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 2011/Q4

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

IDENTIFICATION

01 Exact Legal Name of Respondent Avista Corporation	02 Year/Period of Report End of 2011/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 Christy Burmeister-Smith	06 Title of Contact Person 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	04/13/2012

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	04/13/2012
02 Title VP, Controller, Prin. Acctg Officer	Christy Burmeister-Smith	

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 Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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".

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LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Lines Added During the Year	424-425	
68	Substations	426-427	
69	Transactions with Associated (Affiliated) Companies	429	
70	Footnote Data	450	

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	04/13/2012	End of 2011/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	04/13/2012	End of 2011/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. (formerly known as	Provider of utility bill	79.2	Subsidiary of
5	Advantage IQ, Inc.)	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	Avista Power, LLC	Inactive	100	Affiliate of
18				Avista Capital
19				
20	Avista Turbine Power, Inc.	Inactive	100	Subsidiary of
21				Avista Capital
22				
23	Avista Ventures, Inc.	Inactive	100	Subsidiary of
24				Avista Capital
25				
26	Pentzer Corporation	Parent company of Bay Area	100	Subsidiary of
27		Manufacturing and Pentzer		Avista Capital

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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1		Venture Holdings.		
2				
3	Pentzer Venture Holdings	Inactive	100	Subsidiary of
4				Pentzer Corporation
5				
6	Bay Area Manufacturing	Holding Company	100	Subsidiary of
7				Pentzer Corporation
8				
9	Advanced Manufacturing and Development, Inc.	Performs custom sheet metal	82.95	Subsidiary of
10	dba Metalfx	manufacturing of electronic		Bay Area
11		enclosures, parts and systems		Manufacturing.
12		for the computer, telecom and		
13		medical industries. AM&D		
14		also has a wood products		
15		division.		
16				
17	Spokane Energy, LLC	Owns an electric capactiy	100	Affiliate of
18		contract.		Avista Corp.
19				
20	Avista Capital II	An affiliated business trust	100	Affiliate of
21		formed by the Company.		Avista Corp.
22		Issued Pref. Trust Securities		
23				
24	Avista Northwest Resources, LLC	Formed in 2009 to own	100	Affiliate of
25		an interest in a venture		Avista Capital
26		fund investment		
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	04/13/2012	End of 2011/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	Steam Plant Square, LLC	Commercial office and retail	85	Affiliate of
2		leasing.		Avista Development
3				
4	Courtyard Office Center, LLC	Commercial office and retail	100	Affiliate of
5		leasing.		Avista Development
6				
7	Steam Plant Brew Pub, LLC	Restaurant operations	85	Affiliate of Steam
8				Plant Square, LLC
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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	04/13/2012	End of 2011/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 Customer Solutions	D. F. Kopczynski	
21	(effective 4/2011)		
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	(effective 4/2011)		
31			
32	Vice President, responsible for Energy Delivery	J. R. Thackston	
33	(effective 4/2011)		
34			
35	Treasurer	D. C. Thoren	
36			
37	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	04/13/2012	End of 2011/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 (effective 8/1/2011)	16 Ivy Court, Langhorne, PA 19047
9		
10	Roy Lewis Eiguren (resigned 2/5/2011)	702 W. Idaho St., Suite 1100, Boise, ID 83702
11		
12	Rick R. Holley (effective 8/1/2011)	999 Third Ave., Suite 4300, Seattle, WA 98104
13		
14	John F. Kelly***	142 Isla Dorada Blvd., Coral Gables, FL 33143
15		
16	Michael L. Noel	11960 W. Six Shooter Rd., Prescott, AZ 86305
17		
18	Heidi B. Stanley	P.O. Box 2884, Spokane, WA 99220
19		
20	R. John Taylor***	111 Main Street, Lewiston, ID 83501
21		
22	Marc F. Racicot	28013 Swan Cove Dr., Big Fork, MT 59911
23		
24	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
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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
1	The Company has no formula rates.	
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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
1	No formula				
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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
1		No formula rates		
2				
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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	04/13/2012	End of 2011/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. In February 2011, Avista Corp. entered into a new committed line of credit with various financial institutions in the total amount of $400.0 million with an expiration date of February 2015 that replaced its $320.0 million and $75.0 million committed lines of credit. In December 2011, this committed line of credit was amended to extend the expiration date to February 2017 and revise the pricing terms.

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. At December 31, 2011, the Company had borrowed $61.0 million under this committed line of credit and there were $29.0 million of letters of credit outstanding.

The new committed line of credit was approved by regulatory commissions as follows:WUTC (Docket No. UE-101544 Order 01) IPUC (Case No. AVU-U-10-01 Order No. 32096) and the OPUC (Docket UF 4265 Order No. 10-370).

In December 2011, the Company issued $85.0 million of 4.45 percent First Mortgage Bonds due in 2041. 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 12, 2011, the shareholders of Avista Corp. approved an amendment of the Company's Restated Articles of Incorporation and Bylaws to provide for the annual election of the Board of Directors. Previously, under Article FIFTH fo the Articles of Incorporation, the Board was divided into three classes, which is referred to as a classifed or staggered board. Each year, the shareholders would elect one class (approximately one-third of the Board) for a term of three years. The Bylaws contained a similar provision.

On August 12, 2011, the Board of Directors of Avista Avista Corp. amended the Company's Bylaws.

Amendments to Section 2 of Article II Regarding Special Meetings

Section 2 of Article II of the Bylaws has been amended to identify specific information required to be included in a shareholder's demand for a special meeting. This includes information as to the shareholder making the demand, any individual to be nominated for director, and/or other business to be conducted at the special meeting. The amendments also provide details as to aggregation of shareholder demands and specifications as to the time of the special meeting.

Amendments to Section 11 of Article II Regarding Business to be Conducted at Meetings of Shareholders

Prior to the amendments, the Bylaws provided the right for a shareholder to nominate a candidate for director (in Section 13 of Article III) and/or to bring other business at a shareholder meeting (in Section 11 of Article II). The amendments to Section 11 of Article II (1) consolidate into Section 11 provisions relating to both the nomination of directors and the proposal of other business and (2) refine the procedures to be followed and add to the information to be provided by the shareholder in order for a shareholder to nominate a director or bring other business before a shareholder meeting.

The amendments clarify that only shareholders of record both as of the time of the shareholder notice and as of the time of the meeting are eligible to make nominations or bring other business before the meeting. A shareholder notice must be updated and supplemented by the shareholder to be true and correct as of the record date and continuously thereafter.

A shareholder notice must contain additional information, including information as to:

- Shareholder associated persons, including affiliates of, and persons acting in concert with, the shareholder;
- Nominee associated persons, including affiliates of, and persons acting in concert with, the nominee;
- Purchases and sales by the shareholder of the Company's stock during the 24-month period preceding the shareholder notice;
- Derivative transactions entered into by the shareholder or the nominee or any shareholder or nominee associated persons;
- Agreements, arrangements or understandings between or among the shareholder, any shareholder associated person or any other person that relates to the proposed business or proposal; and
- Additional information about a shareholder's nominee, including (i) the nominee's occupation, (ii) the number of shares owned by the nominee and any nominee associated person as well as any derivative transactions; and (iii) any related person transactions between the nominating shareholder and shareholder associated persons, and the nominee and nominee associated persons.

A shareholder proposing to nominate an individual for election as a director must submit a questionnaire (similar to the Company's directors' and officers' questionnaire) completed and signed by the nominee, which also includes representations by the nominee concerning (i) the absence of certain voting commitments and compensation or indemnification arrangements and (ii) the nominee's compliance with applicable law and Company policies.

Proposed business will not be transacted and proposed nominations will not be made if the shareholder (or qualified representative) does not appear at the meeting and satisfy the other requirements of the Bylaws.

The new procedures and information requirements apply to any nomination to be made at, or other business to be brought before, a shareholder meeting, including any proposal that is to be included in the Company's Proxy Statement pursuant to the SEC's Rule 14a-8.

Amendment to Section 2 of Article III Regarding Number, Tenure and Eligibility

Section 2 of Article III of the Bylaws has been changed to increase the age limit for persons who may be elected or re-elected as a director. Previously, the age limit was 70; it has been changed to 72.

Amendments to Sections 9 and 11 of Article III Regarding Vacancies and Removal

Amendments were made to Sections 9 and 11 of Article III to reflect the Company's decision (as approved by shareholders at the 2011 Annual Meeting of Shareholders) to eliminate classification of the Board of Directors and provide for the annual election of the Board of Directors.

In addition, Section 9 of Article III, which relates to the filling of vacancies on the Board of Directors, and Section 11 of Article III, which relates to the removal of directors, were amended to conform to the amendments to Article FIFTH of the Company's Restated Articles of Incorporation as approved at the 2011 Annual Meeting of Shareholders.

Removal of previous Section 13 of Article III Regarding Nomination of Directors

Provisions with respect to the nomination of directors are now included in Section 11 of Article II. As such, previous Section 13 of Article III has been removed from the Bylaws and previous Section 14 has been renumbered as Section 13.

8. Average annual wage increases were 1.9% for non-exempt employees effective February 28, 2011. Average annual wage increases were 2.5% for exempt employees effective February 28, 2011. Officers received average increases of 3.6% effective February 28, 2011. Certain bargaining unit employees received increases of 3.0% effective March 26, 2011.
9. Reference is made to Note 17 of the Notes to Financial Statements.
10. None
11. Reserved
12. See page 123 of this report.
13. In April 2011, Avista Corp. appointed Roger Woodworth as Vice President and Chief Strategy Officer. Mr. Woodworth was previously Vice President of Customer Solutions. Don Kopczynski was appoined as Vice President of Customer Solutions and Jason Thackston as Vice President of Energy Delivery. Mr. Kopczynski was previously Vice President of Energy Delivery and Mr. Thackston was previously Vice President of Finance.
On May 13, 2011, the Board of Directors of Avista Corporation (Avista Corp. or the Company) decided to increase the number of board members from 9 to 11 and elected Donald C. Burke and Rick R. Holley to fill the two vacancies and serve as directors on the board effective August 1, 2011.
14. Proprietary capital is not less than 30 percent.

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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	04/13/2012	End of 2011/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	3,876,924,839	3,707,841,308
3	Construction Work in Progress (107)	200-201	78,182,230	60,766,153
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		3,955,107,069	3,768,607,461
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	1,333,212,160	1,284,830,029
6	Net Utility Plant (Enter Total of line 4 less 5)		2,621,894,909	2,483,777,432
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)		2,621,894,909	2,483,777,432
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		6,992,076	2,577,031
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		6,021,869	5,403,010
19	(Less) Accum. Prov. for Depr. and Amort. (122)		915,043	908,291
20	Investments in Associated Companies (123)		12,047,000	12,047,000
21	Investment in Subsidiary Companies (123.1)	224-225	71,971,368	77,733,569
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)		18,889,385	21,346,633
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		13,288,292	12,397,507
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		184,929	15,260,734
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		121,487,800	143,280,162
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		945,496	1,722,379
36	Special Deposits (132-134)		22,215,906	7,981,895
37	Working Fund (135)		861,010	762,784
38	Temporary Cash Investments (136)		60,913	17,455,810
39	Notes Receivable (141)		283,666	226,712
40	Customer Accounts Receivable (142)		173,557,636	197,906,612
41	Other Accounts Receivable (143)		7,943,467	8,919,486
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		4,498,489	3,846,839
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		29,252	211,095
45	Fuel Stock (151)	227	4,248,389	6,288,853
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	21,746,205	23,335,143
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 Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report *(Mo, Da, Yr)* 04/13/2012	Year/Period of Report End of 2011/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)		23,609,470	17,242,935
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		16,554,560	10,754,149
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		85,059	0
60	Rents Receivable (172)		1,568,627	1,488,593
61	Accrued Utility Revenues (173)		0	0
62	Miscellaneous Current and Accrued Assets (174)		254,324	213,064
63	Derivative Instrument Assets (175)		1,323,663	17,852,716
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		184,929	15,260,734
65	Derivative Instrument Assets - Hedges (176)		32,408	243,221
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		270,636,633	293,497,874
68	DEFERRED DEBITS			
69	Unamortized Debt Expenses (181)		14,332,877	12,854,887
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	524,250,326	429,832,794
73	Prelim. Survey and Investigation Charges (Electric) (183)		4,180,937	3,946,461
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	34,001,379	17,414,947
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)		23,830,734	25,454,075
82	Accumulated Deferred Income Taxes (190)	234	153,408,420	119,988,041
83	Unrecovered Purchased Gas Costs (191)		-12,140,283	-22,074,296
84	Total Deferred Debits (lines 69 through 83)		741,864,390	587,416,909
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		3,762,875,808	3,510,549,408

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	04/13/2012	end of 2011/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	832,413,930	805,656,943
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	11,686,949	15,798,128
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	-11,086,811	-6,137,359
11	Retained Earnings (215, 215.1, 216)	118-119	364,536,285	326,861,303
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-28,386,302	-24,343,433
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)	-5,636,826	-4,325,953
16	Total Proprietary Capital (lines 2 through 15)		1,185,700,847	1,125,784,347
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,257,171,208	1,098,148,636
19	(Less) Reaquired Bonds (222)	256-257	83,700,000	0
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)		213,200	222,084
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		1,838,814	2,013,529
24	Total Long-Term Debt (lines 18 through 23)		1,223,392,594	1,147,904,191
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		4,749,777	4,974,661
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		3,235,000	2,684,975
29	Accumulated Provision for Pensions and Benefits (228.3)		246,176,609	161,188,441
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		40,530,269	30,984,511
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		2,641,867	52,705
34	Asset Retirement Obligations (230)		3,512,818	3,887,409
35	Total Other Noncurrent Liabilities (lines 26 through 34)		300,846,340	203,772,702
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		61,000,000	110,000,000
38	Accounts Payable (232)		98,160,779	121,798,025
39	Notes Payable to Associated Companies (233)		1,866,383	7,374,317
40	Accounts Payable to Associated Companies (234)		709,883	866,285
41	Customer Deposits (235)		8,868,640	7,958,557
42	Taxes Accrued (236)	262-263	8,292,344	-397,450
43	Interest Accrued (237)		11,797,709	11,290,059
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	04/13/2012	end of 2011/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)		104,100	32,330
48	Miscellaneous Current and Accrued Liabilities (242)		55,333,088	52,383,017
49	Obligations Under Capital Leases-Current (243)		224,884	195,575
50	Derivative Instrument Liabilities (244)		111,353,644	82,467,564
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		40,530,269	30,984,511
52	Derivative Instrument Liabilities - Hedges (245)		18,895,143	58,584
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		2,641,867	52,705
54	Total Current and Accrued Liabilities (lines 37 through 53)		333,434,461	362,989,647
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		947,213	1,089,209
57	Accumulated Deferred Investment Tax Credits (255)	266-267	10,400,886	7,842,362
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	26,584,147	17,050,733
60	Other Regulatory Liabilities (254)	278	20,939,852	31,545,561
61	Unamortized Gain on Reaquired Debt (257)		2,484,655	2,655,731
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		398,500,293	369,622,132
64	Accum. Deferred Income Taxes-Other (283)		259,644,520	240,292,793
65	Total Deferred Credits (lines 56 through 64)		719,501,566	670,098,521
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		3,762,875,808	3,510,549,408

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	04/13/2012	End of 2011/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	1,617,162,384	1,602,043,842		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,169,781,695	1,175,254,099		
5	Maintenance Expenses (402)	320-323	57,411,515	48,270,267		
6	Depreciation Expense (403)	336-337	96,771,421	92,936,677		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	11,307,561	10,067,620		
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)		3,529,991	919,134		
13	(Less) Regulatory Credits (407.4)		19,872,716	11,804,920		
14	Taxes Other Than Income Taxes (408.1)	262-263	83,348,911	73,392,440		
15	Income Taxes - Federal (409.1)	262-263	23,554,951	10,616,573		
16	- Other (409.1)	262-263	1,264,963	469,639		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	29,793,186	41,454,197		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	2,475,028	1,521,709		
19	Investment Tax Credit Adj. - Net (411.4)	266	2,458,952	-177,672		
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)		1,456,974,449	1,439,975,392		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		160,187,935	162,068,450		

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
1,053,850,680	1,069,954,147	563,311,704	532,089,695			2
						3
702,686,156	724,521,516	467,095,539	450,732,583			4
47,524,279	39,000,254	9,887,236	9,270,013			5
78,744,936	75,862,701	18,026,485	17,073,976			6
						7
9,015,875	8,110,496	2,291,686	1,957,124			8
99,047	99,047					9
						10
						11
3,366,279	-1,799,835	163,712	2,718,969			12
17,238,278	9,787,351	2,634,438	2,017,569			13
61,363,417	54,037,916	21,985,494	19,354,524			14
23,647,758	22,733,087	-92,807	-12,116,514			15
922,947	686,110	342,016	-216,471			16
17,702,120	22,478,586	12,091,066	18,975,611			17
2,793,831	1,625,776	-318,803	-104,067			18
2,502,656	-131,436	-43,704	-46,236			19
						20
						21
						22
						23
						24
927,543,361	934,185,315	529,431,088	505,790,077			25
126,307,319	135,768,832	33,880,616	26,299,618			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	04/13/2012	End of 2011/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)		160,187,935	162,068,450		
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)		-21,355	-10,997		
34	(Less) Expenses of Nonutility Operations (417.1)		6,836,563	5,458,722		
35	Nonoperating Rental Income (418)		-2,731	-119,784		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	9,971,326	6,092,992		
37	Interest and Dividend Income (419)		1,293,357	1,800,338		
38	Allowance for Other Funds Used During Construction (419.1)		2,224,987	3,352,964		
39	Miscellaneous Nonoperating Income (421)					
40	Gain on Disposition of Property (421.1)		31,120	402,632		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		6,660,141	6,059,423		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)			3,938		
44	Miscellaneous Amortization (425)		304,717	1,110,572		
45	Donations (426.1)		2,143,177	4,164,132		
46	Life Insurance (426.2)		2,253,671	2,236,551		
47	Penalties (426.3)		281,762	287,129		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,186,022	1,167,774		
49	Other Deductions (426.5)		407,223	776,184		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		6,576,572	9,746,280		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	-2,275	-9,752		
53	Income Taxes-Federal (409.2)	262-263	-962,923	1,419,985		
54	Income Taxes-Other (409.2)	262-263	-349,700	-188,221		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	40,666	-1,578,031		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	4,710,550	4,255,497		
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)		-5,984,782	-4,611,516		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		6,068,351	924,659		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		61,400,721	63,349,463		
63	Amort. of Debt Disc. and Expense (428)		604,805	893,123		
64	Amortization of Loss on Reaquired Debt (428.1)		4,021,281	3,530,313		
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)		-26,307	883,444		
68	Other Interest Expense (431)		2,983,099	2,219,100		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		2,942,302	298,141		
70	Net Interest Charges (Total of lines 62 thru 69)		66,032,414	70,568,419		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		100,223,872	92,424,690		
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)		100,223,872	92,424,690		

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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	04/13/2012	End of 2011/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		325,313,182	294,314,125
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Dividends received from subs		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)		90,252,546	86,331,698
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			-63,736,956	(55,682,194)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-63,736,956	(55,682,194)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		649,442	349,553
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		362,988,164	325,313,182
	APPROPRIATED RETAINED EARNINGS (Account 215)			

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	04/13/2012	End of 2011/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)		364,536,285	326,861,303
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-24,343,434	(20,871,863)
50	Equity in Earnings for Year (Credit) (Account 418.1)		9,971,326	6,092,992
51	(Less) Dividends Received (Debit)			
52	Equity transactions of subsidiaries		-14,014,194	(9,564,563)
53	Balance-End of Year (Total lines 49 thru 52)		-28,386,302	(24,343,434)

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	04/13/2012	End of 2011/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)	100,223,872	92,424,690
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	105,727,999	103,004,297
5	Amortization of deferred power and natural gas costs	21,869,528	-9,795,050
6	Amortization of debt expense	4,617,203	4,414,553
7	Amortization of investment in exchange power	2,450,030	2,450,031
8	Deferred Income Taxes (Net)	21,115,803	36,084,184
9	Investment Tax Credit Adjustment (Net)	2,558,524	2,209,854
10	Net (Increase) Decrease in Receivables	3,428,347	-11,666,672
11	Net (Increase) Decrease in Inventory	-2,737,133	-11,466,814
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	-1,250,437	-1,486,305
14	Net (Increase) Decrease in Other Regulatory Assets	10,565,705	5,858,734
15	Net Increase (Decrease) in Other Regulatory Liabilities	-11,754,169	-4,654,996
16	(Less) Allowance for Other Funds Used During Construction	2,224,987	3,352,964
17	(Less) Undistributed Earnings from Subsidiary Companies	9,971,326	6,092,992
18	Other (provide details in footnote):	-15,689,679	-2,996,589
19			
20	Changes in other non-current assets and liabilities	-816,072	-7,567,021
21	Net change in receivables allowance	651,650	136,069
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	228,764,858	187,503,009
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-240,025,802	-206,800,158
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)	-240,025,802	-206,800,158
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		592,582
38	Federal grant payments received	16,927,752	7,585,367
39	Investments in and Advances to Assoc. and Subsidiary Companies	-5,482,493	
40	Contributions and Advances from Assoc. and Subsidiary Companies		523,909
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	04/13/2012	End of 2011/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	-1,754,160	-1,588,956
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-230,334,703	-199,687,256
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	85,000,000	136,365,000
62	Preferred Stock		
63	Common Stock	26,462,920	46,235,329
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		23,000,000
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	111,462,920	205,600,329
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-195,575	-110,129,764
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):	-10,557,000	
77	Long-term debt and short-term borrowing issuance costs	-4,477,097	-916,100
78	Net Decrease in Short-Term Debt (c)	-49,000,000	
79	Premium paid to repurchase long-term debt		-10,710,164
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-63,736,957	-55,682,184
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-16,503,709	28,162,117
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-18,073,554	15,977,870
87			
88	Cash and Cash Equivalents at Beginning of Period	19,940,973	3,963,103
89			
90	Cash and Cash Equivalents at End of period	1,867,419	19,940,973

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

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

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

Power and natural gas deferrals	1,383,294
Change in special deposits	(6,351,572)
Change in other current assets	(1,508,851)
Non-cash stock compensation	3,602,646
Gain on sale of assets	(122,377)

Schedule Page: 120 Line No.: 76 Column: b

Cash paid for settlement of interest rate swap agreements.

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Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report 04/13/2012	Year/Period of Report End of 2011/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 northeast and southwest 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), formerly Advantage IQ, Inc. (Advantage IQ), a 79.2 percent owned subsidiary as of December 31, 2011. 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 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,
- stock-based compensation, 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):

	2011	2010
Unbilled accounts receivable	$82,950	$84,073

Advertising Expenses
The Company expenses advertising costs as incurred. Advertising expenses were not a material portion of the Company's operating expenses in 2011 and 2010.

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:

	2011	2010
Ratio of depreciation to average depreciable property	2.92%	2.84%

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

- electric thermal production - 33 years,
- hydroelectric production - 74 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):

	2011	2010
Utility taxes	$55,739	$49,953

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:

	2011	2010
Effective AFUDC rate	7.91%	8.25% (1)

(1) Rate was effective from January 1, 2010 to November 30, 2010. Effective December 1, 2010, rate was changed to 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 16 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. Cash and cash equivalents include cash deposits from counterparties.

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 (WUTC) 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 14 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 19 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 WUTC 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

In May 2011, the Financial Accounting Standards Board (FASB) issued 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 will require enhanced disclosures for fair value measurements, including quantitative sensitivity 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 Company will be required to adopt this ASU effective January 1, 2012. The Company does not expect that this ASU will have material impact on its financial condition, results of operations and cash flows.

NOTE 3. ECOVA ACQUISITIONS

The acquisition of Cadence Network in July 2008 was funded with the issuance of Ecova (formerly Advantage IQ) common stock. Under the transaction agreement, the previous owners of Cadence Network can exercise a right to have their shares of Ecova common stock redeemed during July 2011 or July 2012 if Ecova is not liquidated through either an initial public offering or sale of the business to a third party. These rights were not exercised during July 2011. These redemption rights expire July 31, 2012. The redemption price would be determined based on the fair market value of Ecova at the time of the redemption election as determined by certain independent parties. Additionally, certain minority shareholders and option holders of Ecova have the right to put their shares back to Ecova at their discretion.

On December 31, 2010, Ecova acquired substantially all of the assets and liabilities of The Loyalton Group (Loyalton), a Minneapolis-based energy management firm providing energy procurement and price risk management solutions.

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.

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

NOTE 4. 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. Market risk may also be influenced by market participants' nonperformance of their contractual obligations and commitments, which affects the supply of, or demand for, the commodity. 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 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. sells and purchases wholesale electric capacity and energy and fuel as part of the process of acquiring and balancing resources to serve its load obligations. These transactions range from terms of 30 minutes up to multiple years.

Avista Corp. makes continuing projections of:

- electric loads at various points in time (ranging from 30 minutes 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, Avista Corp. makes purchases and sales of electric capacity and energy and fuel to match expected resources to expected electric load requirements. 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.

As part of its resource procurement and management operations in the 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, 2011 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 MWH	Financial MWH	Physical mmBTUs	Financial mmBTUs	Physical MWH	Financial MWH	Physical mmBTUs	Financial mmBTUs
2012	1,021	2,181	39,547	78,575	613	1,398	4,261	71,913
2013	398	1,874	11,742	61,357	254	1,781	1,532	52,817
2014	366	30	5,562	22,328	286	737	1,050	8,900
2015	379	-	2,635	1,502	286	-	-	-
2016	367	-	910	227	287	-	-	-
Thereafter	949	-	-	-	730	-	-	-

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):

	2011	2010
Number of contracts	28	29
Notional amount (in United States dollars)	$7,033	$10,916
Notional amount (in Canadian dollars)	7,192	10,989
Derivatives amount	32	116

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):

	2011	2010
Number of contracts	3	2
Notional amount	$75,000	$50,000
Mandatory cash settlement date	July 2012	July 2012
Number of contracts	2	-
Notional amount	$85,000	-
Mandatory cash settlement date	June 2013	-
Derivative asset	-	127
Derivative liability	(18,895)	(53)

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 entered during the third quarter of 2011 and were settled in connection with the pricing of $85.0 million of First Mortgage Bonds (see Note 11). 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, 2011 (in thousands):

		Fair Value		
Derivative	Balance Sheet Location	Asset	Liability	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)

The following table presents the fair values and locations of derivative instruments recorded on the Balance Sheet as of December 31, 2010 (in thousands):

		Fair Value		
Derivative	Balance Sheet Location	Asset	Liability	Net Asset (Liability)
Foreign currency contracts	Derivative instrument assets - Hedges	$ 116	$ -	$ 116
Interest rate contracts	Derivative instrument liabilities – Hedges	127	-	127
Interest rate contracts	Long-term portion of derivative instrument liabilities - Hedges	-	(53)	(53)
Commodity contracts	Derivative instrument assets current	6,293	(3,701)	2,592
Commodity contracts	Long-term portion of derivative assets	21,249	(5,988)	15,261
Commodity contracts	Derivative instrument liabilities current	5,934	(57,417)	(51,483)
Commodity contracts	Long-term portion of derivative instrument liabilities	1,386	(32,371)	(30,985)
Total derivative instruments recorded on the balance sheet		$35,105	$(99,530)	$(64,425)

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, 2011, the Company had cash deposited as collateral of $18.2 million and letters of credit of $18.8 million outstanding related to its energy derivative contracts.

