234,480				42,060	
13							
14							
15							
16							
17							
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

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

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
			5
12,420,638			6
			7
12,420,638			8
			9
192,420			10
			11
192,420			12
			13
			14
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Defer Gas Exchange (253028)	1,500,000	495	10		1,499,990
2	Rathdrum Refund (253120)	273,398	550	33,822		239,576
3	NE Tank Spil (253130)	70,367	186	53,570		16,797
4	Bills Pole Rentals (253140)	257,105			23,855	280,960
5	CR-CS2 GE LTSA (253150)				2,999,302	2,999,302
6	CR-Credit Resource Actg				1,577,531	1,577,531
7	DOC EECE Grant (253155)	850,255	136	97,705		752,550
8	Defer Comp Retired Execs (253900)	79,658	431	20,409		59,249
9	Defer Comp Active Execs (253910)	8,652,744			153,406	8,806,150
10	Executive Incent Plan (253920)	140,000				140,000
11	Unbilled Revenue (253990)	1,812,993	908	1,129,552		683,441
12	WA Energy Recovery Mechanism	12,947,627	186	12,947,628	8,756,639	8,756,638
13	Misc Deferred Credits				357,782	357,782
14						
15						
16						
17						
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35						
36						
37						
38						
39						
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41						
42						
43						
44						
45						
46						
47	TOTAL	26,584,147		14,282,696	13,868,515	26,169,966

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	269,492,281	7,435,394	
3	Gas	96,448,805	5,665,663	
4	Other	32,559,207	7,690,353	
5	TOTAL (Enter Total of lines 2 thru 4)	398,500,293	20,791,410	
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	398,500,293	20,791,410	
10	Classification of TOTAL			
11	Federal Income Tax	387,433,970	20,791,410	
12	State Income Tax	11,066,323		
13	Local Income Tax			

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
						276,927,675	2
						102,114,468	3
-75,090						40,174,470	4
-75,090						419,216,613	5
							6
							7
							8
-75,090						419,216,613	9
							10
-75,090						408,150,290	11
						11,066,323	12
							13

NOTES (Continued)

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Electric	28,652,909	-8,327,674	512,038
4				
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	28,652,909	-8,327,674	512,038
10	Gas			
11	Gas	-3,884,914	1,801,980	
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	-3,884,914	1,801,980	
18	Other	234,876,525	4,169,890	
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	259,644,520	-2,355,804	512,038
20	Classification of TOTAL			
21	Federal Income Tax	255,410,714	-2,355,804	512,038
22	State Income Tax	4,233,806		
23	Local Income Tax			

NOTES

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

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

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

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
[redacted]							1
							2
-1,537,191					-737,482	17,538,524	3
							4
							5
							6
							7
							8
-1,537,191					-737,482	17,538,524	9
[redacted]							10
					279,708	-1,803,226	11
							12
							13
							14
							15
							16
					279,708	-1,803,226	17
	4,818,267		4,281,489			229,946,659	18
-1,537,191	4,818,267		4,281,489		-457,774	245,681,957	19
[redacted]							20
-1,537,191	4,818,267		4,281,489		-457,774	241,448,151	21
						4,233,806	22
							23

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Idaho Investment Tax Credit (254005)	12,316,743	190	8,670		12,308,073
2	Oregon BETC Credit (254010)	69,822			1,484,162	1,553,984
3	Noxon, ITC (254025)	2,737,108			606,909	3,344,017
4	Defer Gas Exchange (254028)					
5	Oregon Commercial Fee (254120)	(655)	805	1,288		-1,943
6	FAS 109 Invest Credit (254180)	126,252	190	22,644		103,608
7	Nez Perce (254220)	704,372	557	22,008		682,364
8	Oregon Senate Bill (254250)	771,592	407	842,062		-70,470
9	Reg liability CCX CR ID (254300)					
10	Accrue Lake CDA IPA int (254325)					
11	Decoupling Rebate (254328)				5,531	5,531
12	Idaho DSIT Amort (254335)	3,483,474	407	3,483,474		
13	BPA Res Exch Regulatory Liab (254345)	178,328	186	178,328		
14	Reg Liability WA Rec's				93,222	93,222
15	Unrealized Currency Exchange (254399)	11,097	143	7,495		3,602
16	Reg Liability Other (254700)					
17	Mark to Market ST (254740)	25,468	176	25,467		1
18	Mark to Market FAS133 (254750)					
19	Colstrip/CS2	516,251	186	516,250		1
20	Idaho PCA				18,566,192	18,566,192
21	SWAPS on FMBS				18,656,780	18,656,780
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	20,939,852		5,107,686	39,412,796	55,244,962

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	315,137,034	324,834,634
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	286,567,954	280,139,238
5	Large (or Ind.) (See Instr. 4)	119,588,721	122,559,992
6	(444) Public Street and Highway Lighting	7,240,388	6,940,809
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales	1,025,713	1,037,295
10	TOTAL Sales to Ultimate Consumers	729,559,810	735,511,968
11	(447) Sales for Resale	148,004,414	118,011,777
12	TOTAL Sales of Electricity	877,564,224	853,523,745
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	877,564,224	853,523,745
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	559,797	572,046
18	(453) Sales of Water and Water Power	468,800	506,582
19	(454) Rent from Electric Property	2,971,731	2,880,894
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	124,709,799	183,611,801
22	(456.1) Revenues from Transmission of Electricity of Others	11,641,754	12,755,612
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	140,351,881	200,326,935
27	TOTAL Electric Operating Revenues	1,017,916,105	1,053,850,680

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

ELECTRIC OPERATING REVENUES (Account 400)

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

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
3,608,626	3,728,029	318,692	316,763	2
				3
3,127,158	3,122,058	39,869	39,618	4
2,099,648	2,147,014	1,395	1,380	5
25,878	25,828	503	455	6
				7
				8
11,695	12,204	94	87	9
8,873,005	9,035,133	360,553	358,303	10
5,634,398	4,084,890			11
14,507,403	13,120,023	360,553	358,303	12
				13
14,507,403	13,120,023	360,553	358,303	14

Line 12, column (b) includes $ -799,381 of unbilled revenues.

Line 12, column (d) includes -15,142 MWH relating to unbilled revenues

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	RESIDENTIAL SALES (440)					
2	1 Residential Service	3,484,858	291,806,496	303,699	11,475	0.0837
3	2 Residential Service					
4	3 Residential Service					
5	12 Res. & Farm Gen. Service	75,161	9,446,488	13,168	5,708	0.1257
6	15 MOPS II Residential					
7	22 Res. & Farm Lg. Gen. Service	50,650	4,107,894	92	550,543	0.0811
8	30 Pumping-Special					
9	32 Res. & Farm Pumping Service	10,198	1,010,209	1,733	5,885	0.0991
10	48 Res. & Farm Area Lighting	4,430	1,094,345			0.2470
11	49 Area Lighting-High-Press.	251	75,691			0.3016
12	56 Centralia Refund					
13	95 Wind Power		160,823			
14	72 Residential Service					
15	73 Residential Service					
16	74 Residential Service					
17	76 Residential Service					
18	77 Residential Service					
19	58A Tax Adjustment		-47,048			
20	58 Tax Adjustment		8,615,208			
21	SubTotal	3,625,548	316,270,106	318,692	11,376	0.0872
22	Residential-Unbilled	-16,922	-1,133,072			0.0670
23	Total Residential Sales	3,608,626	315,137,034	318,692	11,323	0.0873
24						
25	COMMERCIAL SALES (442)					
26	2 General Service					
27	3 General Service					
28	11 General Service	772,355	83,803,542	35,386	21,827	0.1085
29	12 Res. & Farm Gen. Service					
30	16 MOPS II Commercial					
31	19 Contract-General Service					
32	21 Large General Service	1,908,187	162,246,489	3,377	565,054	0.0850
33	25 Extra Lg. Gen. Service	348,081	20,748,315	13	26,775,462	0.0596
34	28 Contract-Extra Large Serv					
35	31 Pumping Service	89,861	7,275,014	1,093	82,215	0.0810
36	47 Area Lighting-Sod. Vap	6,276	1,393,223			0.2220
37	49 Area Lighting-High-Press.	2,452	564,944			0.2304
38	56 Centralia Refune					
39	95 Wind Power		79,231			
40	74 Large General Service					
41	TOTAL Billed	14,522,545	878,363,605	360,553	40,279	0.0605
42	Total Unbilled Rev.(See Instr. 6)	-15,142	-799,381	0	0	0.0528
43	TOTAL	14,507,403	877,564,224	360,553	40,237	0.0605

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	75 Large General Service					
2	76 Large General Service					
3	77 General Service					
4	58A Tax Adjustment		-48,098			
5	58 Tax Adjustment		10,339,542			
6	SubTotal	3,127,212	286,402,202	39,869	78,437	0.0916
7	Commercial-Unbilled	-54	165,752			-3.0695
8	Total Commercial	3,127,158	286,567,954	39,869	78,436	0.0916
9						
10	INDUSTRIAL SALES (442)					
11	2 General Service					
12	3 General Service					
13	8 Lg Gen Time of Use					
14	11 General Service	8,606	962,379	250	34,424	0.1118
15	12 Res. & Farm Gen. Service					
16	21 Large General Service	200,418	16,508,790	174	1,151,828	0.0824
17	25 Extra Lg. Gen. Service	1,806,952	94,575,610	18	100,386,222	0.0523
18	28 Contract - Extra Large Service		19,250			
19	29 Contract Lg. Gen. Service					
20	30 Pumping Service - Special	20,821	1,422,369	32	650,656	0.0683
21	31 Pumping Service	57,284	4,798,691	774	74,010	0.0838
22	32 Pumping Svc Res & Firm	3,407	283,556	147	23,177	0.0832
23	47 Area Lighting-Sod. Vap.	232	49,905			0.2151
24	49 Area Lighting - High-Press	57	12,024			0.2109
25	95 Wind Power		1,728			
26	72 General Service					
27	73 General Service					
28	74 Large General Service					
29	75 Large General Service					
30	76 Pumping Service					
31	77 General Service					
32	58A Tax Adjustment		-1,027			
33	58 Tax Adjustment		791,207			
34	SubTotal	2,097,777	119,424,482	1,395	1,503,783	0.0569
35	Industrial-Unbilled	1,871	164,239			0.0878
36	Total Industrial	2,099,648	119,588,721	1,395	1,505,124	0.0570
37						
38	STREET AND HWY LIGHTING (444)					
39	6 Mercury Vapor St. Ltg.					
40	7 HP Sodium Vap. St. Ltg					
41	TOTAL Billed	14,522,545	878,363,605	360,553	40,279	0.0605
42	Total Unbilled Rev.(See Instr. 6)	-15,142	-799,381	0	0	0.0528
43	TOTAL	14,507,403	877,564,224	360,553	40,237	0.0605

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	11 General Service	93	10,825	3	31,000	0.1164
2	41 Co-Owned St. Lt. Service	219	42,131	20	10,950	0.1924
3	42 Co-Owned St. Lt. Service	20,709	6,499,743	386	53,650	0.3139
4	High-Press. Sod. Vap.					
5	43 Cust-Owned St. Lt. Energy	9	911	2	4,500	0.1012
6	and Maint. Service					
7	44 Cust-Owned St. Lt. Energy	855	131,590	30	28,500	0.1539
8	and Maint. Svce - High-Pres					
9	Sodium Vapor					
10	45 Cust. Owned St. Lt. Energy Svc	1,356	95,578	12	113,000	0.0705
11	46 Cust. Owned St. Lt. Energy Svc	2,674	250,832	50	53,480	0.0938
12	58A Tax Adjustment		-691			
13	58 Tax Adjustment		205,769			
14	SubTotal	25,915	7,236,688	503	51,521	0.2792
15	Street & Hwy Lighting-Unbilled	-37	3,700			-0.1000
16	Total Street & Hwy Lighting	25,878	7,240,388	503	51,447	0.2798
17						
18	OTHER SALES TO PUBLIC					
19	(445)					
20	None					
21						
22	INTERDEPARTMENTAL SALES	11,695	1,025,713	94	124,415	0.0877
23	58 Tax Adjustment					
24	Total Interdepartmental	11,695	1,025,713	94	124,415	0.0877
25						
26	SALES FOR RESALE (447)	5,634,398	148,004,414			0.0263
27	61 Sales to Other Utilities (NDA)					
28						
29						
30	Total Sales for Resale	5,634,398	148,004,414			0.0263
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	14,522,545	878,363,605	360,553	40,279	0.0605
42	Total Unbilled Rev.(See Instr. 6)	-15,142	-799,381	0	0	0.0528
43	TOTAL	14,507,403	877,564,224	360,553	40,237	0.0605

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	BP Energy Company	SF	ISDA			
2	BP Energy Company	SF	Tariff 9			
3	Barclays Bank PLC	SF	Tariff 9			
4	Black Hills Power, Inc.	SF	Tariff 9			
5	Bonneville Power Administration	LF	Tariff 8			
6	Bonneville Power Administration	LF	ACS-06			
7	Bonneville Power Administration	SF	Tariff 9			
8	Bonneville Power Administration	LF	Tariff 12			
9	British Columbia Hydro and Power Author	LF	Tariff 12			
10	Brookfield Energy Marketing LP	SF	Tariff 9			
11	Burbank, City of	SF	Tariff 9			
12	Calpine Energy Services LP	SF	Tariff 9			
13	Cargill Power Markets, LLC	SF	Tariff 9			
14	Cargill Power Markets, LLC	SF	ISDA			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
			3,390,228	3,390,228	1
113,231		2,426,058		2,426,058	2
3,000		79,050		79,050	3
5,232		27,546		27,546	4
16,377		326,932		326,932	5
3,208		48,972		48,972	6
165,964		4,781,908		4,781,908	7
12		328		328	8
42		506		506	9
1,800		39,600		39,600	10
800		18,000		18,000	11
256,448		7,177,948		7,177,948	12
475,617		8,328,494		8,328,494	13
			185,242	185,242	14
0	0	0	0	0	
5,634,398	4,356,037	103,627,704	40,020,673	148,004,414	
5,634,398	**4,356,037**	**103,627,704**	**40,020,673**	**148,004,414**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Chelan County PUD No. 1	SF	Tariff 9			
2	Chelan County PUD No. 1	LF	Tariff 12			
3	Citigroup Energy, Inc.	SF	Tariff 9			
4	Clark County PUD No. 1	SF	Tariff 9			
5	Clatskanie Peoples PUD	SF	Tariff 9			
6	Conoco Phillips	SF	Tariff 9			
7	Conoco Phillips	SF	Tariff 9			
8	Constellation Energy Commodities Group	SF	Tariff 9			
9	DB Energy Trading, LLC	SF	Tariff 9			
10	Douglas County PUD No. 1	SF	Tariff 9			
11	EDF Trading North America	SF	Tariff 9			
12	Eugene Water & Electric Board	SF	Tariff 9			
13	Exelon Generation Company, LLC	SF	Tariff 9			
14	Grant County PUD No. 2	SF	Tariff 9			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
13,016		324,890		324,890	1
6		314		314	2
151,169		2,965,764		2,965,764	3
12,283		328,437		328,437	4
4,429		115,516		115,516	5
3		60		60	6
	122,976			122,976	7
45,200		575,600		575,600	8
117,600		2,709,771		2,709,771	9
10,440		251,040		251,040	10
227,272		4,516,189		4,516,189	11
15,010		431,861		431,861	12
3,600		95,780		95,780	13
13,660		336,785		336,785	14
0	0	0	0	0	
5,634,398	4,356,037	103,627,704	40,020,673	148,004,414	
5,634,398	**4,356,037**	**103,627,704**	**40,020,673**	**148,004,414**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Grant County PUD No. 2	LF	Tariff 12			
2	Grant County PUD No. 2	SF	Tariff 9			
3	Iberdrola Renewables, LLC	SF	Tariff 9			
4	Iberdrola Renewables, LLC	SF	Tariff 9			
5	Iberdrola Renewables, LLC	SF	Tariff 9			
6	Idaho Power Company	SF	Tariff 9			
7	Idaho Power Company	LF	Tariff 12			
8	Idaho Power Balancing	SF	Tariff 9			
9	J. Aron & Company	SF	Tariff 9			
10	J. Aron & Company	SF	ISDA			
11	JP Morgan Ventures Energy	SF	Tariff 9			
12	JP Morgan Ventures Energy	SF	ISDA			
13	Macquarie Energy, LLC	SF	Tariff 9			
14	Modesto Irrigation District	SF	Tariff 9			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
24		420		420	1
	5,450			5,450	2
649,215		12,891,335		12,891,335	3
	213,100			213,100	4
	150			150	5
63,858		1,103,030		1,103,030	6
51		1,127		1,127	7
78,131		1,253,347		1,253,347	8
2,600		71,900		71,900	9
			373,354	373,354	10
73,235		1,270,923		1,270,923	11
			74,686	74,686	12
217,256		5,176,604		5,176,604	13
144		1,296		1,296	14
0	0	0	0	0	
5,634,398	4,356,037	103,627,704	40,020,673	148,004,414	
5,634,398	**4,356,037**	**103,627,704**	**40,020,673**	**148,004,414**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Morgan Stanley Capital Group, Inc.	SF	ISDA			
2	Morgan Stanley Capital Group, Inc.	SF	ISDA			
3	NaturEner Power Watch, LLC	SF	Tariff 9			
4	NaturEner Power Watch, LLC	LF	Tariff 12			
5	NaturEner Power Watch, LLC	SF	Tariff 9			
6	NaturEner Power Watch, LLC	SF	Tariff 9			
7	NaturEner Power Watch, LLC	SF	Tariff 9			
8	Newedge USA, LLC	SF	ISDA			
9	NextEra Energy Power Market	SF	Tariff 9			
10	Noble America Gas & Power	SF	Tariff 9			
11	NorthWestern Energy LLC	SF	Tariff 10			
12	NorthWestern Energy LLC	SF	Tariff 10			
13	NorthWestern Energy LLC	SF	Tariff 9			
14	NorthWestern Energy LLC	SF	Tariff 9			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
303,760		7,396,782		7,396,782	1
			1,805,094	1,805,094	2
5,852		116,165		116,165	3
7		174		174	4
	176,410			176,410	5
	285,479			285,479	6
	1,520			1,520	7
			14,144,512	14,144,512	8
400		9,600		9,600	9
2,800		76,700		76,700	10
	335,017			335,017	11
			89,074	89,074	12
16,533		276,443		276,443	13
94,379		2,069,628		2,069,628	14
0	0	0	0	0	
5,634,398	4,356,037	103,627,704	40,020,673	148,004,414	
5,634,398	**4,356,037**	**103,627,704**	**40,020,673**	**148,004,414**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	NorthWestern Energy LLC	LF	Tariff 12			
2	NorthWestern Energy LLC	LF	Tariff 9			
3	NorthWestern Energy LLC	SF	Tariff 10			
4	Okanogan County PUD	SF	Tariff 9			
5	PacifiCorp	SF	Tariff 9			
6	PacifiCorp	LF	Tariff 12			
7	PacifiCorp	LF	Tariff 9			
8	Peaker LLC	LF	Tariff 9			
9	Pend Oreille Public Utility District	LF	Tariff 9			
10	Pend Oreille Public Utility District	LF	Tariff 9			
11	Pend Oreille Public Utility District	SF	Tariff 9			
12	Pend Oreille Public Utility District	LF	290 (PNCA)			
13	Portland General Electric Company	SF	Tariff 9			
14	Portland General Electric Company	LF	Tariff 12			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
36		806		806	1
7,657		139,740		139,740	2
	938,790			938,790	3
4,010		94,763		94,763	4
71,026		1,858,816		1,858,816	5
195		4,308		4,308	6
4,875		88,925		88,925	7
	1,748,921			1,748,921	8
	421,348			421,348	9
18,697		312,353		312,353	10
66,903		829,908		829,908	11
	16,696			16,696	12
229,965		3,599,607		3,599,607	13
73		1,919		1,919	14
0	0	0	0	0	
5,634,398	4,356,037	103,627,704	40,020,673	148,004,414	
5,634,398	**4,356,037**	**103,627,704**	**40,020,673**	**148,004,414**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Powerex	SF	Tariff 9			
2	Powerex	SF	Tariff 9			
3	PPL EnergyPlus, LLC	SF	Tariff 9			
4	PPL EnergyPlus, LLC	SF	Tariff 9			
5	PPL EnergyPlus, LLC	LF	Tariff 9			
6	Puget Sound Energy	LF	Tariff 9			
7	Puget Sound Energy	SF	Tariff 9			
8	Puget Sound Energy	LF	Tariff 12			
9	Rainbow Energy Marketing	SF	Tariff 9			
10	Redding, City of	SF	Tariff 9			
11	Sacramento Municipal Utility District	SF	Tariff 9			
12	Sacramento Municipal Utility District	LF	Tariff 12			
13	Sacramento Municipal Utility District	LF	Tariff 9			
14	San Diego Gas & Electric Company	SF	Tariff 9			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
232,936		4,997,478		4,997,478	1
	580			580	2
	200			200	3
74,125		1,866,240		1,866,240	4
17,400		317,590		317,590	5
22,275		406,516		406,516	6
101,119		2,770,411		2,770,411	7
29		683		683	8
128,301		1,702,326		1,702,326	9
1,520		24,320		24,320	10
17,110		421,061		421,061	11
4		33		33	12
573,915		17,875,745		17,875,745	13
11,972		139,235		139,235	14
0	0	0	0	0	
5,634,398	4,356,037	103,627,704	40,020,673	148,004,414	
5,634,398	**4,356,037**	**103,627,704**	**40,020,673**	**148,004,414**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW): Average Monthly NCP Demand (e)	Actual Demand (MW): Average Monthly CP Demand (f)
1	Seattle City Light	SF	Tariff 9			
2	Seattle City Light	LF	Tariff 12			
3	Shell Energy N.A.	SF	Tariff 9			
4	Shell Energy N.A.	SF	ISDA			
5	Shell Energy N.A.	SF	Tariff 9			
6	Sierra Pacific Power Company	SF	Tariff 9			
7	Sierra Pacific Power Company	LF	Tariff 12			
8	Snohomish County PUD	SF	Tariff 9			
9	Southern California Edison Company	SF	Tariff 9			
10	Sovereign Power	LF	Tariff 10			
11	Sovereign Power	LF	Tariff 9			
12	Tacoma Power	SF	Tariff 9			
13	Tacoma Power	SF	Tariff 9			
14	Tenaska Power Services Co.	SF	Tariff 9			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
14,272		243,614		243,614	1
35		564		564	2
476,337		8,085,026		8,085,026	3
			1,498,757	1,498,757	4
	1,000			1,000	5
20,628		605,143		605,143	6
90		2,086		2,086	7
5,997		147,826		147,826	8
4		72		72	9
	78,800			78,800	10
13,957		241,125		241,125	11
8,928		148,702		148,702	12
	9,600			9,600	13
2,267		41,688		41,688	14
0	0	0	0	0	
5,634,398	4,356,037	103,627,704	40,020,673	148,004,414	
5,634,398	**4,356,037**	**103,627,704**	**40,020,673**	**148,004,414**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	The Energy Authority	SF	Tariff 9			
2	TransAlta Energy Marketing	SF	Tariff 9			
3	Tri-State Generation & Transmission As	SF	Tariff 9			
4	Turlock Irrigation District	SF	Tariff 9			
5	IntraCompany Wheeling	LF				
6	IntraCompany Generation	LF				
7	Revenue Adjustment	AD				
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
29,338		718,629		718,629	1
268,795		5,630,907		5,630,907	2
44,746		522,965		522,965	3
1,200		-1,640		-1,640	4
		-17,834,609	17,834,609		5
			625,117	625,117	6
-3					7
					8
					9
					10
					11
					12
					13
					14
0	0	0	0	0	
5,634,398	4,356,037	103,627,704	40,020,673	148,004,414	
5,634,398	**4,356,037**	**103,627,704**	**40,020,673**	**148,004,414**	

Schedule Page: 310 Line No.: 1 Column: b
SWAP

Schedule Page: 310 Line No.: 5 Column: b
BPA Contract Terminates September 30, 2028.

Schedule Page: 310 Line No.: 6 Column: b
BPA Contract Terminates January 1, 2036.

Schedule Page: 310 Line No.: 8 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310 Line No.: 9 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310 Line No.: 14 Column: b
SWAP

Schedule Page: 310.1 Line No.: 2 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.2 Line No.: 1 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.2 Line No.: 4 Column: b
Capacity

Schedule Page: 310.2 Line No.: 7 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.2 Line No.: 10 Column: b
SWAP

Schedule Page: 310.2 Line No.: 12 Column: b
SWAP

Schedule Page: 310.3 Line No.: 2 Column: b
SWAP

Schedule Page: 310.3 Line No.: 4 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.3 Line No.: 6 Column: b
Capacity

Schedule Page: 310.3 Line No.: 7 Column: b
Capacity

Schedule Page: 310.3 Line No.: 8 Column: b
SWAP

Schedule Page: 310.3 Line No.: 11 Column: b
Capacity

Schedule Page: 310.3 Line No.: 12 Column: b
Bundled Transmission

Schedule Page: 310.4 Line No.: 1 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.4 Line No.: 2 Column: b
NorthWestern Energy LLC sale expires October 31, 2013.

Schedule Page: 310.4 Line No.: 6 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.4 Line No.: 7 Column: b
PacifiCorp sale terminates October 31, 2013.

Schedule Page: 310.4 Line No.: 8 Column: b
Peaker, LLC capacity contract terminates December 31, 2016.

Schedule Page: 310.4 Line No.: 9 Column: b
Contract expires 9/30/2014.

Schedule Page: 310.4 Line No.: 10 Column: b
Contract expires 9/30/2014.

Schedule Page: 310.4 Line No.: 12 Column: b
Contract expires 9/30/2014.

Schedule Page: 310.4 Line No.: 14 Column: b

NWPP Reserve Sharing Sales

Schedule Page: 310.5 Line No.: 5 Column: b

PPL sale terminates October 31, 2013.

Schedule Page: 310.5 Line No.: 6 Column: b

Puget Sound Energy sale terminates October 31, 2013.

Schedule Page: 310.5 Line No.: 8 Column: b

NWPP Reserve Sharing Sales

Schedule Page: 310.5 Line No.: 12 Column: b

NWPP Reserve Sharing Sales

Schedule Page: 310.5 Line No.: 13 Column: b

Contract expires 2014.

Schedule Page: 310.6 Line No.: 2 Column: b

NWPP Reserve Sharing Sales

Schedule Page: 310.6 Line No.: 4 Column: b

SWAP

Schedule Page: 310.6 Line No.: 7 Column: b

NWPP Reserve Sharing Sales

Schedule Page: 310.6 Line No.: 10 Column: b

Sovereign Power contract terminates 1-31-2015

Schedule Page: 310.6 Line No.: 11 Column: b

Sovereign Power Contract terminates 1-31-2015

Schedule Page: 310.7 Line No.: 5 Column: a

Intracompany Wheeling

Schedule Page: 310.7 Line No.: 5 Column: b

IntraCompany Wheeling terminates 09/30/2023.

Schedule Page: 310.7 Line No.: 6 Column: a

Intracompany Generation - Sale of Ancillary Services

Schedule Page: 310.7 Line No.: 6 Column: b

IntraCompany Generation - Sale of Ancillary Services.

Schedule Page: 310.7 Line No.: 7 Column: b

Estimated revenues - true up in later periods.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	405,853	502,678
5	(501) Fuel	27,965,080	31,254,162
6	(502) Steam Expenses	4,007,068	4,303,460
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	903,817	910,212
10	(506) Miscellaneous Steam Power Expenses	2,366,646	2,398,191
11	(507) Rents	21,917	32,398
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	35,670,381	39,401,101
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	496,860	587,143
16	(511) Maintenance of Structures	607,138	723,510
17	(512) Maintenance of Boiler Plant	4,845,432	6,088,972
18	(513) Maintenance of Electric Plant	584,214	1,401,570
19	(514) Maintenance of Miscellaneous Steam Plant	565,141	852,347
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	7,098,785	9,653,542
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	42,769,166	49,054,643
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	2,403,166	2,576,301
45	(536) Water for Power	1,177,037	1,118,184
46	(537) Hydraulic Expenses	7,432,593	7,340,213
47	(538) Electric Expenses	6,299,336	5,780,431
48	(539) Miscellaneous Hydraulic Power Generation Expenses	620,314	703,631
49	(540) Rents	6,810,597	6,605,536
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	24,743,043	24,124,296
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	583,198	557,119
54	(542) Maintenance of Structures	606,145	420,759
55	(543) Maintenance of Reservoirs, Dams, and Waterways	1,355,754	2,953,754
56	(544) Maintenance of Electric Plant	2,804,743	2,343,586
57	(545) Maintenance of Miscellaneous Hydraulic Plant	485,261	503,926
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	5,835,101	6,779,144
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	30,578,144	30,903,440

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	1,289,906	1,438,316
63	(547) Fuel	64,054,801	54,982,069
64	(548) Generation Expenses	1,693,501	1,077,281
65	(549) Miscellaneous Other Power Generation Expenses	619,292	570,980
66	(550) Rents	50,652	-31,837
67	TOTAL Operation (Enter Total of lines 62 thru 66)	67,708,152	58,036,809
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	1,867,043	680,635
70	(552) Maintenance of Structures	12,412	12,248
71	(553) Maintenance of Generating and Electric Plant	7,706,560	1,480,762
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	161,209	154,760
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	9,747,224	2,328,405
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	77,455,376	60,365,214
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	239,356,429	209,550,746
77	(556) System Control and Load Dispatching	864,537	714,621
78	(557) Other Expenses	145,305,655	228,635,614
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	385,526,621	438,900,981
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	536,329,307	579,224,278
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,165,264	2,091,494
84			
85	(561.1) Load Dispatch-Reliability	14,379	16,630
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,175,921	1,247,742
87	(561.3) Load Dispatch-Transmission Service and Scheduling	962,648	965,661
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development		
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	419,664	318,511
94	(563) Overhead Lines Expenses	468,930	518,176
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	17,551,614	17,489,619
97	(566) Miscellaneous Transmission Expenses	1,787,287	1,679,342
98	(567) Rents	115,925	127,552
99	TOTAL Operation (Enter Total of lines 83 thru 98)	24,661,632	24,454,727
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	2,123,807	1,313,699
102	(569) Maintenance of Structures	451,661	426,540
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software		
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	1,139,396	1,146,932
108	(571) Maintenance of Overhead Lines	1,750,864	2,405,427
109	(572) Maintenance of Underground Lines	8,377	1,731
110	(573) Maintenance of Miscellaneous Transmission Plant	96,193	28,956
111	TOTAL Maintenance (Total of lines 101 thru 110)	5,570,298	5,323,285
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	30,231,930	29,778,012

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	2,195,632	1,845,376
135	(581) Load Dispatching		
136	(582) Station Expenses	631,080	697,949
137	(583) Overhead Line Expenses	2,900,414	1,798,684
138	(584) Underground Line Expenses	1,054,524	-183,983
139	(585) Street Lighting and Signal System Expenses	166,256	273,778
140	(586) Meter Expenses	2,249,211	1,873,149
141	(587) Customer Installations Expenses	676,051	740,863
142	(588) Miscellaneous Expenses	7,563,801	7,032,031
143	(589) Rents	352,108	262,304
144	TOTAL Operation (Enter Total of lines 134 thru 143)	17,789,077	14,340,151
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	1,720,093	1,148,214
147	(591) Maintenance of Structures	370,675	343,805
148	(592) Maintenance of Station Equipment	886,849	833,760
149	(593) Maintenance of Overhead Lines	8,225,646	8,049,756
150	(594) Maintenance of Underground Lines	1,007,658	1,021,119
151	(595) Maintenance of Line Transformers	972,946	2,832,509
152	(596) Maintenance of Street Lighting and Signal Systems	674,264	598,658
153	(597) Maintenance of Meters	62,373	102,477
154	(598) Maintenance of Miscellaneous Distribution Plant	495,770	493,719
155	TOTAL Maintenance (Total of lines 146 thru 154)	14,416,274	15,424,017
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	32,205,351	29,764,168
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	577,883	633,265
160	(902) Meter Reading Expenses	2,905,712	2,827,145
161	(903) Customer Records and Collection Expenses	8,191,471	8,056,519
162	(904) Uncollectible Accounts	2,129,547	2,631,760
163	(905) Miscellaneous Customer Accounts Expenses	229,446	138,558
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	14,034,059	14,287,247

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	24,468,409	28,480,145
169	(909) Informational and Instructional Expenses	1,111,618	919,411
170	(910) Miscellaneous Customer Service and Informational Expenses	176,221	133,783
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	25,756,248	29,533,339
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	7,948	12,086
176	(913) Advertising Expenses		154
177	(916) Miscellaneous Sales Expenses		-3,913
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	7,948	8,327
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	36,662,334	24,938,251
182	(921) Office Supplies and Expenses	4,136,952	4,059,668
183	(Less) (922) Administrative Expenses Transferred-Credit	65,805	61,444
184	(923) Outside Services Employed	11,659,879	14,466,792
185	(924) Property Insurance	1,325,546	1,223,344
186	(925) Injuries and Damages	2,428,175	4,400,051
187	(926) Employee Pensions and Benefits	1,364,064	1,258,918
188	(927) Franchise Requirements	5,747	5,738
189	(928) Regulatory Commission Expenses	6,659,471	5,675,735
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	2,394	1,087
192	(930.2) Miscellaneous General Expenses	3,255,338	2,747,891
193	(931) Rents	1,032,665	883,149
194	TOTAL Operation (Enter Total of lines 181 thru 193)	68,466,760	59,599,180
195	Maintenance		
196	(935) Maintenance of General Plant	7,813,751	8,015,884
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	76,280,511	67,615,064
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	714,845,354	750,210,435

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	BP Corporation NA	SF	ISDA			
2	BP Energy Comp	SF	WSPP			
3	Barclays Bank PLC	SF	ISDA			
4	Black Hills Power, Inc.	SF	WSPP			
5	Bonneville Power Administration	LF	WNP#3 Agr.			
6	Bonneville Power Administration	SF	WSPP			
7	Bonneville Power Administration	SF	Tariff #8			
8	Bonneville Power Administration	OS	BPA OATT			
9	Bonneville Power Administration	SF	BPA OATT			
10	Brookfield Energy Marketing LP	SF	WSPP			
11	Calpine Energy Services LP	SF	WSPP			
12	Cargill Power Markets	SF	WSPP			
13	Cargill Power Markets	SF	ISDA			
14	City of Redding	SF	WSPP			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
					15,837,095	15,837,095	1
219,559				10,235,099		10,235,099	2
					2,543,595	2,543,595	3
10,075				298,187		298,187	4
400,152				15,306,064		15,306,064	5
229,831				3,651,694		3,651,694	6
19,570				375,448		375,448	7
				-3,257	31,794	28,537	8
2,461				47,536	-85,033	-37,497	9
1,200				20,900		20,900	10
217,577				5,480,202		5,480,202	11
118,032				1,303,411		1,303,411	12
					-2,964	-2,964	13
43				138		138	14
8,188,382	548,640	547,803	15,727,976	181,867,301	41,761,152	239,356,429	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	City of Spokane	LU	PURPA			
2	City of Spokane	IU	PURPA			
3	Chelan County PUD	IU	Rocky Reach			
4	Chelan County PUD	SF	WSPP			
5	Chelan County PUD	IU	Chelan Sys			
6	Citigroup Energy	SF	WSPP			
7	Clark County PUD No. 1	SF	WSPP			
8	Clatskanie PUD	SF	WSPP			
9	Constellation Energy Commodities Group	SF	WSPP			
10	Douglas County PUD No. 1	LU	Wells			
11	Douglas County PUD No. 1	LU	Wells Settlement			
12	Douglas County PUD No. 1	IF	Wells			
13	Douglas County PUD No. 1	SF	WSPP			
14	Douglas County PUD No. 1	EX	305			
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
51,735				2,295,160		2,295,160	1
140,300				6,297,071		6,297,071	2
-15,027				3,194		3,194	3
5,824				34,444		34,444	4
332,946			11,383,976			11,383,976	5
147,159				2,916,118		2,916,118	6
10,745				147,657		147,657	7
7,990				65,100		65,100	8
4,150				27,597		27,597	9
139,650				1,578,461		1,578,461	10
44,507				1,137,850		1,137,850	11
188,173			4,344,000			4,344,000	12
17,458				166,972		166,972	13
	102,330	102,296		1,435,500	667	1,436,167	14
8,188,382	548,640	547,803	15,727,976	181,867,301	41,761,152	239,356,429	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	DB Energy Trading LLC	SF	WSPP			
2	DB Energy Trading LLC	SF	ISDA			
3	EDF Trading No America	SF	WSPP			
4	Eugene Water & Electric Board	SF	WSPP			
5	Exelon Generation Company, LLC	SF	WSPP			
6	Ford Hydro Limited Partnership	LU	PURPA			
7	Grant County PUD No. 2	LU	Priest Rapids			
8	Grant County PUD No. 2	SF	WSPP			
9	Grant County PUD No. 2	EX	FERC #104			
10	Hydro Technology Systems	LU	PURPA			
11	Iberdrola Renewables LLC	SF	WSPP			
12	Idaho County Power & Light	LU	PURPA			
13	Idaho Power Company	SF	WSPP			
14	Idaho Power Company - Balancing	SF	WSPP			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
79,375				510,250		510,250	1
					-48,724	-48,724	2
194,544				4,090,839		4,090,839	3
9,044				112,578		112,578	4
400				9,800		9,800	5
3,239				233,826		233,826	6
332,137				5,716,927		5,716,927	7
26,030				344,648		344,648	8
					12,864	12,864	9
11,140				564,880		564,880	10
368,848				3,744,374		3,744,374	11
2,224				99,095		99,095	12
32,416				639,689		639,689	13
880				21,720		21,720	14
8,188,382	548,640	547,803	15,727,976	181,867,301	41,761,152	239,356,429	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Inland Power & Light Company	RQ	208			
2	Jim White	LU	PURPA			
3	J P Morgan Ventures Energy LLC	SF	WSPP			
4	J P Morgan Ventures Energy LLC	LU	PPM Energy			
5	J P Morgan Ventures Energy LLC	SF	ISDA			
6	Kootenai Electric Cooperative	IU	PURPA			
7	Macquarie Energy LLC	SF	WSPP			
8	Modesto Irrigation District	SF	WSPP			
9	Morgan Stanley Capital Group	SF	WSPP			
10	Morgan Stanley Capital Group	SF	ISDA			
11	Newedge USA LLC	SF	ISDA			
12	NextEra Energy Power Marketing LLC	SF	WSPP			
13	Noble America Gas & Power Corp.	SF	WSPP			
14	NorthWestern Energy LLC	SF	WSPP			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
92				5,780		5,780	1
1,142				110,943		110,943	2
488,936				10,975,404		10,975,404	3
80,350				3,454,792		3,454,792	4
					-3,357	-3,357	5
9,535				136,038		136,038	6
136,564				3,351,516		3,351,516	7
45				675		675	8
264,761				6,276,079		6,276,079	9
					2,540,145	2,540,145	10
					16,639,357	16,639,357	11
1,640				18,120		18,120	12
6,200				65,700		65,700	13
95,133				2,652,684		2,652,684	14
8,188,382	548,640	547,803	15,727,976	181,867,301	41,761,152	239,356,429	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW): Average Monthly NCP Demand (e)	Actual Demand (MW): Average Monthly CP Demand (f)
1	Okanogan County PUD No. 1	SF	WSPP			
2	PPL Energy Plus	SF	WSPP			
3	PacifiCorp	SF	WSPP			
4	Palouse Wind LLC	LU	PPA			
5	Pend Oreille County PUD No. 1	SF	Pend O'			
6	Pend Oreille County PUD No. 1	SF	Pend O'			
7	Phillips Ranch	LU	PURPA			
8	Portland General Electric Company	EX	304			
9	Portland General Electric Company	EX	178			
10	Portland General Electric Company	SF	WSPP			
11	Potlatch Corporation	LU	PURPA			
12	Powerex Corp	SF	WSPP			
13	Powerex Corp	SF	ISDA			
14	Puget Sound Energy	SF	WSPP			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
3,250				30,893		30,893	1
1,034,365				21,297,776		21,297,776	2
57,264				932,603		932,603	3
61,450				1,779,694		1,779,694	4
20,836				356,190		356,190	5
106,344	4,849	4,493		2,146,759	-4,091	2,142,668	6
47				2,333		2,333	7
	431,507	431,057					8
	9,954	9,743			42,035	42,035	9
16,707				284,869		284,869	10
421,680				18,098,506		18,098,506	11
39,424				611,644		611,644	12
					411,624	411,624	13
37,126				516,995		516,995	14
8,188,382	548,640	547,803	15,727,976	181,867,301	41,761,152	239,356,429	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Rainbow Energy Marketing Corp	SF	WSPP			
2	Sacramento Municipal Utility District	SF	WSPP			
3	San Diego Gas & Electric	SF	WSPP			
4	Seattle City Light	SF	WSPP			
5	Sheep Creek Hydro	LU	PURPA			
6	Shell Energy	SF	ISDA			
7	Shell Energy	SF	WSPP			
8	Sierra Pacific Power Company	SF	WSPP			
9	Snohomish County PUD No. 1	SF	WSPP			
10	Southern California Edison Co.	SF	WSPP			
11	Sovereign Power	IF	Sovereign			
12	Spokane County	LU	PURPA			
13	Stimson Lumber	IU	PURPA			
14	Tacoma Power	SF	WSPP			
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
29,939				663,683		663,683	1
1,400				28,050		28,050	2
492				10,385		10,385	3
49,798				866,905		866,905	4
7,249				288,303		288,303	5
					3,221,028	3,221,028	6
321,879				4,404,333		4,404,333	7
623				14,026		14,026	8
31,567				360,020		360,020	9
8				101		101	10
7,293				113,586		113,586	11
1,355				82,262		82,262	12
35,383				1,759,425		1,759,425	13
79,578				2,682,815		2,682,815	14
8,188,382	548,640	547,803	15,727,976	181,867,301	41,761,152	239,356,429	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW): Average Monthly NCP Demand (e)	Actual Demand (MW): Average Monthly CP Demand (f)
1	Tenaska Power Services Company	SF	WSPP			
2	The Energy Authority	SF	WSPP			
3	TransAlta Energy Marketing	SF	WSPP			
4	Tri-State Generation & Transmission As	SF	WSPP			
5	IntraCompany Generation Services	OS	OATT			
6	Rathdrum Power LLC	LF	Lancaster			
7	Other - Inadvertent Interchange	EX				
8						
9						
10						
11						
12						
13						
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
10,640				289,466		289,466	1
37,948				309,082		309,082	2
125,421				3,786,592		3,786,592	3
2,090				25,109		25,109	4
					625,117	625,117	5
1,208,441				24,167,993		24,167,993	6
		214					7
							8
							9
							10
							11
							12
							13
							14
8,188,382	548,640	547,803	15,727,976	181,867,301	41,761,152	239,356,429	