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, 2011 was $154.9 million. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2011, the Company could be required to post $61.3 million of 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. The Company seeks to mitigate 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, and
- conducting transactions on exchanges with fully collateralized clearing arrangements that significantly reduce counterparty default risk.

These credit policies include an evaluation of the financial condition and credit ratings of counterparties, collateral requirements or other credit enhancements, such as letters of credit or parent company guarantees. The Company also uses standardized agreements that allow for the netting or offsetting of positive and negative exposures associated with a single counterparty or affiliated group.

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 margin agreements with certain counterparties and margin calls are periodically made and/or received. Margin calls are triggered when exposures exceed predetermined 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 5. 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):

	2011	2010
Utility plant in service	$342,539	$336,796
Accumulated depreciation	(225,746)	(219,770)

NOTE 6. 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):

	2011	2010
Asset retirement obligation at beginning of year	$3,887	$3,971
New liability recognized	-	19
Liability settled	(612)	(460)
Accretion expense	238	357
Asset retirement obligation at end of year	$3,513	$3,887

NOTE 7. PENSION PLANS AND OTHER POSTRETIREMENT BENEFIT PLANS

The Company has a defined benefit pension plan covering substantially all regular full-time employees. 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 $26 million in cash to the pension plan in 2011 and $21 million in 2010. The Company expects to contribute $44 million in cash to the pension plan in 2012.

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):

	2012	2013	2014	2015	2016	Total 2017-2021
Expected benefit payments	$20,484	$21,899	$23,189	$24,759	$26,100	$154,146

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):

	2012	2013	2014	2015	2016	Total 2017-2021

Expected benefit payments	$5,277	$5,390	$5,523	$5,735	$5,946	$32,231

The Company expects to contribute $5.3 million to other postretirement benefit plans in 2012, 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, 2011 and 2010 and the components of net periodic benefit costs for the years ended December 31, 2011 and 2010 (dollars in thousands):

	Pension		Other postretirement	
	2011	2010	2011	2010
Change in benefit obligation:				
Benefit obligation as of beginning of year	$433,491	$378,235	$60,339	$39,560
Service cost	12,936	11,609	1,805	684
Interest cost	24,134	23,231	4,126	2,624
Actuarial loss	44,148	38,547	42,476	21,657
Transfer of accrued vacation	-	-	450	367
Benefits paid	(20,517)	(18,131)	(4,466)	(4,553)
Benefit obligation as of end of year	$494,192	$433,491	$104,730	$60,339
Change in plan assets:				
Fair value of plan assets as of beginning of year	$306,712	$272,732	$22,875	$20,394
Actual return on plan assets	14,705	29,846	(420)	2,481
Employer contributions	26,000	21,000	-	-
Benefits paid	(19,267)	(16,866)	-	-
Fair value of plan assets as of end of year	$328,150	$306,712	$22,455	$22,875
Funded status	$(166,042)	$(126,779)	$(82,275)	$(37,464)
Unrecognized net actuarial loss	192,883	149,819	76,187	35,149
Unrecognized prior service cost	665	1,140	(1,005)	(1,154)
Unrecognized net transition obligation	-	-	505	1,011
Prepaid (accrued) benefit cost	27,506	24,180	(6,588)	(2,458)
Additional liability	(193,548)	(150,959)	(75,687)	(35,006)
Accrued benefit liability	$(166,042)	$(126,779)	$(82,275)	$(37,464)
Accumulated pension benefit obligation	$429,135	$377,606	-	-
Accumulated postretirement benefit obligation:				
For retirees			$39,470	$27,921
For fully eligible employees			$29,597	$15,618
For other participants			$35,663	$16,800
Included in accumulated comprehensive loss (income) (net of tax):				
Unrecognized net transition obligation	$ -	$ -	$ 328	$ 657
Unrecognized prior service cost	433	741	(653)	(750)
Unrecognized net actuarial loss	125,374	97,382	49,522	22,847
Total	125,807	98,123	49,197	22,754
Less regulatory asset	(119,360)	(92,570)	(49,873)	(23,981)
Accumulated other comprehensive loss (income)	$6,447	$5,553	$(676)	$(1,227)
Weighted average assumptions as of December 31:				
Discount rate for benefit obligation	5.04%	5.69%	4.98%	5.50%
Discount rate for annual expense	5.68%	6.28%	5.53%	6.00%
Expected long-term return on plan assets	7.40%	7.75%	7.00%	7.75%
Rate of compensation increase	4.87%	4.72%		
Medical cost trend pre-age 65 – initial			7.50%	8.00%
Medical cost trend pre-age 65 – ultimate			5.00%	5.00%
Ultimate medical cost trend year pre-age 65			2017	2017
Medical cost trend post-age 65 – initial			8.00%	8.00%
Medical cost trend post-age 65 – ultimate			6.00%	6.00%
Ultimate medical cost trend year post-age 65			2018	2015

	2011	2010	2011	2010
Components of net periodic benefit cost:				
Service cost	$12,936	$11,609	$1,805	$ 684
Interest cost	24,134	23,231	4,126	2,624
Expected return on plan assets	(23,115)	(21,381)	(1,601)	(1,581)
Transition obligation recognition	-	-	505	505
Amortization of prior service cost	475	650	(149)	(149)
Net loss recognition	9,493	7,189	3,458	1,379
Net periodic benefit cost	$23,923	$21,298	$8,144	$3,462

Plan Assets

The Finance Committee of the Company's Board of Directors establishes 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:

	2011	2010
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, 2011 and 2010.

The following table discloses by level within the fair value hierarchy (refer to Note 14 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

The following table discloses by level within the fair value hierarchy (refer to Note 14 for a description of the fair value hierarchy) of the pension plan's assets measured and reported as of December 31, 2010 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ 335	$ -	$ -	$ 335
Mutual funds:				
Fixed income securities	96,026	-	-	96,026
U.S. equity securities	104,232	-	-	104,232
International equity securities	53,964	-	-	53,964
Absolute return (1)	12,662	-	-	12,662
Commodities (2)	7,133	-	-	7,133
Common/collective trusts:				
U.S. equity securities	-	13,653	-	13,653
Absolute return (1)	-	-	95	95
Real estate	-	-	423	423
Partnership/closely held investments:				
Absolute return (1)	-	-	16,917	16,917
Private equity funds (3)	-	-	1,272	1,272
Total	$274,352	$13,653	$18,707	$306,712

(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, 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 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, 2010 (dollars in thousands):

	Common/collective trusts		Partnership/closely held investments	
	Absolute return	Real estate	Absolute return	Private equity funds
Balance, as of January 1, 2010	$844	$6,029	$15,794	$1,561
Realized gains (losses)	(233)	630	-	(148)
Unrealized gains (losses)	(193)	(160)	1,123	(48)
Purchases (sales), net	(323)	(6,076)	-	(93)
Balance, as of December 31, 2010	$ 95	$ 423	$16,917	$1,272

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 2011 and 2010.

The market-related value of other postretirement plan assets was determined as of December 31, 2011 and 2010.
The following table discloses by level within the fair value hierarchy (refer to Note 14 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

The following table discloses by level within the fair value hierarchy (refer to Note 14 for a description of the fair value hierarchy) of other postretirement plan assets measured and reported as of December 31, 2010 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ 118	$ -	$ -	$ 118
Mutual funds:				
Fixed income securities	8,320	-	-	8,320
U.S. equity securities	6,986	-	-	6,986
International equity securities	5,572	-	-	5,572
U.S. equity securities	1,785	-	-	1,785
Other	94	-	-	94
Total	$22,875	$ -	$ -	$22,875

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, 2011 by $14.8 million and the service and interest cost by $0.8 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, 2011 by $12.3 million and the service and interest cost by $0.7 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):

	2011	2010
Employer 401(k) matching contributions	$5,452	$4,797

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):

	2011	2010
Deferred compensation assets and liabilities	$8,653	$9,285

NOTE 8. 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, 2011, the Company had $12.4 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 2007 and all issues were resolved related to these years. The IRS has not completed an examination of the Company's 2008, 2009 or 2010 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 2011 or 2010.

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):

	2011	2010
Regulatory assets for deferred income taxes	$84,576	$90,025

NOTE 9. 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):

	2011	2010
Utility power resources	$557,619	$649,408

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):

	2012	2013	2014	2015	2016	Thereafter	Total
Power resources	$218,599	$157,401	$139,180	$116,184	$111,698	$1,037,268	$1,780,330
Natural gas resources	134,047	102,923	87,926	72,632	54,475	639,790	1,091,793
Total	$352,646	$260,324	$227,106	$188,816	$166,173	$1,677,058	$2,872,123

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):

	2012	2013	2014	2015	2016	Thereafter	Total
Contractual obligations	$29,103	$30,346	$30,891	$28,392	$32,528	$246,503	$397,763

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):

	2011	2010
PUD contract costs	$10,533	$8,287

Information as of December 31, 2011 pertaining to these PUD contracts is summarized in the following table (dollars in thousands):

	Company's Current Share of					
	Output	Kilowatt Capability	Annual Costs (1)	Debt Service Costs (1)	Bonds Outstanding	Expira-tion Date
Chelan County PUD:						
Rocky Reach Project	2.9%	37,000	$ 2,017	$ 887	$ -	2011
Douglas County PUD:						
Wells Project	3.4%	28,000	2,456	876	3,613	2018
Grant County PUD:						
Priest Rapids and Wanapum Projects	3.3%	65,800	6,060	2,203	30,263	2055
Totals		130,800	$10,533	$3,966	$33,876	

(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 2011. 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):

	2012	2013	2014	2015	2016	Thereafter	Total
Minimum payments	$3,337	$3,332	$3,305	$3,195	$3,106	$44,835	$61,110

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

NOTE 10. NOTES PAYABLE

In February 2011, Avista Corp. entered into a new committed line of credit with various financial institutions in the total amount of $400.0 million with an expiration date of February 2015 that replaced its $320.0 million and $75.0 million committed lines of credit. In December 2011, this committed line of credit was amended to extend the expiration date to February 2017 and revise the pricing terms.

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, 2011, 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):

	2011	2010
Balance outstanding at end of period	$61,000	$110,000
Letters of credit outstanding at end of period	$29,030	$ 27,126
Average interest rate at end of period	1.12%	0.57%

NOTE 11. BONDS

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

Maturity Year	Description	Interest Rate	2011	2010
2012	Secured Medium-Term Notes	7.37%	$ 7,000	$ 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 (3)	4.45%	85,000	-
	Total secured long-term debt		1,263,700	1,178,700
2023	Unsecured Pollution Control Bonds	6.00%	4,100	4,100
	Settled interest rate swaps		(10,629)	(951)
	Secured Pollution Control Bonds held by Avista Corporation (1) (2)		(83,700)	(83,700)
	Total bonds		$1,173,471	$1,098,149

(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 December 2011, the Company issued $85.0 million of 4.45 percent First Mortgage Bonds due in 2041.

The following table details future long-term debt maturities including advances from associated companies (see Note 12) (dollars in thousands):

	2012	2013	2014	2015	2016	Thereafter	Total
Debt maturities	$7,000	$50,000	$ -	$ -	$ -	$1,178,647	$1,235,647

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, 2011, property additions and retired bonds would have allowed the Company to issue $727.1 million in aggregate principal amount of additional First Mortgage Bonds.

See Note 10 for information regarding First Mortgage Bonds issued to secure the Company's obligations under its committed line of credit agreement.

NOTE 12. 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:

	2011	2010
Low distribution rate	1.13%	1.13%
High distribution rate	1.40	1.41
Distribution rate at the end of the year	1.40	1.17

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 13. LEASES

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

	2011	2010
Rental expense	$2,853	$2,885

Future minimum lease payments required under operating leases having initial or remaining noncancelable lease terms in excess of one year as of December 31, 2011 were as follows (dollars in thousands):

	2012	2013	2014	2015	2016	Thereafter	Total
Minimum payments required	$1,412	$1,259	$1,260	$437	$131	$2,367	$6,866

NOTE 14. 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):

	2011		2010	
	Carrying	Estimated	Carrying	Estimated

	Value	Fair Value	Value	Fair Value
Bonds	$1,184,100	$1,369,763	$1,099,100	$1,139,765
Advances from associated companies	51,547	43,810	51,547	37,114

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, 2011 and 2010 at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Counterparty Netting (1)	Total
December 31, 2011					
Assets:					
Energy commodity derivatives	$ -	$80,571	$5,630	$(84,877)	$1,324
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	$18,488	$(84,877)	$111,354
Interest rate swaps	-	18,895	-	-	18,895
Total	$ -	$196,638	$18,488	$(84,877)	$130,249
December 31, 2010					
Assets:					
Energy commodity derivatives	$ -	$15,124	$19,739	$(17,010)	$ 17,853
Interest rate swaps	-	127	-	-	127
Foreign currency derivatives	-	116	-	-	116
Deferred compensation assets:					

Fixed income securities	1,854	-	-	-	1,854
Equity securities	6,211	-	-	-	6,211
Total	$8,065	$15,367	$19,739	$(17,010)	$26,161
Liabilities:					
Energy commodity derivatives	$ -	$93,198	$6,280	$(17,010)	$82,468
Interest rate swaps	-	53	-	-	53
Total	$ -	$93,251	$6,280	$(17,010)	$82,521

(1) The Company is permitted to net derivative assets and derivative liabilities with the same counterparty when a legally enforceable master netting agreement exists.

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.

The Company also has certain contracts that, primarily due to the length of the respective contract, require the use of internally developed forward price estimates, which include significant inputs that may not be observable or corroborated in the market. These derivative contracts are included in Level 3. Refer to Note 4 for further discussion of the Company's energy commodity derivative assets and liabilities.

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 $1.3 million as of December 31, 2011 and $1.2 million as of December 31, 2010.

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

	Assets		Liabilities	
	2011	2010	2011	2010
Balance as of January 1	$19,739	$57,276	$(6,280)	$(7,806)
Total gains or losses (realized/unrealized):				
Included in net income	-	-	-	-
Included in other comprehensive income	-	-	-	-
Included in regulatory assets/liabilities (1)	(14,084)	(34,943)	(10,792)	1,209
Purchases	-	-	-	-
Issuance	-	-	-	-
Settlements	(25)	(2,594)	2,988	317
Transfers to other categories (2)	-	-	(4,404)	-
Ending balance as of December 31	$5,630	$19,739	$(18,488)	$(6,280)

(1) The WUTC 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.

NOTE 15. 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 2010, the Company entered into an amended and restated sales agency agreement with a sales agent to issue up to 3,087,500 shares of its common stock from time to time.

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

	2011	2010
Shares issued under sales agency agreement	807,000	2,054,110

The Company has 10 million authorized shares of preferred stock. The Company did not have any preferred stock outstanding as of December 31, 2011 and 2010.

NOTE 16. STOCK COMPENSATION PLANS

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, 2011, 0.2 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, 2011, 1.8 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):

	2011	2010
Stock-based compensation expense	$5,756	$4,916
Income tax benefits	2,014	1,720

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

	2011	2010
Number of shares under stock options:		
Options outstanding at beginning of year	201,674	523,973
Options granted	-	-
Options exercised	(107,575)	(101,649)
Options canceled	(1,600)	(220,650)
Options outstanding and exercisable at end of year	92,499	201,674
Weighted average exercise price:		
Options exercised	$12.25	$11.51

Options canceled	$11.80	$22.60
Options outstanding and exercisable at end of year	$10.69	$11.53
Cash received from options exercised (in thousands)	$1,318	$2,179
Intrinsic value of options exercised (in thousands)	$1,279	$1,006
Intrinsic value of options outstanding (in thousands)	$1,393	$2,217

Information for options outstanding and exercisable as of December 31, 2011 is as follows:

Exercise Prices	Number of Shares	Weighted Average Exercise Price	Weighted Average Remaining Life (in years)
$10.17	80,499	$10.17	0.85
$12.41	6,000	12.41	1.35
$15.88	6,000	15.88	0.36
Total	92,499	$10.69	0.85

As of December 31, 2011 and 2010, the Company's stock options were fully vested and expensed.

Restricted Shares

Restricted shares 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, 2011 was 0.7 years. The following table summarizes restricted stock activity for the years ended December 31:

	2011	2010
Unvested shares at beginning of year	84,134	71,904
Shares granted	50,618	43,800
Shares cancelled	(431)	-
Shares vested	(40,839)	(31,570)
Unvested shares at end of year	93,482	84,134
Weighted average fair value at grant date	$23.06	$19.80
Unrecognized compensation expense at end of year (in thousands)	$932	$735
Intrinsic value, unvested shares at end of year (in thousands)	$2,407	$1,895
Intrinsic value, shares vested during the year (in thousands)	$934	$682

Performance Shares

Performance share grants have vesting periods of three years. Performance 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 2011 grants 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. 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 granted. 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:

	2011	2010
Risk-free interest rate	1.2%	1.4%
Expected life, in years	3	3
Expected volatility	26.9%	27.8%
Dividend yield	4.7%	4.6%
Weighted average grant date fair value (per share)	$20.79	$15.30

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

The following summarizes performance share activity:

	2011	2010
Opening balance of unvested performance shares	325,700	300,601
Performance shares granted	184,600	168,700
Performance shares canceled	(2,177)	-
Performance shares vested	(156,778)	(143,601)
Ending balance of unvested performance shares	351,345	325,700
Intrinsic value of unvested performance shares (in thousands)	$9,047	$7,335
Unrecognized compensation expense (in thousands)	$2,991	$2,330

The weighted average remaining vesting period for the Company's performance shares outstanding as of December 31, 2011 was 1.5 years. Unrecognized compensation expense as of December 31, 2011 will be recognized during 2012 and 2013. The following summarizes the impact of the market condition on the vested performance shares:

	2011	2010
Performance shares vested	156,778	143,601
Impact of market condition on shares vested	(15,678)	21,540
Shares of common stock earned	141,100	165,141
Intrinsic value of common stock earned (in thousands)	$3,633	$3,719

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

Awards outstanding under the performance share grants 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, 2011 and 2010, the Company had recognized compensation expense and a liability of $1.0 million and $0.9 million related to the dividend component of performance share grants.

NOTE 17. 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 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 December 31, 2011, 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.

Many of the orders that the FERC has issued in the California refund proceedings were appealed to the Ninth Circuit. In October 2004, the Ninth Circuit ordered that briefing proceed in two rounds. The first round was limited to three issues: (1) which parties are subject to the FERC's refund jurisdiction in light of the exemption for government-owned utilities in section 201(f) of the FPA; (2) the temporal scope of refunds under section 206 of the FPA; and (3) which categories of transactions are subject to refunds. The second round of issues and their corresponding briefing schedules have not yet been set by the Ninth Circuit.

In September 2005, the Ninth Circuit held that the FERC did not have the authority to order refunds for sales made by municipal utilities in the California refund proceeding. 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. A FERC hearing on that issue is scheduled to commence in April 2012. A May 2011 FERC order denied a motion filed by Avista Energy and Avista Corp. asking that the companies be dismissed from any further proceedings involving alleged tariff violations under FPA section 309. Avista Energy and Avista Corp. sought rehearing of that ruling in June 2011. As noted above, in Docket No. EL02-115, Avista Energy and Avista Corp. were absolved of any wrongdoing related to allegations of tariff violations during 2000 and 2001 and have argued that the doctrines of *res judicata* and collateral estoppel preclude relitigation of the same issues. The California AG, the CPUC, PG&E and SCE also 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. They also filed a petition for review of the May 2011 order with the Ninth Circuit.

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. 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 Department of Water Resources (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 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 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. A procedural schedule in this docket has not yet been set.

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 Administrative Law Judge (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.

Based on information currently known to the Company's management, and the ALJ's granting of Avista Corp. and Avista Energy's summary disposition motion, 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 allege that the holding ponds and remediation activities have adversely impacted their property. They allege contamination, decrease in water tables, reduced flow of streams on their property and other similar impacts to their property. They also seek 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 have subsequently appealed the court's decision. 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. Although the final resolution of this complaint remains uncertain, based on information currently known to the Company's management, the Company does not expect this complaint will have a material effect on its financial condition, results of operations or cash flows.

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. The actual cleanup, if any, will not occur until the RI/FS is finalized and approved by the EPA. Based on the review of its records related to Harbor Oil, the Company does not believe it is a major 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 (DOE), 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, the DOE 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 has until May 27, 2012 to develop mitigation strategies to address the low levels of dissolved oxygen. It is not possible to provide cost estimates at this time because the mitigation measures have not been fully identified or approved by the DOE. 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 EPA and the Idaho Department of Environmental Quality (Idaho DEQ) are preparing draft National Pollutant Discharge Elimination System permits and the 401 Water Quality Certifications for the Idaho dischargers, respectively, which once issued will be released for a 30-day public comment period.

The IPUC and the WUTC 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. In 2002, the Company submitted a Gas Supersaturation Control Program (GSCP) to the Idaho DEQ and U.S. Fish and Wildlife Service (USFWS). This submission was part of the Clark Fork Settlement Agreement for licensing the use of Cabinet Gorge. The GSCP provided for the possible opening and modification of two diversion tunnels around Cabinet Gorge to allow streamflow to be diverted when flows are in excess of powerhouse capacity. In 2007, engineering studies determined that the tunnels would not sufficiently reduce Total Dissolved Gas (TDG). In consultation with the Idaho DEQ and the USFWS, the Company developed an addendum to the GSCP. The GSCP addendum abandons the concept to reopen the two diversion tunnels and requires the Company to evaluate a variety of different options to abate TDG. In March 2010, the FERC approved the GSCP addendum of preliminary design for alternative abatement measures. In the second quarter of 2011, the Company completed preliminary feasibility assessments for several alternative abatement measures and determined that two alternatives will be considered for continued development. Further analysis and review of these alternatives is expected to be completed through at least the middle of 2012. 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 is evaluating 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. In 2009, the Company selected a contractor to design a permanent upstream passage facility at Cabinet Gorge. The Company anticipates that the design and cost estimates will be completed by the end of 2012 with construction taking place in 2013 and 2014.

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 the DOE 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 the DOE as "Aluminum Recycling – Trentwood." Operators of the UPR property maintained piles of aluminum "black dross," which can be designated 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 the DOE's proposed findings in November 2009. In December 2009, Pentzer received notice from the DOE that it had been designated as a potentially liable party for any hazardous substances located on this site. UPR completed a RI/FS Work Plan in June 2010. At that time, UPR requested a

contribution from Pentzer towards the cost of performing the RI/FS and also an access agreement to investigate the material deposited on the Pentzer property. Pentzer concluded an access agreement with UPR in October 2010. UPR completed the RI/FS during the fourth quarter of 2011. 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.

Injury from Overhead Electric Line (Munderloh v. Avista)
On March 4, 2010, the plaintiff and his wife filed a complaint against Avista Corp. in Spokane County Superior Court. Plaintiffs alleged that while the plaintiff was employed by a third party as a laborer at their construction site, he came into contact with Avista Corp.'s electric line, was injured and suffered economic and non-economic damages. Plaintiffs further alleged that Avista Corp. was at fault for failing to relocate the overhead electric line which it controlled and operated adjacent to the construction site. In January 2012, Avista Corp. and its insurance provider reached a settlement with the plaintiffs. Avista Corp. has expensed its share of the settlement (including legal fees) of $2 million (which was recorded in 2010 and 2011).

Damages from Fire in Stevens County, Washington
In August 2010, a fire in Stevens County, Washington occurred during a wind storm. The apparent cause of the fire may be a tree located outside of Avista Corp.'s right-of-way that came in contact with an electric line owned by Avista Corp. The fire area is a rural farm and timber landscape. The fire destroyed two residences and six outbuildings. The Company is not aware of any personal injuries resulting from the fire. Although no lawsuits have been filed, Avista Corp. has received several claims and it is possible that additional claims may be made and lawsuits may be filed against the Company. The Company has expensed its estimated liability for this matter, which was not material to its financial condition, results of operations or cash flows. Based on information currently known to the Company's management, the Company does not expect this complaint 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, expired in April 2010. New agreements were reached in December 2010 (expiring 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 an 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 its intent to initiate an 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 18. INFORMATION SERVICES CONTRACTS

The Company has information services contracts that expire at various times through 2017. 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):

	2011	2010
Information service contract payments	$13,038	$13,426

The majority of the costs are included in other operating expenses in the Statements of Income. Minimum contractual obligations under the Company's information services contracts are $13.0 million in 2012, $10.5 million in 2013, $8.0 million in 2014, and $7.0 million in each of 2015, 2016 and 2017.

NOTE 19. REGULATORY MATTERS

Power Cost Deferrals and Recovery Mechanisms

Deferred power supply costs are recorded as a deferred charge on the Balance Sheets for future 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 WUTC 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 $12.9 million as of December 31, 2011.

The initial amount of power supply costs in excess or below the level in retail rates, which the Company either incurs the cost of, or receives the benefit from, 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 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 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 to the Company
+/- $0 - $4 million	0%	100%
+ between $4 million - $10 million	50%	50%
- between $4 million - $10 million	75%	25%
+/- excess over $10 million	90%	10%

Avista Corp. has a Power Costs 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 $0.7 million as of December 31, 2011 and a regulatory asset of $18.3 million as of December 31, 2010.

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 $12.1 million as of December 31, 2011 and $22.1 million as of December 31, 2010.

Washington General Rate Cases
In November 2010, the WUTC approved an all-party settlement stipulation in the Company's general rate case filed in March 2010. As agreed to in the settlement stipulation, electric rates for the Company's Washington customers increased by an average of 7.4 percent, which was designed to increase annual revenues by $29.5 million. Natural gas rates for the Company's Washington customers increased by an average of 2.9 percent, which was designed to increase annual revenues by $4.6 million. The new electric and natural gas rates became effective on December 1, 2010.

In December 2011, the WUTC 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 will occur 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 will 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. For 2011, the Company deferred $0.5 million of maintenance costs in Washington.

Idaho General Rate Cases
In September 2010, the IPUC approved a settlement agreement in the Company's general rate case filed in March 2010. The new electric and natural gas rates became effective on October 1, 2010. As agreed to in the settlement, base electric rates for the Company's Idaho customers increased by an average of 9.3 percent, which was designed to increase annual revenues by $21.2 million. Base natural gas rates for the Company's Idaho customers increased by an average of 2.6 percent, which was designed to increase annual revenues by $1.8 million.