Schedule Page: 326 Line No.: 1 Column: a

Fianncial SWAP

Schedule Page: 326 Line No.: 3 Column: a

Financial SWAP

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

Ancillary Services - Spinning & Supplemental

Schedule Page: 326 Line No.: 9 Column: a

Non Monetary

Schedule Page: 326 Line No.: 13 Column: a

Financial SWAP

Schedule Page: 326.1 Line No.: 14 Column: a

Non Monetary

Schedule Page: 326.2 Line No.: 2 Column: a

Financial SWAP

Schedule Page: 326.2 Line No.: 9 Column: a

Non Monetary

Schedule Page: 326.3 Line No.: 1 Column: a

Service to Deer Lake from Inland Power and Light. No demand charges associated with the agreement.

Schedule Page: 326.3 Line No.: 5 Column: a

Financial SWAP

Schedule Page: 326.3 Line No.: 10 Column: a

Financial SWAP

Schedule Page: 326.3 Line No.: 11 Column: a

Financial SWAP

Schedule Page: 326.4 Line No.: 6 Column: a

Non Monetary

Schedule Page: 326.4 Line No.: 9 Column: a

Non Monetary

Schedule Page: 326.4 Line No.: 13 Column: a

Financial SWAP

Schedule Page: 326.5 Line No.: 6 Column: a

Financial Swap

Schedule Page: 326.6 Line No.: 5 Column: a

Ancillary Services

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Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	PacifiCorp	PacifiCorp	PacifiCorp	LFP
2	Seattle City Light	Seattle City Light	Grant County PUD	LFP
3	Tacoma City Light	Tacoma City Light	Grant County PUD	LFP
4	Grant County Public Utility District	Grant County Public Utility Distr	Grant County Public Utility Distr	LFP
5	Spokane Indian Tribes	Bonneville Power Administration	Spokane Indian Tribes	LFP
6	USBR	Bonneville Power Administration	East Greenacres	LFP
7	Consolidated Irrigation District	Bonneville Power Administration	Consolidated Irrigation District	LFP
8	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	FNO
9	City of Spokane	City of Spokane	Avista Corporation	OS
10	Stimpson	Plummer	Avista Corporation	OS
11	Hydro Tech Industries	Meyers Falls	Avista Corporation	OS
12	Palouse Wind	Palouse Wind	Avista Corporation	OS
13	Kootenai Electric Cooperative	Kootenai Electric Cooperative	Avista Corporation	OS
14	Coral Power	Bonneville Power Administration	Northwestern Montana	SFP
15	Cargill Power Markets	Bonneville Power Administration	Idaho Power Company	SFP
16	Cargill Power Markets	Northwestern Montana	Avista Corporation	SFP
17	Cargill Power Markets	Northwestern Montana	Bonneville Power Administration	SFP
18	Cargill Power Markets	Northwestern Montana	Chelan County PUD	SFP
19	Cargill Power Markets	Northwestern Montana	PacifiCorp	SFP
20	Morgan Stanley Capital Group	Bonneville Power Administration	Northwestern Montana	SFP
21	Morgan Stanley Capital Group	Northwestern Montana	Bonneville Power Administration	SFP
22	Morgan Stanley Capital Group	Northwestern Montana	Chelan County PUD	SFP
23	Morgan Stanley Capital Group	Northwestern Montana	Grant County PUD	SFP
24	Morgan Stanley Capital Group	Puget Sound Energy	Northwestern Montana	SFP
25	Morgan Stanley Capital Group	Grant County PUD	Northwestern Montana	SFP
26	Morgan Stanley Capital Group	Chelan County PUD	Idaho Power Company	SFP
27	Morgan Stanley Capital Group	Chelan County PUD	Northwestern Montana	SFP
28	Bonneville Power Administration	Bonneville Power Administration	Idaho Power Company	SFP
29	Portland General Electric	Northwestern Montana	Bonneville Power Administration	SFP
30	Idaho Power Company	Bonneville Power Administration	Idaho Power Company	SFP
31	Idaho Power Company	Idaho Power Company	Bonneville Power Administration	SFP
32	Idaho Power Company LSE	Bonneville Power Administration	Idaho Power Company	SFP
33	Idaho Power Company LSE	Bonneville Power Administration	PacifiCorp	SFP
34	Idaho Power Company LSE	Northwestern Montana	Bonneville Power Administration	SFP
	TOTAL			

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
FERC No. 182	Dry Creek Walla Wall	Dry Gulch	20	56,261	56,261	1
FERC Trf No. 8	Chelan-Stratford 115	Stratford 115kV SS		238,208	238,208	2
FERC Trf No. 8	Chelan-Stratford 115	Stratford 115kV SS		238,208	238,208	3
FERC No. 104	Stratford Substation	Coulee Cy/Wilson Crk	25	88,595	88,595	4
FERC Trf No. 8	Westside	Little Falls	1	3,035	3,035	5
FERC Trf No. 8	Bell Substation	Post Falls	3	3,210	3,210	6
FERC Trf No. 8	Bell Substation	BKR/OPT/EFM/LIB	3	5,840	5,840	7
FERC Trf No. 8				1,814,455	1,814,455	8
FERC No. 155	Sunset-Westside 115k	Westside				9
FERC Trf No. 8	AVA Syst	AVA Syst				10
FERC Trf No. 8						11
FERC Trf No. 8						12
FERC Trf No. 8						13
FERC Trf No. 8				4,108	4,108	14
FERC Trf No. 8				9,777	9,777	15
FERC Trf No. 8				400	400	16
FERC Trf No. 8				8,840	8,840	17
FERC Trf No. 8				3,288	3,288	18
FERC Trf No. 8				800	800	19
FERC Trf No. 8				10	10	20
FERC Trf No. 8				55	55	21
FERC Trf No. 8				5,752	5,752	22
FERC Trf No. 8				175	175	23
FERC Trf No. 8				10	10	24
FERC Trf No. 8				5,540	5,540	25
FERC Trf No. 8				162	162	26
FERC Trf No. 8				22	22	27
FERC Trf No. 8				21,941	21,941	28
FERC Trf No. 8				12,105	12,105	29
FERC Trf No. 8				57,240	57,240	30
FERC Trf nO.				6,400	6,400	31
FERC Trf No. 8				279,786	279,786	32
FERC Trf No. 8				800	800	33
FERC Trf No. 8				15	15	34
			52	**3,191,975**	**3,191,975**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

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

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
214,489			214,489	1
150,992		30,930	181,922	2
150,992		30,930	181,922	3
26,707			26,707	4
23,746			23,746	5
16,517			16,517	6
38,837			38,837	7
6,992,205			6,992,205	8
		27,973	27,973	9
		9,480	9,480	10
		6,120	6,120	11
		200,000	200,000	12
		6,073	6,073	13
42,458			42,458	14
100,607			100,607	15
1,538			1,538	16
33,386			33,386	17
13,225			13,225	18
3,077			3,077	19
9,230			9,230	20
883			883	21
50,629			50,629	22
2,431			2,431	23
4,615			4,615	24
45,183			45,183	25
2,894			2,894	26
393			393	27
258,163			258,163	28
69,225			69,225	29
304,590			304,590	30
27,690			27,690	31
1,073,182			1,073,182	32
2,492			2,492	33
50			50	34
11,330,248	**0**	**311,506**	**11,641,754**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Idaho Power Company LSE	PacifiCorp	Idaho Power Company	SFP
2	Idaho Power Company LSE	PacifiCorp	Northwestern Montana	SFP
3	Idaho Power Company LSE	Idaho Power Company	Bonneville Power Administration	SFP
4	Powerex	Bonneville Power Administration	Idaho Power Company	SFP
5	Powerex	Bonneville Power Administration	Northwestern Montana	SFP
6	Rainbow Energy Marketing Corporation	Avista Corporation	Bonneville Power Administration	SFP
7	Rainbow Energy Marketing Corporation	Bonneville Power Administration	Idaho Power Company	SFP
8	Rainbow Energy Marketing Corporation	Douglas County PUD	Idaho Power Company	SFP
9	PacifiCorp	PacifiCorp	Bonneville Power Administration	SFP
10	Coral Power	Bonneville Power Administration	Northwestern Montana	NF
11	Coral Power	Northwestern Montana	Bonneville Power Administration	NF
12	Coral Power	Northwestern Montana	Chelan County PUD	NF
13	Coral Power	Northwestern Montana	Grant County PUD	NF
14	Coral Power	Grant County PUD	Northwestern Montana	NF
15	Coral Power	Chelan County PUD	Idaho Power Company	NF
16	Coral Power	Chelan County PUD	Northwestern Montana	NF
17	Cargill Power Markets	Avista Corporation	Northwestern Montana	NF
18	Cargill Power Markets	Bonneville Power Administration	Idaho Power Company	NF
19	Cargill Power Markets	Bonneville Power Administration	Northwestern Montana	NF
20	Cargill Power Markets	Northwestern Montana	Bonneville Power Administration	NF
21	Cargill Power Markets	Northwestern Montana	Chelan County PUD	NF
22	Cargill Power Markets	Northwestern Montana	Idaho Power Company	NF
23	Cargill Power Markets	Northwestern Montana	Avista Corporation	NF
24	PPL Energy Plus	Bonneville Power Administration	Idaho Power Company	NF
25	PPL Energy Plus	Bonneville Power Administration	Northwestern Montana	NF
26	PPL Energy Plus	Northwestern Montana	Bonneville Power Administration	NF
27	PPL Energy Plus	Northwestern Montana	Chelan County PUD	NF
28	PPL Energy Plus	Northwestern Montana	Idaho Power Company	NF
29	PPL Energy Plus	Northwestern Montana	Grant County PUD	NF
30	Morgan Stanley Capital Group	Bonneville Power Administration	Chelan County PUD	NF
31	Morgan Stanley Capital Group	Bonneville Power Administration	Idaho Power Company	NF
32	Morgan Stanley Capital Group	Bonneville Power Administration	Northwestern Montana	NF
33	Morgan Stanley Capital Group	Northwestern Montana	Bonneville Power Administration	NF
34	Morgan Stanley Capital Group	Northwestern Montana	Chelan County PUD	NF
	TOTAL			

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
FERC Trf No. 8				34,751	34,751	1
FERC Trf No. 8				192	192	2
FERC Trf No. 8				174	174	3
FERC Trf No. 8				8,158	8,158	4
FERC Trf No. 8				204	204	5
FERC Trf No. 8				1,275	1,275	6
FERC Trf No. 8				33,764	33,764	7
FERC Trf No. 8				704	704	8
FERC Trf No. 8				1,301	1,301	9
FERC Trf No. 8				12,450	12,450	10
FERC Trf No. 8				2,579	2,579	11
FERC Trf No. 8				4,134	4,134	12
FERC Trf No. 8				1,273	1,273	13
FERC Trf No. 8				20	20	14
FERC Trf No. 8				6	6	15
FERC Trf No. 8				113	113	16
FERC Trf No. 8				273	273	17
FERC Trf No. 8				14,687	14,687	18
FERC Trf No. 8				1,843	1,843	19
FERC Trf No. 8				1,000	1,000	20
FERC Trf No. 8				440	440	21
FERC Trf No. 8				367	367	22
FERC Trf No. 8				800	800	23
FERC Trf No. 8				25	25	24
FERC Trf No. 8				3,871	3,871	25
FERC Trf No. 8				1,510	1,510	26
FERC Trf No. 8				30	30	27
FERC Trf No. 8				985	985	28
FERC Trf No. 8				50	50	29
FERC Trf No. 8				50	50	30
FERC Trf No. 8				143	143	31
FERC Trf No. 8				824	824	32
FERC Trf No. 8				18,001	18,001	33
FERC Trf No. 8				1,681	1,681	34
			52	**3,191,975**	**3,191,975**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

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

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
147,137			147,137	1
640			640	2
580			580	3
89,908			89,908	4
1,561			1,561	5
6,606			6,606	6
146,584			146,584	7
3,720			3,720	8
73,840			73,840	9
43,983			43,983	10
16,075			16,075	11
24,922			24,922	12
7,960			7,960	13
57			57	14
42			42	15
735			735	16
733			733	17
37,735			37,735	18
7,163			7,163	19
8,623			8,623	20
4,441			4,441	21
10,000			10,000	22
2,613			2,613	23
147			147	24
22,901			22,901	25
9,274			9,274	26
173			173	27
5,710			5,710	28
362			362	29
251			251	30
902			902	31
5,116			5,116	32
109,523			109,523	33
10,455			10,455	34
11,330,248	**0**	**311,506**	**11,641,754**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Morgan Stanley Capital Group	Northwestern Montana	Idaho Power Company	NF
2	Morgan Stanley Capital Group	Northwestern Montana	Grant County PUD	NF
3	Morgan Stanley Capital Group	Chelan County PUD	Bonneville Power Administration	NF
4	Morgan Stanley Capital Group	Chelan County PUD	Idaho Power Company	NF
5	Morgan Stanley Capital Group	Chelan County PUD	Northwestern Montana	NF
6	Naturener	Bonneville Power Administration	Northwestern Montana	NF
7	Northwestern Energy	Bonneville Power Administration	Northwestern Montana	NF
8	Norwestern Energy	Northwestern Montana	Bonneville Power Administration	NF
9	Powerex	Bonneville Power Administration	Idaho Power Company	NF
10	Powerex	Bonneville Power Administration	Northwestern Montana	NF
11	Powerex	Bonneville Power Administration	Puget Sound Energy	NF
12	Powerex	Northwest Montana	Bonneville Power Administration	NF
13	Powerex	Puget Sound Energy	Idaho Power Company	NF
14	Powerex	Grant County PUD	Idaho Power Company	NF
15	Powerex	Chelan County PUD	Northwestern Montana	NF
16	Bonneville Power Administration	Bonneville Power Administration	Idaho Power Company	NF
17	Bonneville Power Administration	Idaho Power Company	Bonneville Power Administration	NF
18	Portland General Electric	Northwestern Montana	Bonneville Power Administration	NF
19	Portland General Electric	Northwestern Montana	Portland General Electric	NF
20	PPM Energy	Bonneville Power Administration	Idaho Power Company	NF
21	Puget Sound Energy	Northwestern Montana	Bonneville Power Administration	NF
22	Puget Sound Energy	Idaho Power Company	Bonneville Power Administration	NF
23	Idaho Power Company	Avista Corporation	Bonneville Power Administration	NF
24	Idaho Power Company	Bonneville Power Company	Idaho Power Company	NF
25	Idaho Power Company	PacifiCorp	Idaho Power Company	NF
26	Idaho Power Company	PacifiCorp	Northwestern Montan	NF
27	Idaho Power Company	Idaho Power Company	Bonneville Power Administration	NF
28	Grant County PUD	Avista Corporation	Grant County PUD	NF
29	Idaho Power Company LSE	Bonneville Power Administration	Idaho Power Company	NF
30	Idaho Power Company LSE	PacifiCorp	Idaho Power Company	NF
31	Idaho Power Company LSE	PacifiCorp	Northwestern Montana	NF
32	The Energy Authority	Bonneville Power Administration	Northwestern Montana	NF
33	The Energy Authority	Northwestern Montana	Bonneville Power Administration	NF
34	TransAlta Energy Marketing	Bonneville Power Administration	Idaho Power Company	NF
	TOTAL			

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
FERC Trf No. 8				72	72	1
FERC Trf No. 8				277	277	2
FERC Trf No. 8				68	68	3
FERC Trf No. 8				81	81	4
FERC Trf No. 8				53	53	5
FERC Trf No. 8				24	24	6
FERC Trf No. 8				1,789	1,789	7
FERC Trf No. 8				459	459	8
FERC Trf No. 8				20,421	20,421	9
FERC Trf No. 8				4,407	4,407	10
FERC Trf No. 8				71	71	11
FERC Trf No. 8				81	81	12
FERC Trf No. 8				101	101	13
FERC Trf No. 8				35	35	14
FERC Trf No. 8				754	754	15
FERC Trf No. 8				60,832	60,832	16
FERC Trf No. 8				556	556	17
FERC Trf No. 8				1,014	1,014	18
FERC Trf No. 8				697	697	19
FERC Trf No. 8				174	174	20
FERC Trf No. 8						21
FERC Trf No. 8				325	325	22
FERC Trf No. 8				2,256	2,256	23
FERC Trf No. 8				11,789	11,789	24
FERC Trf No. 8				3,399	3,399	25
FERC Trf No. 8				150	150	26
FERC Trf No. 8				1,366	1,366	27
FERC Trf No. 8						28
FERC Trf No. 8				31,735	31,735	29
FERC Trf No. 8				400	400	30
FERC Trf No. 8				269	269	31
FERC Trf No. 8				90	90	32
FERC Trf No. 8				180	180	33
FERC Trf No. 8				16	16	34
			52	**3,191,975**	**3,191,975**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

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

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
482			482	1
2,386			2,386	2
442			442	3
588			588	4
385			385	5
138			138	6
10,323			10,323	7
2,966			2,966	8
97,794			97,794	9
21,735			21,735	10
142			142	11
943			943	12
806			806	13
356			356	14
6,016			6,016	15
208,090			208,090	16
1,996			1,996	17
6,532			6,532	18
4,143			4,143	19
3,225			3,225	20
144			144	21
1,875			1,875	22
6,716			6,716	23
79,968			79,968	24
20,902			20,902	25
922			922	26
8,143			8,143	27
2,423			2,423	28
130,602			130,602	29
2,337			2,337	30
2,122			2,122	31
664			664	32
1,039			1,039	33
410			410	34
11,330,248	**0**	**311,506**	**11,641,754**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Sierra Pacific Power Company	Bonneville Power Administration	Idaho Power Company	NF
2	PacifiCorp	PacifiCorp	Idaho Power Company	NF
3	Tri-State G & T	Avista Corporation	Bonneville Power Administration	NF
4	Tri-State G & T	Bonneville Power Administration	Northwestern Montana	NF
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
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32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
FERC Trf No. 8				230	230	1
FERC Trf No. 8				33,822	33,822	2
FERC Trf No. 8				362	362	3
FERC Trf No. 8				904	904	4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
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						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			52	**3,191,975**	**3,191,975**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

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

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
1,327			1,327	1
232,473			232,473	2
2,229			2,229	3
5,566			5,566	4
				5
				6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17
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				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
11,330,248	**0**	**311,506**	**11,641,754**	

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

Use of facilities

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

Use of facilities

Schedule Page: 328 Line No.: 9 Column: m

Use of facilities

Schedule Page: 328 Line No.: 10 Column: m

Use of facilities

Schedule Page: 328 Line No.: 11 Column: m

Use of facilities

Schedule Page: 328 Line No.: 12 Column: m

Deferral fee for long-term firm agreement.