The 2010 settlement agreement includes a rate mitigation plan under which the impact on customers of the new rates will be reduced by amortizing $11.1 million ($17.5 million when grossed up for income taxes and other revenue-related items) of previously deferred state income taxes over a two-year period as a credit to customers. While the Company's cash collections from customers will be reduced by this amortization during the two-year period, the mitigation plan will have no impact on the Company's net income. Retail rates increased on October 1, 2011 and will increase on October 1, 2012 as the deferred state income tax balance is amortized.

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 will occur 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. For 2011, the Company deferred $0.1 million of operation and maintenance costs in Idaho.

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.

NOTE 20. SUPPLEMENTAL CASH FLOW INFORMATION (in thousands)

	2011	2010
Cash paid for interest	$63,876	$68,638
Cash paid for income taxes	$16,631	$10,641

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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	04/13/2012	End of 2011/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		(2,350,286)		
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value		(1,975,667)		
4	Total (lines 2 and 3)		(1,975,667)		
5	Balance of Account 219 at End of Preceding Quarter/Year		(4,325,953)		
6	Balance of Account 219 at Beginning of Current Year		(4,325,953)		
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value	134,046	(1,444,919)		
9	Total (lines 7 and 8)	134,046	(1,444,919)		
10	Balance of Account 219 at End of Current Quarter/Year	134,046	(5,770,872)		

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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			(2,350,286)		
2					
3			(1,975,667)		
4			(1,975,667)	92,424,690	90,449,023
5			(4,325,953)		
6			(4,325,953)		
7					
8			(1,310,873)		
9			(1,310,873)	100,223,872	98,912,999
10			(5,636,826)		

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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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)	3,864,957,269	2,917,785,393
4	Property Under Capital Leases	7,203,330	
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	3,872,160,599	2,917,785,393
9	Leased to Others		
10	Held for Future Use	4,764,240	4,548,660
11	Construction Work in Progress	78,182,230	53,960,320
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	3,955,107,069	2,976,294,373
14	Accum Prov for Depr, Amort, & Depl	1,333,212,160	1,021,837,476
15	Net Utility Plant (13 less 14)	2,621,894,909	1,954,456,897
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	1,305,984,420	1,012,217,392
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	27,227,740	9,620,084
22	Total In Service (18 thru 21)	1,333,212,160	1,021,837,476
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)	1,333,212,160	1,021,837,476

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
752,830,310				194,341,566	3
1,619,846				5,583,484	4
					5
					6
					7
754,450,156				199,925,050	8
					9
215,580					10
3,796,778				20,425,132	11
					12
758,462,514				220,350,182	13
257,685,142				53,689,542	14
500,777,372				166,660,640	15
					16
					17
256,805,796				36,961,232	18
					19
					20
879,346				16,728,310	21
257,685,142				53,689,542	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
257,685,142				53,689,542	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	04/13/2012	End of 2011/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	44,074,880	21,539
4	(303) Miscellaneous Intangible Plant	4,143,627	1,124,723
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	48,218,507	1,146,262
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	2,230,396	
9	(311) Structures and Improvements	125,140,461	591,757
10	(312) Boiler Plant Equipment	161,061,407	2,438,448
11	(313) Engines and Engine-Driven Generators		6,770
12	(314) Turbogenerator Units	48,281,086	4,584,801
13	(315) Accessory Electric Equipment	26,933,559	170,098
14	(316) Misc. Power Plant Equipment	15,654,982	271,689
15	(317) Asset Retirement Costs for Steam Production	585,275	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	379,887,166	8,063,563
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	56,519,848	812,384
28	(331) Structures and Improvements	42,301,445	1,038,076
29	(332) Reservoirs, Dams, and Waterways	119,976,644	2,755,135
30	(333) Water Wheels, Turbines, and Generators	149,576,061	9,796,679
31	(334) Accessory Electric Equipment	33,808,809	167,627
32	(335) Misc. Power PLant Equipment	7,336,556	755,858
33	(336) Roads, Railroads, and Bridges	1,999,562	
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	411,518,925	15,325,759
36	D. Other Production Plant		
37	(340) Land and Land Rights	905,168	
38	(341) Structures and Improvements	16,136,395	351,526
39	(342) Fuel Holders, Products, and Accessories	21,152,323	11,213
40	(343) Prime Movers	21,876,780	
41	(344) Generators	196,733,793	88,312
42	(345) Accessory Electric Equipment	16,776,704	558,873
43	(346) Misc. Power Plant Equipment	1,578,892	46,828
44	(347) Asset Retirement Costs for Other Production	351,683	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	275,511,738	1,056,752
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,066,917,829	24,446,074

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
	555,503		44,651,922		3
424,577	-555,503		4,288,270		4
424,577			48,940,192		5
					6
					7
	-1		2,230,395		8
51,777	-1		125,680,440		9
991,803			162,508,052		10
			6,770		11
1,609,494	1		51,256,394		12
9,843	1		27,093,815		13
24,650			15,902,021		14
			585,275		15
2,687,567			385,263,162		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			57,332,232		27
65,911			43,273,610		28
16,803	1		122,714,977		29
3,845,369			155,527,371		30
14,181			33,962,255		31
56,089	1		8,036,326		32
	1		1,999,563		33
					34
3,998,353	3		422,846,334		35
					36
	-1		905,167		37
	1		16,487,922		38
			21,163,536		39
	1		21,876,781		40
			196,822,105		41
407,118	1		16,928,460		42
	1		1,625,721		43
			351,683		44
407,118	3		276,161,375		45
7,093,038	6		1,084,270,871		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	04/13/2012	End of 2011/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	19,715,090	-463,241
49	(352) Structures and Improvements	16,585,558	191,955
50	(353) Station Equipment	192,799,947	12,363,687
51	(354) Towers and Fixtures	17,120,821	
52	(355) Poles and Fixtures	135,112,530	10,606,619
53	(356) Overhead Conductors and Devices	108,159,786	4,478,936
54	(357) Underground Conduit	2,605,488	
55	(358) Underground Conductors and Devices	2,330,071	
56	(359) Roads and Trails	1,872,245	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	496,301,536	27,177,956
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	5,421,664	1,015,426
61	(361) Structures and Improvements	14,521,649	3,147,114
62	(362) Station Equipment	97,095,752	10,983,315
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	229,311,309	15,245,912
65	(365) Overhead Conductors and Devices	151,716,380	12,168,713
66	(366) Underground Conduit	77,764,059	4,622,115
67	(367) Underground Conductors and Devices	129,764,215	7,211,295
68	(368) Line Transformers	178,517,769	16,202,328
69	(369) Services	120,176,772	3,530,447
70	(370) Meters	46,055,010	2,845,946
71	(371) Installations on Customer Premises		
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	31,767,549	2,959,546
74	(374) Asset Retirement Costs for Distribution Plant	129,707	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,082,241,835	79,932,157
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	124,681	260,372
87	(390) Structures and Improvements	3,588,759	2,162,163
88	(391) Office Furniture and Equipment	1,990,857	1,260,100
89	(392) Transportation Equipment	15,583,236	1,480,318
90	(393) Stores Equipment	390,377	4,952
91	(394) Tools, Shop and Garage Equipment	3,257,564	121,621
92	(395) Laboratory Equipment	1,127,660	
93	(396) Power Operated Equipment	34,906,066	624,284
94	(397) Communication Equipment	41,361,517	2,981,804
95	(398) Miscellaneous Equipment	8,468	4,784
96	SUBTOTAL (Enter Total of lines 86 thru 95)	102,339,185	8,900,398
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)	102,339,185	8,900,398
100	TOTAL (Accounts 101 and 106)	2,796,018,892	141,602,847
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)	2,796,018,892	141,602,847

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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
198			19,251,651		48
2	1		16,777,512		49
1,882,931	1		203,280,704		50
	-1		17,120,820		51
106,857	1		145,612,293		52
23,291	-1		112,615,430		53
			2,605,488		54
	1		2,330,072		55
	1		1,872,246		56
					57
2,013,279	3		521,466,216		58
					59
			6,437,090		60
	-1		17,668,762		61
2,542,958	1		105,536,110		62
					63
494,267			244,062,954		64
499,424			163,385,669		65
77,022			82,309,152		66
423,061	-1		136,552,448		67
2,970,698	1		191,749,400		68
74,876	-1		123,632,342		69
1,033,158			47,867,798		70
					71
					72
90,626			34,636,469		73
			129,707		74
8,206,090	-1		1,153,967,901		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			385,053		86
21,099			5,729,823		87
			3,250,957		88
555,575	-1		16,507,978		89
			395,329		90
180,883	-1		3,198,301		91
80,314	-1		1,047,345		92
915,836	-2		34,614,512		93
345,564	2		43,997,759		94
93	-3		13,156		95
2,099,364	-6		109,140,213		96
					97
					98
2,099,364	-6		109,140,213		99
19,836,348	2		2,917,785,393		100
					101
					102
					103
19,836,348	2		2,917,785,393		104

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	04/13/2012	End of 2011/Q4

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
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21	Other Property:			
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47	Total			4,548,660

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	04/13/2012	End of 2011/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	Transportation equipment	4,320,203
2	Spokane Smart Circuit	1,399,425
3	Moscow 230kv sub Rebuild 230kv yard	4,003,243
4	CS2 Capital Improvements	2,882,912
5	Noxon Rapids Unit 4 Runner Upgrade	4,561,285
6	Nine Mile Redevelopment	2,585,686
7	Moducom Replacement (RTCCS)	1,211,481
8	Clark Fork Implement PME Agreement	8,783,766
9	Spokane River Implementation (PM&E)	2,946,846
10	Thornton 230kv Switching Station Construct	1,642,396
11	Minor Projects (1198) under $1,000,000	16,613,151
12		
13		
14	Research Development and Demonstrating	
15	SGDP Pullman Smart Grid Demonstration Project	3,009,926
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43	TOTAL	53,960,320

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	04/13/2012	End of 2011/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	960,938,591	960,938,591		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	71,282,017	71,282,017		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	1,156,249	1,156,249		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	-268,781	-268,781		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	72,169,485	72,169,485		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	19,411,599	19,411,599		
13	Cost of Removal	4,694,867	4,694,867		
14	Salvage (Credit)	2,298,997	2,298,997		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	21,807,469	21,807,469		
16	Other Debit or Cr. Items (Describe, details in footnote):	916,785	916,785		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	1,012,217,392	1,012,217,392		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	264,325,752	264,325,752		
21	Nuclear Production				
22	Hydraulic Production-Conventional	107,230,789	107,230,789		
23	Hydraulic Production-Pumped Storage				
24	Other Production	70,362,789	70,362,789		
25	Transmission	174,033,587	174,033,587		
26	Distribution	348,254,793	348,254,793		
27	Regional Transmission and Market Operation				
28	General	48,009,683	48,009,683		
29	TOTAL (Enter Total of lines 20 thru 28)	1,012,217,393	1,012,217,393		

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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	04/13/2012	End of 2011/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		177,019,809
3	Avista Capital - Equity in Earnings			-100,908,756
4	OCI Investment in Subs			
5	Avista Capital - Other Changes in Net Investment			1,622,516
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42	Total Cost of Account 123.1 $ 0		TOTAL	77,733,569

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	04/13/2012	End of 2011/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
	-6,965,982	170,053,827		2
9,971,326	-10,509,950	-101,447,380		3
	134,045	134,045		4
	1,608,360	3,230,876		5
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9,971,326	-15,733,527	71,971,368		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	04/13/2012	End of 2011/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)	6,288,853	4,248,389	(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)	15,715,351	15,450,514	(1)
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	2,314,543	2,354,732	(1)
8	Transmission Plant (Estimated)	91,697	48,245	(1)
9	Distribution Plant (Estimated)	320,705	216,491	(1)
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	4,892,847	3,676,223	(1),(2)
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	23,335,143	21,746,205	
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)	29,623,996	25,994,594	

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

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

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	04/13/2012	End of 2011/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					
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21	**Generation Studies**				
22	Palouse Wind Interconnect	1,941	186210		
23	Deep Creek Interconnect	221	186210		
24	AVA Noxon Upgrade	40,214	186210		
25	Martinsdale Wind Interconnect	7,327	186210	2,578	
26	AVA Nine Mile Upgrade	946	186210		
27	Rattlesnake Flat Interconnect	323	186210		
28	Horizon Wind Interconnect	61,845	186210	27,345	
29	Lancaster L&L Interconnect	24,709	186210		
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Schedule Page: 231 Line No.: 22 Column: b

Total charges incurred life to date

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

Total charges incurred life to date

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

Total charges incurred life to date

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

Total charges incurred life to date

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

Total charges incurred life to date

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

Total charges incurred life to date

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

Total charges incurred life to date

Schedule Page: 231 Line No.: 29 Column: b

Total charges incurred life to date

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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	Balance at Beginning of Current Quarter/Year	Debits	CREDITS		Balance at end of Current Quarter/Year
				Written off During the Quarter/Year Account Charged	Written off During the Period Amount	
	(a)	(b)	(c)	(d)	(e)	(f)
1	Regulatory Asset FAS 106	945,504		926	472,752	472,752
2	Guaranteed Residual Value-Airplane					
3	Reg Asset Post Ret Liab	178,984,752	81,373,881			260,358,633
4	Regulatory Asset FAS109 Utility Plant	75,577,163		283	4,960,648	70,616,515
5	Regulatory Asset Lancaster Generation	6,686,667		407	1,360,000	5,326,667
6	Regulatory Asset FAS109 DSIT Non Plant	2,155,470		283	393,156	1,762,314
7	Regulatory Asset FAS109 DFIT State Tax Cr	6,051,287	618,402			6,669,689
8	Regulatory Asset FAS109 WNP3	6,391,322		283	737,503	5,653,819
9	Regulatory Asset Roseburg/Medford		142,470			142,470
10	Regulatory Asset- Spokane River Relicense	779,834		407	78,736	701,098
11	Regulatory Asset- Spokane River PM&E	722,510		557	73,312	649,198
12	Regulatory Asset- Lake CDA Fund	9,859,729		407	211,065	9,648,664
13	Regulatory Asset- Lake CDA IPA Fund	2,000,000				2,000,000
14	Reg Assets- Decouplings Surcharge	471,659		407	281,377	190,282
15	Regulatory Asset ID DSIT Amort	299,605		407	228,671	70,934
16	Regulatory Asset RTO Deposits- ID	70,805		560	70,805	
17	Regulatory Asset BPA Residential Exchange	663,953		254	559,317	104,636
18	Regulatory Asset- CNC Transmission		735,906			735,906
19	DEF CS2 & COLSTRIP		516,251	407	373,025	143,226
20	LiDAR O&M REG DEF		337,879			337,879
21	ID Wind Gen AFUDC	239,600	118,664			358,264
22	Regulatory Asset Wartsila Units	1,427,393		407	337,788	1,089,605
23	MTM St Regulatory Asset	48,891,073	20,793,570			69,684,643
24	MTM Lt Regulatory Asset	15,723,775	24,621,563			40,345,338
25	Regulatory Asset FAS143 Asset Retirement Obligation	3,065,031		230	347,542	2,717,489
26	Reg Asset AN- CDA Lake Settlement	40,385,976		407	1,199,436	39,186,540
27	Reg Asset WA-CDA Lake Settlement	1,508,506		407	152,118	1,356,388
28	Regulatory Asset Workers Comp	2,930,760		242	307,660	2,623,100
29	CS2 Lev Ret	1,444,359		407	194,260	1,250,099
30	Regulatory Asset ID PCA Deferral 1	14,738,444		557	14,738,444	
31	Regulatory Asset ID PCA Deferral 2	3,566,306		557	1,548,377	2,017,929
32	Regulatory Asset ID PCA Deferral 3			557	2,762,169	-2,762,169
33	Reg Asset-Future Payments- Lake CDA					
34	DSM Asset	4,251,311	798,418		4,251,311	798,418
35						
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43						
44	TOTAL	429,832,794	130,057,004		35,639,472	524,250,326

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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	04/13/2012	End of 2011/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		406		1,110,999
3	Regulatory Asset-Decoupling def	-44,776	24,924	407		-19,852
4	WA Deferred Power Costs		12,947,628		12,947,628	
5	Regulatory Asset RTO Deposit	79,107		560	79,107	
6	WA ERM YTD Contra Account	2,073,933		540	360,684	1,713,249
7	Regulatory Asset-Mt lease pymt	4,059,744		540	676,632	3,383,112
8	Colstrip Common Fac.	2,355,642		406		2,355,642
9	Prepaid airplane Lease LT	613,191			147,166	466,025
10	Misc DD- airplane lease cap	48,316	41,865			90,181
11	Plant Allocation of clearing jr	1,285,306		var	145,033	1,140,273
12	Misc DD- IR Swaps	52,705	18,842,438	var		18,895,143
13	Misc Error Suspense	440,253		var	435,028	5,225
14	Renewable Energy-Cert Fees	174,000				174,000
15	Nez Perce Settlement	171,173		557	5,212	165,961
16	Long Term Note Rec acct	559,428		143	349,959	209,469
17	Reg Asset ID-Lake Cdal	302,005		506	30,975	271,030
18	ID Panhandle Forest Use Permit	181,017				181,017
19	Credit Union Labor and Exp	61,111		var	35,349	25,762
20	Outdoor Lghtng Greenbelt Pathwy		65,248			65,248
21	Horizon Wind Interco	61,343	502			61,845
22	Insurance Recvy CDA Lake		320,932			320,932
23	KF Water Rights Supply		1,179,357			1,179,357
24	Reclass Idaho Clk Fork Relic	716,098			263,252	452,846
25	PG & E Canada to N Cal trans	886,173			886,173	
26	Misc Work Orders <$50,000	26,317		var	175,749	-149,432
27	Subsidiary Billings	33,376	9,076	var		42,452
28	"Null" Projects directly to 186	4,457	10,740	var		15,197
29	Regulatory Assets Consv	2,112,766		908	266,868	1,845,898
30	Regulatory Assets Consv			908	200	-200
31	Regulatory Assets Consv	51,263		908	51,263	
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47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	17,414,947				34,001,379

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	04/13/2012	End of 2011/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		11,937,146	9,302,194
3			
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	11,937,146	9,302,194
9	Gas		
10		777,990	1,056,690
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15	777,990	1,056,690
17	Other	107,272,905	143,049,536
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	119,988,041	153,408,420

Notes

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	04/13/2012	End of 2011/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		
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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	04/13/2012	End of 2011/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
58,422,781	832,413,930			93,482	2,155,695	2
						3
58,422,781	832,413,930			93,482	2,155,695	4
						5
						6
						7
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						9
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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	04/13/2012	End of 2011/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	11,686,949
2		
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40	TOTAL	11,686,949

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	04/13/2012	End of 2011/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	11,086,811
2		
3		
4		
5		
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7		
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19		
20		
21		
22	TOTAL	11,086,811

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

Capital Stock expense activity, 2011

Beginning Balance	(6,137,359)
Issuance of common stock	371,235
TAX BENEFIT - OPTIONS EXERCISED	1,036,587
Excess Tax Benefits on stock compensation	(1,113,753)
Stock compensation accrual	(5,243,519)
Ending Balance	(11,086,810)

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	04/13/2012	End of 2011/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	KETTLE FALLS P C REV BONDS DUE 14	4,100,000	135,855
7	ADVANCE ASSOCIATED-AVISTA CAPITAL II (ToPRS)	51,547,000	1,296,086
8	FMBS - 6.37% SERIES C	25,000,000	158,304
9	FMBS - 5.45% SERIES	90,000,000	1,432,081
10	FMBS - 6.25% SERIES	150,000,000	2,180,435
11	FMBS - 5.70% SERIES	150,000,000	4,924,304
12	FMBS - 5.95% SERIES	250,000,000	3,081,419
13	FMBS - 5.125% SERIES	250,000,000	2,859,788
14	COLSTRIP 2010A PCRBs DUE 2032	66,700,000	
15	COLSTRIP 2010B PCRBs DUE 2034	17,000,000	
16	FMBS - 1.68% SERIES	50,000,000	305,790
17	FMBS - 3.89% SERIES	52,000,000	383,338
18	FMBS - 5.55% SERIES	35,000,000	258,834
19	INTEREST RATE SWAPS		
20	SERIES C SET UP		666,169
21	4.45% SERIES DUE 12-14-2041	85,000,000	649,256
22	Reaquired Bonds COLSTRIP 2010A PCRBs DUE 2032	-66,700,000	
23	Reaquired Bonds COLSTRIP 2010B PCRBs DUE 2034	-17,000,000	
24			
25			
26			
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28			
29			
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31			
32			
33	TOTAL	1,228,647,000	18,661,462

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/Q4

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
07-29-1993	12-01-2023	07-29-1993	12-01-2023	4,100,000	246,000	6
06-03-1997	06-01-2037	06-03-1997	06-01-2037	51,547,000	622,458	7
06-19-1998	06-19-2028	06-19-1998	06-19-2028	25,000,000	1,592,500	8
11-18-2004	12-01-2019	11-18-2004	12-01-2019	90,000,000	4,905,000	9
11-17-2005	12-01-2035	11-17-2005	12-01-2035	150,000,000	9,375,000	10
12-15-2006	07-01-2037	12-15-2006	07-01-2037	150,000,000	8,550,000	11
04-02-2008	06-01-2018	04-02-2008	06-01-2018	250,000,000	14,875,000	12
09-22-2009	04-01-2022	09-22-2009	04-01-2022	250,000,000	12,812,500	13
12-15-2010	10-1-2032	12-15-2010	10-1-2032	66,700,000	829,054	14
12-15-2010	3-1-2034	12-15-2010	3-1-2034	17,000,000	211,303	15
12-30-2010	12-30-2013	12-30-2010	12-30-2013	50,000,000	840,000	16
12-20-2010	12-20-2020	12-20-2010	12-20-2020	52,000,000	2,022,800	17
12-20-2010	12-20-2040	12-20-2010	12-20-2040	35,000,000	1,942,500	18
Various	Various	Various	Various	-10,628,792		19
6-15-1998	6-15-2013	6-15-1998	6-15-2013			20
12-14-2011	12-14-2041	12-14-2011	12-14-2041	85,000,000	178,618	21
12-15-2010	10-1-2032	12-15-2010	10-1-2032	-66,700,000	-829,054	22
12-15-2010	3-1-2034	12-15-2010	3-1-2034	-17,000,000	-211,303	23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				1,218,018,208	60,626,576	33

Schedule Page: 256 Line No.: 7 Column: i

Variable long-term debt. The average interest rate in 2011 was 1.21%

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.: 15 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.: 15 Column: c

The Company reaquired these bonds in 2010.

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

These expenses are based on the current invoices. Additional invoices may be accumulated through 2012.

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	04/13/2012	End of 2011/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)	100,223,872
2		
3		
4	Taxable Income Not Reported on Books	
5		4,132,079
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		106,924,572
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		34,121,655
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		-205,490,170
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	79,554,340
28	Show Computation of Tax:	
29	State Tax	1,264,936
30	Federal Tax Net Income less State Tax	80,819,276
31		
32	Federal Tax @ 35%	28,286,746
33		
34	Prior Year & Misc True Ups	-5,843,978
35	Cabinet Gorge Tax Credits	-200,441
36		
37	Total Federal Tax Expense	22,242,327
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	04/13/2012	End of 2011/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 Prior	25,778,732				-25,778,732
3	Income Tax 2006	-26,489,010				26,489,010
4	Income Tax 2007	-1,183,314				1,183,314
5	Income Tax 2008	9,475,241				-9,475,241
6	Income Tax 2009	-5,697,255		87,118		5,491,947
7	Income Tax 2010	-11,724,719		573,685	-2,500,000	8,793,184
8	Income Tax (Current)			23,563,086	18,311,502	-15,215,558
9	Retained Earnings					
10	Prior Retained Earnings	-9,789,766				9,789,766
11	Prior Retained Earnings	-386,409		-960,169		-46,098
12	Current Retained Earnings			-2,070,474		-1,231,592
13	Total Federal	-20,016,500		21,193,246	15,811,502	
14						
15	STATE OF WASHINGTON:					
16	Property Tax (2009)	8,281		-8,281		
17	Property Tax (2010)	8,027,008		508,159	8,538,360	
18	Property Tax (2011)			9,704,000		
19	Excise Tax (2006)	-464		464		
20	Excise Tax (2007)	121,563		-121,563		
21	Excise Tax (2010)	2,581,941		13,233	2,616,669	-1,000
22	Excise Tax (2011)			24,690,035	22,105,004	
23	Natural Gas Use Tax	7,830		26,405	22,506	1,000
24	Municipal Occupation Tax	2,654,720		22,526,422	22,058,138	
25	Sales & Use Tax (2006)	-8,173				
26	Sales & Use Tax (2010)	49,548			49,548	
27	Sales & Use Tax (2011)			1,185,097	998,572	
28	Motor Vehicle Tax (2011)			4,514	4,514	
29	Total Washington	13,442,254		58,528,485	56,393,311	
30						
31	STATE OF IDAHO:					
32	Income Tax (2006)	346,389				-346,389
33	Income Tax (2007)	-104,516			-12,784	91,732
34	Income Tax (2008)	101,312				-101,312
35	Income Tax (2009)	-295,531			-295,531	
36	Income Tax (2010)	-306,681		21,104	-290,601	-9,657
37	Income Tax (2011)			527,976	625,000	355,969
38	Property Tax (2009)	1,647				
39	Property Tax (2010)	2,312,704			2,316,574	
40	Property Tax (2011)			5,227,764	2,595,826	
41	TOTAL	-397,450		106,828,455	98,138,661	

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	04/13/2012	End of 2011/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
						3
						4
						5
-118,190					87,118	6
142,150		1,464,873			-891,188	7
-9,963,974		23,369,204			193,882	8
						9
						10
-1,392,676					-960,169	11
-3,302,066					-2,070,474	12
-14,634,756		24,834,077			-3,640,831	13
						14
						15
		-8,512			231	16
-3,193		496,446			11,713	17
9,704,000		7,733,000			1,971,000	18
					464	19
					-121,563	20
-22,495		16,721			-3,488	21
2,585,031		18,311,100			6,378,935	22
12,729		5,916			20,489	23
3,123,004		16,742,746			5,783,676	24
-8,173						25
						26
186,525					1,185,097	27
					4,514	28
15,577,428		43,297,417			15,231,068	29
						30
						31
						32
						33
						34
						35
-4,633		-1,305			22,410	36
258,945		476,761			51,215	37
1,647						38
-3,870						39
2,631,938		4,333,356			894,408	40
8,292,344		87,120,442			19,708,015	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	04/13/2012	End of 2011/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	Motor Vehicle Tax (2011)			23,443	23,443	
2	Sales & Use Tax (2005)	436				
3	Sales & Use Tax (2009)	2				-2
4	Sales & Use Tax (2010)	7,942			7,942	
5	Sales & Use Tax (2011)			139,758	97,726	
6	Irrigation Credits (2011)			2,930	123	-2,808
7	KWH Tax (2010)	27,854		-3,237	24,618	
8	KWH Tax (2011)			415,997	395,292	
9	Franchise Tax (2010)	1,497,225			1,512,732	
10	Franchise Tax (2011)			4,515,253	2,885,371	
11	Total Idaho	3,588,783		10,870,988	9,885,731	-12,467
12						
13	STATE OF MONTANA:					
14	Income Tax (2006)	520,245				-520,245
15	Income Tax (2009)	-175				175
16	Income Tax (2010)	-173,349		4,599		-3,219
17	Income Tax (2011)			353,970	385,000	520,070
18	Property Tax (2009)	-430		430		
19	Property Tax (2010)	3,300,187		38	3,300,225	
20	Property Tax (2011)			6,929,022	3,474,789	
21	Colstrip Generation Tax			2,963	2,963	
22	KWH Tax (2010)	249,521			249,521	
23	KWH Tax (2011)			1,213,273	945,666	
24	Motor Vehicle Tax (2011)			1,350	1,350	
25	Consumer Council Tax	5,336		-386	4,944	
26	Public Commission Tax	9		44	43	
27	Total Montana	3,901,344		8,505,303	8,364,501	-3,219
28						
29	STATE OF OREGON:					
30	Income Tax (2006)	300,531				-300,531
31	Income Tax (2007)	-241,891			-11,629	
32	Income Tax (2008)	351,469				-351,469
33	Income Tax (2009)	-337,923				337,923
34	Income Tax (2010)	13,576		-182,250	-265,000	-5,007
35	Income Tax (2011)			467,672	395,000	314,077
36	Property Tax (2009)	426,658		-426,657		-1
37	Property Tax (2010)	-2,180,864		2,180,863	1,791,031	1
38	Property Tax (2011)			1,926,500	2,022,001	
39	Motor Vehicle Tax (2011)			1,138	1,138	
40	BETC Credit (2006 & Prior)	-420,805				420,805
41	TOTAL	-397,450		106,828,455	98,138,661	