Schedule Page: 328 Line No.: 13 Column: m

Forfeited long term point to point transmission deposit.

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Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Bonneville Power Admin	LFP			1,496,931			1,496,931
2	Bonneville Power Admin	LFP			11,076,480		1,749,048	12,825,528
3	Bonneville Power Admin	LFP			788,748			788,748
4	Bonneville Power Admin	OS					24,360	24,360
5	Bonneville Power Admin	FNS			1,030,177		131,833	1,162,010
6	Bonneville Power Admin	NF	20,986	20,986		90,870	-25,842	65,028
7	Benton County PUD No. 1	NF	2,003	2,003		2,169		2,169
8	Clark County PUD No. 1	NF	566	566		651		651
9	Grays Harbor County PUD	NF	115	115		135		135
10	Klickitat PUD	NF	45	45		45		45
11	Kootenai Electric Coop	LFP			45,222			45,222
12	Northern Lights	LFP			133,517			133,517
13	NorthWestern Energy	SFP			179,362		12,713	192,075
14	NorthWestern Energy	NF	17,731	17,731		76,775		76,775
15	Portland General Elec	LFP			628,000		14,989	642,989
16	Portland General Elec	NF	5,128	5,128		7,442		7,442
	TOTAL		112,114	112,114	15,378,437	266,076	1,907,101	17,551,614

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Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Puget Sound Energy	NF	22,085	22,085		29,169		29,169
2	Seattle City Light	NF	43,113	43,113		58,298		58,298
3	Tacoma Power	NF	342	342		522		522
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		112,114	112,114	15,378,437	266,076	1,907,101	17,551,614

Schedule Page: 332	Line No.: 2	Column: g

Ancillary Services

Schedule Page: 332	Line No.: 4	Column: g

Use of Facilities

Schedule Page: 332	Line No.: 5	Column: g

Ancillary Services

Schedule Page: 332	Line No.: 6	Column: g

Out of Period Adjustments

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Ancillary Services

Schedule Page: 332	Line No.: 15	Column: g

Ancillary Services

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	769,943
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	106,896
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	1,421,612
6	Community Relations	203,174
7	Other Misc & General Expenses	644
8	Directors Fees and Expenses	611,507
9	Education and Informational	141,562
10		
11		
12		
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17		
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44		
45		
46	TOTAL	3,255,338

Schedule Page: 335 Line No.: 5 Column: b

Schedule Page: 335 Line No.: 5

Vendor	Purpose	Amount
Vendors Under $5000		132,017.11
ALDERBROOK RESORT & SPA	Employee Lodging	4,019.44
AMEREN	Professional Services	7,048.06
AMERICAN GAS ASSOCIATION	Miscellaneous	.00
AMERICAN STOCK TRANSFER & TRUST CO	General Services	5,801.70
AZAR'S FOOD SERVICES	Employee Business Meals	8,076.95
BROADRIDGE ICS	General Services	59,207.85
CITIBANK NA	Miscellaneous	44,785.65
COATES KOKES	Professional Services	5,298.42
COMPUTERSHARE SHAREOWNER SERVICES LLC	Postage	75,420.89
CORP CREDIT CARD	Telecommunication Use	134,155.55
CORPORATE RISK SOLUTIONS INC	Professional Services	18,342.40
CUTAWAY MEDIA	Miscellaneous	5,043.08
DAVID D HOLMES	Office Supplies	5,736.96
DAVIS HIBBITTS & MIDGHALL INC	Professional Services	9,906.05
DAVIS WRIGHT TREMAINE LLP	Miscellaneous	9,499.44
DENNIS P VERMILLION	Employee Misc Expenses	5,953.48
DESAUTEL HEGE COMMUNICATIONS	Professional Services	31,277.23
DUFFY RESEARCH	Miscellaneous	5,290.73
ENTERPRISE RENT A CAR	Miscellaneous	5,646.22
HANNA & ASSOCIATES INC	Printing	20,721.44
INLAND NORTHWEST PARTNERS	Subscriptions	5,899.58
INNOVATE WASHINGTON FOUNDATION	Professional Services	23,918.62
JASON R THACKSTON	Employee Misc Expenses	13,137.46
KAREN S FELTES	Employee Misc Expenses	7,426.75
KLUNDT HOSMER DESIGN	Professional Services	18,790.70
MARK T THIES	Employee Misc Expenses	6,372.49
MDI MARKETING	Advertising Expenses	9,832.63
MELLON INVESTOR SERVICES LLC	Miscellaneous	16,389.60
MICHAEL G ANDREA	Employee Misc Expenses	17,936.42
MICHAEL J FAULKENBERRY	Employee Misc Expenses	.00
MOODYS INVESTORS SERVICE	Miscellaneous	97,259.40
NYSE MARKET INC	General Services	39,143.67
RICOH USA INC	Printing	7,654.42
ROCKY MOUNTAIN INSTITUTE	Professional Services	18,011.00
SIXTH MAN MARKETING LLC	Professional Services	7,924.84
STANDARD & POORS	Miscellaneous	76,347.09
THE BANK OF NEW YORK MELLON	Miscellaneous	8,499.75
THE DAVENPORT HOTEL	Miscellaneous	14,087.66
UNION BANK OF CALIFORNIA	Miscellaneous	25,215.40
VAN NESS FELDMAN	Legal Services	16,427.75

Schedule Page: 335	Line No.: 8	Column: b

Directors

	2012 Expenses
Vendor Name	
HEIDI B STANLEY	$67,840
MARC F RACICOT	$61,053
ERIK J ANDERSON	$62,905
KRISTIANNE BLAKE	$63,017
REBECCA A KLEIN	$50,608
JOHN F KELLY	$79,492
MICHAEL L NOEL	$46,751
R JOHN TAYLOR	$53,925
SCOTT L MORRIS	$16,249
RICK R HOLLEY	$58,304
DONALD C BURKE	$51,354

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.

Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.

In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.

For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.

4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			5,693,753		5,693,753
2	Steam Production Plant	10,710,230				10,710,230
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	8,975,915				8,975,915
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	8,366,040			2,450,031	10,816,071
7	Transmission Plant	10,730,725				10,730,725
8	Distribution Plant	31,842,769				31,842,769
9	Regional Transmission and Market Operation					
10	General Plant	3,902,111				3,902,111
11	Common Plant-Electric	8,489,414		1,582,119		10,071,533
12	TOTAL	83,017,204		7,275,872	2,450,031	92,743,107

B. Basis for Amortization Charges

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	STEAM PLANT						
13	Colstrip No. 3						
14	311	51,012	65.00	-5.00	2.28	S1.5	17.88
15	312	78,402	60.00	-10.00	2.70	R1	18.57
16	314	23,215	50.00	-10.00	3.39	O1	28.07
17	315	9,550	55.00	-5.00	2.49	S1.5	20.78
18	316	9,030	50.00		2.26	R2	15.88
19	Subtotal	171,209					
20							
21	Colstrip No. 4						
22	311	50,229	65.00	-5.00	2.35	S1.5	21.32
23	312	50,571	60.00	-10.00	2.83	R1	23.84
24	314	15,774	50.00	-10.00	3.50	O1	28.31
25	315	6,699	55.00	-5.00	2.59	S1.5	25.11
26	316	4,299	50.00		2.46	R3	19.98
27	Subtotal	127,572					
28							
29	Kettle Falls						
30	310	148	35.00		2.19	SQ	
31	311	24,982	65.00	-5.00	2.34	S1.5	20.59
32	312	42,375	60.00	-10.00	3.31	R1	22.43
33	314	13,345	50.00	-10.00	3.18	O1	16.35
34	315	9,913	55.00	-5.00	2.74	S1.5	17.61
35	316	2,612	50.00		2.68	R2	21.44
36	Subtotal	93,375					
37							
38	HYDRO PLANT						
39	Cabinet Gorge						
40	330	7,842	75.00		2.75	R3	67.57
41	331	10,943	110.00	-5.00	1.62	R0.5	56.19
42	332	31,785	100.00		1.79	R1.5	77.96
43	333	37,880	60.00	-5.00	2.59	R1.5	52.14
44	334	5,605	45.00		1.43	R2.5	16.54
45	335	3,416	65.00		0.13	R1	1.20
46	336	1,099	60.00		2.05	S2.5	17.49
47	Subtotal	98,570					
48							
49	Noxon Rapids						
50	330	30,389	75.00		2.83	R3	69.37

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	331	14,911	110.00	-5.00	1.77	R0.5	81.53
13	332	32,991	100.00		1.79	R1.5	75.35
14	333	88,323	60.00	-5.00	2.89	R1.5	56.01
15	334	14,223	45.00		2.53	R2.5	43.88
16	335	3,378	65.00		0.97	R1	19.90
17	336	247	60.00		2.12	R2.5	39.60
18	Subtotal	184,462					
19							
20	Post Falls						
21	330	199	75.00		3.79	R3	56.46
22	331	1,466	110.00	-5.00	0.36	R0.5	56.29
23	332	6,344	100.00		2.72	R1.5	92.62
24	333	2,234	60.00	-5.00	0.16	R1.5	
25	334	716	45.00		0.14	R2.5	0.01
26	335	223	65.00		2.68	R1	53.83
27	Subtotal	11,182					
28							
29	Long Lake						
30	330	171	75.00		5.68	R3	45.63
31	331	2,429	110.00	-5.00	0.12	R0.5	15.32
32	332	16,673	100.00		1.10	R1.5	24.34
33	333	8,824	60.00	-5.00	1.29	R1.5	13.91
34	334	2,823	45.00		0.82	R2.5	30.46
35	335	529	65.00		1.58	R1	30.46
36	Subtotal	31,449					
37							
38	Little Falls						
39	330	4,214	75.00		7.03	R3	56.31
40	331	1,188	110.00	-5.00	0.12	R0.5	2.00
41	332	5,066	100.00		1.51	R1.5	51.95
42	333	3,940	60.00	-5.00	0.51	R1.5	
43	334	2,056	45.00		0.93	R2.5	12.81
44	335	144	65.00		1.18	R1	19.46
45	Subtotal	16,608					
46							
47	Upper Falls						
48	330	64	75.00		2.48	R4	37.64
49	331	936	110.00	-5.00	0.12	R0.5	9.42
50	332	7,677	100.00		1.20	R1.5	76.61

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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	333	1,186	60.00	-5.00	0.90	R1.5	6.67
13	334	4,268	45.00		1.85	R2.5	37.00
14	335	107	65.00		2.30	R1	51.46
15	Subtotal	14,238					
16							
17	Nine Mile						
18	330	10	75.00		4.59	R3	34.35
19	331	3,950	110.00	-5.00	2.35	R0.5	80.39
20	332	13,620	100.00		2.16	R1.5	72.53
21	333	9,627	60.00	-5.00	3.03	R1.5	56.34
22	334	2,637	45.00		2.57	R2.5	31.52
23	335	297	65.00		2.31	R1	45.87
24	336	625	60.00		2.64	S2.5	56.50
25	Subtotal	30,766					
26							
27	Monroe Street						
28	331	8,444	110.00	-5.00	1.82	R0.5	109.02
29	332	9,978	100.00		1.72	R1.5	99.22
30	333	11,030	60.00	-5.00	2.28	R1.5	60.23
31	334	1,685	45.00		2.97	R2.5	45.13
32	335	34	65.00		2.04	R1	64.37
33	336	50	60.00		2.17	S2.5	59.42
34	Subtotal	31,221					
35							
36	OTHER PRODUCTION						
37	Northeast Turbine						
38	341	745			0.98	SQ	
39	342	31	55.00		1.31	R3	
40	343	9,058	50.00		7.83	S2.5	8.42
41	344	2,605	45.00		0.72	R3	
42	345	1,238	40.00		8.54	S1.5	11.83
43	346	406			1.24	SQ	
44	Subtotal	14,083					
45							
46	Rathdrum Turbine						
47	341	3,258			3.95	SQ	
48	342	1,696	55.00		4.10	R2.5	44.14
49	343	5,502	50.00		3.61	S2.5	33.50
50	344	48,858	45.00		3.37	R3	35.49

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	345	2,567	40.00		3.56	S1.5	
13	Subtotal	61,881					
14							
15	Kettle Falls CT						
16	342	89	55.00		4.74	R3	39.59
17	343	9,071	50.00		4.71	S2.5	35.98
18	344	4	45.00		4.98	R3	36.77
19	345	14	40.00		4.48	S1.5	28.83
20	Subtotal	9,178					
21							
22	Boulder Park						
23	341	1,205			2.63	SQ	
24	342	116	55.00		2.71	R3	37.93
25	343	57	50.00		3.01	S2.5	40.21
26	344	30,611	45.00		2.84	R3	32.97
27	345	443	40.00		2.97	S1.5	31.24
28	346	7			2.69	SQ	
29	Subtotal	32,439					
30							
31	Coyote Springs 2						
32	341	11,374			2.76	SQ	
33	342	19,145	55.00		2.85	R3	44.23
34	344	119,026	45.00		2.92	R3	41.58
35	345	12,818	40.00		3.10	S1.5	32.07
36	346	1,306			2.76	SQ	
37	Subtotal	163,669					
38							
39	Solar Power	183					
40	Subtotal	183					
41	TRANSMISSION PLANT						
42	350	1,488	75.00		1.28	R4	53.27
43	352	17,104	60.00	-5.00	1.61	R4	44.73
44	353	213,222	47.00	-15.00	2.39	R3	31.13
45	354	17,123	70.00	-20.00	1.87	S3	43.89
46	355	154,798	60.00	-30.00	1.84	R3	37.27
47	356	116,768	60.00	-10.00	1.93	R3	43.30
48	357	2,605	60.00		1.58	R4	52.84
49	358	2,330	55.00		1.73	S3	41.27
50	359	1,872	65.00		1.65	R4	45.05

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Subtotal	527,310					
13	DISTRIBUTION PLANT						
14	360		75.00				
15	361	17,970	55.00	-10.00	1.80	R3	35.51
16	362	111,338	42.00	-10.00	2.60	R1.5	28.26
17	364	261,335	50.00	-25.00	2.66	R2.5	34.66
18	365	173,752	50.00	-15.00	2.46	R2.5	35.35
19	366	85,678	45.00	-10.00	2.71	R3	36.09
20	367	141,650	28.00	-15.00	6.38	L4	23.05
21	368	198,972	44.00	-5.00	2.00	R2	27.21
22	369	132,648	60.00	-15.00	1.63	R3	38.01
23	370	47,965	38.00		2.39	S1	33.72
24	373	16,356	32.00	-15.00	1.08	R2.5	8.68
25	373.4	20,029	32.00	-5.00	2.82	R2.5	18.79
26	Subtotal	1,207,693					
27							
28	GENERAL PLANT						
29	390.1	6,229	55.00	-5.00	1.85	S2	20.91
30	391.1	7,870	5.00		17.67	SQ	3.80
31	393	395	25.00		2.25	SQ	22.97
32	394	3,186	20.00		4.22	SQ	10.35
33	395	920	15.00		7.72	SQ	7.82
34	397	48,855	15.00		5.40	SQ	5.17
35	398	31	10.00		2.37	SQ	7.80
36	Subtotal	67,486					
37							
38	MISC POWER						
39	392	3,742	11.00	10.00	3.70	S3	
40	396	2,806	15.00	10.00	5.40	L2	
41	Subtotal	6,548					
42							
43							
44							
45							
46							
47							
48							
49							
50							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Lancaster						
13	342	92					52.43
14	344	208					42.90
15	SUBTOTAL	300					
16							
17	TOTAL COMPANY	2,901,422					
18							
19							
20							
21							
22							
23							
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26							
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Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	Federal Energy Regulatory Commission				
2	Charges include annual fee and license fees				
3	for the Spokane River Project, the Cabinet				
4	Gorge Project and the Noxon Rapids Project.	2,431,364	185,496	2,616,860	
5					
6					
7					
8					
9	Washington Utilities and Transportation				
10	Commission: includes annual fee and various				
11	other electric dockets	960,565	1,301,327	2,261,892	
12					
13	Includes annual fee and various other natural				
14	gas dockets	320,188	495,445	815,633	
15					
16	Idaho Public Utilities Commission				
17	Includes annual fee and various other electric				
18	dockets	620,838	245,606	866,444	
19					
20	Includes annual fee and various other natural				
21	gas dockets	172,199	111,074	283,273	
22					
23	Public Utility Commission of Oregon				
24	Includes annual fees and various other natural				
25	gas dockets	528,779	127,724	656,503	
26					
27	Not directly assigned electric		913,764	913,764	
28	Not directly assigned natural gas		354,716	354,716	
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	5,033,933	3,735,152	8,769,085	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
							2
							3
Electric	928	2,616,860					4
							5
							6
							7
							8
							9
							10
Electric	928	2,261,892					11
							12
							13
Gas	928	815,633					14
							15
							16
							17
Electric	928	866,444					18
							19
							20
Gas	928	283,273					21
							22
							23
							24
Gas	928	656,503					25
							26
Electric	928	913,764					27
Gas	928	354,716					28
							29
							30
							31
							32
							33
							34
							35
							36
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							44
							45
		8,769,085					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
(1) Generation
a. hydroelectric
i. Recreation fish and wildlife
ii Other hydroelectric
b. Fossil-fuel steam
c. Internal combustion or gas turbine
d. Nuclear
e. Unconventional generation
f. Siting and heat rejection
(2) Transmission
a. Overhead
b. Underground
(3) Distribution
(4) Regional Transmission and Market Operation
(5) Environment (other than equipment)
(6) Other (Classify and include items in excess of $50,000.)
(7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
(1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	A 3 Electric - Distribution	Smart Grid Demonstration Grant (Meters)
2		
3		
4		
5		
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11		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	Amount (f)	Unamortized Accumulation (g)	Line No.
2,206,824	1,052,379	107	3,259,203		1
25,640	217	108	25,857		2
53,577	31	580	53,608		3
12,395	107,877	587	120,272		4
-1,800	261,141	588	259,341		5
100,719		920	100,719		6
376	28,997	921	29,373		7
2,881	42,820	923	45,701		8
50		926	50		9
85		930	85		10
	109,684	935	109,684		11
					12
					13
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Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

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.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	10,264,200		
4	Transmission	2,656,676		
5	Regional Market			
6	Distribution	7,508,530		
7	Customer Accounts	6,924,109		
8	Customer Service and Informational	711,342		
9	Sales	5,487		
10	Administrative and General	16,143,773		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	44,214,117		
12	Maintenance			
13	Production	3,410,007		
14	Transmission	985,166		
15	Regional Market			
16	Distribution	4,058,266		
17	Administrative and General			
18	TOTAL Maintenance (Total of lines 13 thru 17)	8,453,439		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	13,674,207		
21	Transmission (Enter Total of lines 4 and 14)	3,641,842		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	11,566,796		
24	Customer Accounts (Transcribe from line 7)	6,924,109		
25	Customer Service and Informational (Transcribe from line 8)	711,342		
26	Sales (Transcribe from line 9)	5,487		
27	Administrative and General (Enter Total of lines 10 and 17)	16,143,773		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	52,667,556	10,330,471	62,998,027
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply	828,785		
34	Storage, LNG Terminaling and Processing	8,363		
35	Transmission			
36	Distribution	3,578,184		
37	Customer Accounts	2,710,084		
38	Customer Service and Informational	349,486		
39	Sales	1,488		
40	Administrative and General	5,910,809		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	13,387,199		
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission	866,735		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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	Distribution	2,641,810		
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	3,508,545		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)	828,785		
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru	8,363		
56	Transmission (Lines 35 and 47)	866,735		
57	Distribution (Lines 36 and 48)	6,219,994		
58	Customer Accounts (Line 37)	2,710,084		
59	Customer Service and Informational (Line 38)	349,486		
60	Sales (Line 39)	1,488		
61	Administrative and General (Lines 40 and 49)	5,910,809		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	16,895,744	3,381,109	20,276,853
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	69,563,300	13,711,580	83,274,880
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	29,696,485	9,212,974	38,909,459
69	Gas Plant	8,275,727	2,948,976	11,224,703
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	37,972,212	12,161,950	50,134,162
72	Plant Removal (By Utility Departments)			
73	Electric Plant	1,508,765	290,831	1,799,596
74	Gas Plant	124,325	23,965	148,290
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	1,633,090	314,796	1,947,886
77	Other Accounts (Specify, provide details in footnote):			
78				
79	Stores (163)	1,901,710	-1,901,710	
80				
81				
82	Preliminary Survey and Investigation (183)	71,274		71,274
83	Small Tool Expense (184)	3,296,582	-3,296,582	
84	Miscellaneous Deferred Debits (186)	1,349,092		1,349,092
85				
86				
87	Non-operating Expenses (417)	747,089		747,089
88	Exp. of Certain Civic, Political and Related Activities (426)	620,960		620,960
89	Employee Incentive Plan (232380)	4,843,441	-4,843,441	
90	DSM Tarrif Rider and Payrool Equalization Liab. (242600, 242	18,112,648	-16,199,994	1,912,654
91	Incentive / Stock Compensation (238000)	81,070		81,070
92				
93				
94				
95	TOTAL Other Accounts	31,023,866	-26,241,727	20,982,133
96	TOTAL SALARIES AND WAGES	140,192,468	-53,401	156,339,061

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

1 & 2. Common Plant in service and accumulated provision for depreciation

Acct. No.	Description	
303	Intangible	45,144,377
389	Land and Land Rights	5,145,059
390	Structures and Improvements	79,806,317
391	Office Furniture and Equipment	43,816,402
392	Transportation Equipment	10,012,212
393	Stores Equipment	2,090,919
394	Tools, Shop & Garage Equipment	8,961,605
395	Laboratory Equipment	518,893
396	Power Operated Equipment	2,089,948
397	Communications Equipment	29,859,394
398	Miscellaneous Equipment	395,531
399	Asset Retirement Cost	371,024
	Total Common Plant	228,211,683
	Const. Work in Progress	41,012,084
	Total Utility Plant	269,223,767
	Acc. Prov. for Dep. & Amort.	62,591,095
	Net Utility Plant	206,632,672

3. Common Expenses allocated to Electric and Gas departments:

Acct. No.	Description	Total	Allocation to Electric Dept	Allocated to Gas Dept	Basis of Allocation
901	Cust acct/collect supervision	1,092,096	577,883	514,213	#of cust @ yr end
902	Meter reading expenses	4,577,785	2,820,602	1,757,183	#of cust @ yr end
903	Cust rec and collection expenses	14,555,244	7,921,994	6,633,250	#of cust @ yr end
903.90-99	A/R misc fees	0	0	0	net direct plant
904	Uncollectible accounts	4,024,467	2,129,547	1,894,920	#of cust @ yr end
905	Misc cust acct expenses	433,612	229,446	204,166	#of cust @ yr end
907	Cust svce & Info exp supervision	0	0	0	#of cust @ yr end
908	Cust assistance expenses	1,139,474	702,079	437,395	#of cust @ yr end
909	Info & instruct expenses	1,799,793	1,097,730	702,063	#of cust @ yr end
910	Misc cust serv & info	333,026	176,221	156,805	#of cust @ yr end

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

	expenses				
911	Sales expense -supervision	0	0	0	#of cust @ yr end
912	Demo & selling expenses	12,899	7,948	4,951	#of cust @ yr end
913	Advertising expenses	0	0	0	#of cust @ yr end
916	Misc sales expenses	0	0	0	#of cust @ yr end
920	Admin & gen salaries	48,284,146	34,866,302	13,417,844	four factor
921	Office supplies expenses	5,575,058	4,025,163	1,549,895	four factor
922	Admin expenses tranf-credit	2,046	1,474	572	four factor
923	Outside services employed	15,901,289	11,456,226	4,445,063	four factor
924	Property insurance	1,527,074	1,100,165	426,909	four factor
925	Injuries and damages	6,188,683	4,602,591	1,586,092	four factor
926	Employee pensions & benefits	65,169,666	47,031,676	18,137,990	four factor
927	Franchise requirement	0	0	0	four factor
928	Regulatory commission expenses	2,475,738	1,863,514	612,224	four factor
929	Duplicate charges-credit	0	0	0	four factor
930.1	General advertising expenses	3,191	2,394	797	four factor
930.2	Misc general expenses	3,615,670	2,629,958	985,712	four factor
931	Rents	1,310,844	955,469	355,375	four factor
935	Maint of general plant	9,235,270	6,776,630	2,458,640	four factor
403	Depreciation	11,694,987	8,489,414	3,205,573	four factor
404	Amort of LTD term plant	7,902,269	5,693,753	2,208,516	four factor

Note 1: The four factor allocator is made up of 25 percent each of customer counts, direct labor, direct O&M & Net direct plant

4. Letters of approval received from staffs of State Regulatory Commissions in 1993

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PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	616	MW	125,032			
2	Reactive Supply and Voltage						
3	Regulation and Frequency Response	66,451	MWh	8,744	69,924	MW	625,117
4	Energy Imbalance				629	MW	1,196,883
5	Operating Reserve - Spinning	835	MWh	17,300	27,475	MWh	251,722
6	Operating Reserve - Supplement	835	MWh	17,300	113,257	MWh	1,141,098
7	Other	1,307,347	MW	11,687,679	1,307,347	MW	11,687,679
8	Total (Lines 1 thru 7)	1,376,084		11,856,055	1,518,632		14,902,499

Schedule Page: 398   Line No.: 7   Column: b

Interdepartmental spinning reserve service for Native Load.

Schedule Page: 398   Line No.: 7   Column: d

Interdepartmental spinning reserve service for Native Load.

Schedule Page: 398   Line No.: 7   Column: e

Interdepartmental spinning reserve service for Native Load.

Schedule Page: 398   Line No.: 7   Column: g

Interdepartmental spinning reserve service for Native Load.

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MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	1,980	19	1800	1,479	307	138	16	55	268
2	February	1,860	28	800	1,397	306	138	17	20	465
3	March	1,798	7	700	1,351	289	138	15	20	169
4	Total for Quarter 1	5,638			4,227	902	414	48	95	902
5	April	1,704	4	1900	1,305	228	138	8	34	290
6	May	2,049	31	1200	1,094	205	140	24	609	117
7	June	1,975	22	1500	1,204	222	140	25	408	153
8	Total for Quarter 2	5,728			3,603	655	418	57	1,051	560
9	July	2,359	10	1600	1,511	269	160	35	419	26
10	August	2,358	7	1600	1,527	270	152	26	409	151
11	September	1,804	20	1700	1,180	208	154	20	262	175
12	Total for Quarter 3	6,521			4,218	747	466	81	1,090	352
13	October	1,955	26	900	1,313	239	146	17	257	168
14	November	1,913	26	2000	1,428	266	139	19	80	422
15	December	1,991	18	1800	1,432	284	138	17	137	322
16	Total for Quarter 4	5,859			4,173	789	423	53	474	912
17	Total Year to Date/Year	23,746			16,221	3,093	1,721	239	2,710	2,726

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ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY	
2	Generation (Excluding Station Use):	
3	Steam	1,708,156
4	Nuclear	
5	Hydro-Conventional	4,088,289
6	Hydro-Pumped Storage	
7	Other	1,155,679
8	Less Energy for Pumping	
9	Net Generation (Enter Total of lines 3 through 8)	6,952,124
10	Purchases	8,188,382
11	Power Exchanges:	
12	Received	548,640
13	Delivered	547,803
14	Net Exchanges (Line 12 minus line 13)	837
15	Transmission For Other (Wheeling)	
16	Received	3,191,975
17	Delivered	3,191,975
18	Net Transmission for Other (Line 16 minus line 17)	
19	Transmission By Others Losses	
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	15,141,343

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	8,873,005
23	Requirements Sales for Resale (See instruction 4, page 311.)	
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	5,634,398
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	10,284
27	Total Energy Losses	623,656
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	15,141,343

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MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month	Total Monthly Energy	Monthly Non-Requirments Sales for Resale & Associated Losses	MONTHLY PEAK		
				Megawatts (See Instr. 4)	Day of Month	Hour
	(a)	(b)	(c)	(d)	(e)	(f)
29	January	1,389,466	465,083	1,554	12	0800
30	February	1,258,480	431,544	1,455	28	0800
31	March	1,133,575	317,623	1,377	1	1900
32	April	1,192,231	468,611	1,341	4	1900
33	May	1,287,401	569,913	1,243	15	1700
34	June	1,252,346	562,240	1,242	21	1700
35	July	1,354,143	539,059	1,571	12	1600
36	August	1,235,182	410,700	1,579	7	1600
37	September	1,124,323	418,145	1,222	4	1500
38	October	1,264,983	501,390	1,309	24	0800
39	November	1,310,507	507,159	1,428	12	1800
40	December	1,338,706	442,931	1,499	17	1800
41	TOTAL	15,141,343	5,634,398			

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Coyote Springs 2* (b)			Plant Name: *Spokane N.E.* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Not Applicable			Not Applicable		
3	Year Originally Constructed	2003			1978		
4	Year Last Unit was Installed	2003			1978		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	287.00			61.80		
6	Net Peak Demand on Plant - MW (60 minutes)	302			57		
7	Plant Hours Connected to Load	4634			34		
8	Net Continuous Plant Capability (Megawatts)	284			65		
9	When Not Limited by Condenser Water	284			0		
10	When Limited by Condenser Water	284			0		
11	Average Number of Employees	13			1		
12	Net Generation, Exclusive of Plant Use - KWh	1142118000			181000		
13	Cost of Plant: Land and Land Rights	0			157277		
14	Structures and Improvements	11373980			744320		
15	Equipment Costs	152294712			14071031		
16	Asset Retirement Costs	351682			0		
17	Total Cost	164020374			14972628		
18	Cost per KW of Installed Capacity (line 17/5) Including	571.4996			242.2755		
19	Production Expenses: Oper, Supv, & Engr	1169237			22093		
20	Fuel	31006780			7488		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	1321189			36789		
26	Misc Steam (or Nuclear) Power Expenses	213982			65179		
27	Rents	84474			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	1539692			60		
30	Maintenance of Structures	0			1591		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	7358436			48314		
33	Maintenance of Misc Steam (or Nuclear) Plant	21585			60324		
34	Total Production Expenses	42715375			241838		
35	Expenses per Net KWh	0.0374			1.3361		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas			Gas		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF			MCF		
38	Quantity (Units) of Fuel Burned	7783936	0	0	2757	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1020000	0	0	1020000	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	3.983	0.000	0.000	2.716	0.000	0.000
41	Average Cost of Fuel per Unit Burned	3.983	0.000	0.000	2.716	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	3.905	0.000	0.000	2.663	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.027	0.000	0.000	0.041	0.000	0.000
44	Average BTU per KWh Net Generation	6952.000	0.000	0.000	15537.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Kettle Falls* (d)			Plant Name: *Colstrip* (e)			Plant Name: *Rathdrum* (f)			Line No.
Steam			Steam			Gas Turbine			1
Conventional			Conventional			Not Applicable			2
1983			1984			1995			3
1983			1985			1995			4
50.70			233.40			166.50			5
50			232			163			6
5721			8759			121			7
54			222			167			8
54			222			0			9
54			222			0			10
28			200			2			11
209169000			1498987000			6943000			12
2199206			1289095			621682			13
24981463			101239544			3258386			14
68239127			197540525			58622642			15
450687			134589			0			16
95870483			300203753			62502710			17
1890.9365			1286.2200			375.3917			18
236937			168916			78738			19
8293636			19671443			288574			20
0			0			0			21
647346			3359721			0			22
0			0			0			23
0			0			0			24
799598			104219			171316			25
381045			1899735			170153			26
0			21917			0			27
0			0			0			28
139679			344866			12496			29
118754			488385			9678			30
1678350			3167082			0			31
268369			315845			182279			32
129205			435936			35857			33
12692919			29978065			949091			34
0.0607			0.0200			0.1367			35
Wood	Gas		Coal	Oil		Gas			36
TON	MCF		TON	BBL		MCF			37
362090	3615	0	949474	1508	0	92542	0	0	38
8600000	1020000	0	16970000	5880000	0	1020000	0	0	39
22.877	2.806	0.000	20.503	135.220	0.000	3.118	0.000	0.000	40
22.877	2.806	0.000	20.503	135.220	0.000	3.118	0.000	0.000	41
2.660	2.751	0.000	1.208	23.000	0.000	3.057	0.000	0.000	42
0.040	0.036	0.000	0.013	0.000	0.000	0.042	0.000	0.000	43
14907.000	0.000	0.000	10755.000	0.000	0.000	13595.000	0.000	0.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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Line No.	Item (a)	Plant Name: *Boulder Park* (b)	Plant Name: (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Internal Comb	
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional	
3	Year Originally Constructed	2002	
4	Year Last Unit was Installed	2002	
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	24.60	0.00
6	Net Peak Demand on Plant - MW (60 minutes)	25	0
7	Plant Hours Connected to Load	317	0
8	Net Continuous Plant Capability (Megawatts)	24	0
9	When Not Limited by Condenser Water	0	0
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	2	0
12	Net Generation, Exclusive of Plant Use - KWh	5577000	0
13	Cost of Plant: Land and Land Rights	185629	0
14	Structures and Improvements	1204874	0
15	Equipment Costs	31233796	0
16	Asset Retirement Costs	0	0
17	Total Cost	32624299	0
18	Cost per KW of Installed Capacity (line 17/5) Including	1326.1910	0
19	Production Expenses: Oper, Supv, & Engr	10710	0
20	Fuel	154783	0
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	0	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	108811	0
26	Misc Steam (or Nuclear) Power Expenses	25587	0
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	-730	0
30	Maintenance of Structures	504	0
31	Maintenance of Boiler (or reactor) Plant	0	0
32	Maintenance of Electric Plant	105337	0
33	Maintenance of Misc Steam (or Nuclear) Plant	35699	0
34	Total Production Expenses	440701	0
35	Expenses per Net KWh	0.0790	0.0000

Line No.	Item (a)	(b)			(c)		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas					
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF					
38	Quantity (Units) of Fuel Burned	48878	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1020000	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	3.167	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	3.167	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	3.105	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.028	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	8939.000	0.000	0.000	0.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
			Gas						36
			MCF						37
0	0	0	48878	0	0	0	0	0	38
0	0	0	1020000	0	0	0	0	0	39
0.000	0.000	0.000	3.167	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	3.167	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	3.105	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.028	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	8939.000	0.000	0.000	0.000	0.000	0.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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Plant Name: (d)			Plant Name: (e)			Plant Name: (f)			Line No.
									1
									2
									3
									4
0.00			0.00			0.00			5
0			0			0			6
0			0			0			7
0			0			0			8
0			0			0			9
0			0			0			10
0			0			0			11
0			0			0			12
0			0			0			13
0			0			0			14
0			0			0			15
0			0			0			16
0			0			0			17
0			0			0			18
0			0			0			19
0			0			0			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
0			0			0			25
0			0			0			26
0			0			0			27
0			0			0			28
0			0			0			29
0			0			0			30
0			0			0			31
0			0			0			32
0			0			0			33
0			0			0			34
0.0000			0.0000			0.0000			35
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Schedule Page: 402 Line No.: -1 Column: b

Operated by Portland General Electric.

Schedule Page: 402 Line No.: -1 Column: c

designed for peak load service

Schedule Page: 402 Line No.: -1 Column: e

Joint project operated by PPL Montana LLC.