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)	
					23,443	1
436						2
						3
						4
42,032					139,758	5
					2,931	6
1					-3,237	7
20,705		439,201			-23,204	8
-15,507						9
1,629,882		3,197,860			1,317,393	10
4,561,576		8,445,873			2,425,117	11
						12
						13
						14
						15
-171,969		4,599				16
489,040		353,970				17
		430				18
		38				19
3,454,233		6,928,306			716	20
		2,963				21
						22
267,607		1,213,273				23
					1,350	24
6		-342			-44	25
10					44	26
4,038,927		8,503,237			2,066	27
						28
						29
						30
-230,262						31
						32
						33
91,318		-27,995			-154,255	34
386,749		116,918			350,754	35
		-429,839			3,182	36
-1,791,031		1,355,254			825,609	37
-95,501		1,025,500			901,000	38
					1,138	39
						40
8,292,344		87,120,442			19,708,015	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	04/13/2012	End of 2011/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)	Adjustments (f)
1	BETC Credit (2007)	243,353				-243,353
2	BETC Credit (2008)	-40,383				40,383
3	BETC Credit (2009)	-92,178				92,178
4	BETC Credit (2010)	-68,844		70,292		
5	BETC Credit (2011)			-55,896		-310,013
6	Glendale Regulatory Cr. 2008	-210,889				
7	Glendate Regulatory Cr. 2009	70,289				
8	Franchise Tax (2010)	903,988			878,386	
9	Franchise Tax (2011)			3,813,595	2,910,513	
10	Total Oregon	-1,283,913		7,795,257	7,721,440	-5,007
11						
12	STATE OF CALIFORNIA:					
13	Income Tax (2005)	-5,211				5,211
14	Income Tax (2006)	-314				314
15	Income Tax (2009)	-800				800
16	Income Tax (2010)	-2,400		1,600		
17	Income Tax (2011)				1,600	-6,325
18	Total California	-8,725		1,600	1,600	
19						
20	MISCELLANEOUS STATES:					
21	Income Tax (2008)	-1				1
22	Income Tax (2010)	-17,884				17,884
23	Total Misc States	-17,885				17,885
24						
25	COUNTY & MUNICIPAL					
26	WA Renewable Energy			-65,567	-65,007	1
27	Misc.	-2,808		-857	25,583	2,807
28	Total County	-2,808		-66,424	-39,424	2,808
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	-397,450		106,828,455	98,138,661	

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	04/13/2012	End of 2011/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
						3
1,448					70,292	4
-365,909					-55,896	5
-210,889						6
70,289						7
25,602						8
903,082					3,813,595	9
-1,215,104		2,039,838			5,755,419	10
						11
						12
						13
						14
						15
-800					1,600	16
-7,925						17
-8,725					1,600	18
						19
						20
						21
						22
						23
						24
						25
-561					-65,567	26
-26,441					-857	27
-27,002					-66,424	28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
8,292,344		87,120,442			19,708,015	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	04/13/2012	End of 2011/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		7,564,178	190	2,602,228			
7							
8	TOTAL	7,564,178		2,602,228			
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Gas Propertry (100%	278,184			411	43,704	
11							
12	TOTAL PROPERTY	278,184				43,704	
13							
14							
15							
16							
17							
18							
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48							

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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
10,166,406			6
			7
10,166,406			8
			9
234,480			10
			11
234,480			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
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			47
			48

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	04/13/2012	End of 2011/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)	2,249,960	495	749,960		1,500,000
2						
3	Centralia Environmental (253110)					
4	Rathdrum Refund (253120)	307,220	550	33,822		273,398
5	NE Tank Spil (253130)	87,106	186	16,739		70,367
6	Bills Pole Rentals (253140)	223,141			33,964	257,105
7	CR-CS2 GE LTSA (253150)					
8	DOC EECE Grant (253155)	900,017	136	49,762		850,255
9	DOC EECE Admin Fee (253160)	100,000	184	100,000		
10	IR Swaps (254170)	126,864	176	126,864		
11						
12	Sale/Leaseback on Bldg (253850)	261,456	931	261,456		
13	ID Clark Fork Relic (253890)			716,098	263,251	-452,847
14	Defer Comp Retired Execs (253900)	93,956	431	14,298		79,658
15	Defer Comp Active Execs (253910)	9,285,113	128	632,369		8,652,744
16	Executive Incent Plan (253920)	140,000				140,000
17	Unbilled Revenue (253990)	3,275,900	908	1,462,907		1,812,993
18	Idaho Clark Fork (253890)				452,846	452,846
19	WA Energy Recovery Mechanism				12,947,628	12,947,628
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
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41						
42						
43						
44						
45						
46						
47	TOTAL	17,050,733		4,164,275	13,697,689	26,584,147

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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	04/13/2012	End of 2011/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	253,937,772	12,716,918	
3	Gas	87,786,031	4,392,566	
4	Other	27,898,329	19,871,688	
5	TOTAL (Enter Total of lines 2 thru 4)	369,622,132	36,981,172	
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	369,622,132	36,981,172	
10	Classification of TOTAL			
11	Federal Income Tax	358,555,809	36,981,172	
12	State Income Tax	11,066,323		
13	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) 04/13/2012	Year/Period of Report End of 2011/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
			-2,837,591			269,492,281	2
			-4,270,208			96,448,805	3
-139,667					-15,071,143	32,559,207	4
-139,667			-7,107,799		-15,071,143	398,500,293	5
							6
							7
							8
-139,667			-7,107,799		-15,071,143	398,500,293	9
							10
-139,667			-7,107,799		-15,071,143	387,433,970	11
						11,066,323	12
							13

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	04/13/2012	End of 2011/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)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Electric	45,150,364	-14,360,567	512,038
4		-1,259,488		
5		402,332		
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	44,293,208	-14,360,567	512,038
10	Gas			
11	Gas	-7,377,179	3,589,665	
12		-21,363		
13		-69,458		
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	-7,468,000	3,589,665	
18	Other	203,467,585	1,762,403	
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	240,292,793	-9,008,499	512,038
20	Classification of TOTAL			
21	Federal Income Tax	236,058,987	-9,008,499	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) 04/13/2012	Year/Period of Report End of 2011/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.
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	(k)	
							1
							2
-30,191			737,503			29,510,065	3
						-1,259,488	4
						402,332	5
							6
							7
							8
-30,191			737,503			28,652,909	9
							10
					-6,579	-3,794,093	11
						-21,363	12
						-69,458	13
							14
							15
							16
					-6,579	-3,884,914	17
	4,395,661		-34,042,198			234,876,525	18
-30,191	4,395,661		-33,304,695		-6,579	259,644,520	19
							20
-30,191	4,395,661		-33,304,695		-6,579	255,410,714	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	04/13/2012	End of 2011/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 (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS: Account Credited (c)	DEBITS: Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Idaho Investment Tax Credit (254005)	11,133,372			1,183,371	12,316,743
2	Oregon BETC Credit (254010)	104,733	190	34,911		69,822
3	Noxon, ITC (254025)	2,036,509			700,599	2,737,108
4	Defer Gas Exchange (254028)					
5	Oregon Commercial Fee (254120)	116,233	805	116,888		-655
6	FAS 109 Invest Credit (254180)	149,784	190	23,532		126,252
7	Nez Perce (254220)	726,380	557	22,008		704,372
8	Oregon Senate Bill (254250)	2,544,937	407	1,773,345		771,592
9	Reg liability CCX CR ID (254300)					
10	Accrue Lake CDA IPA int (254325)					
11	Idaho DSIT Amort	14,713,202	407	11,229,728		3,483,474
12	BPA Res Exch Regulatory Liab (254345)				178,328	178,328
13	Unrealized Currency Exchange (254399)	26,289	143	15,192		11,097
14	Reg Liability Other (254700)					
15	Mark to Market ST (254740)	(5,878)			31,346	25,468
16	Mark to Market FAS133 (254750)					
17	Colstrip/CS2				516,251	516,251
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
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37						
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39						
40						
41	TOTAL	31,545,561		13,215,604	2,609,895	20,939,852

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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	04/13/2012	End of 2011/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	324,834,634	296,626,659
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	280,139,238	265,219,243
5	Large (or Ind.) (See Instr. 4)	122,559,992	114,792,344
6	(444) Public Street and Highway Lighting	6,940,809	6,702,211
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales	1,037,295	999,779
10	TOTAL Sales to Ultimate Consumers	735,511,968	684,340,236
11	(447) Sales for Resale	118,011,777	256,319,131
12	TOTAL Sales of Electricity	853,523,745	940,659,367
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	853,523,745	940,659,367
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	572,046	567,270
18	(453) Sales of Water and Water Power	506,582	281,752
19	(454) Rent from Electric Property	2,880,894	2,797,559
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	183,611,801	113,233,443
22	(456.1) Revenues from Transmission of Electricity of Others	12,755,612	12,414,756
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	200,326,935	129,294,780
27	TOTAL Electric Operating Revenues	1,053,850,680	1,069,954,147

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
3,728,029	3,618,328	316,763	315,282	2
				3
3,122,058	3,100,156	39,618	39,489	4
2,147,014	2,099,333	1,380	1,376	5
25,828	26,114	455	449	6
				7
				8
12,204	12,458	87	86	9
9,035,133	8,856,389	358,303	356,682	10
4,084,890	6,251,508			11
13,120,023	15,107,897	358,303	356,682	12
				13
13,120,023	15,107,897	358,303	356,682	14

Line 12, column (b) includes $ -1,974,338 of unbilled revenues.

Line 12, column (d) includes -23,780 MWH relating to unbilled revenues

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	04/13/2012	End of 2011/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	3,590,480	301,314,506	302,039	11,887	0.0839
3	2 Residential Service					
4	3 Residential Service					
5	12 Res. & Farm Gen. Service	71,405	8,703,605	12,882	5,543	0.1219
6	15 MOPS II Residential					
7	22 Res. & Farm Lg. Gen. Service	61,828	4,904,594	110	562,073	0.0793
8	30 Pumping-Special					
9	32 Res. & Farm Pumping Service	13,475	1,219,906	1,732	7,780	0.0905
10	48 Res. & Farm Area Lighting	4,510	1,083,580			0.2403
11	49 Area Lighting-High-Press.	263	76,345			0.2903
12	56 Centralia Refund					
13	95 Wind Power		169,006			
14	72 Residential Service					
15	73 Residential Service					
16	74 Residential Service					
17	76 Residential Service					
18	77 Residential Service					
19	58A Tax Adjustment		-48,199			
20	58 Tax Adjustment		8,832,778			
21	SubTotal	3,741,961	326,256,121	316,763	11,813	0.0872
22	Residential-Unbilled	-13,932	-1,421,487			0.1020
23	Total Residential Sales	3,728,029	324,834,634	316,763	11,769	0.0871
24						
25	COMMERCIAL SALES (442)					
26	2 General Service					
27	3 General Service					
28	11 General Service	687,787	73,870,251	34,406	19,990	0.1074
29	12 Res. & Farm Gen. Service					
30	16 MOPS II Commercial					
31	19 Contract-General Service					
32	21 Large General Service	1,994,021	167,113,070	4,121	483,868	0.0838
33	25 Extra Lg. Gen. Service	350,677	20,553,796	13	26,975,154	0.0586
34	28 Contract-Extra Large Serv					
35	31 Pumping Service	90,239	7,107,213	1,078	83,710	0.0788
36	47 Area Lighting-Sod. Vap	6,405	1,361,962			0.2126
37	49 Area Lighting-High-Press.	2,429	547,547			0.2254
38	56 Centralia Refune					
39	95 Wind Power		79,387			
40	74 Large General Service					
41	TOTAL Billed	13,143,803	855,498,083	358,303	36,683	0.0651
42	Total Unbilled Rev.(See Instr. 6)	-23,780	-1,974,338	0	0	0.0830
43	TOTAL	13,120,023	853,523,745	358,303	36,617	0.0651

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	04/13/2012	End of 2011/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		-46,188			
5	58 Tax Adjustment		10,012,254			
6	SubTotal	3,131,558	280,599,292	39,618	79,044	0.0896
7	Commercial-Unbilled	-9,500	-460,054			0.0484
8	Total Commercial	3,122,058	280,139,238	39,618	78,804	0.0897
9						
10	INDUSTRIAL SALES (442)					
11	2 General Service					
12	3 General Service					
13	8 Lg Gen Time of Use					
14	11 General Service	7,218	804,378	240	30,075	0.1114
15	12 Res. & Farm Gen. Service					
16	21 Large General Service	176,431	14,368,712	176	1,002,449	0.0814
17	25 Extra Lg. Gen. Service	1,887,175	100,473,589	18	104,843,056	0.0532
18	28 Contract - Extra Large Service	555	272,978	1	555,000	0.4919
19	29 Contract Lg. Gen. Service					
20	30 Pumping Service - Special	20,570	1,360,444	33	623,333	0.0661
21	31 Pumping Service	51,160	4,313,597	764	66,963	0.0843
22	32 Pumping Svc Res & Firm	3,979	329,798	148	26,885	0.0829
23	47 Area Lighting-Sod. Vap.	244	49,051			0.2010
24	49 Area Lighting - High-Press	55	11,142			0.2026
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		-1,145			
33	58 Tax Adjustment		691,517			
34	SubTotal	2,147,387	122,675,789	1,380	1,556,078	0.0571
35	Industrial-Unbilled	-373	-115,797			0.3104
36	Total Industrial	2,147,014	122,559,992	1,380	1,555,807	0.0571
37						
38	STREET AND HWY LIGHTING (444)					
39	6 Mercury Vapor St. Ltg.					
40	7 HP Sodium Vap. St. Ltg					
41	TOTAL Billed	13,143,803	855,498,083	358,303	36,683	0.0651
42	Total Unbilled Rev.(See Instr. 6)	-23,780	-1,974,338	0	0	0.0830
43	TOTAL	13,120,023	853,523,745	358,303	36,617	0.0651

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	04/13/2012	End of 2011/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	35	3,831	1	35,000	0.1095
2	41 Co-Owned St. Lt. Service	221	41,186	16	13,813	0.1864
3	42 Co-Owned St. Lt. Service	20,522	6,273,012	374	54,872	0.3057
4	High-Press. Sod. Vap.					
5	43 Cust-Owned St. Lt. Energy	9	870	1	9,000	0.0967
6	and Maint. Service					
7	44 Cust-Owned St. Lt. Energy	848	126,664	28	30,286	0.1494
8	and Maint. Svce - High-Pres					
9	Sodium Vapor					
10	45 Cust. Owned St. Lt. Energy Svc	1,342	90,896	6	223,667	0.0677
11	46 Cust. Owned St. Lt. Energy Svc	2,826	256,418	29	97,448	0.0907
12	58A Tax Adjustment		-658			
13	58 Tax Adjustment		125,590			
14	SubTotal	25,803	6,917,809	455	56,710	0.2681
15	Street & Hwy Lighting-Unbilled	25	23,000			0.9200
16	Total Street & Hwy Lighting	25,828	6,940,809	455	56,765	0.2687
17						
18	OTHER SALES TO PUBLIC					
19	(445)					
20	None					
21						
22	INTERDEPARTMENTAL SALES	12,204	1,037,295	87	140,276	0.0850
23	58 Tax Adjustment					
24	Total Interdepartmental	12,204	1,037,295	87	140,276	0.0850
25						
26	SALES FOR RESALE (447)					
27	61 Sales to Other Utilities (NDA)	4,084,890	118,011,777			0.0289
28						
29						
30	Total Sales for Resale	4,084,890	118,011,777			0.0289
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	13,143,803	855,498,083	358,303	36,683	0.0651
42	Total Unbilled Rev.(See Instr. 6)	-23,780	-1,974,338	0	0	0.0830
43	TOTAL	13,120,023	853,523,745	358,303	36,617	0.0651

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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	04/13/2012	End of 2011/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 long-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	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	BNP Paribas Energy Trading GP	SF	Tariff 9			
2	BP Corporation North America, Inc.	SF	ISDA			
3	BP Energy Company	SF	Tariff 9			
4	Barclays Bank PLC	SF	Tariff 9			
5	Barclays Bank PLC	SF	ISDA			
6	Black Hills Power, Inc.	SF	Tariff 9			
7	Bonneville Power Administration	LF	Tariff 8			
8	Bonneville Power Administration	LF	ACS-06			
9	Bonneville Power Administration	IF	ACS-06			
10	Bonneville Power Administration	IF	ACS-06			
11	Bonneville Power Administration	SF	Tariff 8			
12	Bonneville Power Administration	SF	Tariff 8			
13	Bonneville Power Administration	SF	Tariff 9			
14	Bonneville Power Administration	LF	Tariff 12			
	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	04/13/2012	End of 2011/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,line 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.
2,000		27,750		27,750	1
			1,914,104	1,914,104	2
163,879		4,088,552		4,088,552	3
12,600		418,200		418,200	4
			1,516,245	1,516,245	5
2,000		63,600		63,600	6
36,646		984,595		984,595	7
5,242		119,889		119,889	8
586		16,625		16,625	9
323		5,639		5,639	10
136		6,086		6,086	11
216		3,584		3,584	12
59,988		1,679,184		1,679,184	13
47		1,283		1,283	14
0	0	0	0	0	
4,084,890	3,831,927	90,494,503	23,685,347	118,011,777	
4,084,890	**3,831,927**	**90,494,503**	**23,685,347**	**118,011,777**	

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	04/13/2012	End of 2011/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 long-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	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	Burbank, City of	SF	Tariff 9			
2	Cargill Power Markets, LLC	SF	Tariff 9			
3	Cargill Power Markets, LLC	SF	ISDA			
4	Chelan County PUD No. 1	SF	Tariff 9			
5	Citigroup Energy, Inc.	SF	Tariff 9			
6	Clark County PUD No. 1	SF	Tariff 9			
7	Clatskanie Peoples PUD	SF	Tariff 9			
8	Conoco Phillips	SF	Tariff 9			
9	Conoco Phillips	SF	Tariff 9			
10	DB Energy Trading, LLC	SF	Tariff 9			
11	Douglas County PUD No. 1	SF	Tariff 9			
12	EDF Trading North America	SF	Tariff 9			
13	Eugene Water & Electric Board	SF	Tariff 9			
14	Exelon Generation Company, LLC	SF	Tariff 9			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE: Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
1,200		13,800		13,800	1
101,108		2,983,870		2,983,870	2
			40,880	40,880	3
3,200		89,100		89,100	4
280,649		8,043,419		8,043,419	5
3,505		96,085		96,085	6
1,407		38,881		38,881	7
10		301		301	8
	122,640			122,640	9
50,250		1,496,328		1,496,328	10
6,367		182,450		182,450	11
132,259		2,854,423		2,854,423	12
11,230		347,775		347,775	13
14,977		461,361		461,361	14
0	0	0	0	0	
4,084,890	3,831,927	90,494,503	23,685,347	118,011,777	
4,084,890	**3,831,927**	**90,494,503**	**23,685,347**	**118,011,777**	

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	04/13/2012	End of 2011/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 long-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	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	Grant County PUD No. 2	SF	Tariff 9			
2	Grant County PUD No. 2	LF	Tariff 12			
3	Grant County PUD No. 2	SF	Tariff 9			
4	Iberdrola Renewables, Inc.	SF	Tariff 9			
5	Iberdrola Renewables, Inc.	SF	Tariff 9			
6	Idaho Power Company	SF	Tariff 9			
7	Idaho Power Company	LF	Tariff 12			
8	J. Aron & Company	SF	Tariff 9			
9	JP Morgan Ventures Energy	SF	Tariff 9			
10	JP Morgan Ventures Energy	SF	ISDA			
11	Macquarie Energy, LLC	SF	Tariff 9			
12	Modesto Irrigation District	SF	Tariff 9			
13	Morgan Stanley Capital Group, Inc.	SF	ISDA			
14	Morgan Stanley Capital Group, Inc.	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) 04/13/2012	Year/Period of Report End of 2011/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,line 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.
16,739		428,726		428,726	1
10		290		290	2
	4,490			4,490	3
427,490		9,421,223		9,421,223	4
	16,028			16,028	5
12,685		368,257		368,257	6
24		738		738	7
1,600		43,300		43,300	8
44,119		598,870		598,870	9
			8,058	8,058	10
138,335		3,850,381		3,850,381	11
14,018		288,942		288,942	12
224,401		5,594,465		5,594,465	13
			556,480	556,480	14
0	0	0	0	0	
4,084,890	3,831,927	90,494,503	23,685,347	118,011,777	
4,084,890	**3,831,927**	**90,494,503**	**23,685,347**	**118,011,777**	

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	04/13/2012	End of 2011/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	NaturEner Power Watch, LLC	SF	Tariff 9			
2	NaturEner Power Watch, LLC	LF	Tariff 12			
3	NaturEner Power Watch, LLC	SF	Tariff 9			
4	NaturEner Power Watch, LLC	SF	Tariff 9			
5	NaturEner Power Watch, LLC	SF	Tariff 9			
6	Newedge USA, LLC	SF	ISDA			
7	Northpoint Energy Solutions, Inc.	SF	Tariff 9			
8	NorthWestern Energy LLC	SF	Tariff 10			
9	NorthWestern Energy LLC	SF	Tariff 10			
10	NorthWestern Energy LLC	SF	Tariff 9			
11	NorthWestern Energy LLC	SF	Tariff 9			
12	NorthWestern Energy LLC	LF	Tariff 12			
13	NorthWestern Energy LLC	LF	Tariff 9			
14	NorthWestern Energy LLC	SF	Tariff 10			
	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	04/13/2012	End of 2011/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,line 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.
15,172		366,432		366,432	1
21		433		433	2
	190,508			190,508	3
	443,158			443,158	4
	10,134			10,134	5
			1,954,135	1,954,135	6
1,400		25,300		25,300	7
	250,968			250,968	8
			66,615	66,615	9
10		212		212	10
86,427		1,809,278		1,809,278	11
62		2,017		2,017	12
8,060		180,206		180,206	13
	493,631			493,631	14
0	0	0	0	0	
4,084,890	3,831,927	90,494,503	23,685,347	118,011,777	
4,084,890	**3,831,927**	**90,494,503**	**23,685,347**	**118,011,777**	

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	04/13/2012	End of 2011/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	Okanogan County PUD	SF	Tariff 9			
2	Pacific NW Generating Coop	SF	Tariff 9			
3	PacifiCorp	SF	Tariff 9			
4	PacifiCorp	LF	Tariff 12			
5	PacifiCorp	LF	Tariff 9			
6	Peaker LLC	LF	Tariff 9			
7	Pend Oreille Public Utility District	LF	Tariff 10			
8	Pend Oreille Public Utility District	LF	Tariff 9			
9	Pend Oreille Public Utility District	SF	Tariff 9			
10	Pend Oreille Public Utility District	LF	Tariff10			
11	Portland General Electric Company	SF	Tariff 9			
12	Portland General Electric Company	LF	Tariff 12			
13	Powerex	SF	Tariff 9			
14	PPL EnergyPlus, LLC	SF	Tariff 10			
	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	04/13/2012	End of 2011/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,line 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.
1,360		41,030		41,030	1
1,607		49,181		49,181	2
135,090		2,823,870		2,823,870	3
220		6,180		6,180	4
5,129		114,677		114,677	5
	1,752,215			1,752,215	6
	429,634			429,634	7
12,424		310,335		310,335	8
44,749		1,097,662		1,097,662	9
	25,592			25,592	10
63,934		1,878,106		1,878,106	11
44		1,260		1,260	12
140,882		3,547,303		3,547,303	13
	3,340			3,340	14
0	0	0	0	0	
4,084,890	3,831,927	90,494,503	23,685,347	118,011,777	
4,084,890	**3,831,927**	**90,494,503**	**23,685,347**	**118,011,777**	

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	04/13/2012	End of 2011/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	PPL EnergyPlus, LLC	SF	Tariff 9			
2	PPL EnergyPlus, LLC	LF	Tariff 9			
3	Public Service of Colorado	SF	Tariff 9			
4	Puget Sound Energy	LF	Tariff 9			
5	Puget Sound Energy	SF	Tariff 9			
6	Puget Sound Energy	LF	Tariff 12			
7	Rainbow Energy Marketing	SF	Tariff 9			
8	Sacramento Municipal Utility District	SF	Tariff 9			
9	Sacramento Municipal Utility District	LF	Tariff 12			
10	Sacramento Municipal Utility District	LF	Tariff 9			
11	San Diego Gas & Electric Company	SF	Tariff 9			
12	Seattle City Light	SF	Tariff 9			
13	Shell Energy N.A.	SF	Tariff 9			
14	Shell Energy N.A.	SF	ISDA			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,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.
106,190		3,170,650		3,170,650	1
18,319		409,559		409,559	2
5,400		65,554		65,554	3
23,448		524,236		524,236	4
93,895		2,611,700		2,611,700	5
33		1,053		1,053	6
46,504		1,043,215		1,043,215	7
46,693		1,154,473		1,154,473	8
21		241		241	9
631,511		22,439,158		22,439,158	10
12,199		71,125		71,125	11
20,749		419,830		419,830	12
400,968		9,293,732		9,293,732	13
			-182,108	-182,108	14
0	0	0	0	0	
4,084,890	3,831,927	90,494,503	23,685,347	118,011,777	
4,084,890	**3,831,927**	**90,494,503**	**23,685,347**	**118,011,777**	

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	04/13/2012	End of 2011/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 Classifi-cation	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	Shell Energy N.A.	SF	Tariff 9			
2	Sierra Pacific Power Company	SF	Tariff 9			
3	Sierra Pacific Power Company	LF	Tariff 12			
4	Silicon Valley Power	SF	Tariff 9			
5	Snohomish County PUD	SF	Tariff 9			
6	Sovereign Power	LF	Tariff 10			
7	Sovereign Power	LF	Tariff 9			
8	Tacoma Power	SF	Tariff 9			
9	Tacoma Power	SF	Tariff 10			
10	Tenaska Power Services Co.	SF	Tariff 9			
11	The Energy Authority	SF	Tariff 9			
12	TransAlta Energy Marketing	SF	Tariff 9			
13	Turlock Irrigation District	SF	Tariff 9			
14	IntraCompany Wheeling	LF				
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,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.
	10,320			10,320	1
36,015		672,723		672,723	2
42		1,304		1,304	3
400		130		130	4
13,415		382,500		382,500	5
	78,469			78,469	6
14,159		311,020		311,020	7
22,742		322,997		322,997	8
	800			800	9
1,602		45,191		45,191	10
15,206		448,834		448,834	11
288,545		7,383,370		7,383,370	12
998		16,501		16,501	13
		-17,166,047	17,166,047		14
0	0	0	0	0	
4,084,890	3,831,927	90,494,503	23,685,347	118,011,777	
4,084,890	**3,831,927**	**90,494,503**	**23,685,347**	**118,011,777**	

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	04/13/2012	End of 2011/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	IntraCompany Generation	LF				
2	Revenue Adjustment	AD				
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

SALES FOR RESALE (Account 447) (Continued)

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

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

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
			644,891	644,891	1
-1					2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
0	0	0	0	0	
4,084,890	3,831,927	90,494,503	23,685,347	118,011,777	
4,084,890	**3,831,927**	**90,494,503**	**23,685,347**	**118,011,777**	

Name of Respondent Avista Corporation	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report 2011/Q4

FOOTNOTE DATA

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

Schedule Page: 310 Line No.: 5 Column: b
SWAP

Schedule Page: 310 Line No.: 7 Column: b
BPA Contract Terminates September 30, 2028.

Schedule Page: 310 Line No.: 8 Column: b
BPA Contract Terminates January 1, 2036.

Schedule Page: 310 Line No.: 14 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.1 Line No.: 3 Column: b
SWAP

Schedule Page: 310.2 Line No.: 2 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.2 Line No.: 5 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.: 14 Column: b
SWAP

Schedule Page: 310.3 Line No.: 2 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.3 Line No.: 4 Column: b
Capacity

Schedule Page: 310.3 Line No.: 5 Column: b
Capacity

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

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

Schedule Page: 310.3 Line No.: 9 Column: b
Bundled Transmission

Schedule Page: 310.3 Line No.: 12 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.3 Line No.: 13 Column: b
NorthWestern Energy LLC sale expires October 31, 2013.

Schedule Page: 310.4 Line No.: 4 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.4 Line No.: 5 Column: b
PacifiCorp sale terminates October 31, 2013.

Schedule Page: 310.4 Line No.: 6 Column: b
Peaker, LLC capacity contract terminates December 31, 2016.

Schedule Page: 310.4 Line No.: 7 Column: b
Contract expires 9/30/2014.

Schedule Page: 310.4 Line No.: 8 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
NWPP Reserve Sharing Sales

Schedule Page: 310.5 Line No.: 2 Column: b
PPL sale terminates October 31, 2013.

FOOTNOTE DATA

Schedule Page: 310.5 Line No.: 4 Column: b

Puget Sound Energy sale terminates October 31, 2013.

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

NWPP Reserve Sharing Sales

Schedule Page: 310.5 Line No.: 9 Column: b

NWPP Reserve Sharing Sales

Schedule Page: 310.5 Line No.: 10 Column: b

Contract expires 2014.

Schedule Page: 310.5 Line No.: 14 Column: b

SWAP

Schedule Page: 310.6 Line No.: 3 Column: b

NWPP Reserve Sharing Sales

Schedule Page: 310.6 Line No.: 6 Column: b

Sovereign Power contract terminates 1-31-2015

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

Sovereign Power Contract terminates 1-31-2015

Schedule Page: 310.6 Line No.: 14 Column: a

Intracompany Wheeling

Schedule Page: 310.6 Line No.: 14 Column: b

IntraCompany Wheeling terminates 09/30/2023.

Schedule Page: 310.7 Line No.: 1 Column: a

Intracompany Generation - Sale of Ancillary Services

Schedule Page: 310.7 Line No.: 1 Column: b

IntraCompany Generation - Sale of Ancillary Services.

Schedule Page: 310.7 Line No.: 2 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	04/13/2012	End of 2011/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	502,678	536,766
5	(501) Fuel	31,254,162	28,352,582
6	(502) Steam Expenses	4,303,460	4,265,708
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	910,212	838,347
10	(506) Miscellaneous Steam Power Expenses	2,398,191	2,468,855
11	(507) Rents	32,398	15,498
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	39,401,101	36,477,756
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	587,143	501,359
16	(511) Maintenance of Structures	723,510	610,113
17	(512) Maintenance of Boiler Plant	6,088,972	4,899,998
18	(513) Maintenance of Electric Plant	1,401,570	645,697
19	(514) Maintenance of Miscellaneous Steam Plant	852,347	661,490
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	9,653,542	7,318,657
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	49,054,643	43,796,413
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	2,576,301	2,349,973
45	(536) Water for Power	1,118,184	900,793
46	(537) Hydraulic Expenses	7,340,213	5,932,977
47	(538) Electric Expenses	5,780,431	5,726,408
48	(539) Miscellaneous Hydraulic Power Generation Expenses	703,631	733,429
49	(540) Rents	6,605,536	6,529,629
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	24,124,296	22,173,209
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	557,119	376,904
54	(542) Maintenance of Structures	420,759	522,921
55	(543) Maintenance of Reservoirs, Dams, and Waterways	2,953,754	1,290,854
56	(544) Maintenance of Electric Plant	2,343,586	1,789,839
57	(545) Maintenance of Miscellaneous Hydraulic Plant	503,926	177,024
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	6,779,144	4,157,542
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	30,903,440	26,330,751

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	04/13/2012	End of 2011/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	1,438,316	873,063
63	(547) Fuel	54,982,069	115,449,329
64	(548) Generation Expenses	1,077,281	2,463,056
65	(549) Miscellaneous Other Power Generation Expenses	570,980	505,589
66	(550) Rents	-31,837	33,433
67	TOTAL Operation (Enter Total of lines 62 thru 66)	58,036,809	119,324,470
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	680,635	798,646
70	(552) Maintenance of Structures	12,248	8,426
71	(553) Maintenance of Generating and Electric Plant	1,480,762	1,691,146
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	154,760	116,403
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	2,328,405	2,614,621
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	60,365,214	121,939,091
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	209,550,746	277,079,128
77	(556) System Control and Load Dispatching	714,621	555,351
78	(557) Other Expenses	228,635,614	126,323,056
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	438,900,981	403,957,535
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	579,224,278	596,023,790
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,091,494	2,210,636
84	(561) Load Dispatching	2,230,033	2,192,996
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate 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	318,511	272,063
94	(563) Overhead Lines Expenses	518,176	447,185
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	17,489,619	17,742,126
97	(566) Miscellaneous Transmission Expenses	1,679,342	1,617,125
98	(567) Rents	127,552	120,946
99	TOTAL Operation (Enter Total of lines 83 thru 98)	24,454,727	24,603,077
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	1,313,699	665,430
102	(569) Maintenance of Structures	426,540	275,169
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	1,146,932	1,157,114
108	(571) Maintenance of Overhead Lines	2,405,427	1,751,805
109	(572) Maintenance of Underground Lines	1,731	11,590
110	(573) Maintenance of Miscellaneous Transmission Plant	28,956	-2,754
111	TOTAL Maintenance (Total of lines 101 thru 110)	5,323,285	3,858,354
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	29,778,012	28,461,431

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	04/13/2012	End of 2011/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	1,845,376	1,495,137
135	(581) Load Dispatching		
136	(582) Station Expenses	697,949	715,019
137	(583) Overhead Line Expenses	1,798,684	1,402,987
138	(584) Underground Line Expenses	-183,983	581,320
139	(585) Street Lighting and Signal System Expenses	273,778	226,745
140	(586) Meter Expenses	1,873,149	1,773,001
141	(587) Customer Installations Expenses	740,863	790,470
142	(588) Miscellaneous Expenses	7,032,031	6,426,792
143	(589) Rents	262,304	294,788
144	TOTAL Operation (Enter Total of lines 134 thru 143)	14,340,151	13,706,259
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	1,148,214	1,261,570
147	(591) Maintenance of Structures	343,805	396,786
148	(592) Maintenance of Station Equipment	833,760	785,071
149	(593) Maintenance of Overhead Lines	8,049,756	7,948,732
150	(594) Maintenance of Underground Lines	1,021,119	845,853
151	(595) Maintenance of Line Transformers	2,832,509	1,094,896
152	(596) Maintenance of Street Lighting and Signal Systems	598,658	652,322
153	(597) Maintenance of Meters	102,477	138,937
154	(598) Maintenance of Miscellaneous Distribution Plant	493,719	270,915
155	TOTAL Maintenance (Total of lines 146 thru 154)	15,424,017	13,395,082
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	29,764,168	27,101,341
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	633,265	592,956
160	(902) Meter Reading Expenses	2,827,145	2,739,310
161	(903) Customer Records and Collection Expenses	8,056,519	7,798,575
162	(904) Uncollectible Accounts	2,631,760	1,674,638
163	(905) Miscellaneous Customer Accounts Expenses	138,558	131,019
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	14,287,247	12,936,498

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	04/13/2012	End of 2011/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)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	28,480,145	27,971,131
169	(909) Informational and Instructional Expenses	919,411	874,830
170	(910) Miscellaneous Customer Service and Informational Expenses	133,783	168,978
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	29,533,339	29,014,939
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	12,086	4,734
176	(913) Advertising Expenses	154	452
177	(916) Miscellaneous Sales Expenses	-3,913	192,237
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	8,327	197,423
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	24,938,251	25,316,910
182	(921) Office Supplies and Expenses	4,059,668	4,127,587
183	(Less) (922) Administrative Expenses Transferred-Credit	61,444	50,151
184	(923) Outside Services Employed	14,466,792	15,053,420
185	(924) Property Insurance	1,223,344	1,300,926
186	(925) Injuries and Damages	4,400,051	5,380,816
187	(926) Employee Pensions and Benefits	1,258,918	1,098,670
188	(927) Franchise Requirements	5,738	6,027
189	(928) Regulatory Commission Expenses	5,675,735	5,550,292
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	1,087	204,098
192	(930.2) Miscellaneous General Expenses	2,747,891	3,269,466
193	(931) Rents	883,149	872,289
194	TOTAL Operation (Enter Total of lines 181 thru 193)	59,599,180	62,130,350
195	Maintenance		
196	(935) Maintenance of General Plant	8,015,884	7,655,998
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	67,615,064	69,786,348
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	750,210,435	763,521,770

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	04/13/2012	End of 2011/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	Barclays Bank PLC	SF	WSPP			
5	Black Creek Hydro	LU	FERC #1			
6	Black Hills Power, Inc.	SF	WSPP			
7	BNP Paribas Energy	SF	WSPP			
8	Bonneville Power Administration	LF	WNP#3 Agr.			
9	Bonneville Power Administration	SF	WSPP			
10	Bonneville Power Administration	SF	Tariff #8			
11	Bonneville Power Administration	OS	BPA OATT			
12	Bonneville Power Administration	SF	BPA OATT			
13	Burbank, City of	SF	WSPP			
14	Cargill Power Markets	SF	WSPP			
	Total					

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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)	
					13,527,006	13,527,006	1
119,792				5,231,908		5,231,908	2
					2,063,985	2,063,985	3
5,400				93,770		93,770	4
6,556				118,379		118,379	5
1,200				42,600		42,600	6
2,600				66,950		66,950	7
413,808				14,835,948		14,835,948	8
109,219				2,486,097		2,486,097	9
42,646				935,422		935,422	10
479				38,412	65,289	103,701	11
11,429				263,479	103,645	367,124	12
800				4,400		4,400	13
85,388				2,239,586		2,239,586	14
6,724,582	543,343	544,267	10,024,722	179,037,706	20,488,318	209,550,746	

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	04/13/2012	End of 2011/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	Chelan County PUD	IU	Rocky Reach			
3	Chelan County PUD	SF	WSPP			
4	Chelan County PUD	IU	Chelan Sys			
5	Citigroup Energy	SF	WSPP			
6	Clark County PUD No. 1	SF	WSPP			
7	Clatskanie PUD	SF	WSPP			
8	Douglas County PUD No. 1	LU	Wells			
9	Douglas County PUD No. 1	LU	Wells Settlement			
10	Douglas County PUD No. 1	IF	Wells			
11	Douglas County PUD No. 1	SF	Purch Agreement			
12	Douglas County PUD No. 1	SF	WSPP			
13	Douglas County PUD No. 1	EX	305			
14	DB Energy Trading 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	04/13/2012	End of 2011/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)	
60,332				2,386,675		2,386,675	1
191,584				2,017,258		2,017,258	2
3,814				79,511		79,511	3
131,241			5,569,128			5,569,128	4
142,125				2,957,300		2,957,300	5
2,450				67,075		67,075	6
3,805				109,802		109,802	7
139,355				1,596,598		1,596,598	8
35,258				859,581		859,581	9
187,768			4,322,429			4,322,429	10
			6,678			6,678	11
64,192				1,533,468		1,533,468	12
	92,025	92,145		1,170,000	-3,458	1,166,542	13
16,600				535,620		535,620	14
6,724,582	543,343	544,267	10,024,722	179,037,706	20,488,318	209,550,746	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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.

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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	EDF Trading No America	SF	WSPP			
2	Eugene Water & Electric Board	SF	WSPP			
3	Exelon Generation Company, LLC	SF	WSPP			
4	Ford Hydro Limited Partnership	LU	PURPA			
5	Grant County PUD No. 2	LU	Priest Rapids			
6	Grant County PUD No. 2	SF	WSPP			
7	Grant County PUD No. 2	EX	FERC #104			
8	Grant County PUD No. 2	LU	Displacement			
9	Hinson Power Company, LLC	SF	WSPP			
10	Hydro Technology Systems	LU	PURPA			
11	Idaho Power Company	SF	WSPP			
12	Inland Power & Light Company	RQ	208			
13	Iberdrola Renewables	SF	WSPP			
14	Iberdrola Renewables	SF	WSPP			
	Total					

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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)	
30,957				827,808		827,808	1
7,325				161,435		161,435	2
10,409				301,991		301,991	3
4,693				261,077		261,077	4
361,969				6,059,895		6,059,895	5
23,024				491,249		491,249	6
					-1,604	-1,604	7
151,146				4,168,867		4,168,867	8
102,225				3,001,698		3,001,698	9
10,115				509,456		509,456	10
4,340				87,888		87,888	11
94				6,211		6,211	12
408,890				10,553,784		10,553,784	13
			25			25	14
6,724,582	543,343	544,267	10,024,722	179,037,706	20,488,318	209,550,746	

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	04/13/2012	End of 2011/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	Intercontinental Exchange LLC	SF	ISDA			
2	Jim White	LU	PURPA			
3	John Day Hydro	LU	PURPA			
4	J P Morgan Ventures Energy LLC	SF	WSPP			
5	J P Morgan Ventures Energy LLC	LU	PPM Energy			
6	J P Morgan Ventures Energy LLC	SF	ISDA			
7	Macquarie Energy LLC	SF	WSPP			
8	Morgan Stanley Capital Group	SF	WSPP			
9	Morgan Stanley Capital Group	SF	ISDA			
10	NaturEner Power Watch	SF	WSPP			
11	Newedge USA, LLC	SF	ISDA			
12	Noble America Gas & Power Corp.	SF	WSPP			
13	Northpoint Energy Solutions	SF	WSPP			
14	NorthWestern Energy LLC	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		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)	
					191,375	191,375	1
1,381				121,911		121,911	2
2,522				107,517		107,517	3
20,756				317,553		317,553	4
86,322				3,633,293		3,633,293	5
					396,368	396,368	6
43,258				938,840		938,840	7
240,110				8,105,106		8,105,106	8
					388,202	388,202	9
226				1,957		1,957	10
					206,244	206,244	11
800				18,072		18,072	12
47							13
6,209				152,713		152,713	14
6,724,582	543,343	544,267	10,024,722	179,037,706	20,488,318	209,550,746	

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	04/13/2012	End of 2011/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	Pacific NW Gen Corp	SF	WSPP			
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	WSPP			
14	Powerex Corp	SF	ISDA			
	Total					

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)	
99,000				1,815,899		1,815,899	1
778,874				18,922,509		18,922,509	2
51,282				1,381,022		1,381,022	3
10,383				202,042		202,042	4
19,417				363,965		363,965	5
112,108	6,123	7,906		2,615,997	-53,947	2,562,050	6
51				2,775		2,775	7
	434,325	433,960					8
	10,228	10,256			14,343	14,343	9
72,854				1,954,886		1,954,886	10
444,172				19,069,774		19,069,774	11
145,238				6,004,747		6,004,747	12
			126,462			126,462	13
					503,024	503,024	14
6,724,582	543,343	544,267	10,024,722	179,037,706	20,488,318	209,550,746	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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	Public Service Co of Colorado	SF	WSPP			
2	Puget Sound Energy	SF	WSPP			
3	Rainbow Energy Marketing Corp	SF	WSPP			
4	Sacramento Municipal Utility District	SF	WSPP			
5	San Diego Gas & Electric	SF	WSPP			
6	Seattle City Light	SF	WSPP			
7	Sempra Energy Trading	SF	WSPP			
8	Sheep Creek Hydro	LU	PURPA			
9	Shell Energy	SF	ISDA			
10	Shell Energy	SF	WSPP			
11	Sierra Pacific Power Company	SF	WSPP			
12	Snohomish County PUD No. 1	SF	WSPP			
13	Southern California Edison Co.	SF	WSPP			
14	Sovereign Power	IF	Sovereign			
	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	04/13/2012	End of 2011/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)	
200				6,000		6,000	1
30,733				762,771		762,771	2
40,264				976,170		976,170	3
600				8,800		8,800	4
28				118		118	5
50,020				1,224,730		1,224,730	6
30,400				1,717,600		1,717,600	7
7,556				303,156		303,156	8
					2,442,955	2,442,955	9
375,598				10,363,783		10,363,783	10
225				10,650		10,650	11
20,395				410,899		410,899	12
515				12,066		12,066	13
6,937				137,638		137,638	14
6,724,582	543,343	544,267	10,024,722	179,037,706	20,488,318	209,550,746	

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	04/13/2012	End of 2011/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:

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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	Spokane County	LU	PURPA			
2	Stimson Lumber	IU	PURPA			
3	Tacoma Power	SF	WSPP			
4	Tenaska Power Services Company	SF	WSPP			
5	The Energy Authority	SF	WSPP			
6	TransAlta Energy Marketing	SF	WSPP			
7	Western Area Power Admin - Upper Great	SF	NWPP Res Sharing			
8	IntraCompany Generation Services	OS	OATT			
9	Rathdrum Power LLC	LF	Lancaster			
10	Other - Inadvertent Interchange	EX				
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	04/13/2012	End of 2011/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)	
				28,407		28,407	1
36,224				1,921,705		1,921,705	2
39,005				1,169,078		1,169,078	3
800				24,200		24,200	4
20,469				372,248		372,248	5
201,107				4,929,414		4,929,414	6
1				37		37	7
					644,891	644,891	8
835,467				22,826,460		22,826,460	9
	642						10
							11
							12
							13
							14
6,724,582	543,343	544,267	10,024,722	179,037,706	20,488,318	209,550,746	

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.: 11 Column: a

Ancillary Services - Spinning & Supplemental

Schedule Page: 326 Line No.: 12 Column: a

Non Monetary

Schedule Page: 326.1 Line No.: 13 Column: a

Non Monetary

Schedule Page: 326.2 Line No.: 7 Column: a

Non Monetary

Schedule Page: 326.3 Line No.: 1 Column: a

Financial SWAP

Schedule Page: 326.3 Line No.: 6 Column: a

Financial SWAP

Schedule Page: 326.3 Line No.: 9 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.: 14 Column: a

Financial SWAP

Schedule Page: 326.5 Line No.: 9 Column: a

Financial Swap

Schedule Page: 326.6 Line No.: 8 Column: a

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	04/13/2012	End of 2011/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	Bonneville Power Administration	LFP
3	Tacoma City Light	Tacoma City Light	Bonneville Power Administration	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	Puget Sound Energy	LFP
10	Stimpson	Plummer	Avista Corporation	LFP
11	Bonneville Power Administration	Bonneville Power Administration	Idaho Power Company	NF
12	Bonneville Power Administration	Avista Corp	Bonneville Power Administration	NF
13	Bonneville Power Administration	Bonneville Power Administration	Idaho Power Company	SFP
14	Bonneville Power Administration	Bonneville Power Administration	Avista Corp	NF
15	Idaho Power Company	Grant County PUD	Idaho Power Company	NF
16	Idaho Power Company	Bonneville Power Administration	Idaho Power Company	NF
17	Idaho Power Company	Bonneville Power Administration	Idaho Power Company	SFP
18	Idaho Power Company	Idaho Power Company	Bonneville Power Administration	SFP
19	Idaho Power Company	Idaho Power Company	Chelan County PUD	SFP
20	Idaho Power Company	Idaho Power Company	Northwest Montana	SFP
21	Idaho Power Company	Idaho Power Company	Avista Corp	SFP
22	Idaho Power Company	AVA (MIDC)	Idaho Power Company	SFP
23	Idaho Power Company	Northwest Montana	Idaho Power Company	SFP
24	Idaho Power Company	Bonneville Power Administration	Northwest Montana	NF
25	Idaho Power Company	Pacificorp	Idaho Power Company	SFP
26	Idaho Power Company	Idaho Power Company	Bonneville Power Administration	NF
27	Pacificorp	Pacificorp	Idaho Power Company	NF
28	Pacificorp	Pacificorp	Bonneville Power Administration	NF
29	Powerex	Bonneville Power Administration	Idaho Power Company	NF
30	Powerex	Northwest Montana	Bonneville Power Administration	NF
31	Powerex	Idaho Power Company	Bonneville Power Administration	NF
32	Powerex	Northwest Montana	Northwest Montana	NF
33	Powerex	Pacificorp	Idaho Power Company	NF
34	Powerex	Bonneville Power Administration	Idaho Power Company	SFP
	TOTAL			

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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	59,445	59,445	1
FERC Trf No. 8	Chelan-Stratford 115	Stratford 115kV SS		211,700	211,700	2
FERC Trf No. 8	Chelan-Stratford 115	Stratford 115kV SS		211,700	211,700	3
FERC No. 104	Stratford Substation	Coulee Cy/Wilson Crk	25	82,715	82,715	4
FERC Trf No. 8	Westside	Little Falls	2	3,203	3,203	5
FERC Trf No. 8	Bell Substation	Post Falls	3	3,847	3,847	6
FERC Trf No. 8	Bell Substation	BKR/OPT/EFM/LIB	3	5,070	5,070	7
FERC Trf No. 8				1,852,397	1,852,397	8
FERC No. 155	Sunset-Westside 115k	Westside	23	143,384	143,384	9
FERC Trf No. 8	AVA Syst	AVA Syst		3,616	3,616	10
FERC Trf No. 8				4,312	4,312	11
FERC Trf No. 8						12
FERC Trf No. 8				25,328	25,328	13
FERC Trf No. 8				628	628	14
FERC Trf No. 8				175	175	15
FERC Trf No. 8				37,869	37,869	16
FERC Trf No. 8				75,914	75,914	17
FERC Trf No. 8				159,295	159,295	18
FERC Trf No. 8				1,888	1,888	19
FERC Trf No. 8				1,600	1,600	20
FERC Trf No. 8				7,400	7,400	21
FERC Trf No. 8				112	112	22
FERC Trf No. 8				605	605	23
FERC Trf No. 8				1,200	1,200	24
FERC Trf No. 8				24,348	24,348	25
FERC Trf No. 8				150	150	26
FERC Trf No. 8				97,223	97,223	27
FERC Trf No. 8				8,848	8,848	28
FERC Trf No. 8				13,999	13,999	29
FERC Trf No. 8				972	972	30
FERC Trf No. 8				110	110	31
FERC Trf No. 8				27	27	32
FERC Trf No. 8				126	126	33
FERC Trf No. 8				1,688	1,688	34
			76	3,322,223	3,322,223	

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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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.
228,253			228,253	1
180,956			180,956	2
180,956			180,956	3
29,029			29,029	4
22,546			22,546	5
16,517			16,517	6
44,944			44,944	7
7,192,533			7,192,533	8
127,508		32,088	159,596	9
790			790	10
84,571	10,917		95,488	11
	6		6	12
55,288			55,288	13
6,439			6,439	14
	1,010		1,010	15
13,598	104,960		118,558	16
455,293			455,293	17
784,512			784,512	18
13,566			13,566	19
20,412			20,412	20
46,270			46,270	21
569			569	22
3,073			3,073	23
	17,575		17,575	24
113,025			113,025	25
1,191			1,191	26
7,351	509,179		516,530	27
53,978			53,978	28
9,366	81,299		90,665	29
4,240	1,661		5,901	30
196	541		737	31
	171		171	32
	815		815	33
11,352			11,352	34
11,653,149	**1,070,375**	**32,088**	**12,755,612**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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	Puget Sound Energy	Bonneville Power Administration	Idaho Power Company	NF
2	Puget Sound Energy	Puget Sound Energy	Idaho Power Company	SFP
3	Puget Sound Energy	Puget Sound Energy	Bonneville Power Administration	SFP
4	Powerex	Bonneville Power Administration	Northwest Montana	NF
5	Puget Sound Energy	Bonneville Power Administration	Bonneville Power Administration	SFP
6	Puget Sound Energy	Bonneville Power Administration	Idaho Power Company	SFP
7	Puget Sound Energy	Northwest Montana	Bonneville Power Administration	NF
8	Portland General Electric	Northwest Montana	Bonneville Power Administration	NF
9	Portland General Electric	Northwest Montana	Portland General Electric	SFP
10	Portland General Electric	Northwest Montana	Portland General Electric	NF
11	Morgan Stanley Capital Group	Bonneville Power Administration	Idaho Power Company	NF
12	Morgan Stanley Capital Group	Northwest Montana	Chelan County PUD	NF
13	Morgan Stanley Capital Group	Northwest Montana	Portland General Electric	NF
14	Morgan Stanley Capital Group	Northwest Montana	Idaho Power Company	NF
15	Morgan Stanley Capital Group	Northwest Montana	Bonneville Power Administration	NF
16	Morgan Stanley Capital Group	Northwest Montana	Pacificorp	SFP
17	Morgan Stanley Capital Group	Bonneville Power Administration	Northwest Montana	NF
18	Morgan Stanley Capital Group	Idaho Power Company	Bonneville Power Administration	NF
19	Morgan Stanley Capital Group	Northwest Montana	Idaho Power Company	SFP
20	Morgan Stanley Capital Group	Northwest Montana	Grant County PUD	NF
21	Sierra Pacific Power Co	Bonneville Power Administration	Idaho Power Company	SFP
22	Sierra Pacific Power Co	Chelan County PUD	Idaho Power Company	SFP
23	Sierra Pacific Power Co	Douglas County PUD	Idaho Power Company	SFP
24	Sierra Pacific Power Co	Bonneville Power Administration	Idaho Power Company	NF
25	Sierra Pacific Power Co	Portland General Electric	Idaho Power Company	NF
26	Sierra Pacific Power Co	Puget Sound Energy	Idaho Power Company	NF
27	Cargill Power Markets	AVA (MIDC)	Idaho Power Company	NF
28	Cargill Power Markets	Northwest Montana	Pacificorp	SFP
29	Cargill Power Markets	Pacificorp	Idaho Power Company	NF
30	Cargill Power Markets	Bonneville Power Administration	Idaho Power Company	SFP
31	Cargill Power Markets	Northwest Montana	Bonneville Power Administration	SFP
32	Cargill Power Markets	Idaho Power Company	Bonneville Power Administration	SFP
33	Cargill Power Markets	Bonneville Power Administration	Idaho Power Company	NF
34	Cargill Power Markets	Northwest Montana	Bonneville Power Administration	NF
	TOTAL			