Schedule Page: 402 Line No.: -1 Column: f

designed for peak load service

Schedule Page: 402.1 Line No.: -1 Column: b

designed for peak load service

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 2545 Plant Name: Monroe Street (b)	FERC Licensed Project No. 2545 Plant Name: Upper Falls (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Run-of-River
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1890	1922
4	Year Last Unit was Installed	1992	1922
5	Total installed cap (Gen name plate Rating in MW)	14.80	10.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	19	13
7	Plant Hours Connect to Load	8,298	7,236
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	15	10
10	(b) Under the Most Adverse Oper Conditions	15	10
11	Average Number of Employees	1	9
12	Net Generation, Exclusive of Plant Use - Kwh	102,158,000	59,630,000
13	Cost of Plant		
14	Land and Land Rights	0	1,081,854
15	Structures and Improvements	8,443,779	936,027
16	Reservoirs, Dams, and Waterways	9,977,635	7,676,779
17	Equipment Costs	12,749,437	5,561,235
18	Roads, Railroads, and Bridges	50,448	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	31,221,299	15,255,895
21	Cost per KW of Installed Capacity (line 20 / 5)	2,109.5472	1,525.5895
22	Production Expenses		
23	Operation Supervision and Engineering	10,049	19,416
24	Water for Power	0	0
25	Hydraulic Expenses	95	474
26	Electric Expenses	555,976	557,976
27	Misc Hydraulic Power Generation Expenses	30,542	55,681
28	Rents	0	0
29	Maintenance Supervision and Engineering	2,492	15,349
30	Maintenance of Structures	1,578	4,579
31	Maintenance of Reservoirs, Dams, and Waterways	141,080	-37,860
32	Maintenance of Electric Plant	79,552	134,141
33	Maintenance of Misc Hydraulic Plant	937	3,239
34	Total Production Expenses (total 23 thru 33)	822,301	752,995
35	Expenses per net KWh	0.0080	0.0126

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 2545 Plant Name: Nine Mile Falls (d)	FERC Licensed Project No. 2545 Plant Name: Post Falls (e)	FERC Licensed Project No. 2058 Plant Name: Cabinet Gorge (f)	Line No.
Run-of-River	Storage	Storage	1
Conventional	Conventional	Outdoor	2
1908	1906	1952	3
1994	1980	1953	4
26.40	14.80	265.00	5
22	26	264	6
8,715	8,186	8,740	7
			8
18	18	295	9
18	18	255	10
1	1	12	11
106,194,000	82,967,000	1,198,885,000	12
			13
33,429	3,570,115	11,550,027	14
3,950,732	1,466,897	10,942,975	15
13,619,813	6,344,384	31,786,471	16
12,560,784	3,171,979	46,900,620	17
625,181	0	1,098,564	18
0	0	0	19
30,789,939	14,553,375	102,278,657	20
1,166.2856	983.3361	385.9572	21
			22
524	106,918	94,164	23
0	0	0	24
1,741	11	0	25
631,502	646,740	1,204,847	26
32,320	31,988	115,131	27
0	0	0	28
41,452	25,353	27,414	29
31,842	18,615	227,613	30
49,218	262,530	92,203	31
271,387	193,659	460,001	32
588	14,161	50,175	33
1,060,574	1,299,975	2,271,548	34
0.0100	0.0157	0.0019	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 2058 Plant Name: Noxon Rapids (b)	FERC Licensed Project No. 2545 Plant Name: Long Lake (c)
1	Kind of Plant (Run-of-River or Storage)	Storage	Storage
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional
3	Year Originally Constructed	1959	1915
4	Year Last Unit was Installed	1977	1924
5	Total installed cap (Gen name plate Rating in MW)	480.60	70.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	537	89
7	Plant Hours Connect to Load	8,748	7,684
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	622	90
10	(b) Under the Most Adverse Oper Conditions	580	90
11	Average Number of Employees	13	5
12	Net Generation, Exclusive of Plant Use - Kwh	1,822,999,000	513,474,000
13	Cost of Plant		
14	Land and Land Rights	35,624,343	1,765,942
15	Structures and Improvements	14,911,402	2,428,620
16	Reservoirs, Dams, and Waterways	32,991,048	16,672,732
17	Equipment Costs	105,923,602	12,176,179
18	Roads, Railroads, and Bridges	246,561	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	189,696,956	33,043,473
21	Cost per KW of Installed Capacity (line 20 / 5)	394.7086	472.0496
22	Production Expenses		
23	Operation Supervision and Engineering	97,245	117,198
24	Water for Power	0	0
25	Hydraulic Expenses	108,221	9,952
26	Electric Expenses	1,246,803	750,618
27	Misc Hydraulic Power Generation Expenses	131,698	59,370
28	Rents	0	0
29	Maintenance Supervision and Engineering	24,264	6,450
30	Maintenance of Structures	120,543	116,267
31	Maintenance of Reservoirs, Dams, and Waterways	92,448	596,307
32	Maintenance of Electric Plant	883,402	324,905
33	Maintenance of Misc Hydraulic Plant	73,594	33,895
34	Total Production Expenses (total 23 thru 33)	2,778,218	2,014,962
35	Expenses per net KWh	0.0015	0.0039

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 2545 Plant Name: Little Falls (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
Run-of-River			1
Conventional			2
1910			3
1911			4
32.00	0.00	0.00	5
38	0	0	6
7,633	0	0	7
			8
36	0	0	9
36	0	0	10
5	0	0	11
201,982,000	0	0	12
			13
4,325,371	0	0	14
1,188,042	0	0	15
5,065,501	0	0	16
6,140,499	0	0	17
0	0	0	18
0	0	0	19
16,719,413	0	0	20
522.4817	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
9,945	0	0	25
654,236	0	0	26
19,125	0	0	27
812,382	0	0	28
5,047	0	0	29
50,418	0	0	30
112,862	0	0	31
154,090	0	0	32
973	0	0	33
1,819,078	0	0	34
0.0090	0.0000	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Kettle Falls CT	2002	7.20	8.0	860,000	9,178,263
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Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
1,274,759	75,672	33,050	29,273	Nat Gas	327	1
						2
						3
						4
						5
						6
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	Group Sum		60.00	60.00		1.00		
2								
3	Group Sum		115.00	115.00		1,535.00		
4								
5	Beacon Sub #4	BPA Bell Sub	230.00	230.00	Steel Tower	1.00		1
6	Beacon Sub	BPA Bell Sub	230.00	230.00	H Type	5.00		1
7	Beacon Sub #5	BPA Bell Sub	230.00	230.00	Steel Pole	4.00		1
8	Beacon Sub #5	BPA Bell Sub	230.00	230.00	H Type	2.00		1
9	Beacon	Cabinet Gorge Plant	230.00	230.00	Steel Tower		1.00	1
10	Beacon	Cabinet Gorge Plant	230.00	230.00	Steel Pole	28.00		2
11	Beacon	Cabinet Gorge Plant	230.00	230.00	H Type	53.00		1
12	Beacon Sub	Lolo Sub	230.00	230.00	Steel Tower	1.00		1
13	Beacon Sub	Lolo Sub	230.00	230.00	H Type	102.00		1
14	Benewah	Shawnee	230.00	230.00	Steel Pole	60.00		1
15	Noxon Plant	Pine Creek Sub	230.00	230.00	Steel Pole	29.00		1
16	Noxon Plant	Pine Creek Sub	230.00	230.00	H Type	14.00		1
17	Cabinet Gorge Plant	Noxon	230.00	230.00	H Type	19.00		1
18	Benewah Sw. Station	Pine Creek Sub	230.00	230.00	Steel Tower			1
19	Benewah Sw. Station	Pine Creek Sub	230.00	230.00	H Type	43.00		1
20	Divide Creek	Lolo Sub	230.00	230.00	Steel Tower			1
21	Divide Creek	Lolo Sub	230.00	230.00	H Type	43.00		1
22	N. Lewiston	Walla Walla	230.00	230.00	H Type	43.00		1
23	N. Lewiston	Walla Walla	230.00	230.00	Steel Pole	4.00		1
24	N. Lewiston	Shawnee	230.00	230.00	Steel Pole	7.00		1
25	N. Lewiston	Shawnee	230.00	230.00	H Type	27.00		1
26	Walla Walla	Wanapum	230.00	230.00	Alum			1
27	Walla Walla	Wanapum	230.00	230.00	H Type	78.00		1
28	BPA (Libby)	Noxon Plant	230.00	230.00	Steel Tower	1.00		1
29	BPA/Hot Springs #1	Noxon Plant	230.00	230.00	Steel Tower	1.00		1
30	BPA/Hot Springs #2	Noxon Plant (dead)	230.00	230.00	Steel Tower		2.00	1
31	BPA/Hot Springs #2	Noxon Plant	230.00	230.00	H Type	68.00		1
32	BPA Line	West Side Sub	230.00	230.00	Steel Pole	2.00		2
33	Hatwai	N. Lewiston Sub	230.00	230.00	H Type	7.00		1
34	Divide Creek	Imnaha	230.00	230.00	H Type	20.00		1
35	Colstrip Plant	Broadview	500.00	500.00				
36					TOTAL	2,198.00	3.00	32

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
	136,038	498,412	634,450					1
								2
	9,921,384	119,820,203	129,741,587	287,452	1,009,993		1,297,445	3
								4
1272 ACSS								5
1272 ACSS	17,912	1,316,679	1,334,591					6
1272 ACSS								7
1272 ACSS	30,323	3,275,357	3,305,680					8
1272 ACSS								9
1590 ACSS								10
1590 ACSR	1,118,774	36,035,588	37,154,362	225	87,185		87,410	11
1272 ACSS								12
1272 McMAL	456,162	8,425,652	8,881,814		19,983		19,983	13
1590 ACSS	570,207	48,024,931	48,595,138	1,807	5,039		6,846	14
1272 ACSR								15
954 McMAL	1,052,733	17,987,859	19,040,592	2,617	541,564		544,181	16
954 McMAL	177,733	1,306,125	1,483,858		7,521		7,521	17
954 McMAL								18
954 McMAL	285,240	2,605,672	2,890,912	23,018	38,394		61,412	19
1272 McMAL								20
1272 McMAL	86,228	3,698,864	3,785,092	15,592	1,164		16,756	21
1272 McMAL								22
1272 McMAL	623,984	6,978,675	7,602,659	3,383	1,251		4,634	23
1272 ACSR								24
1272 ACSR	872,150	10,042,777	10,914,927		1,900		1,900	25
1272 McMAL								26
1272 McMAL	70,781	2,709,710	2,780,491	7,396	16,158		23,554	27
1272 ACSR								28
1272 ACSR		19,521	19,521	1,856	4,888		6,744	29
1272 McMAL								30
1272 McMAL	293,365	4,039,470	4,332,835	7,214	34,451		41,665	31
1272 ACSR	36,461	594,543	631,004					32
1590 ACSR	106,581	2,722,818	2,829,399	997	202		1,199	33
1272 McMAL	201,359	1,312,849	1,514,208	178	1,710		1,888	34
	595,789	30,117,774	30,713,563	62,425	205,692	91,626	359,743	35
	16,653,204	301,533,479	318,186,683	414,160	1,977,095	91,626	2,482,881	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	No additions during 2012						
2							
3							
4							
5							
6							
7							
8							
9							
10							
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43							
44	TOTAL						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).

3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage KV (Operating)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)	(k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
									1
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Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	STATE OF WASHINGTON				
2					
3	Airway Heights	Distr. Unattended	115.00	13.80	
4	Barker Road	Distr. Unattended	115.00	13.80	
5	Beacon	Trnsm. & Distr Unatt	230.00	115.00	13.80
6	Boulder	Trnsm. Unattended	230.00	115.00	13.80
7	Chester	Distr. Unattended	115.00	13.80	
8	Chewelah 115Kv	Distr. Unattended	115.00	13.80	
9	Colbert	Distr. Unattended	115.00	13.80	
10	College & Walnut	Distr. Unattended	115.00	13.80	
11	Colville 115Kv	Distr. Unattended	115.00	13.80	
12	Critchfield	Distr. Unattended	115.00	13.80	
13	Deer Park	Dist. Unattended	115.00	13.80	
14	Dry Creek	Transm. Unattended	230.00	115.00	13.80
15	Dry Gulch	Distr. Unattended	115.00	13.80	
16	East Colfax	Distr. Unattended	115.00	13.80	
17	East Farms	Distr. Unattended	115.00	13.80	
18	Fort Wright	Distr. Unattended	115.00	13.80	
19	Francis and Cedar	Distr. Unattended	115.00	13.80	
20	Gifford	Distr. Unattended	115.00	34.00	
21	Glenrose	Distr. Unattended	115.00	13.80	
22	Greenwood	Distr. Unattended	115.00	13.80	
23	Hallett & White	Distr. Unattended	115.00	13.80	
24	Indian Trail	Dist. Unattended	115.00	13.80	
25	Industrial Park	Dist. Unattended	115.00	13.80	
26	Kettle Falls	Distr. Unattended	115.00	13.80	
27	Lee & Reynolds	Distr. Unattended	115.00	13.80	
28	Liberty Lake	Distr. Unattended	115.00	13.80	
29	Little Falls 115/34Kv	Distr. Unattended	115.00	34.00	
30	Lyons & Standard	Distr. Unattended	115.00	13.80	
31	Mead	Distr. Unattended	115.00	13.80	
32	Metro	Distr. Unattended	115.00	13.80	
33	Milan	Distr. Unattended	115.00	13.80	
34	Millwood	Dist. Unattended	115.00	13.80	
35	Ninth & Central	Distr. Unattended	115.00	13.80	
36	Northeast	Distr. Unattended	115.00	13.80	
37	Northwest	Distr. Unattended	115.00	13.80	
38	Opportunity	Dist. Unattended	115.00	13.80	
39	Othello	Distr. Unattended	115.00	13.80	
40	Post Street	Distr. Unattended	115.00	13.80	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
						2
24	2		Frcd Oil&Air Fan&Cap	39	40	3
12	1		Two Stage Fan	1	20	4
536	4		Two Stage Fan	2	560	5
300	2		Two Stage Fan	2	500	6
24	2		Frcd Oil & Air Fan	2	40	7
12	1		Two Stage Fan	1	20	8
12	1		Frcd Oil & Air Fan	16	20	9
36	2		Two Stage Fan	2	60	10
31	3		Frcd Oil & Air Fan	3	45	11
12	1		Two Stage Fan	1	20	12
12	1		Two Stage Fan	1	20	13
150	1		Two Stage Fan & Caps	223	250	14
24	2		Frcd Oil & Air Fan	2	40	15
12	1		FrOil/Air Fan	1	20	16
12	1		Two Stage Fan	1	20	17
24	2	1	Fr Oil/Air/2StgFan	2	40	18
36	2		Two Stage Fan	2	60	19
12	1					20
12	1		Frcd Oil & Air Fan	1	20	21
12	1		Two Stage Fan	1	20	22
12	1		Two Stg Fan	1	20	23
12	1		Two Stage Fan	1	20	24
24	2		Two Stg/Pt/Frcd Oil	14	45	25
12	1		Frcd Oil & Air Fan	1	20	26
12	1		Two Stage Fan	1	20	27
24	2		Two Stage Fan	2	40	28
12	1					29
36	2		Two Stage Fan	2	60	30
18	1		Two Stage Fan	1	30	31
24	2		Two Stage Fan	2	40	32
24	2		Frcd Oil & Air Fan	2	40	33
24	2	2	FrcAir/FrcOil/AirFan	2	40	34
24	2	1	Frcd & Two Stage Fan	2	40	35
24	2		Two Stage Fan	2	40	36
24	2		Two Stage Fan	2	40	37
12	1		Two Stage Fan	1	20	38
24	2		FrOil/AirFan	2	40	39
36	2		Frcd Oil & Wt Fan	2	60	40

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Pound Lane	Distr. Unattended	115.00	13.80	
2	Ross Park	Distr. Unattended	115.00	13.80	
3	Roxboro	Distr. Unattended	115.00	24.00	
4	Shawnee	Trans. Unattended	230.00	115.00	13.80
5	Silver Lake	Distr. Unattended	115.00	13.80	
6	Southeast	Distr. Unattended	115.00	13.80	
7	South Othello	Distr. Unattended	115.00	13.80	
8	South Pullman	Distr. Unattended	115.00	13.80	
9	Sunset	Distr. Unattended	115.00	13.80	
10	Terre View	Dist. Unattended	115.00	13.80	
11	Third & Hatch	Distr. Unattended	115.00	13.80	
12	Turner	Dist. Unattended	115.00	13.80	
13	Waikiki	Distr. Unattended	115.00	13.80	
14	West Side	Trans. Unattended	230.00	115.00	13.80
15	Other: 28substa less than 10MVA	Distr. Unattended			
16					
17	STATE OF IDAHO				
18	Appleway	Dist. Unattended	115.00	13.80	
19	Avondale	Dist. Unattended	115.00	13.80	
20	Benewah	Trans. Unattended	230.00	115.00	13.80
21	Big Creek	Distr. Unattended	115.00	13.80	
22	Blue Creek	Distr. Unattended	115.00	13.80	
23	Bunker Hill Limited	Distr. Unattended	115.00	13.80	
24	Cabinet Gorge (Switchyard)	Trans. Unattended	230.00	115.00	13.80
25	Clark Fork	Distr. Unattended	115.00	21.80	
26	Coeur d'Alene 15th Ave	Distr. Unattended	115.00	13.80	
27	Cottonwood	Distr. Unattended	115.00	24.90	
28	Dalton	Distr. Unattended	115.00	13.80	
29	Grangeville	Distr. Unattended	115.00	13.80	
30	Holbrook	Distr. Unattended	115.00	13.80	
31	Huetter	Distr. Unattended	115.00	13.80	
32	Idaho Road	Distr Unattended	115.00	13.80	
33	Juliaetta	Distr. Unattended	115.00	13.80	
34	Kamiah	Dist. Unattended	115.00	13.80	
35	Kooskia	Distr. Unattended	115.00	13.80	
36	Lolo	Tran & Dist Unattnd	230.00	115.00	13.80
37	Moscow	Distr. Unattended	115.00	13.80	
38	Moscow 230Kv	Tran & Dist Unattnd	230.00	115.00	13.80
39	North Moscow	Distr. Unattended	115.00	13.80	
40	North Lewiston 230kV	Trans Unattended	230.00	115.00	13.80

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
24	2		Two Stage Fan	2	40	1
30	2		Two Stage Fan	2	54	2
24	2		Two Stage Fan	2	40	3
150	1		Two Stage Fan	1	250	4
12	1		Frcd Oil & Air Fan	1	20	5
30	2		Two Stage Fan	2	50	6
12	1		Two Stage Fan	1	20	7
30	2		Two Stage Fan	2	50	8
33	2		Two Stage Fan & Caps	50	55	9
12	1		Two Stage Fan	1	20	10
54	3		Two Stg Fan & Cap	103	90	11
36	2		Two Stg Fan	2	60	12
24	2		Two Stage Fan	2	40	13
250	2					14
166	34	3				15
						16
						17
36	2		Two Stage Fan	2	60	18
12	1		Two Stage Fan	1	20	19
75	1		Two Stage Fan & Caps	223	125	20
18	2		Portable Fan	2	22	21
20	3	1				22
12	1		Frcd Air Fan	1	16	23
75	1		Two Stage Fan	1	125	24
10	1		Frcd Air Fan	1	13	25
36	2		Two Stage Fan	2	60	26
12	1		Two Stage Fan	1	20	27
24	2		FrcOil/Air2StgFan	2	40	28
25	4		FrcdOil/Air/Pt Fan&C	17	34	29
12	1		Two Stage Fan	1	20	30
12	1		Two Stage Fan	1	20	31
12	1		Two Stage Fan	1	20	32
12	1		Frcd Oil & Air Fan	1	20	33
12	1		Two Stage Fan	1	20	34
15	3		Frcd Air Fan	3	20	35
262	3		Frcd Oil/Air/Two Stg	1	270	36
24	2		FrOil/Air/2Stg Fan	2	40	37
137	2	2	Capacitors	48		38
12	1		Two Stage Fan	1	20	39
250	1	1	Capacitors	48		40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	North Lewiston	Distr. Unattended	115.00	13.80	
2	Oden	Distr. Unattended	115.00	21.80	
3	Oldtown	Distr. Unattended	115.00	21.80	
4	Orofino	Distr. Unattended	115.00	13.80	
5	Osburn	Distr. Unattended	115.00	13.80	
6	Pine Creek	Tran & Dist Unattnd	230.00	115.00	13.80
7	Pleasant View	Distr. Unattended	115.00	13.80	
8	Plummer	Dist Unattended	115.00	13.80	
9	Post Falls	Distr. Unattended	115.00	13.80	
10	Potlatch	Distr. Unattended	115.00	13.80	
11	Prarie	Distr. Unattended	115.00	13.80	
12	Priest River	Distr. Unattended	115.00	20.80	
13	Rathdrum	Trans & Distr Unattd	230.00	115.00	13.80
14	Sagle	Dist. Unattended	115.00	20.80	
15	Sandpoint	Distr. Unattended	115.00	20.80	
16	South Lewiston	Distr. Unattended	115.00	13.80	
17	Sweetwater	Distr. Unattended	115.00	24.90	
18	St. Maries	Distr. Unattended	115.00	23.90	
19	Tenth & Stewart	Distr. Unattended	115.00	13.80	
20	Wallace	Distr. Unattended	115.00	13.80	
21	Other: 13 substa less than 10 MVA	Distr. Unattended			
22					
23	STATE OF MONTANA				
24	1 substation less than 10 MVA	Distr. Unattended			
25					
26	SUBSTA. @ GENERATING PLANTS				
27	STATE OF WASHINGTON				
28	Boulder Park	Trans. Attended	115.00	13.80	
29	Kettle Falls	Trans. Attended	115.00	13.80	
30	Long Lake	Trans. Attended	115.00	4.00	
31	Nine Mile	Trans. Attended	115.00	13.80	2.30
32	Little Falls	Trans. Attended	115.00	4.00	
33	Northeast	Trans. Attended	115.00	13.80	
34	Post Street	Trans. Attended	13.80	4.00	
35					
36	STATE OF IDAHO				
37	Cabinet Gorge (HED)	Trans. Attended	230.00	13.80	
38	Post Falls	Trans. Attended	115.00	2.30	
39	Rathdrum	Trans. Attended	115.00	13.80	
40	STATE OF MONTANA				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
10	3					1
10	1		Frcd Air Fan	1	13	2
18	2		Frcd Air Fan	2	22	3
20	2		Frcd Oil & Air Fan	1	28	4
12	1		Portable Fan	1	15	5
262	3		Two Stg Fan/Capacito	45	270	6
12	1		Two Stage Fan	1	20	7
12	1		Two Stage Fan	1	20	8
18	1		Two Stage Fan	1	30	9
15	2		Portable Fan	2	19	10
12	1		Frcd Oil & Air Fan	1	20	11
10	1		Frcd Air Fan	1	13	12
474	4		Frcd Oil & Air Fan	50	490	13
12	1		Two Stage Fan	1	20	14
30	3		Frcd Air Fan	3	38	15
27	4		Port Fan/FrcdOil/Air	4	39	16
12	1		Frcd Oil & Air Fan	1	20	17
24	2		Two Stage Fan	2	40	18
30	2		Frcd Oil/Air/Two Stg	2	50	19
10	3					20
70	13					21
						22
						23
5	1					24
						25
						26
						27
36	1		Two Stage Fan	1	60	28
34	1	1	Two Stage Fan	1	62	29
80	4	1				30
24	2		Frcd Oil & Air Fan	1	40	31
24	2		Frcd Oil & Air Fan	2	40	32
36	1		Two Stage Fan	1	60	33
35	2					34
						35
						36
300	6	1	Frcd Oil and Air Fan			37
16	2		Frcd Air/Oil/Air Fan	2	21	38
114	2	1	Two Stage Fan	2	190	39
						40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Noxon	Trans. Attended	230.00	13.80	
2					
3	STATE OF OREGON				
4	Coyote Springs II	Trans. Attended	500.00	13.80	18.00
5					
6	SUMMARY:				
7	Washington:				
8	4 subs	Trans. Unattended			
9	75 subs	Distr. Unattended			
10	1 subs	Tran & Dist Unattnd			
11	7 subs	Trans. Attended			
12	Idaho:				
13	3 subs	Trans. Unattended			
14	48 subs	Distr. Unattended			
15	4 subs	Tran & Dist Unattnd			
16	3 subs	Trans. Attended			
17	Montana: 1 sub	Trans. Attended			
18	1 sub	Distr. Unattended			
19	Oregon: 1 sub	Trans. Unattended			
20	System: 148 subs				
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
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35					
36					
37					
38					
39					
40					

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
435	9	1	Two Stage Fan	2	635	1
						2
						3
213	1	1	Two Stage fan	1	355	4
						5
						6
						7
850						8
1200						9
536						10
269						11
						12
400						13
668						14
1135						15
430						16
435						17
5						18
213						19
6141						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
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						35
						36
						37
						38
						39
						40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013	End of 2012/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21				
22				
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IDAHO PUBLIC
UTILITIES COMMISSION

Avista Corp.