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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				417	417	1
FERC Trf No. 8				490	490	2
FERC Trf No. 8				27,359	27,359	3
FERC Trf No. 8				87	87	4
FERC Trf No. 8				150,105	150,105	5
FERC Trf No. 8				200	200	6
FERC Trf No. 8				6,178	6,178	7
FERC Trf No. 8				2,369	2,369	8
FERC Trf No. 8						9
FERC Trf No. 8				2,404	2,404	10
FERC Trf No. 8				1,300	1,300	11
FERC Trf No. 8				866	866	12
FERC Trf No. 8				203	203	13
FERC Trf No. 8				5,604	5,604	14
FERC Trf No. 8				18,677	18,677	15
FERC Trf No. 8				600	600	16
FERC Trf No. 8				111	111	17
FERC Trf No. 8				160	160	18
FERC Trf No. 8				150	150	19
FERC Trf No. 8				1,832	1,832	20
FERC Trf No. 8				3,000	3,000	21
FERC Trf No. 8				800	800	22
FERC Trf No. 8				400	400	23
FERC Trf No. 8				1,233	1,233	24
FERC Trf No. 8				100	100	25
FERC Trf No. 8				150	150	26
FERC Trf No. 8				782	782	27
FERC Trf No. 8				112	112	28
FERC Trf No. 8				15	15	29
FERC Trf No. 8				368	368	30
FERC Trf No. 8				400	400	31
FERC Trf No. 8				221	221	32
FERC Trf No. 8				5,615	5,615	33
FERC Trf No. 8				1,822	1,822	34
			76	**3,322,223**	**3,322,223**	

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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.
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17	2,617		2,634	1
3,295			3,295	2
213,531			213,531	3
	550		550	4
1,380,464			1,380,464	5
1,690			1,690	6
3,462	37,012		40,474	7
202	14,118		14,320	8
80,600			80,600	9
	14,426		14,426	10
1,226	7,011		8,237	11
	5,242		5,242	12
	1,359		1,359	13
3,099	31,889		34,988	14
58,883	58,215		117,098	15
2,308			2,308	16
	685		685	17
	976		976	18
4,615			4,615	19
11,340			11,340	20
11,537			11,537	21
3,077			3,077	22
1,538			1,538	23
	7,726		7,726	24
	750		750	25
	1,125		1,125	26
	4,861		4,861	27
646			646	28
	87		87	29
2,123			2,123	30
4,459			4,459	31
2,464			2,464	32
5,293	29,650		34,943	33
10,953	54		11,007	34
11,653,149	**1,070,375**	**32,088**	**12,755,612**	

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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	Cargill Power Markets	Northwest Montana	Pacificorp	NF
2	Cargill Power Markets	Idaho Power Company	Bonneville Power Administration	NF
3	Coral Power	Northwest Montana	Chelan County PUD	NF
4	Coral Power	Chelan County PUD	Northwest Montana	NF
5	Coral Power	Bonneville Power Administration	Idaho Power Company	NF
6	Coral Power	Idaho Power Company	Chelan County PUD	NF
7	Transalta Enery Marketing US	Bonneville Power Administration	Idaho Power Company	NF
8	Transalta Enery Marketing US	Bonneville Power Administration	Northwest Montana	NF
9	Transalta Enery Marketing US	Northwest Montana	Bonneville Power Administration	NF
10	NaturEner USA	Northwest Montana	Bonneville Power Administration	NF
11	NaturEner USA	Northwest Montana	Bonneville Power Administration	SFP
12	NaturEner USA	Bonneville Power Administration	Northwest Montana	NF
13	NaturEner USA	Northwest Montana	Bonneville Power Administration	NF
14	Northwest Default Services	Northwest Montana	Bonneville Power Administration	NF
15	PPM Energy	Bonneville Power Administration	Idaho Power Company	NF
16	Tenaska	Bonneville Power Administration	Northwest Montana	NF
17	The Energy Authority	Northwest Montana	Bonneville Power Administration	NF
18	PPL Energy Plus	Northwest Montana	Bonneville Power Administration	NF
19	PPL Energy Plus	Bonneville Power Administration	Northwest Montana	NF
20	PPL Energy Plus	Northwest Montana	Idaho Power Company	NF
21	PPL Energy Plus	Bonneville Power Administration	Idaho Power Company	NF
22	PPL Energy Plus	Northwest Montana	AVA	NF
23	PPL Energy Plus	Northwest Montana	Portland General Electric	NF
24	Rainbow Energy Marketing	AVAT	Idaho Power Company	SFP
25	Rainbow Energy Marketing	Bonneville Power Administration	Idaho Power Company	SFP
26	Rainbow Energy Marketing	AVAT	Idaho Power Company	NF
27	Rainbow Energy Marketing	Northwest Montana	Idaho Power Company	NF
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

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		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
FERC Trf No. 8				1,100	1,100	1
FERC Trf No. 8				388	388	2
FERC Trf No. 8				21,636	21,636	3
FERC Trf No. 8				356	356	4
FERC Trf No. 8				75	75	5
FERC Trf No. 8				85	85	6
FERC Trf No. 8				491	491	7
FERC Trf No. 8				50	50	8
FERC Trf No. 8				50	50	9
FERC Trf No. 8				140	140	10
FERC Trf No. 8				2,983	2,983	11
FERC Trf No. 8				251	251	12
FERC Trf No. 8				536	536	13
FERC Trf No. 8				330	330	14
FERC Trf No. 8				430	430	15
FERC Trf No. 8				95	95	16
FERC Trf No. 8				53	53	17
FERC Trf No. 8				1,142	1,142	18
FERC Trf No. 8				45	45	19
FERC Trf No. 8				3,983	3,983	20
FERC Trf No. 8				475	475	21
FERC Trf No. 8				180	180	22
FERC Trf No. 8				90	90	23
FERC Trf No. 8				6,879	6,879	24
FERC Trf No. 8				400	400	25
FERC Trf No. 8				4,092	4,092	26
FERC Trf No. 8				864	864	27
						28
						29
						30
						31
						32
						33
						34
			76	3,322,223	3,322,223	

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.
	5,441		5,441	1
614	1,424		2,038	2
71,571	66,743		138,314	3
	2,054		2,054	4
	500		500	5
	498		498	6
2,550	1,333		3,883	7
289			289	8
	288		288	9
428	995		1,423	10
23,230			23,230	11
1,396	707		2,103	12
3,692			3,692	13
375	1,587		1,962	14
664	2,250		2,914	15
	750		750	16
	306		306	17
2,568	4,171		6,739	18
	260		260	19
	23,889		23,889	20
	2,766		2,766	21
	1,083		1,083	22
	520		520	23
28,945			28,945	24
1,683			1,683	25
	5,220		5,220	26
	1,103		1,103	27
				28
				29
				30
				31
				32
				33
				34
11,653,149	**1,070,375**	**32,088**	**12,755,612**	

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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) 04/13/2012	Year/Period of Report End of 2011/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)	TRANSFER OF ENERGY: 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	Bonneville Power Admin	LFP			1,256,535			1,256,535
2	Bonneville Power Admin	LFP			11,112,176		1,749,048	12,861,224
3	Bonneville Power Admin	LFP			788,748			788,748
4	Bonneville Power Admin	OS					24,360	24,360
5	Bonneville Power Admin	FNS			1,056,888		155,720	1,212,608
6	Bonneville Power Admin	NF	29,191	29,191		126,399		126,399
7	Benton County PUD No. 1	NF	772	772		961		961
8	Clark County PUD No. 1	NF	360	360		540		540
9	Grays Harbor County PUD	NF	100	100		145		145
10	Kootenai Electric Coop	LFP			45,222			45,222
11	Northern Lights	LFP			135,884			135,884
12	NorthWestern Energy	NF	25,614	25,614	184,876	110,909	14,781	310,566
13	Portland General Elec	LFP			642,989			642,989
14	Puget Sound Energy	NF	28,852	28,852		67,225		67,225
15	Seattle City Light	NF	9,989	9,989		13,776		13,776
16	Tacoma Power	NF	1,528	1,528		2,437		2,437
	TOTAL		96,406	96,406	15,223,318	322,392	1,943,909	17,489,619

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.: 12 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	04/13/2012	End of 2011/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	497,788
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	123,353
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	1,432,942
6		
7	Community Relations	179,255
8	Education and Informational	19,843
9	Directors Fees	494,710
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
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43		
44		
45		
46	TOTAL	2,747,891

Schedule Page: 335 Line No.: 5 Column: b

Schedule Page: 335 Line No.: 5

Vendor	Purpose	Amount
VENDORS LESS THAN $5,000		80,982
ADVENTURES IN ADVERTISING	010 General Services	9563
AMERICAN GAS ASSOCIATION	885 Miscellaneous	0
AZAR'S FOOD SERVICES	215 Employee Business Meals	5483.49
BNY MELLON	910 Postage	4975
BROADRIDGE ICS	010 General Services	55285
CAREY INTERNATIONAL INC	220 Employee Car Rental	5995.36
CITIBANK NA	885 Miscellaneous	41777.89
COPYRIGHT CLEARANCE CENTER INC	885 Miscellaneous	7194.23
CORP CREDIT CARD	020 Professional Services	103838.92
DAVID D HOLMES	205 Airfare	5239
DAVIS HIBBITTS & MIDGHALL INC	020 Professional Services	32337.96
DESAUTEL HEGE COMMUNICATIONS	020 Professional Services	5083.32
DEWEY & LEBOEUF LLP	010 General Services	43182.2
DILIGENT BOARD MEMBER SERVICES INC	935 Subscriptions	20629.16
DONALD C BURKE	205 Airfare	14585.74
ENERGY INDUSTRY CBT ALLIANCE	861 Lease Hardware/Software	5067
ENTERPRISE RENT A CAR	220 Employee Car Rental	6016
GARD COMMUNICATIONS	020 Professional Services	6206
HANNA & ASSOCIATES INC	020 Professional Services	12366.34
INLAND NORTHWEST PARTNERS	826 Sponsorships	5931
JASON R THACKSTON	205 Airfare	3660.72
KAREN S FELTES	205 Airfare	3760.4
KLUNDT HOSMER DESIGN	020 Professional Services	19607.83
MARIAN MCMAHON DURKIN	210 Employee Auto Mileage	3799
MARK T THIES	215 Employee Business Meals	7982.77
MELLON INVESTOR SERVICES LLC	010 General Services	90012
MERRILL LYNCH PIERCE FENNER & SMITH INC	885 Miscellaneous	24067.86
MICHAEL G ANDREA	205 Airfare	15428
MICHAEL J FAULKENBERRY	205 Airfare	0
MOODYS INVESTORS SERVICE	885 Miscellaneous	86859.6
NYSE MARKET INC	010 General Services	38450.57
RICK R HOLLEY	205 Airfare	8201.55
STANDARD & POORS	010 General Services	73087.19

STEVE L VINCENT	205 Airfare	0
STRATEGIC RESEARCH ASSOCIATES	020 Professional Services	5091.06
THE BANK OF NEW YORK MELLON	885 Miscellaneous	8540
THE COEUR D ALENE	215 Employee Business Meals	14563.11
THE DAVENPORT HOTEL	215 Employee Business Meals	11240.64
THE SALVATION ARMY KROC CENTER	925 Rental Expense - Other	4244
TOWERS WATSON PENNSYLVANIA INC	020 Professional Services	9861
WILMINGTON TRUST COMPANY	885 Miscellaneous	3619.15

Schedule Page: 335 Line No.: 9 Column: b

Schedule Page: 335 Line No.: 9

Directors	2011 Expenses
Vendor Name	
HEIDI B STANLEY	$66,148
MARC F RACICOT	$48,456
ERIK J ANDERSON	$65,199
KRISTIANNE BLAKE	$62,825
REBECCA A KLEIN	$21,881
JOHN F KELLY	$79,285
MICHAEL L NOEL	$49,053
R JOHN TAYLOR	$54,935
ROY EIGUREN	$14,330
SCOTT L MORRIS	$9,907

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	04/13/2012	End of 2011/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			5,177,241		5,177,241
2	Steam Production Plant	10,577,524				10,577,524
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	8,685,826				8,685,826
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	8,347,066			2,450,031	10,797,097
7	Transmission Plant	10,240,671				10,240,671
8	Distribution Plant	30,035,667				30,035,667
9	Regional Transmission and Market Operation					
10	General Plant	3,414,097				3,414,097
11	Common Plant-Electric	7,444,085		1,388,603		8,832,688
12	TOTAL	78,744,936		6,565,844	2,450,031	87,760,811

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	04/13/2012	End of 2011/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	50,782	65.00	-5.00	2.28	S1.5	17.88
15	312	78,044	60.00	-10.00	2.70	R1	18.57
16	314	22,184	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	9,072	50.00		2.26	R2	15.88
19	Subtotal	169,632					
20							
21	Colstrip No. 4						
22	311	49,926	65.00	-5.00	2.35	S1.5	21.32
23	312	50,322	60.00	-10.00	2.83	R1	23.84
24	314	15,728	50.00	-10.00	3.50	O1	28.31
25	315	6,706	55.00	-5.00	2.59	S1.5	25.11
26	316	4,226	50.00		2.46	R3	19.98
27	Subtotal	126,908					
28							
29	Kettle Falls						
30	310	148	35.00		2.19	SQ	
31	311	24,972	65.00	-5.00	2.34	S1.5	20.59
32	312	41,461	60.00	-10.00	3.31	R1	22.43
33	314	13,345	50.00	-10.00	3.18	O1	16.35
34	315	10,838	55.00	-5.00	2.74	S1.5	17.61
35	316	2,604	50.00		2.68	R2	21.44
36	Subtotal	93,368					
37							
38	HYDRO PLANT						
39	Cabinet Gorge						
40	330	7,971	75.00		2.75	R3	67.57
41	331	10,758	110.00	-5.00	1.62	R0.5	56.19
42	332	31,134	100.00		1.79	R1.5	77.96
43	333	37,864	60.00	-5.00	2.59	R1.5	52.14
44	334	5,601	45.00		1.43	R2.5	16.54
45	335	3,325	65.00		0.13	R1	1.20
46	336	1,099	60.00		2.05	S2.5	17.49
47	Subtotal	97,752					
48							
49	Noxon Rapids						
50	330	29,974	75.00		2.83	R3	69.37

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	04/13/2012	End of 2011/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	331	14,761	110.00	-5.00	1.77	R0.5	81.53
13	332	32,298	100.00		1.79	R1.5	75.35
14	333	80,791	60.00	-5.00	2.89	R1.5	56.01
15	334	14,201	45.00		2.53	R2.5	43.88
16	335	3,378	65.00		0.97	R1	19.90
17	336	225	60.00		2.12	R2.5	39.60
18	Subtotal	175,628					
19							
20	Post Falls						
21	330	2,732	75.00		3.79	R3	56.46
22	331	1,369	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	13,618					
28							
29	Long Lake						
30	330	417	75.00		5.68	R3	45.63
31	331	2,226	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	31,492					
37							
38	Little Falls						
39	330	4,217	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	3,971	60.00	-5.00	0.51	R1.5	
43	334	2,037	45.00		0.93	R2.5	12.81
44	335	144	65.00		1.18	R1	19.46
45	Subtotal	16,623					
46							
47	Upper Falls						
48	330	64	75.00		2.48	R4	37.64
49	331	584	110.00	-5.00	0.12	R0.5	9.42
50	332	7,668	100.00		1.20	R1.5	76.61

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	13,877					
16							
17	Nine Mile						
18	330	11	75.00		4.59	R3	34.35
19	331	3,942	110.00	-5.00	2.35	R0.5	80.39
20	332	13,562	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	30,701					
26							
27	Monroe Street						
28	331	8,444	110.00	-5.00	1.82	R0.5	109.02
29	332	9,971	100.00		1.72	R1.5	99.22
30	333	11,031	60.00	-5.00	2.28	R1.5	60.23
31	334	1,679	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	31,209					
35							
36	OTHER PRODUCTION						
37	Northeast Turbine						
38	341	649			0.98	SQ	
39	342	32	55.00		1.31	R3	
40	343	9,090	50.00		7.83	S2.5	8.42
41	344	2,605	45.00		0.72	R3	
42	345	1,187	40.00		8.54	S1.5	11.83
43	346	302			1.24	SQ	
44	Subtotal	13,865					
45							
46	Rathdrum Turbine						
47	341	3,259			3.95	SQ	
48	342	1,696	55.00		4.10	R2.5	44.14
49	343	3,658	50.00		3.61	S2.5	33.50
50	344	48,858	45.00		3.37	R3	35.49

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	04/13/2012	End of 2011/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	345	2,567	40.00		3.56	S1.5	
13	Subtotal	60,038					
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	1,176			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	345	40.00		2.97	S1.5	31.24
28	346	7			2.69	SQ	
29	Subtotal	32,312					
30							
31	Coyote Springs 2						
32	341	11,404			2.76	SQ	
33	342	19,139	55.00		2.85	R3	44.23
34	344	117,072	45.00		2.92	R3	41.58
35	345	12,815	40.00		3.10	S1.5	32.07
36	346	1,316			2.76	SQ	
37	Subtotal	161,746					
38							
39	Solar Power	63					
40	Subtotal	63					
41	TRANSMISSION PLANT						
42	350	16,483	75.00		1.28	R4	53.27
43	352	16,778	60.00	-5.00	1.61	R4	44.73
44	353	203,281	47.00	-15.00	2.39	R3	31.13
45	354	17,121	70.00	-20.00	1.87	S3	43.89
46	355	145,612	60.00	-30.00	1.84	R3	37.27
47	356	112,615	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

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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	Subtotal	518,697					
13	DISTRIBUTION PLANT						
14	360	1,852					
15	361	17,668	55.00	-10.00	1.80	R3	35.51
16	362	105,535	42.00	-10.00	2.60	R1.5	28.26
17	364	244,092	50.00	-25.00	2.66	R2.5	34.66
18	365	163,415	50.00	-15.00	2.46	R2.5	35.35
19	366	82,591	45.00	-10.00	2.71	R3	36.09
20	367	136,552	28.00	-15.00	6.38	L4	23.05
21	368	191,749	44.00	-5.00	2.00	R2	27.21
22	369	123,633	60.00	-15.00	1.63	R3	38.01
23	370	47,868	38.00		2.39	S1	33.72
24	373	34,636	32.00	-15.00	1.08	R2.5	8.68
25	373.4		32.00	-5.00	2.82	R2.5	18.79
26	Subtotal	1,149,591					
27							
28	GENERAL PLANT						
29	390.1	5,730	55.00	-5.00	1.85	S2	20.91
30	391.1	3,251	5.00		17.67	SQ	3.80
31	393	395	25.00		2.25	SQ	22.97
32	394	3,198	20.00		4.22	SQ	10.35
33	395	1,047	15.00		7.72	SQ	7.82
34	397	43,998	15.00		5.40	SQ	5.17
35	398	13	10.00		2.37	SQ	7.80
36	Subtotal	57,632					
37							
38	MISC POWER						
39	392	16,508	11.00	10.00	3.70	S3	
40	396	34,615	15.00	10.00	5.40	L2	
41	Subtotal	51,123					
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	04/13/2012	End of 2011/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	209					42.90
15	SUBTOTAL	301					
16							
17	TOTAL COMPANY	2,855,354					
18							
19							
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21							
22							
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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	04/13/2012	End of 2011/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.	2,327,107	202,546	2,529,653	
5					
6					
7					
8					
9	Washington Utilities and Transportation				
10	Commission: includes annual fee and various				
11	other electric dockets	872,126	286,153	1,158,279	
12					
13	Includes annual fee and various other natural				
14	gas dockets	289,160	130,359	419,519	
15					
16	Idaho Public Utilities Commission				
17	Includes annual fee and various other electric				
18	dockets	576,708	170,811	747,519	
19					
20	Includes annual fee and various other natural				
21	gas dockets	145,504	80,123	225,627	
22					
23	Public Utility Commission of Oregon				
24	Includes annual fees and various other natural				
25	gas dockets	478,612	147,655	626,267	
26					
27	Not directly assigned electric		1,239,905	1,239,905	
28	Not directly assigned natural gas		473,073	473,073	
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	4,689,217	2,730,625	7,419,842	

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	04/13/2012	End of 2011/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	2,529,653					4
							5
							6
							7
							8
							9
							10
Electric	928	1,158,279					11
							12
							13
Gas	928	419,519					14
							15
							16
							17
Electric	928	747,519					18
							19
							20
Gas	928	225,627					21
							22
							23
							24
Gas	928	626,267					25
							26
Electric	928	1,239,905					27
Gas	928	473,073					28
							29
							30
							31
							32
							33
							34
							35
							36
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							45
		7,419,842					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	04/13/2012	End of 2011/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	A 3 Electric - Distribution	Smart Grid Demonstration Grant (Meters)
3	A 3 Electric - Distribution	Smart Grid Demonstration Grant (Meters)
4	A 3 Electric - Distribution	Smart Grid Demonstration Grant (Meters)
5	A 3 Electric - Distribution	Smart Grid Demonstration Grant (Meters)
6	A 3 Electric - Distribution	Smart Grid Demonstration Grant (Meters)
7	A 3 Electric - Distribution	Smart Grid Demonstration Grant (Meters)
8	A 3 Electric - Distribution	Smart Grid Demonstration Grant (Meters)
9		
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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) 04/13/2012	Year/Period of Report End of 2011/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)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
129,515	66,653	580	196,168		1
8,383	7,767	583	11,958		2
282,255	38,814	588	321,069		3
35,041	10,079	920	45,120		4
20,361	8,967	921	29,328		5
98,353	28,229	923	126,582		6
290	144	930	434		7
58,987	26,476	935	85,463		8
					9
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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	04/13/2012	End of 2011/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	10,108,638		
4	Transmission	2,555,587		
5	Regional Market			
6	Distribution	3,537,312		
7	Customer Accounts	6,635,947		
8	Customer Service and Informational	608,330		
9	Sales	2,539		
10	Administrative and General	14,718,926		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	38,167,279		
12	Maintenance			
13	Production	3,168,302		
14	Transmission	1,011,134		
15	Regional Market			
16	Distribution	3,758,066		
17	Administrative and General			
18	TOTAL Maintenance (Total of lines 13 thru 17)	7,937,502		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	13,276,940		
21	Transmission (Enter Total of lines 4 and 14)	3,566,721		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	7,295,378		
24	Customer Accounts (Transcribe from line 7)	6,635,947		
25	Customer Service and Informational (Transcribe from line 8)	608,330		
26	Sales (Transcribe from line 9)	2,539		
27	Administrative and General (Enter Total of lines 10 and 17)	14,718,926		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	46,104,781	11,838,552	57,943,333
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply	910,821		
34	Storage, LNG Terminaling and Processing	5,879		
35	Transmission			
36	Distribution	4,046,697		
37	Customer Accounts	2,826,844		
38	Customer Service and Informational	337,946		
39	Sales	968		
40	Administrative and General	5,428,676		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	13,557,831		
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	798,502		

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	04/13/2012	End of 2011/Q4

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	2,343,437		
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	3,141,939		
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)	910,821		
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru	5,879		
56	Transmission (Lines 35 and 47)	798,502		
57	Distribution (Lines 36 and 48)	6,390,134		
58	Customer Accounts (Line 37)	2,826,844		
59	Customer Service and Informational (Line 38)	337,946		
60	Sales (Line 39)	968		
61	Administrative and General (Lines 40 and 49)	5,428,676		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	16,699,770		16,699,770
63	Other Utility Departments			
64	Operation and Maintenance		9,290,766	9,290,766
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	62,804,551	21,129,318	83,933,869
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	31,008,041	7,970,742	38,978,783
69	Gas Plant	6,251,691	1,607,023	7,858,714
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	37,259,732	9,577,765	46,837,497
72	Plant Removal (By Utility Departments)			
73	Electric Plant	1,628,348	414,566	2,042,914
74	Gas Plant	92,200	23,473	115,673
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	1,720,548	438,039	2,158,587
77	Other Accounts (Specify, provide details in footnote):			
78				
79	Stores Expense (163)	1,869,614	-1,869,614	
80	Preliminary Survey and Investigation (183)	8,813		8,813
81	Small Tool Expense (184)	3,119,577	-3,119,577	
82	Miscellaneous Deferred Debits (186)	520,405		520,405
83	Non-Operationg Expenses (417)	489,467		489,467
84	Exenditures of Crtain Civic, Political, and Related Activitie	574,052		574,052
85	Employee Incentive (232380)	10,160,248	-10,160,248	
86	DSM Tarrif Rider and Payroll Equal Liability (242600, 242700)	17,576,289	-15,753,459	1,822,830
87	Incentive/Stock Comp (238000)	58,821		58,821
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	34,377,286	-30,902,898	19,227,847
96	TOTAL SALARIES AND WAGES	136,162,117	242,224	152,157,800

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	04/13/2012	End of 2011/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	36,486,614
389	Land and Land Rights	5,145,059
390	Structures and Improvements	72,348,596
391	Office Furniture and Equipment	42,811,765
392	Transportation Equipment	9,240,957
393	Stores Equipment	1,772,869
394	Tools, Shop & Garage Equipment	5,790,359
395	Laboratory Equipment	552,552
396	Power Operated Equipment	2,089,948
397	Communications Equipment	22,919,776
398	Miscellaneous Equipment	395,531
399	Asset Retirement Cost	371,024
	Total Common Plant	199,925,050
	Const. Work in Progress	20,425,132
	Total Utility Plant	220,350,182
	Acc. Prov. for Dep. & Amort.	53,689,542
	Net Utility Plant	166,660,640