2012

IDAHO

State Electric Annual Report

(IC 61-405)

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Name of Respondent	This Report is:	Date of Report	Year / Period of Report
Avista Corporation	[X] An Original [ ] A Resubmission	mm/dd/yyyy 4/12/2013	End of 2012 / Q4

STATEMENT OF UTILITY OPERATING INCOME - IDAHO

Instructions

1. For each account below, report the amount attributable to the state of Idaho based on Idaho jurisdictional Results of Operations.
2. Provide any necessary important notes regarding this statement of utility operating income in a footnote in the available space at the bottom of this page

Line No.	Account (a)	Refer to Form 1 Page (b)	TOTAL SYSTEM - IDAHO Current Year (c)	Prior Year (d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)	300-301	450,171,070	490,826,505
3	Operating Expenses			
4	Operation Expenses (401)	320-323	313,684,985	372,734,080
5	Maintenance Expenses (402)	320-323	20,099,052	1,449,373
6	Depreciation Expense (403)	336-337	33,505,585	32,159,853
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	-	-
8	Amortization & Depletion of Utility Plant (404-405)	336-337	3,047,756	2,650,538
9	Amortization of Utility Plant Acquisition Adjustment (406)	336-337	67,304	67,304
10	Amort. of Property Losses, Unrecov Plant and Regulatory Study Costs (407)		-	-
11	Amortization of Conversion Expenses (407)		-	-
12	Regulatory Debits (407.3)		(1,870,742)	(9,642,712)
13	(Less) Regulatory Credits (407.4)		(5,824,027)	(2,460,999)
14	Taxes Other Than Income Taxes (408.1)	262-263	14,639,363	14,029,701
15	Income Taxes - Federal (409.1)	262-263	6,730,137	11,858,943
16	- Other (409.1)	262-263	-	-
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	10,655,054	8,946,025
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	-	-
19	Investment Tax Credit Adjustment - Net (411.4)	266	(85,353)	(69,896)
20	(Less) Gains from Disposition of Utility Plant (411.6)		-	-
21	Losses from Disposition 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 line 4 through 24)		394,649,114	431,722,210
26	Net Utility Operating Income (Total line 2 less 25)		55,521,956	59,104,295

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STATEMENT OF UTILITY OPERATING INCOME - IDAHO

Instructions

or in a separate schedule.

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

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		Line No.
Current Year (e)	Prior Year (f)	Current Year (g)	Prior Year (h)	Current Year (i)	Prior Year (j)	
						1
354,298,765	374,727,202	95,872,305	116,099,303			2
						3
237,642,238	276,342,925	76,042,747	96,391,155			4
17,657,900		2,441,152	1,449,373			5
28,775,543	27,602,346	4,730,042	4,557,507			6
						7
2,502,863	2,133,508	544,893	517,030			8
67,304	67,304					9
						10
						11
(1,870,742)	(9,332,082)		(310,630)			12
(5,824,027)	(2,460,999)					13
12,291,725	11,783,114	2,347,638	2,246,587			14
6,585,305	11,102,578	144,832	756,365			15
						16
8,217,502	6,419,332	2,437,552	2,526,693			17
						18
(68,625)	(52,928)	(16,728)	(16,968)			19
						20
						21
						22
						23
						24
305,976,986	323,605,098	88,672,128	108,117,112	-	-	25
48,321,779	51,122,104	7,200,177	7,982,191	-	-	26

Name of Respondent	This Report is:	Date of Report	Year / Period of Report
Avista Corporation	[X] An Original [ ] A Resubmission	mm/dd/yyyy 4/12/2013	End of 2012 / Q4

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

Instructions

1. Report below the original cost of utility plant in service necessary to furnish utility service to customers in the state of Idaho, and the accumulated provisions for depreciation, amortization, and depletion attributable to that plant in service.
2. Report in column (c) the amount for electric function, in column (d) the amount for gas function, in columns (e), (f), and (g) report other (specify),

Line No.	Account (a)	Total Company End of Current Year (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	1,327,736,695	1,079,511,442
4	Property Under Capital Leases	334,898	
5	Plant Purchased or Sold	-	
6	Completed Construction not Classified	-	
7	Experimental Plant Unclassified	-	
8	Total (Total lines 3 through 7)	1,328,071,593	1,079,511,442
9	Leased to Others	-	
10	Held for Future Use	414,587	199,007
11	Construction Work in Progress	42,866,262	28,686,005
12	Acquisition Adjustments	-	
13	Total Utility Plant (Total lines 8 through 12)	1,371,352,441	1,108,396,454
14	Accumulated Provision for Depreciation, Amortization, and Depletion	470,102,780	389,935,675
15	Net Utility Plant (Line 13 less line 14)	901,249,661	718,460,779
16	Detail of Accumulated Provision for Depreciation, Amortization, and Depletion		
17	In Service		
18	Depreciation	461,324,559	387,309,090
19	Amortization and Depletion of Producing Natural Gas Lands / Land Rights	-	
20	Amortization of Underground Storage Lands / Land Rights	-	
21	Amortization of Other Utility Plant	8,778,221	2,626,585
22	Total (Total lines 18 through 21)	470,102,780	389,935,675
23	Leased to Others		
24	Depreciation	-	
25	Amortization and Depletion	-	
26	Total Leased to Others	-	-
27	Held for Future Use		
28	Depreciation	-	
29	Amortization	-	
30	Total Held for Future Use	-	-
31	Abandonment of Leases (Natural Gas)	-	
32	Amortization of Plant Acquisition Adjustment	-	
33	Total Accumulated Provision (Total lines 22, 26, 30, 31, 32)	470,102,780	389,935,675

(1) A small portion of the Company's electric distribution plant is located in Montana. For jurisdictional reporting purposes, those amounts are included as Idaho plant.

Name of Respondent	This Report is:	Date of Report	Year / Period of Report
Avista Corporation	[X] An Original [ ] A Resubmission	mm/dd/yyyy 4/12/2013	End of 2012 / Q4

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

Instructions

and in column (h) common function.

3. In order to accurately reflect utility plant in service necessary to furnish utility service to customers in the state of Idaho, electric and gas plant not directly assigned is allocated to the state of Idaho as appropriate and included in column (c) and (d).

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
176,602,456				71,622,797	3
274,405				60,493	4
					5
					6
					7
176,876,861	-	-	-	71,683,290	8
					9
215,580					10
1,950,046				12,230,211	11
					12
179,042,487	-	-	-	83,913,501	13
59,175,488	-	-	-	20,991,617	14
119,866,998	-	-	-	62,921,884	15
					16
					17
58,893,849				15,121,620	18
					19
					20
281,639				5,869,997	21
59,175,488	-	-	-	20,991,617	22
					23
					24
					25
-	-	-	-	-	26
					27
					28
					29
-	-	-	-	-	30
					31
					32
59,175,488	-	-	-	20,991,617	33

Name of Respondent	This Report is:	Date of Report	Year / Period of Report
Avista Corporation	[X] An Original [ ] A Resubmission	mm/dd/yyyy 4/12/2013	End of 2012 / Q4

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

Instructions

1. Report below the original cost of electric plant in service necessary to furnish electric utility service to customers in the state of Idaho. Include electric plant not directly assigned as allocated to the state of Idaho.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, include by primary plant account increases in column (c), additions, and reductions in column (e), adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such amounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) distributions of

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	301 Organization	-	-
3	302 Franchises and Consents	15,311,508	-
4	303 Miscellaneous Intangible Plant	985,166	181,767
5	TOTAL Intangible Plant (Total of lines 2, 3, and 4)	16,296,674	181,767
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	310 Land and Land Rights	775,285	-
9	311 Structures and Improvements	43,686,521	186,820
10	312 Boiler Plant Equipment	59,029,184	327,183
11	313 Engines and Engine-Driven Generators	2,353	-
12	314 Turbogenerator Units	17,816,722	382,552
13	315 Accessory Electric Equipment	9,417,810	96
14	316 Miscellaneous Power Plant Equipment	5,527,543	10,820
15	317 Asset Retirement Costs for Steam Production	-	-
16	TOTAL Steam Production Plant (Total of lines 8 through 15)	136,255,418	907,471
17	B. Nuclear Production Plant		
18	320 Land and Land Rights	-	-
19	321 Structures and Improvements	-	-
20	322 Reactor Plant Equipment	-	-
21	323 Turbogenerator Units	-	-
22	324 Accessory Electric Equipment	-	-
23	325 Miscellaneous Power Plant Equipment	-	-
24	326 Asset Retirement Costs for Nuclear Production	-	-
25	TOTAL Nuclear Production Plant (Total of lines 18 through 24)	-	-
26	C. Hydraulic Production Plant		
27	330 Land and Land Rights	19,928,684	810,533
28	331 Structures and Improvements	15,041,907	227,706
29	332 Reservoirs, Dams, and Waterways	42,655,726	669,387
30	333 Water Wheels, Turbines, and Generators	54,061,315	2,736,195
31	334 Accessory Electric Equipment	11,805,280	18,036
32	335 Miscellaneous Power Plant Equipment	2,793,427	85,307
33	336 Roads, Railroads, and Bridges	695,048	7,415
34	337 Asset Retirement Costs for Hydraulic Production	-	-
35	TOTAL Hydraulic Production Plant (Total of lines 27 through 34)	146,981,387	4,554,579
36	D. Other Production Plant		
37	340 Land and Land Rights	314,636	-
38	341 Structures and Improvements	5,731,202	(10,616)
39	342 Fuel Holders, Products, and Accessories	7,356,445	1,904
40	343 Prime Movers	7,604,369	1,843,247
41	344 Generators	69,319,124	1,556,881
42	345 Accessory Electric Equipment	5,884,333	34,129
43	346 Miscellaneous Power Plant Equipment	565,100	(3,697)
44	347 Asset Retirement Costs for Other Production	-	-
45	TOTAL Other Production Plant (Total of lines 37 through 44)	96,775,209	3,421,848
46	TOTAL Production Plant (Total of lines 16, 25, 35, and 45)	380,012,014	8,883,898

(1) A small portion of the Company's electric distribution plant is located in Montana. For jurisdictional reporting purposes, those amounts are included as Idaho plant.

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Avista Corporation	[X] An Original [ ] A Resubmission	mm/dd/yyyy 4/12/2013	End of 2012 / Q4

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

Instructions

these tentative classifications in columns (c) and (d), including the reversals of the prior year's tentative account distributions of these amounts. Careful observance of these instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance End of Year (g)		Line No.
					1
-	-	-	-		2
-	101,313	-	15,412,821		3
181,814	(16,939)	-	968,180		4
181,814	84,374	-	16,381,001		5
					6
					7
-	445,271	-	1,220,556		8
888	292,278	-	44,164,731		9
112,030	710,220	-	59,954,557		10
-	16	-	2,369		11
7,738	117,890	-	18,309,426		12
2,457	(261,272)	-	9,154,177		13
-	39,519	-	5,577,882		14
-	-	-	-		15
123,113	1,343,922	-	138,383,698		16
					17
-	-	-	-		18
-	-	-	-		19
-	-	-	-		20
-	-	-	-		21
-	-	-	-		22
-	-	-	-		23
-	-	-	-		24
-	-	-	-		25
					26
-	(240,689)	(221,444)	20,277,084		27
2,447	222,374	-	15,489,540		28
-	(111,944)	221,444	43,434,613		29
85,063	336,817	-	57,049,264		30
6,242	83,904	-	11,900,978		31
-	(34,978)	-	2,843,756		32
-	4,600	-	707,063		33
-	-	-	-		34
93,752	260,084	-	151,702,298		35
					36
-	2,082	-	316,718		37
-	81,302	-	5,801,888		38
-	48,676	-	7,407,025		39
-	(1,158,989)	-	8,288,627		40
786,769	402,540	-	70,491,776		41
-	69,026	-	5,987,488		42
-	40,259	-	601,662		43
-	-	-	-		44
786,769	(515,104)	-	98,895,184		45
1,003,634	1,088,902	-	388,981,180		46

Name of Respondent	This Report is:	Date of Report	Year / Period of Report
Avista Corporation	[X] An Original [ ] A Resubmission	mm/dd/yyyy 4/12/2013	End of 2012 / Q4

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	350 Land and Land Rights	6,691,874	111,243
49	352 Structures and Improvements	5,831,863	19,366
50	353 Station Equipment	70,660,373	4,620,853
51	354 Towers and Fixtures	5,951,197	739
52	355 Poles and Fixtures	50,614,833	6,675,835
53	356 Overhead Conductors and Devices	39,145,124	3,274,963
54	357 Underground Conduit	905,668	-
55	358 Underground Conductors and Devices	809,933	-
56	359 Roads and Trails	650,793	-
57	359.1 Asset Retirement Costs for Transmission Plant	-	-
58	TOTAL Transmission Plant (Total of lines 48 through 57)	181,261,658	14,702,999
59	4. DISTRIBUTION PLANT		
60	360 Land and Land Rights	2,943,488	19,879
61	361 Structures and Improvements	5,228,068	3,805
62	362 Station Equipment	36,802,755	1,529,299
63	363 Storage Battery Equipment	-	-
64	364 Poles, Towers, and Fixtures	94,768,240	4,989,182
65	365 Overhead Conductors and Devices	62,578,020	3,402,347
66	366 Underground Conduit	31,009,659	802,448
67	367 Underground Conductors and Devices	48,590,338	2,447,566
68	368 Line Transformers	63,870,263	2,314,736
69	369 Services	46,273,660	1,232,992
70	370 Meters	20,626,945	(8,134,590)
71	371 Installations on Customer Premises	-	-
72	372 Leased Property on Customer Premises	-	-
73	373 Street Lighting and Signal Systems	13,826,257	613,544
74	374 Asset Retirement Costs for Distribution Plant	-	-
75	TOTAL Distribution Plant (Total of lines 60 through 74)	426,517,693	9,221,208
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	380 Land and Land Rights	-	-
78	381 Structures and Improvements	-	-
79	382 Computer Hardware	-	-
80	383 Computer Software	-	-
81	384 Communication Equipment	-	-
82	385 Miscellaneous Regional Transmission and Market Operation Plant	-	-
83	386 Asset Retirement Costs for Regional Transmission and Operation Plant	-	-
84	TOTAL Transmission and Market Operation Plant (Total lines 77 through 83)	-	-
85	6. GENERAL PLANT		
86	389 Land and Land Rights	369,788	-
87	390 Structures and Improvements	3,047,640	249,750
88	391 Office Furniture and Equipment	745,321	1,235,452
89	392 Transportation Equipment	4,937,621	635,061
90	393 Stores Equipment	136,686	-
91	394 Tools, Shop and Garage Equipment	923,350	34,557
92	395 Laboratory Equipment	351,289	-
93	396 Power Operated Equipment	11,576,127	3,025,489
94	397 Communication Equipment	14,189,489	592,605
95	398 Miscellaneous Equipment	5,878	5,727
96	SUBTOTAL (Total of lines 86 through 95)	36,283,189	5,778,641
97	399 Other Tangible Property	-	-
98	399.1 Asset Retirement Costs for General Plant	-	-
99	TOTAL General Plant (Total of lines 96, 97 and 98)	36,283,189	5,778,641
100	TOTAL (Accounts 101 and 106)	1,040,371,228	38,768,513
101	102 Electric Plant Purchased	-	-
102	102 (Less) Electric Plant Sold	-	-
103	103 Experimental Plant Unclassified	-	-
104	TOTAL Electric Plant in Service (Total of lines 100 through 103)	1,040,371,228	38,768,513

Name of Respondent	This Report is:	Date of Report	Year / Period of Report
Avista Corporation	[X] An Original [ ] A Resubmission	mm/dd/yyyy 4/12/2013	End of 2012 / Q4

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance End of Year (g)		Line No.
					47
-	(25,398)	-	6,777,719		48
26,553	160,144	-	5,984,820		49
110,486	(564,302)	-	74,606,438		50
-	39,377	-	5,991,313		51
110,569	(3,016,322)	-	54,163,777		52
27,195	(1,535,903)	-	40,856,989		53
-	5,992	-	911,660		54
-	5,359	-	815,292		55
-	4,306	-	655,099		56
-	-	-	-		57
274,803	(4,926,747)	-	190,763,107		58
					59
-	(17,863)	-	2,945,504		60
22,237	-	-	5,209,636		61
346,669	1	-	37,985,386		62
-	-	-	-		63
222,396	-	-	99,535,026		64
181,742	-	-	65,798,625		65
97,072	(160)	-	31,714,875		66
175,387	1	-	50,862,518		67
78,398	-	-	66,106,601		68
55,458	-	-	47,451,194		69
146	8,529,784	152,725	21,174,718		70
-	-	-	-		71
-	-	-	-		72
45,835	2	-	14,393,968		73
-	-	-	-		74
1,225,340	8,511,765	152,725	443,178,051		75
					76
-	-	-	-		77
-	-	-	-		78
-	-	-	-		79
-	-	-	-		80
-	-	-	-		81
-	-	-	-		82
-	-	-	-		83
-	-	-	-		84
					85
-	8	-	369,796		86
387	950	-	3,297,953		87
120,963	3,713	-	1,863,523		88
375,449	19,117	-	5,216,350		89
-	107	-	136,793		90
32,735	404	(2,707)	922,869		91
47,632	226	-	303,883		92
1,268,573	15,162	-	13,348,205		93
25,064	(19,907)	-	14,737,123		94
-	3	-	11,608		95
1,870,803	19,783	(2,707)	40,208,103		96
-	-	-			97
-	-	-			98
1,870,803	19,783	(2,707)	40,208,103		99
4,556,394	4,778,077	150,018	1,079,511,442		100
-	-	-			101
-	-	-			102
-	-	-			103
4,556,394	4,778,077	150,018	1,079,511,442		104

Name of Respondent	This Report is:	Date of Report	Year / Period of Report
Avista Corporation	[X] An Original [ ] A Resubmission	*mm/dd/yyyy* 4/12/2013	End of 2012 / Q4

ELECTRIC OPERATING REVENUES - IDAHO

Instructions

1. Report below operating revenues attributable to the state of Idaho for each prescribed account in accordance with jurisdictional Results of Operations. Report the portion of total operating revenue and megawatt hours which pertains to unbilled revenue and MWH pertaining unbilled revenue in the lines provided.
2. 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.
3. If increases or decreases from previous period (columns (c), (e), and (g)) are not derived from previously reported figures, explain any inconsistencies in a footnote in the available space at the bottom of the page, or in a separate schedule.