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	1,196,261	633,265	562,996	#of cust @ yr end
902	Meter reading expenses	4,348,392	2,682,001	1,666,391	#of cust @ yr end
903	Cust rec & collection expenses	14,237,450	7,764,819	6,472,631	#of cust @ yr end
903.90-99	A/R misc fees	3,102	2,499	603	net direct plant
904	Uncollectible accounts	4,971,494	2,631,760	2,339,734	#of cust @ yr end
905	Misc cust acct expenses	261,741	138,559	123,182	#of cust @ yr end
907	Cust srvc & Info exp supervision	0	0	0	#of cust @ yr end
908	Cust Assistance Exps	993,589	612,825	380,764	#of cust @ yr end
909	Info & instruct advert	1,497,853	909,681	588,172	#of cust @ yr end

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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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				
910	Misc cust srvc & info expenses	252,720	133,782	118,938	#of cust @ yr end
911	Sales expense sprvsn	0	0	0	#of cust @ yr end
912	Demo and selling expenses	19,595	12,086	7,509	#of cust @ yr end
913	Advertising expenses	250	184	96	#of cust @ yr end
916	Misc sales expenses	-6,231	-3,913	-2,318	#of cust @ yr end
920	Admin & gen salaries	32,146,433	23,363,041	8,783,392	four factor
921	Office supplies & expenses	5,398,252	3,909,715	1,488,537	four factor
922	Admin expenses tranf-cred	12,870	9,316	3,554	four factor
923	Outside srvcs employed	19,751,264	14,299,436	5,451,828	four factor
924	Property insurance	1,413,687	1,023,269	390,418	four factor
925	Injuries and damages	6,899,218	5,172,581	1,726,637	four factor
926	Employee pensions & benefits	55,735,917	40,467,113	15,268,804	four factor
927	Franchise requirement	0	0	0	four factor
928	Regulatory commission expenses	1,712,979	1,239,906	473,073	four factor
929	Duplicate charges-credit	0	0	0	four factor
930.1	Gener advert expenses	1,375	1,087	288	four factor
930.2	Misc general expenses	3,078,308	2,247,297	831,011	four factor
931	Rents	1,119,392	810,286	309,106	four factor
935	Maint of general plant	9,457,716	6,980,101	2,477,615	four factor
403	Depreciation	10,192,690	7,444,086	2,748,604	four factor
404	Amort of LTD term plant	7,162,267	5,184,914	1,977,353	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

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	04/13/2012	End of 2011/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)				
3	Net Sales (Account 447)				
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
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46	TOTAL				

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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	04/13/2012	End of 2011/Q4

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	621	MW	126,119			
2	Reactive Supply and Voltage						
3	Regulation and Frequency Response	176,508	MWh	25,833	72,135	MW	644,891
4	Energy Imbalance				545	MW	1,078,492
5	Operating Reserve - Spinning	12,462	MWh	166,436	67,290	MWh	775,938
6	Operating Reserve - Supplement	4,289	MWh	38,820	19,000	MWh	199,740
7	Other	1,332,314	MW	11,910,891	1,332,314	MW	11,910,891
8	Total (Lines 1 thru 7)	1,526,194		12,268,099	1,491,284		14,609,952

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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Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/Q4

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	2,226	11	800	1,520	365	139	20		
2	February	2,212	1	800	1,554	348	139	40	98	
3	March	1,891	1	1900	1,325	269	139	32	87	107
4	Total for Quarter 1	6,329			4,399	982	417	92	185	107
5	April	1,721	29	900	1,242	246	139	15	93	127
6	May	1,647	3	800	1,184	245	141	33	77	268
7	June	1,726	28	1700	890	225	141	36	470	107
8	Total for Quarter 2	5,094			3,316	716	421	84	640	502
9	July	2,229	7	1600	1,212	251	142	31	624	128
10	August	2,174	25	1600	1,403	251	141	47	378	459
11	September	2,029	12	1700	1,184	234	141	36	470	357
12	Total for Quarter 3	6,432			3,799	736	424	114	1,472	944
13	October	2,077	25	800	1,120	247	139	18	571	245
14	November	2,161	6	1900	1,495	239	138	29	289	332
15	December	2,086	13	1800	1,497	295	138	40	156	160
16	Total for Quarter 4	6,324			4,112	781	415	87	1,016	737
17	Total Year to Date/Year	24,179			15,626	3,215	1,677	377	3,313	2,290

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	04/13/2012	End of 2011/Q4

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	1,723,844
4	Nuclear	
5	Hydro-Conventional	4,534,293
6	Hydro-Pumped Storage	
7	Other	723,596
8	Less Energy for Pumping	
9	Net Generation (Enter Total of lines 3 through 8)	6,981,733
10	Purchases	6,724,582
11	Power Exchanges:	
12	Received	543,343
13	Delivered	544,267
14	Net Exchanges (Line 12 minus line 13)	-924
15	Transmission For Other (Wheeling)	
16	Received	3,322,223
17	Delivered	3,322,223
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)	13,705,391

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	9,035,133
23	Requirements Sales for Resale (See instruction 4, page 311.)	
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	4,084,890
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	12,962
27	Total Energy Losses	572,406
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	13,705,391

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	04/13/2012	End of 2011/Q4

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 (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	1,238,294	297,020	1,669	11	0800
30	February	1,124,385	278,878	1,634	24	1900
31	March	1,049,047	227,575	1,439	1	1900
32	April	1,127,384	363,789	1,295	19	0800
33	May	1,103,475	382,950	1,205	3	0800
34	June	1,065,344	361,988	1,290	28	1400
35	July	1,272,866	514,442	1,399	18	1700
36	August	1,063,916	247,363	1,535	25	1600
37	September	1,050,895	324,848	1,391	8	1700
38	October	1,074,422	326,642	1,308	26	0800
39	November	1,212,341	373,335	1,463	16	0800
40	December	1,323,022	386,060	1,536	12	1800
41	TOTAL	13,705,391	4,084,890			

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	04/13/2012	End of 2011/Q4

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)	305			15		
7	Plant Hours Connected to Load	2878			11		
8	Net Continuous Plant Capability (Megawatts)	278			61		
9	When Not Limited by Condenser Water	278			0		
10	When Limited by Condenser Water	278			0		
11	Average Number of Employees	26			1		
12	Net Generation, Exclusive of Plant Use - KWh	705060000			289000		
13	Cost of Plant: Land and Land Rights	0			157277		
14	Structures and Improvements	11404321			649350		
15	Equipment Costs	150343022			13223841		
16	Asset Retirement Costs	351682			0		
17	Total Cost	162099025			14030468		
18	Cost per KW of Installed Capacity (line 17/5) Including	564.8050			227.0302		
19	Production Expenses: Oper, Supv, & Engr	1388084			16276		
20	Fuel	25676757			25845		
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	737505			25634		
26	Misc Steam (or Nuclear) Power Expenses	130150			0		
27	Rents	-53			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	375406			-268		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	946608			79014		
33	Maintenance of Misc Steam (or Nuclear) Plant	34423			0		
34	Total Production Expenses	29288880			146501		
35	Expenses per Net KWh	0.0415			0.5069		
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	4885955	0	0	6140	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1015000	0	0	1020000	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	5.255	0.000	0.000	4.209	0.000	0.000
41	Average Cost of Fuel per Unit Burned	5.255	0.000	0.000	4.209	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	5.178	0.000	0.000	4.127	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.036	0.000	0.000	0.089	0.000	0.000
44	Average BTU per KWh Net Generation	7034.000	0.000	0.000	21671.000	0.000	0.000

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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

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
		49			226			87	6
		7041			8732			100	7
		50			222			149	8
		50			222			0	9
		50			222			0	10
		31			185			2	11
		291125000			1432719000			7784000	12
		941300			1289095			621682	13
		24972282			100708158			3258386	14
		68248040			195830246			56779395	15
		450687			134589			0	16
		94612309			297962088			60659463	17
		1866.1205			1276.6156			364.3211	18
		297508			190834			5383	19
		12914735			18339428			424032	20
		0			0			0	21
		709559			3593901			0	22
		0			0			0	23
		0			0			0	24
		816839			93372			346210	25
		366766			1858634			0	26
		0			32398			0	27
		0			0			0	28
		150522			396605			909	29
		41915			681596			2045	30
		1483616			4605356			0	31
		746359			655211			283769	32
		173174			679172			0	33
		17700993			31126507			1062348	34
		0.0608			0.0217			0.1365	35
Wood	Gas		Coal	Oil		Gas			36
TON	MCF		TON	BBL		MCF			37
501279	6135	0	898634	2445	0	102349	0	0	38
8500000	1020000	0	16905667	140000	0	1015000	0	0	39
25.724	3.236	0.000	20.081	120.294	0.000	4.143	0.000	0.000	40
25.724	3.236	0.000	20.081	120.294	0.000	4.143	0.000	0.000	41
3.030	3.172	0.000	1.190	20.310	0.000	4.082	0.000	0.000	42
0.044	0.038	0.000	0.013	0.000	0.000	0.055	0.000	0.000	43
14638.000	0.000	0.000	10615.000	0.000	0.000	13346.000	0.000	0.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a 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: *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	482			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	1			0		
12	Net Generation, Exclusive of Plant Use - KWh	9088000			0		
13	Cost of Plant: Land and Land Rights	144733			0		
14	Structures and Improvements	1175864			0		
15	Equipment Costs	31136453			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	32457050			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	1319.3923			0		
19	Production Expenses: Oper, Supv, & Engr	20202			0		
20	Fuel	395557			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	99710			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	40709			0		
30	Maintenance of Structures	8505			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	266293			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	830976			0		
35	Expenses per Net KWh	0.0914			0.0000		
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	90015	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1015000	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	4.394	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	4.394	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	4.329	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.044	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	10053.000	0.000	0.000	0.000	0.000	0.000

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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

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: (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
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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	04/13/2012	End of 2011/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)	16	10
7	Plant Hours Connect to Load	8,644	8,592
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	15	10
10	(b) Under the Most Adverse Oper Conditions	14	10
11	Average Number of Employees	1	1
12	Net Generation, Exclusive of Plant Use - Kwh	109,630,000	73,289,000
13	Cost of Plant		
14	Land and Land Rights	0	1,081,854
15	Structures and Improvements	8,443,779	584,216
16	Reservoirs, Dams, and Waterways	9,971,042	7,667,921
17	Equipment Costs	12,743,784	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)	31,209,053	14,895,226
21	Cost per KW of Installed Capacity (line 20 / 5)	2,108.7198	1,489.5226
22	Production Expenses		
23	Operation Supervision and Engineering	545	379
24	Water for Power	0	0
25	Hydraulic Expenses	4,918	1,201
26	Electric Expenses	502,162	497,364
27	Misc Hydraulic Power Generation Expenses	20,671	41,474
28	Rents	0	0
29	Maintenance Supervision and Engineering	2,678	67,509
30	Maintenance of Structures	5,270	6,114
31	Maintenance of Reservoirs, Dams, and Waterways	96,336	1,629,212
32	Maintenance of Electric Plant	70,810	65,661
33	Maintenance of Misc Hydraulic Plant	6,688	5,898
34	Total Production Expenses (total 23 thru 33)	710,078	2,314,812
35	Expenses per net KWh	0.0065	0.0316

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	04/13/2012	End of 2011/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. 2058 Plant Name: Cabinet Gorge (d)	FERC Licensed Project No. 2058 Plant Name: Noxon Rapids (e)	FERC Licensed Project No. 2545 Plant Name: Long Lake (f)	Line No.
Storage	Storage	Storage	1
Outdoor	Outdoor	Conventional	2
1952	1959	1915	3
1953	1977	1924	4
265.00	480.60	70.00	5
250	408	89	6
8,752	7,515	7,466	7
			8
255	562	87	9
217	288	86	10
11	12	5	11
1,292,344,000	2,109,683,000	555,565,000	12
			13
11,385,537	35,831,527	1,597,959	14
10,780,755	14,738,747	2,225,603	15
31,133,950	32,297,629	16,672,732	16
46,789,901	98,369,380	12,176,179	17
1,098,564	225,369	0	18
0	0	0	19
101,188,707	181,462,652	32,672,473	20
381.8442	377.5752	466.7496	21
			22
124,389	99,117	40	23
0	0	0	24
22,778	83,708	9,368	25
1,109,046	1,136,449	733,309	26
145,238	179,186	62,966	27
0	0	0	28
20,826	104,342	11,246	29
151,002	130,319	47,642	30
199,643	114,602	580,574	31
511,688	314,641	256,943	32
84,762	74,511	10,354	33
2,369,372	2,236,875	1,712,442	34
0.0018	0.0011	0.0031	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	04/13/2012	End of 2011/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: Nine Mile Falls (b)	FERC Licensed Project No. 2545 Plant Name: Post Falls (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Storage
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1908	1906
4	Year Last Unit was Installed	1994	1980
5	Total installed cap (Gen name plate Rating in MW)	26.40	14.80
6	Net Peak Demand on Plant-Megawatts (60 minutes)	21	16
7	Plant Hours Connect to Load	8,747	8,735
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	18	18
10	(b) Under the Most Adverse Oper Conditions	18	15
11	Average Number of Employees	2	2
12	Net Generation, Exclusive of Plant Use - Kwh	90,046,000	90,452,000
13	Cost of Plant		
14	Land and Land Rights	33,429	3,076,554
15	Structures and Improvements	3,943,110	1,369,359
16	Reservoirs, Dams, and Waterways	13,561,817	6,344,384
17	Equipment Costs	12,560,784	3,171,979
18	Roads, Railroads, and Bridges	625,181	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	30,724,321	13,962,276
21	Cost per KW of Installed Capacity (line 20 / 5)	1,163.8000	943.3970
22	Production Expenses		
23	Operation Supervision and Engineering	1,500	97
24	Water for Power	0	0
25	Hydraulic Expenses	1,385	0
26	Electric Expenses	560,812	589,073
27	Misc Hydraulic Power Generation Expenses	45,897	35,464
28	Rents	0	0
29	Maintenance Supervision and Engineering	60,563	12,933
30	Maintenance of Structures	11,687	5,579
31	Maintenance of Reservoirs, Dams, and Waterways	119,871	76,070
32	Maintenance of Electric Plant	406,664	182,071
33	Maintenance of Misc Hydraulic Plant	5,053	6,037
34	Total Production Expenses (total 23 thru 33)	1,213,432	907,324
35	Expenses per net KWh	0.0135	0.0100

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	04/13/2012	End of 2011/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. 0 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
37	0	0	6
7,440	0	0	7
			8
35	0	0	9
35	0	0	10
5	0	0	11
213,284,000	0	0	12
			13
4,325,371	0	0	14
1,188,042	0	0	15
5,065,501	0	0	16
6,152,709	0	0	17
0	0	0	18
0	0	0	19
16,731,623	0	0	20
522.8632	0.0000	0.0000	21
			22
4,321	0	0	23
0	0	0	24
10,126	0	0	25
608,687	0	0	26
23,399	0	0	27
757,954	0	0	28
4,339	0	0	29
37,255	0	0	30
89,321	0	0	31
197,837	0	0	32
32,790	0	0	33
1,766,029	0	0	34
0.0083	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	04/13/2012	End of 2011/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. 0 Plant Name: (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)		
2	Plant Construction type (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total installed cap (Gen name plate Rating in MW)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	0
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	0	0
35	Expenses per net KWh	0.0000	0.0000

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	04/13/2012	End of 2011/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. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			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
0.0000	0.0000	0.0000	21
			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

Schedule Page: 406 Line No.: -2 Column: b

License period from June 1, 2009 to May 31, 2059.

Schedule Page: 406 Line No.: -2 Column: c

License period from June 1, 2009 to May 31, 2059.

Schedule Page: 406 Line No.: -2 Column: d

License period from March 1, 2001 to February 28, 2046

Schedule Page: 406 Line No.: -2 Column: e

License period from March 1, 2001 to February 28, 2046.

Schedule Page: 406 Line No.: -2 Column: f

License period from June 1, 2009 to May 31, 2059.

Schedule Page: 406.1 Line No.: -2 Column: b

License period from June 1, 2009 to May 31, 2059.

Schedule Page: 406.1 Line No.: -2 Column: c

Licensed period from June 1, 2009 to May 31, 2059.

Schedule Page: 406.1 Line No.: -2 Column: d

Not a licensed project.

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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	04/13/2012	End of 2011/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	1,375,000	9,178,263
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7						
8						
9						
10						
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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	04/13/2012	End of 2011/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	80,249	77,906	39,996	Nat Gas	473	1
						2
						3
						4
						5
						6
						7
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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	04/13/2012	End of 2011/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		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	Circuits (h)
1	Group Sum		60.00	60.00		1.00		
2								
3	Group Sum		115.00	115.00		1,544.00		
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	2,207.00	3.00	32

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	04/13/2012	End of 2011/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	70,092	206,130					1
								2
	9,848,311	108,275,898	118,124,209	374,817	1,079,305	884	1,455,006	3
								4
1272 ACSS								5
1272 ACSS	17,912	1,316,679	1,334,591		24,734		24,734	6
1272 ACSS								7
1272 ACSS	30,323	3,275,357	3,305,680		22,522		22,522	8
1272 ACSS								9
1590 ACSS								10
1590 ACSR	1,118,774	36,029,040	37,147,814	508	518,645		519,153	11
1272 ACSS								12
1272 McMAL	456,162	8,679,839	9,136,001	1,011	11,034		12,045	13
1590 ACSS	570,207	47,630,821	48,201,028		6,499		6,499	14
1272 ACSR								15
954 McMAL	1,052,733	17,987,859	19,040,592	4,332	31,449		35,781	16
954 McMAL	177,733	1,091,601	1,269,334	29,781	23,946		53,727	17
954 McMAL								18
954 McMAL	240,045	2,605,672	2,845,717	1,788	18,107		19,895	19
1272 McMAL								20
1272 McMAL	86,228	3,698,377	3,784,605	40,455	114,132		154,587	21
1272 McMAL								22
1272 McMAL	623,984	6,934,229	7,558,213	19,732	5,588		25,320	23
1272 McMAL								24
1272 McMAL	872,150	10,046,041	10,918,191		8,676		8,676	25
1272 McMAL								26
1272 McMAL	70,781	2,673,767	2,744,548	521	124,361		124,882	27
1272 McMAL								28
1272 McMAL		19,521	19,521	980			980	29
1272 McMAL								30
1272 McMAL	292,838	3,308,408	3,601,246		267,967		267,967	31
1272 McMAL	36,461	594,543	631,004		96		96	32
1590 ACSR	106,581	2,546,756	2,653,337	491			491	33
1272 McMAL	201,359	1,298,111	1,499,470					34
	595,789	29,897,923	30,493,712	63,167	311,421	81,739	456,327	35
	16,534,409	287,980,534	304,514,943	537,583	2,568,482	82,623	3,188,688	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	04/13/2012	End of 2011/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		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)	(c)	Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1	No additions during 2011						
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
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	04/13/2012	End of 2011/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) (k)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
									1
									2
									3
									4
									5
									6
									7
									8
									9
									10
									11
									12
									13
									14
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									43
									44

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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		Frcd Oil & Air Fan	4	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		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
28	3		Two Stg/Pt/Frcd Oil	15	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	1	FrcAir/FrcOil/AirFan	2	36	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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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	Pullman Temp	Dist Unattended	115.00	13.80	
3	Ross Park	Distr. Unattended	115.00	13.80	
4	Roxboro	Distr. Unattended	115.00	24.00	
5	Shawnee	Trans. Unattended	230.00	115.00	13.80
6	Silver Lake	Distr. Unattended	115.00	13.80	
7	Southeast	Distr. Unattended	115.00	13.80	
8	South Othello	Distr. Unattended	115.00	13.80	
9	South Pullman	Distr. Unattended	115.00	13.80	
10	Sunset	Distr. Unattended	115.00	13.80	
11	Terre View	Dist. Unattended	115.00	13.80	
12	Third & Hatch	Distr. Unattended	115.00	13.80	
13	Turner	Dist. Unattended	115.00	13.80	
14	Waikiki	Distr. Unattended	115.00	13.80	
15	West Side	Trans. Unattended	230.00	115.00	13.80
16	Other: 28substa less than 10MVA	Distr. Unattended			
17					
18	STATE OF IDAHO				
19	Appleway	Dist. Unattended	115.00	13.80	
20	Avondale	Dist. Unattended	115.00	13.80	
21	Benewah	Trans. Unattended	230.00	115.00	13.80
22	Big Creek	Distr. Unattended	115.00	13.80	
23	Blue Creek	Distr. Unattended	115.00	13.80	
24	Bunker Hill Limited	Distr. Unattended	115.00	13.80	
25	Cabinet Gorge (Switchyard)	Trans. Unattended	230.00	115.00	13.80
26	Clark Fork	Distr. Unattended	115.00	21.80	
27	Coeur d'Alene 15th Ave	Distr. Unattended	115.00	13.80	
28	Cottonwood	Distr. Unattended	115.00	24.90	
29	Dalton	Distr. Unattended	115.00	13.80	
30	Grangeville	Distr. Unattended	115.00	13.80	
31	Holbrook	Distr. Unattended	115.00	13.80	
32	Huetter	Distr. Unattended	115.00	13.80	
33	Idaho Road	Distr Unattended	115.00	13.80	
34	Juliaetta	Distr. Unattended	115.00	13.80	
35	Kamiah	Dist. Unattended	115.00	13.80	
36	Kooskia	Distr. Unattended	115.00	13.80	
37	Lolo	Tran & Dist Unattnd	230.00	115.00	13.80
38	Moscow	Distr. Unattended	115.00	13.80	
39	Moscow 230Kv	Tran & Dist Unattnd	230.00	115.00	13.80
40	North Moscow	Distr. Unattended	115.00	13.80	

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	04/13/2012	End of 2011/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
12	1		Frcd Oil & Air Fan	1	20	2
30	2		Two Stage Fan	2	60	3
24	2		Two Stage Fan	2	40	4
150	1		Two Stage Fan	1	250	5
12	1		Frcd Oil & Air Fan	1	20	6
30	2		Two Stage Fan	2	50	7
12	1		Two Stage Fan	1	20	8
30	2		Two Stage Fan	2	50	9
33	2		Two Stage Fan & Caps	50	55	10
12	1		Two Stage Fan	1	20	11
54	3		Two Stg Fan & Cap	103	90	12
36	2		Two Stg Fan	2	60	13
24	2		Two Stage Fan	2	40	14
250	2					15
166	34	3				16
						17
						18
36	2		Two Stage Fan	2	60	19
12	1		Two Stage Fan	1	20	20
75	1		Two Stage Fan & Caps	223	125	21
18	2		Portable Fan	2	22	22
20	3	1				23
12	1		Frcd Air Fan	1	16	24
75	1		Two Stage Fan	1	125	25
10	1		Frcd Air Fan	1	13	26
36	2		Two Stage Fan	2	60	27
12	1		Two Stage Fan	1	20	28
24	2		FrcOil/Air2StgFan	2	40	29
25	4		FrcdOil/Air/Pt Fan&C	17	34	30
12	1		Two Stage Fan	1	20	31
12	1		Two Stage Fan	1	20	32
12	1		Two Stage Fan	1	20	33
12	1		Frcd Oil & Air Fan	1	20	34
12	1		Two Stage Fan	1	20	35
15	3		Frcd Air Fan	2	20	36
262	3		Frcd Oil/Air/Two Stg	1	270	37
24	2		FrOil/Air/2Stg Fan	2	40	38
137	2	1	Capacitors	48		39
12	1		Two Stage Fan	1	20	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	04/13/2012	End of 2011/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 230kV	Trans Unattended	230.00	115.00	13.80
2	North Lewiston	Distr. Unattended	115.00	13.80	
3	Oden	Distr. Unattended	115.00	21.80	
4	Oldtown	Distr. Unattended	115.00	21.80	
5	Orofino	Distr. Unattended	115.00	13.80	
6	Osburn	Distr. Unattended	115.00	13.80	
7	Pine Creek	Tran & Dist Unattnd	230.00	115.00	13.80
8	Pleasant View	Distr. Unattended	115.00	13.80	
9	Plummer	Dist Unattended	115.00	13.80	
10	Post Falls	Distr. Unattended	115.00	13.80	
11	Potlatch	Distr. Unattended	115.00	13.80	
12	Prarie	Distr. Unattended	115.00	13.80	
13	Priest River	Distr. Unattended	115.00	20.80	
14	Rathdrum	Trans & Distr Unattd	230.00	115.00	13.80
15	Sagle	Dist. Unattended	115.00	20.80	
16	Sandpoint	Distr. Unattended	115.00	20.80	
17	South Lewiston	Distr. Unattended	115.00	13.80	
18	Sweetwater	Distr. Unattended	115.00	24.90	
19	St. Maries	Distr. Unattended	115.00	23.90	
20	Tenth & Stewart	Distr. Unattended	115.00	13.80	
21	Wallace	Distr. Unattended	115.00	13.80	
22	Other: 13 substa less than 10 MVA	Distr. Unattended			
23					
24	STATE OF MONTANA				
25	1 substation less than 10 MVA	Distr. Unattended			
26					
27	SUBSTA. @ GENERATING PLANTS				
28	STATE OF WASHINGTON				
29	Boulder Park	Trans. Attended	115.00	13.80	
30	Kettle Falls	Trans. Attended	115.00	13.80	
31	Long Lake	Trans. Attended	115.00	4.00	
32	Nine Mile	Trans. Attended	115.00	13.80	2.30
33	Little Falls	Trans. Attended	115.00	4.00	
34	Northeast	Trans. Attended	115.00	13.80	
35	Post Street	Trans. Attended	13.80	4.00	
36					
37	STATE OF IDAHO				
38	Cabinet Gorge (HED)	Trans. Attended	230.00	13.80	
39	Post Falls	Trans. Attended	115.00	2.30	
40	Rathdrum	Trans. Attended	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) 04/13/2012	Year/Period of Report End of 2011/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.
250	1	1	Capacitors	48		1
10	3					2
10	1		Frcd Air Fan		13	3
18	2		Frcd Air Fan	2	22	4
20	2		Frcd Oil & Air Fan	1	28	5
12	1		Portable Fan	1	15	6
262	3		Capacitors	48		7
12	1		Two Stage Fan	1	20	8
12	1		Two Stage Fan	1	20	9
18	1		Two Stage Fan	1	30	10
15	2		Portable Fan	2	19	11
12	1		Frcd Oil & Air Fan	1	20	12
10	1		Frcd Air Fan	1	13	13
474	4		Frcd Oil & Air Fan	50	490	14
12	1		Two Stage Fan	1	20	15
30	3		Frcd Air Fan	3	38	16
27	4		Port Fan/FrcdOil/Air	4	39	17
12	1		Frcd Oil & Air Fan	1	20	18
24	2		Two Stage Fan	2	40	19
30	2		Frcd Oil/Air/Two Stg	2	50	20
10	3					21
70	13					22
						23
						24
5	1					25
						26
						27
						28
36	1		Two Stage Fan	1	60	29
34	1	1	Two Stage Fan	1	62	30
80	4	1				31
24	2		Frcd Oil & Air Fan	1	40	32
24	2		Frcd Oil & Air Fan	2	40	33
36	1		Two Stage Fan	1	60	34
35	2					35
						36
						37
300	6	1	Frcd Oil and Air Fan			38
16	2		Frcd Air/Oil/Air Fan	2	21	39
114	2	3	Two Stage Fan	2	190	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	04/13/2012	End of 2011/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 MONTANA				
2	Noxon	Trans. Attended	230.00	13.80	
3					
4	STATE OF OREGON				
5	Coyote Springs II	Trans. Attended	500.00	13.80	18.00
6					
7	SUMMARY:				
8	Washington:				
9	4 subs	Trans. Unattended			
10	76subs	Distr. Unattended			
11	1 subs	Tran & Dist Unattnd			
12	7 subs	Trans. Attended			
13	Idaho:				
14	3 subs	Trans. Unattended			
15	48 subs	Distr. Unattended			
16	4subs	Tran & Dist Unattnd			
17	3 subs	Trans. Attended			
18	Montana: 1 sub	Trans. Attended			
19	1 sub	Distr. Unattended			
20	Oregon: 1 sub	Trans. Unattended			
21	System: 149 subs				
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
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	04/13/2012	End of 2011/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
435	9	1	Two Stage Fan	2	635	2
						3
						4
213	1	1	Two Stage fan	1	355	5
						6
						7
						8
850						9
1200						10
536						11
269						12
						13
400						14
668						15
1135						16
430						17
435						18
5						19
213						20
6141						21
						22
						23
						24
						25
						26
						27
						28
						29
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						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) 04/13/2012	Year/Period of Report End of 2011/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	Effective May 1, 2011 assets held at Avista Energy	Avista Energy	117100	4,415,045
3	associated with Jackson Prairie Gas Storage		107500	7,128,640
4	Facility were transferred to Avista Utilities			
5	to be utilized in the regulated business.			
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				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
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41				
42				

Avista Corp.