Line No.	Account (a)	ELECTRIC OPERATING REVENUE Current Year (b)	ELECTRIC OPERATING REVENUE Prior Year (c)
1	Sales of Electricity		
2	440 Residential Sales	102,933,167	107,877,413
3	442 Commercial and Industrial Sales (3)		
4	Small (or Commercial)	84,744,247	86,211,236
5	Large (or Industrial)	63,150,341	67,439,293
6	444 Public Street and Highway Lighting	2,440,129	2,376,108
7	445 Other Sales to Public Authorities		-
8	446 Sales to Railroads and Railways		-
9	448 Interdepartmental Sales	209,881	217,766
10	TOTAL Sales to Ultimate Customers	(1) 253,477,765	264,121,816
11	447 Sales for Resale	51,786,744	41,020,894
12	TOTAL Sales of Electricity	305,264,509	305,142,710
13	449.1 (Less) Provision for Rate Refunds		-
14	TOTAL Revenues Net of Provision for Refunds	305,264,509	305,142,710
15	Other Operating Revenues		
16	450 Forfeited Discounts		-
17	451 Miscellaneous Service Revenues	201,468	215,731
18	453 Sales of Water and Water Power	164,033	176,088
19	454 Rent from Electric Property	989,469	946,506
20	455 Interdepartmental Rents		-
21	456 Other Electric Revenues	43,608,408	63,813,040
22	456.1 Revenues from Transmission of Electricity for Others	4,070,878	4,433,127
23	457.1 Regional Control Service Revenues		-
24	457.2 Miscellaneous Revenues		-
25			
26	TOTAL Other Operating Revenues	49,034,256	69,584,492
27	TOTAL Electric Operating Revenues	354,298,765	374,727,202

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ELECTRIC OPERATING REVENUES - IDAHO

Instructions

4. Disclose amounts of $250,000 or greater in a footnote at the bottom of the page or in a separate schedule for accounts 451, 456, and 457.2.
5. Commercial and Industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
6. See pages 108-109 in the FERC Form 1, Important Changes During Period, for important new territory added and important rate increases or decreases.
7. Include unmetered sales. Provide details of such Sales in a footnote in the available space at the bottom of this page or in a separate schedule.

MEGAWATT HOURS SOLD		AVG. NO. OF CUSTOMERS PER MONTH			Line No.
Current Year (d)	Previous Year (e)	Current Year (f)	Previous Year (g)		
					1
1,165,138	1,198,793	106,528	105,840		2
					3
996,974	996,844	16,727	16,633		4
1,185,320	1,225,366	468	476		5
9,061	8,971	143	125		6
	-		-		7
	-		-		8
2,396	2,557	44	38		9
(2) 3,358,889	3,432,531	123,910	123,112		10
1,971,476	1,419,675		-		11
5,330,365	4,852,206	123,910	123,112		12
	-		-		13
5,330,365	4,852,206	123,910	123,112		14

(1) Includes $ (683,704) of unbilled revenues.

(2) Includes (6,475) MWH relating to unbilled revenues.

(3) Segregation of Commercial and Industrial made on basis of utilization of energy and not on size of account.

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES - IDAHO

Instructions

1. For each prescribed account below, report operation and maintenance expenses as allocated by the Results of Operations model to the state of Idaho.
2. If the amount for previous year is not derived from previously reported figures, explain in a footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	500 Operation Supervision and Engineering	142,008	174,731
5	501 Fuel	9,784,981	10,863,947
6	502 Steam Expenses	1,402,073	1,495,883
7	503 Steam from Other Sources	-	-
8	504 (Less) Steam Transferred-Cr.	-	-
9	505 Electric Expenses	316,246	316,390
10	506 Miscellaneous Steam Power Expenses	828,089	833,611
11	507 Rents	7,669	11,262
12	509 Allowances	-	-
13	TOTAL Operation (Total of lines 4 through 12)	12,481,066	13,695,824
14	Maintenance		
15	510 Maintenance Supervision and Engineering	173,851	204,091
16	511 Maintenance of Structures	212,438	251,492
17	512 Maintenance of Boiler Plant	1,695,417	2,116,527
18	513 Maintenance of Electric Plant	204,416	487,186
19	514 Maintenance of Miscellaneous Steam Plant	197,743	296,276
20	TOTAL Maintenance (Total of Lines 15 through 19)	2,483,865	3,355,572
21	TOTAL Steam Power Generation Expenses (Total lines 13 & 20)	14,964,931	17,051,396
22	B. Nuclear Power Generation		
23	Operation		
24	517 Operation Supervision and Engineering	-	-
25	518 Fuel	-	-
26	519 Coolants and Water	-	-
27	520 Steam Expenses	-	-
28	521 Steam from Other Sources	-	-
29	522 (Less) Steam Transferred-Cr.	-	-
30	523 Electric Expenses	-	-
31	524 Miscellaneous Nuclear Power Expenses	-	-
32	525 Rents	-	-
33	TOTAL Operation (Total of lines 24 through 32)	-	-
34	Maintenance		
35	528 Maintenance Supervision and Engineering	-	-
36	529 Maintenance of Structures	-	-
37	530 Maintenance of Reactor Plant Equipment	-	-
38	531 Maintenance of Electric Plant	-	-
39	532 Maintenance of Miscellaneous Nuclear Plant	-	-
40	TOTAL Maintenance (Total of lines 35 through 39)	-	-
41	TOTAL Nuclear Power Generation Expenses (Total lines 33 & 40)	-	-
42	C. Hydraulic Power Generation		
43	Operation		
44	535 Operation Supervision and Engineering	840,868	895,522
45	536 Water for Power	411,845	388,681
46	537 Hydraulic Expenses	2,767,437	2,731,943
47	538 Electric Expenses	2,204,138	2,009,278
48	539 Miscellaneous Hydraulic Power Generation Expenses	217,048	244,582
49	540 Rents	2,370,453	2,299,679
50	TOTAL Operation (Total of lines 44 through 49)	8,811,789	8,569,685
51	Maintenance		
52	541 Maintenance Supervision and Engineering	204,061	193,655
53	542 Maintenance of Structures	212,090	146,256
54	543 Maintenance of Reservoirs, Dams, and Waterways	474,378	1,026,725
55	544 Maintenance of Electric Plant	981,380	814,630
56	545 Maintenance of Miscellaneous Hydraulic Plant	169,793	175,165
57	TOTAL Maintenance (Total of lines 53 through 57)	2,041,702	2,356,431
58	TOTAL Hydraulic Power Generation Expenses (Total of lines 50 & 58)	10,853,491	10,926,116
59			

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES - IDAHO

Instructions

1. For each prescribed account below, report operation and maintenance expenses as allocated by the Results of Operations model to the state of Idaho.
2. If the amount for previous year is not derived from previously reported figures, explain in a footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	546 Operation Supervision and Engineering	451,338	499,959
63	547 Fuel	22,412,775	19,111,767
64	548 Generation Expenses	592,556	374,463
65	549 Miscellaneous Other Power Generation Expenses	216,690	198,473
66	550 Rents	17,723	(11,067)
67	TOTAL Operation (Total of lines 62 through 66)	23,691,082	20,173,595
68	Maintenance		
69	551 Maintenance Supervision and Engineering	653,278	236,589
70	552 Maintenance of Structures	4,343	4,257
71	553 Maintenance of Generating and Electric Plant	2,696,525	514,713
72	554 Maintenance of Miscellaneous Other Power Generation Plant	56,407	53,795
73	TOTAL Maintenance (Total of lines 69 through 72)	3,410,553	809,354
74	TOTAL Other Power Generation Expenses	27,101,635	20,982,949
75	E. Other Power Supply Expenses		
76	555 Purchased Power	95,516,653	85,280,960
77	556 System Control and Load Dispatching	302,502	248,402
78	557 Other Expenses	50,030,662	86,945,012
79	TOTAL Other Power Supply Expenses (Total of lines 76 through 78)	145,849,817	172,474,374
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74, & 79)	198,769,874	221,434,835
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	560 Operation Supervision and Engineering	757,626	745,700
84	561 Load Dispatching	753,317	775,159
85	561.1 Load Dispatch-Reliability	-	-
86	561.2 Load Dispatch-Monitor and Operation Transmission System	-	-
87	561.3 Load Dispatch-Transmission Service and Scheduling	-	-
88	561.4 Scheduling, System Control and Dispatch Services	-	-
89	561.5 Reliability, Planning and Standards Development	-	-
90	561.6 Transmission Service Studies	-	-
91	561.7 Generation Interconnection Studies	-	-
92	561.8 Reliability, Planning and Standards Development Services	-	-
93	562 Station Expenses	146,840	110,714
94	563 Overhead Lines Expenses	164,079	180,118
95	564 Underground Lines Expenses	-	-
96	565 Transmission of Electricity by Others	6,141,310	6,079,392
97	566 Miscellaneous Transmission Expenses	625,372	583,739
98	567 Rents	40,562	44,337
99	TOTAL Operation (Total of lines 83 through 98)	8,629,106	8,519,159
100	Maintenance		
101	568 Maintenance Supervision and Engineering	743,120	456,642
102	569 Maintenance of Structures	156,654	148,318
103	569.1 Maintenance of Computer Hardware	-	-
104	569.2 Maintenance of Computer Software	-	-
105	569.3 Maintenance of Communication Equipment	-	-
106	569.4 Maintenance of Miscellaneous Regional Transmission Plant	-	-
107	570 Maintenance of Station Equipment	393,877	398,533
108	571 Maintenance of Overhead Lines	626,044	837,647
109	572 Maintenance of Underground Lines	2,931	774
110	573 Maintenance of Miscellaneous Transmission Plant	32,843	10,131
111	TOTAL Maintenance (Total of lines 101 through 110)	1,955,469	1,852,045
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	10,584,575	10,371,204

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES - IDAHO

Instructions

1. For each prescribed account below, report operation and maintenance expenses as allocated by the Results of Operations model to the state of Idaho.
2. If the amount for previous year is not derived from previously reported figures, explain in a footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	575.1 Operation Supervision	-	-
116	575.2 Day-Ahead and Real-Time Market Facilitation	-	-
117	575.3 Transmission Rights Market Facilitation	-	-
118	575.4 Capacity Market Facilitation	-	-
119	575.5 Ancillary Services Market Facilitation	-	-
120	575.6 Market Monitoring and Compliance	-	-
121	575.7 Market Facilitation, Monitoring, and Compliance Services	-	-
122	575.8 Rents	-	-
123	Total Operation (Total lines 115 through 122)	-	-
124	Maintenance		
125	576.1 Maintenance of Structures and Improvements	-	-
126	576.2 Maintenance of Computer Hardware	-	-
127	576.3 Maintenance of Computer Software	-	-
128	576.4 Maintenance of Communication Equipment	-	-
129	576.5 Maintenance of Miscellaneous Market Operation Plant	-	-
130	Total Maintenance (Total lines 125 through 129)	-	-
131	TOTAL Regional Market Expenses (Total lines 123 & 130)	-	-
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	580 Operation Supervision and Engineering	754,053	604,475
135	581 Load Dispatching	-	-
136	582 Station Expenses	254,492	243,446
137	583 Overhead Line Expenses	894,238	424,700
138	584 Underground Line Expenses	447,249	100,057
139	585 Street Lighting and Signal System Expenses	138,544	195,612
140	586 Meter Expenses	511,301	305,766
141	587 Customer Installations Expenses	302,094	299,434
142	588 Miscellaneous Expenses	2,625,200	2,265,407
143	589 Rents	120,791	81,698
144	TOTAL Operation (Total of lines 134 through 143)	6,047,962	4,520,595
145	Maintenance		
146	590 Maintenance Supervision and Engineering	597,528	400,047
147	591 Maintenance of Structures	203,685	93,155
148	592 Maintenance of Station Equipment	250,486	195,592
149	593 Maintenance of Overhead Lines	2,974,733	2,930,014
150	594 Maintenance of Underground Lines	368,272	336,670
151	595 Maintenance of Line Transformers	247,084	647,883
152	596 Maintenance of Street Lighting and Signal Systems	218,118	176,599
153	597 Maintenance of Meters	24,769	20,783
154	598 Maintenance of Miscellaneous Distribution Plant	120,960	82,942
155	TOTAL Maintenance (Total lines 146 through 154)	5,005,635	4,883,685
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	11,053,597	9,404,280
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	901 Supervision	198,872	217,546
160	902 Meter Reading Expenses	402,147	427,146
161	903 Customer Records and Collection Expenses	2,801,378	2,729,877
162	904 Uncollectable Accounts	732,862	904,089
163	905 Miscellaneous Customer Accounts Expenses	78,962	47,599
164	TOTAL Customer Accounts Expenses (Total of line 159 through 163)	4,214,221	4,326,257

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES - IDAHO

Instructions

1. For each prescribed account below, report operation and maintenance expenses as allocated by the Results of Operations model to the state of Idaho.
2. If the amount for previous year is not derived from previously reported figures, explain in a footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	907 Supervision	-	-
168	908 Customer Assistance Expenses	6,830,136	7,878,529
169	909 Informational and Instructional Expenses	390,120	308,833
170	910 Miscellaneous Customer Service and Informational Expenses	60,645	45,958
171	TOTAL Customer Service and Informational Expenses (Total lines 167 through 170)	7,280,901	8,233,320
172	7. SALES EXPENSES		
173	Operation		
174	911 Supervision	-	-
175	912 Demonstrating and Selling Expenses	2,735	4,152
176	913 Advertising Expenses	-	-
177	916 Miscellaneous Sales Expenses	-	(22)
178	TOTAL Sales Expenses (Total of lines 174 through 177)	2,735	4,130
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	920 Administrative and General Salaries	10,290,220	8,150,383
182	921 Office Supplies and Expenses	1,342,667	1,315,513
183	922 (Less) Administrative Expenses Transferred-Credit	(21,716)	(20,259)
184	923 Outside Services Employed	3,835,186	4,750,405
185	924 Property Insurance	437,430	403,349
186	925 Injuries and Damages	795,256	1,450,711
187	926 Employee Pensions and Benefits	426,919	391,971
188	927 Franchise Requirements	5,747	5,738
189	928 Regulatory Commission Expenses	2,101,988	2,058,197
190	929 (Less) Duplicate Charges-Cr.	-	-
191	930.1 General Advertising Expenses	-	-
192	930.2 Miscellaneous General Expenses	1,080,251	920,702
193	931 Rents	339,611	287,291
194	TOTAL Operation (Total of lines 181 through 193)	20,633,559	19,714,001
195	Maintenance		
196	935 Maintenance of General Plant	2,760,676	2,854,898
197	TOTAL Administrative and General Expenses (Total of lines 194 and 196)	23,394,235	22,568,899
198	TOTAL Elec Op and Maint Expns (Total lines 80, 112, 131, 156, 164, 171, 178, 197)	255,300,138	276,342,925

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TRANSMISSION LINE STATISTICS - IDAHO

Instructions

1. Report information concerning transmission lines physically located in the state of Idaho, including the cost of lines, and expenses for the year. List each transmission line having nominal voltage of 132 kilovolts or greater.
   Transmission lines below this voltage should be grouped and totals reported for each group.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by the State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly-owned structures in column (g). In a footnote in the available space at the bottom of this page or in a separate

Line No.	DESIGNATION		VOLTAGE (KV) *Indicate where other than 60 cycle, 3 phase*		Type of Supporting Structure	LENGTH (Pole Miles) *For underground lines, report circuit miles*		Number of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Group Sum - 115kV		115.00	115.00		609.00		
2								
3	Beacon	Cabinet Gorge Plant	230.00	230.00	Steel Pole	9.00		1
4	Beacon	Cabinet Gorge Plant	230.00	230.00	Steel Pole	5.00		2
5	Beacon	Cabinet Gorge Plant	230.00	230.00	H Type	53.00		1
6	Divide Creek	Lolo Sub	230.00	230.00	Steel Tower			1
7	Divide Creek	Lolo Sub	230.00	230.00	H Type	43.00		1
8	Noxon Plant	Pine Creek Sub	230.00	230.00	H Type	15.00		1
9	Noxon Plant	Pine Creek Sub	230.00	230.00	Steel Pole	15.00		1
10	Cabinet Gorge Plant	Noxon	230.00	230.00	H Type	2.00		1
11	Benewah Sw. Station	Pine Creek Sub	230.00	230.00	Steel Tower			1
12	Benewah Sw. Station	Pine Creek Sub	230.00	230.00	H Type	43.00		1
13	Beacon Sub	Lolo Sub	230.00	230.00	H Type	81.00		1
14	North Lewiston	Walla Walla	230.00	230.00	H Type	8.00		1
15	North Lewiston	Shawnee	230.00	230.00	H Type	1.00		1
16	Hatwai	N. Lewiston Sub	230.00	230.00	H Type	7.00		1
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Name of Respondent **Avista Corporation**	This Report is: [X] An Original [ ] A Resubmission	Date of Report *mm/dd/yyyy* 4/12/2013	Year / Period of Report End of 2012 / Q4

TRANSMISSION LINE STATISTICS - IDAHO

Instructions

schedule, explain the basis of such occupancy and state whether these expenses with respect to such structures are included in the expenses reported for the line designated.

7. Do not report the same transmission line structure twice. Report lower-voltage lines and higher-voltage lines as one line. Designate in a footnote if you do not have include lower-voltage lines with higher-voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving details of such matters as percent ownership by respondent in the line, name of c-owner, basis of sharing expenses of the line, and and how expenses borne by the respondent are accounts for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) through (l) on the book cost at end of year associated with the physical lines reported.

Size of Conductor and Material (i)	COST OF LINE *Include in column (j) land, land rights, and clearing right-of-way* Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
	4,057,033	49,004,722	53,061,756	166,623	611,589	-	778,211	1
			-				-	2
1590 ACSS	-	-	-	-	-	-	-	3
1590 ACSS	-	-	-	-	-	-	-	4
1590 ACSR	1,005,364	20,272,624	21,277,987	225	63,790	-	64,015	5
1272 McMAL	-		-	-	-	-	-	6
1272 McMAL	86,228	3,698,864	3,785,092	15,592	1,164	-	16,756	7
954 McMAL	-	-	-	-	-	-	-	8
1272 ACSR	663,750	10,914,879	11,578,629	2,617	477,461		480,078	9
954 McMAL	131,532	128,808	260,340	-	7,021	-	7,021	10
954 McMAL	-	-	-	-	-	-	-	11
954 McMAL	285,240	2,605,672	2,890,912	23,018	38,394	-	61,412	12
1272 McMAL	363,604	6,989,980	7,353,584	-	4,277	-	4,277	13
1272 McMAL	25,818	1,321,341	1,347,159	3,383	-	-	3,383	14
1272 ACSR	10,015	319,300	329,315	-	-	-	-	15
1590 ACSR	106,581	2,722,818	2,829,399	997	202	-	1,199	16
			-				-	17
			-				-	18
			-				-	19
			-				-	20
			-				-	21
			-				-	22
			-				-	23
			-				-	24
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