2011

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* 4/13/2012	End of 2011 / 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)	TOTAL SYSTEM - IDAHO Prior Year (d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)	300-301	490,826,505	497,983,173
3	Operating Expenses			
4	Operation Expenses (401)	320-323	372,734,080	376,224,721
5	Maintenance Expenses (402)	320-323	1,449,373	1,537,129
6	Depreciation Expense (403)	336-337	32,159,853	31,409,908
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	-	-
8	Amortization & Depletion of Utility Plant (404-405)	336-337	2,650,538	2,323,359
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)		(9,642,712)	(3,012,318)
13	(Less) Regulatory Credits (407.4)		(2,460,999)	(3,408,851)
14	Taxes Other Than Income Taxes (408.1)	262-263	14,029,701	12,468,006
15	Income Taxes - Federal (409.1)	262-263	11,858,943	9,022,201
16	- Other (409.1)	262-263	-	-
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	8,946,025	11,851,175
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	-	-
19	Investment Tax Credit Adjustment - Net (411.4)	266	(69,896)	(62,045)
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)		431,722,210	438,420,589
26	Net Utility Operating Income (Total line 2 less 25)		59,104,295	59,562,584

Name of Respondent	This Report is:	Date of Report	Year / Period of Report
Avista Corporation	[X] An Original [ ] A Resubmission	mm/dd/yyyy 4/13/2012	End of 2011 / Q4

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 Current Year (e)	ELECTRIC UTILITY Prior Year (f)	GAS UTILITY Current Year (g)	GAS UTILITY Prior Year (h)	OTHER UTILITY Current Year (i)	OTHER UTILITY Prior Year (j)	Line No.
						1
374,727,202	384,215,427	116,099,303	113,767,746			2
						3
276,342,925	278,155,614	96,391,155	98,069,107			4
		1,449,373	1,537,129			5
27,602,346	27,054,409	4,557,507	4,355,499			6
						7
2,133,508	1,897,649	517,030	425,710			8
67,304	67,304					9
						10
						11
(9,332,082)	(2,839,169)	(310,630)	(173,149)			12
(2,460,999)	(3,408,851)					13
11,783,114	10,731,713	2,246,587	1,736,293			14
11,102,578	11,243,426	756,365	(2,221,225)			15
						16
6,419,332	7,164,697	2,526,693	4,686,478			17
						18
(52,928)	(44,441)	(16,968)	(17,604)			19
						20
						21
						22
						23
						24
323,605,098	330,022,351	108,117,112	108,398,238	-	-	25
51,122,104	54,193,076	7,982,191	5,369,508	-	-	26

Name of Respondent	This Report is:	Date of Report	Year / Period of Report
Avista Corporation	[X] An Original [ ] A Resubmission	*mm/dd/yyyy* 4/13/2012	End of 2011 / 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)	1,273,609,658	1,040,371,226
4	Property Under Capital Leases	539,883	-
5	Plant Purchased or Sold	-	-
6	Completed Construction not Classified	-	-
7	Experimental Plant Unclassified	-	-
8	Total (Total lines 3 through 7)	1,274,149,541	1,040,371,226
9	Leased to Others	-	-
10	Held for Future Use	342,220	126,640
11	Construction Work in Progress	25,936,903	18,487,561
12	Acquisition Adjustments	-	-
13	Total Utility Plant (Total lines 8 through 12)	1,300,428,664	1,058,985,427
14	Accumulated Provision for Depreciation, Amortization, and Depletion	443,552,903	368,893,863
15	Net Utility Plant (Line 13 less line 14)	856,875,761	690,091,564
16	Detail of Accumulated Provision for Depreciation, Amortization, and Depletion		
17	In Service		
18	Depreciation	436,062,918	366,539,400
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	7,489,985	2,354,463
22	Total (Total lines 18 through 21)	443,552,903	368,893,863
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)	443,552,903	368,893,863

(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* 4/13/2012	End of 2011 / 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
169,548,716				63,689,716	3
480,564				59,319	4
-				-	5
-				-	6
-				-	7
170,029,280	-	-	-	63,749,035	8
-				-	9
215,580				-	10
1,241,836				6,207,506	11
-				-	12
171,486,696	-	-	-	69,956,541	13
55,993,746	-	-	-	18,665,294	14
115,492,950	-	-	-	51,291,247	15
					16
					17
55,783,400				13,740,118	18
-				-	19
-				-	20
210,346				4,925,176	21
55,993,746	-	-	-	18,665,294	22
					23
-				-	24
-				-	25
-	-	-	-	-	26
					27
-				-	28
-				-	29
-	-	-	-	-	30
-				-	31
-				-	32
55,993,746	-	-	-	18,665,294	33

Name of Respondent	This Report is:	Date of Report	Year / Period of Report
Avista Corporation	[X] An Original [ ] A Resubmission	mm/dd/yyyy 4/13/2012	End of 2011 / 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	10,609,425	
4	303 Miscellaneous Intangible Plant		13,008
5	TOTAL Intangible Plant (Total of lines 2, 3, and 4)	10,609,425	13,008
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	310 Land and Land Rights		
9	311 Structures and Improvements		199,832
10	312 Boiler Plant Equipment		799,407
11	313 Engines and Engine-Driven Generators		2,353
12	314 Turbogenerator Units		1,568,742
13	315 Accessory Electric Equipment		59,126
14	316 Miscellaneous Power Plant Equipment		94,439
15	317 Asset Retirement Costs for Steam Production		
16	TOTAL Steam Production Plant (Total of lines 8 through 15)	-	2,723,899
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	6,612,887	443,206
28	331 Structures and Improvements	11,478,401	428,090
29	332 Reservoirs, Dams, and Waterways	36,131,059	43,102
30	333 Water Wheels, Turbines, and Generators	39,674,285	3,682,470
31	334 Accessory Electric Equipment	6,172,922	143,388
32	335 Miscellaneous Power Plant Equipment	2,826,852	755,858
33	336 Roads, Railroads, and Bridges	1,098,564	
34	337 Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Total of lines 27 through 34)	103,994,970	5,496,114
36	D. Other Production Plant		
37	340 Land and Land Rights	621,682	
38	341 Structures and Improvements	3,258,387	19,299
39	342 Fuel Holders, Products, and Accessories	1,787,786	3,898
40	343 Prime Movers	3,658,328	
41	344 Generators	49,066,613	30,697
42	345 Accessory Electric Equipment	2,567,151	179,493
43	346 Miscellaneous Power Plant Equipment		15,618
44	347 Asset Retirement Costs for Other Production		
45	TOTAL Other Production Plant (Total of lines 37 through 44)	60,959,947	249,005
46	TOTAL Production Plant (Total of lines 16, 25, 35, and 45)	164,954,917	8,469,018

(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 4/13/2012	End of 2011 / 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
	4,702,083		15,311,508		3
147,583	1,119,741		985,166		4
147,583	5,821,824	-	16,296,674		5
					6
					7
	775,285		775,285		8
17,998	43,504,686		43,686,520		9
332,458	58,562,235		59,029,184		10
			2,353		11
547,402	16,795,382		17,816,722		12
3,421	9,362,105		9,417,810		13
8,568	5,441,672		5,527,543		14
			-		15
909,847	134,441,365	-	136,255,417		16
					17
			-		18
			-		19
			-		20
			-		21
			-		22
			-		23
			-		24
-	-	-	-		25
					26
	12,872,591		19,928,684		27
41,787	3,177,203		15,041,907		28
16,419	6,497,984		42,655,726		29
1,337,469	12,042,029		54,061,315		30
	5,488,970		11,805,280		31
56,089	(733,194)		2,793,427		32
	(403,516)		695,048		33
			-		34
1,451,764	38,942,067	-	146,981,387		35
					36
	(307,046)		314,636		37
	2,453,516		5,731,202		38
	5,564,761		7,356,445		39
	3,946,041		7,604,369		40
	20,221,814		69,319,124		41
139,813	3,277,502		5,884,333		42
	549,482		565,100		43
			-		44
139,813	35,706,070	-	96,775,209		45
2,501,424	209,089,502	-	380,012,013		46

Name of Respondent	This Report is:	Date of Report	Year / Period of Report
Avista Corporation	[X] An Original [ ] A Resubmission	mm/dd/yyyy 4/13/2012	End of 2011 / 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	8,326,312	(624,767)
49	352 Structures and Improvements	8,601,055	180,603
50	353 Station Equipment	79,067,252	6,258,042
51	354 Towers and Fixtures	556,655	
52	355 Poles and Fixtures	48,114,975	4,382,107
53	356 Overhead Conductors and Devices	29,238,415	2,507,457
54	357 Underground Conduit		
55	358 Underground Conductors and Devices		
56	359 Roads and Trails	1,374,002	
57	359.1 Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Total of lines 48 through 57)	175,278,666	12,703,442
59	4. DISTRIBUTION PLANT		
60	360 Land and Land Rights	2,022,475	921,013
61	361 Structures and Improvements	4,506,979	705,209
62	362 Station Equipment	33,315,646	3,746,737
63	363 Storage Battery Equipment		
64	364 Poles, Towers, and Fixtures	90,127,883	4,738,771
65	365 Overhead Conductors and Devices	59,842,822	2,833,398
66	366 Underground Conduit	29,668,526	1,354,844
67	367 Underground Conductors and Devices	46,256,215	2,477,002
68	368 Line Transformers	61,261,670	2,646,953
69	369 Services	45,238,883	1,063,123
70	370 Meters	28,780,442	219,241
71	371 Installations on Customer Premises		
72	372 Leased Property on Customer Premises		
73	373 Street Lighting and Signal Systems	13,361,255	504,647
74	374 Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Total of lines 60 through 74)	414,382,796	21,210,938
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	101,907	260,372
87	390 Structures and Improvements	1,454,024	1,086,974
88	391 Office Furniture and Equipment		93,740
89	392 Transportation Equipment	2,749,968	611,417
90	393 Stores Equipment	14,745	1,721
91	394 Tools, Shop and Garage Equipment	397,685	40,397
92	395 Laboratory Equipment	104,127	
93	396 Power Operated Equipment	8,574,009	190,101
94	397 Communication Equipment	4,317,221	980,595
95	398 Miscellaneous Equipment	2,299	1,663
96	SUBTOTAL (Total of lines 86 through 95)	17,715,985	3,266,980
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)	17,715,985	3,266,980
100	TOTAL (Accounts 101 and 106)	782,941,789	45,663,386
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)	782,941,789	45,663,386

Name of Respondent	This Report is:	Date of Report	Year / Period of Report
Avista Corporation	[X] An Original [ ] A Resubmission	mm/dd/yyyy 4/13/2012	End of 2011 / 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
	(1,009,671)		6,691,874		48
	(2,949,795)		5,831,863		49
445,976	(14,218,946)		70,660,372		50
	5,394,542		5,951,197		51
53,394	(1,828,855)		50,614,833		52
10,520	7,409,771		39,145,123		53
	905,668		905,668		54
	809,933		809,933		55
	(723,209)		650,793		56
			-		57
509,890	(6,210,562)	-	181,261,656		58
					59
			2,943,488		60
	15,880		5,228,068		61
1,180,895	921,267		36,802,755		62
			-		63
133,319	34,906	(1)	94,768,240		64
108,664	10,464	-	62,578,020		65
17,289	3,578		31,009,659		66
144,942	2,053	10	48,590,338		67
39,556	1,413	(217)	63,870,263		68
26,912	(1,432)	(2)	46,273,660		69
	(113,165)	(8,259,573)	20,626,945		70
			-		71
			-		72
39,645			13,826,257		73
			-		74
1,691,222	874,964	(8,259,783)	426,517,693		75
					76
			-		77
			-		78
			-		79
			-		80
			-		81
			-		82
			-		83
-	-	-	-		84
					85
	7,509		369,788		86
79	506,721		3,047,640		87
	651,581		745,321		88
169,409	1,745,645		4,937,621		89
	120,220		136,686		90
55,978	541,247		923,351		91
31,184	278,346		351,289		92
424,560	3,236,577		11,576,127		93
67,786	8,959,459		14,189,489		94
32	1,948		5,878		95
749,028	16,049,253	-	36,283,190		96
					97
					98
749,028	16,049,253	-	36,283,190		99
5,599,147	225,624,981	(8,259,783)	1,040,371,226		100
					101
					102
					103
5,599,147	225,624,981	(8,259,783)	1,040,371,226		104

Name of Respondent	This Report is:	Date of Report	Year / Period of Report
Avista Corporation	[X] An Original [ ] A Resubmission	*mm/dd/yyyy* 4/13/2012	End of 2011 / 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)	Prior Year (c)
1	Sales of Electricity		
2	440 Residential Sales	107,877,413	100,732,420
3	442 Commercial and Industrial Sales (3)		
4	Small (or Commercial)	86,211,236	82,538,298
5	Large (or Industrial)	67,439,293	64,194,131
6	444 Public Street and Highway Lighting	2,376,108	2,250,093
7	445 Other Sales to Public Authorities	-	-
8	446 Sales to Railroads and Railways	-	-
9	448 Interdepartmental Sales	217,766	187,603
10	TOTAL Sales to Ultimate Customers	(1) 264,121,816	249,902,545
11	447 Sales for Resale	41,020,894	89,301,585
12	TOTAL Sales of Electricity	305,142,710	339,204,130
13	449.1 (Less) Provision for Rate Refunds	-	-
14	TOTAL Revenues Net of Provision for Refunds	305,142,710	339,204,130
15	Other Operating Revenues		
16	450 Forfeited Discounts	-	-
17	451 Miscellaneous Service Revenues	215,731	219,901
18	453 Sales of Water and Water Power	176,088	98,162
19	454 Rent from Electric Property	946,506	892,796
20	455 Interdepartmental Rents	-	-
21	456 Other Electric Revenues	63,813,040	39,445,502
22	456.1 Revenues from Transmission of Electricity for Others	4,433,127	4,325,301
23	457.1 Regional Control Service Revenues	-	-
24	457.2 Miscellaneous Revenues	-	-
25			
26	TOTAL Other Operating Revenues	69,584,492	44,981,662
27	TOTAL Electric Operating Revenues	374,727,202	384,185,792

Name of Respondent **Avista Corporation**	This Report is: [X] An Original [ ] A Resubmission	Date of Report *mm/dd/yyyy* 4/13/2012	Year / Period of Report End of 2011 / Q4

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
1,198,793	1,179,482	105,840	105,286		2
					3
996,844	987,327	16,633	16,573		4
1,225,366	1,210,786	476	476		5
8,971	8,888	125	124		6
-	-	-	-		7
-	-	-	-		8
2,557	2,250	38	28		9
(2) 3,432,531	3,388,733	123,112	122,487		10
1,419,675	2,178,025	-	-		11
4,852,206	5,566,758	123,112	122,487		12
-	-	-	-		13
4,852,206	5,566,758	123,112	122,487		14

(1) Includes $ (861,629) of unbilled revenues.

(2) Includes (8,122) MWH relating to unbilled revenues.

(3) Segregation of Commercial and Industrial made on basis of utilization of energy and not on size of account.

Name of Respondent	This Report is:	Date of Report	Year / Period of Report
Avista Corporation	[X] An Original [ ] A Resubmission	mm/dd/yyyy 4/13/2012	End of 2011 / Q4

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	174,731	180,875
5	501 Fuel	10,863,947	20,786,628
6	502 Steam Expenses	1,495,883	3,677,996
7	503 Steam from Other Sources	-	-
8	504 (Less) Steam Transferred-Cr.	-	-
9	505 Electric Expenses	316,390	37,137
10	506 Miscellaneous Steam Power Expenses	833,611	2,091,958
11	507 Rents	11,262	15,498
12	509 Allowances	-	-
13	TOTAL Operation (Total of lines 4 through 12)	13,695,824	26,790,092
14	Maintenance		
15	510 Maintenance Supervision and Engineering	204,091	342,519
16	511 Maintenance of Structures	251,492	476,268
17	512 Maintenance of Boiler Plant	2,116,527	3,142,255
18	513 Maintenance of Electric Plant	487,186	392,594
19	514 Maintenance of Miscellaneous Steam Plant	296,276	340,410
20	TOTAL Maintenance (Total of Lines 15 through 19)	3,355,572	4,694,046
21	TOTAL Steam Power Generation Expenses (Total lines 13 & 20)	17,051,396	31,484,138
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	895,522	934,058
45	536 Water for Power	388,681	313,836
46	537 Hydraulic Expenses	2,731,943	2,084,620
47	538 Electric Expenses	2,009,278	2,854,717
48	539 Miscellaneous Hydraulic Power Generation Expenses	244,582	472,910
49	540 Rents	2,299,679	2,035,361
50	TOTAL Operation (Total of lines 44 through 49)	8,569,685	8,695,502
51	Maintenance		
52	541 Maintenance Supervision and Engineering	193,655	173,675
53	542 Maintenance of Structures	146,256	375,386
54	543 Maintenance of Reservoirs, Dams, and Waterways	1,026,725	962,831
55	544 Maintenance of Electric Plant	814,630	989,047
56	545 Maintenance of Miscellaneous Hydraulic Plant	175,165	28,098
57	TOTAL Maintenance (Total of lines 53 through 57)	2,356,431	2,529,037
58	TOTAL Hydraulic Power Generation Expenses (Total of lines 50 & 58)	10,926,116	11,224,539
59			

Name of Respondent	This Report is:	Date of Report	Year / Period of Report
Avista Corporation	[X] An Original [ ] A Resubmission	mm/dd/yyyy 4/13/2012	End of 2011 / Q4

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	499,959	25,065
63	547 Fuel	19,111,767	14,903,439
64	548 Generation Expenses	374,463	150,490
65	549 Miscellaneous Other Power Generation Expenses	198,473	265,880
66	550 Rents	(11,067)	(11,784)
67	TOTAL Operation (Total of lines 62 through 66)	20,173,595	15,333,090
68	Maintenance		
69	551 Maintenance Supervision and Engineering	236,589	54,912
70	552 Maintenance of Structures	4,257	4,566
71	553 Maintenance of Generating and Electric Plant	514,713	108,558
72	554 Maintenance of Miscellaneous Other Power Generation Plant	53,795	33,497
73	TOTAL Maintenance (Total of lines 69 through 72)	809,354	201,533
74	TOTAL Other Power Generation Expenses	20,982,949	15,534,623
75	E. Other Power Supply Expenses		
76	555 Purchased Power	85,280,960	96,534,368
77	556 System Control and Load Dispatching	248,402	193,484
78	557 Other Expenses	86,945,012	47,480,397
79	TOTAL Other Power Supply Expenses (Total of lines 76 through 78)	172,474,374	144,208,249
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74, & 79)	221,434,835	202,451,549
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	560 Operation Supervision and Engineering	745,700	783,848
84	561 Load Dispatching	775,159	780,465
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	110,714	118,954
94	563 Overhead Lines Expenses	180,118	342,454
95	564 Underground Lines Expenses	-	-
96	565 Transmission of Electricity by Others	6,079,392	6,181,357
97	566 Miscellaneous Transmission Expenses	583,739	571,167
98	567 Rents	44,337	98,332
99	TOTAL Operation (Total of lines 83 through 98)	8,519,159	8,876,577
100	Maintenance		
101	568 Maintenance Supervision and Engineering	456,642	242,773
102	569 Maintenance of Structures	148,318	112,461
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	398,533	407,648
108	571 Maintenance of Overhead Lines	837,647	1,315,731
109	572 Maintenance of Underground Lines	774	134
110	573 Maintenance of Miscellaneous Transmission Plant	10,131	3,149
111	TOTAL Maintenance (Total of lines 101 through 110)	1,852,045	2,081,896
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	10,371,204	10,958,473

Name of Respondent	This Report is:	Date of Report	Year / Period of Report
Avista Corporation	[X] An Original [ ] A Resubmission	mm/dd/yyyy 4/13/2012	End of 2011 / Q4

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		
135	581 Load Dispatching	604,475	544,983
136	582 Station Expenses	243,446	255,535
137	583 Overhead Line Expenses	424,700	430,850
138	584 Underground Line Expenses	100,057	221,579
139	585 Street Lighting and Signal System Expenses	195,612	182,248
140	586 Meter Expenses	305,766	223,838
141	587 Customer Installations Expenses	299,434	399,146
142	588 Miscellaneous Expenses	2,265,407	1,705,994
143	589 Rents	81,698	87,090
144	TOTAL Operation (Total of lines 134 through 143)	4,520,595	4,051,263
145	Maintenance		
146	590 Maintenance Supervision and Engineering	400,047	429,059
147	591 Maintenance of Structures	93,155	152,578
148	592 Maintenance of Station Equipment	195,592	203,062
149	593 Maintenance of Overhead Lines	2,930,014	2,850,672
150	594 Maintenance of Underground Lines	336,670	277,358
151	595 Maintenance of Line Transformers	647,883	434,393
152	596 Maintenance of Street Lighting and Signal Systems	176,599	212,900
153	597 Maintenance of Meters	20,783	24,206
154	598 Maintenance of Miscellaneous Distribution Plant	82,942	41,510
155	TOTAL Maintenance (Total lines 146 through 154)	4,883,685	4,625,738
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	9,404,280	8,677,001
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	901 Supervision	217,546	203,657
160	902 Meter Reading Expenses	427,146	437,260
161	903 Customer Records and Collection Expenses	2,729,877	2,651,726
162	904 Uncollectable Accounts	904,089	575,171
163	905 Miscellaneous Customer Accounts Expenses	47,599	45,000
164	TOTAL Customer Accounts Expenses (Total of line 159 through 163)	4,326,257	3,912,814

Name of Respondent	This Report is:	Date of Report	Year / Period of Report
Avista Corporation	[X] An Original [ ] A Resubmission	mm/dd/yyyy 4/13/2012	End of 2011 / Q4

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	7,878,529	7,760,232
169	909 Informational and Instructional Expenses	308,833	297,416
170	910 Miscellaneous Customer Service and Informational Expenses	45,958	58,037
171	TOTAL Customer Service and Informational Expenses (Total lines 167 through 170)	8,233,320	8,115,685
172	7. SALES EXPENSES		
173	Operation		
174	911 Supervision	-	-
175	912 Demonstrating and Selling Expenses	4,152	1,626
176	913 Advertising Expenses	-	155
177	916 Miscellaneous Sales Expenses	(22)	15,864
178	TOTAL Sales Expenses (Total of lines 174 through 177)	4,130	17,645
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	920 Administrative and General Salaries	8,150,383	8,513,035
182	921 Office Supplies and Expenses	1,315,513	1,386,720
183	922 (Less) Administrative Expenses Transferred-Credit	(20,259)	(16,287)
184	923 Outside Services Employed	4,750,405	5,043,643
185	924 Property Insurance	403,349	437,241
186	925 Injuries and Damages	1,450,711	1,808,492
187	926 Employee Pensions and Benefits	391,971	343,886
188	927 Franchise Requirements	5,738	6,027
189	928 Regulatory Commission Expenses	2,058,197	1,927,068
190	929 (Less) Duplicate Charges-Cr.	-	-
191	930.1 General Advertising Expenses	-	67,651
192	930.2 Miscellaneous General Expenses	920,702	1,065,763
193	931 Rents	287,291	252,531
194	TOTAL Operation (Total of lines 181 through 193)	19,714,001	20,835,770
195	Maintenance		
196	935 Maintenance of General Plant	2,854,898	1,940,524
197	TOTAL Administrative and General Expenses (Total of lines 194 and 196)	22,568,899	22,776,294
198	TOTAL Elec Op and Maint Expns (Total lines 80, 112, 131, 156, 164, 171, 178, 197)	276,342,925	256,909,461

Name of Respondent Avista Corporation	This Report is: [X] An Original [ ] A Resubmission	Date of Report mm/dd/yyyy 4/13/2012	Year / Period of Report End of 2011 / Q4

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
17								
18								
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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 4/13/2012	End of 2011 / 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.
	3,991,169	39,458,251	43,449,420	235,593	808,513	884	1,044,989	1
			-				-	2
1590 ACSS			-				-	3
1590 ACSS			-				-	4
1590 ACSR	1,005,364	20,266,075	21,271,439	508	68,645	-	69,153	5
1272 McMAL			-				-	6
1272 McMAL	86,228	3,698,377	3,784,605	40,455	114,132	-	154,587	7
954 McMAL			-				-	8
1272 ACSR	663,750	10,914,879	11,578,629	4,332	28,615	-	32,947	9
954 McMAL	131,532	128,808	260,340	624	12,995	-	13,619	10
954 McMAL			-				-	11
954 McMAL	240,045	2,605,672	2,845,717	1,788	18,107	-	19,895	12
1272 McMAL	363,604	7,244,167	7,607,771	320	3,625	-	3,945	13
1272 McMAL	25,818	1,321,341	1,347,159	19,407	3,744	-	23,152	14
1272 McMAL	10,015	319,300	329,315	-	-	-	-	15
1590 ACSR	106,581	2,546,756	2,653,337	491	-	-	491	16
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