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

Form 1 Approved
OMB No. 1902-0021
(Expires 12/31/2011)
Form 1-F Approved
OMB No. 1902-0029
(Expires 12/31/2011)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 1/31/2012)

AVU-E

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UTILITIES COMMISSION

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 2010/Q4

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

IDENTIFICATION

01 Exact Legal Name of Respondent	02 Year/Period of Report
Avista Corporation	End of 2010/Q4

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

/ /

04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)*

1411 East Mission Avenue, Spokane, WA 99207

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

07 Address of Contact Person *(Street, City, State, Zip Code)*

1411 East Mission Avenue, Spokane, WA 99207

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(509) 495-4256	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011

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	04/15/2011
02 Title: VP, Controller, Prin. Acctg Officer		

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/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".

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".

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".

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	04/15/2011	End of 2010/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 Washington, 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

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	Advantage IQ, Inc.	Provider of utility bill	75.74	Subsidiary of
5		processing, payment and		Avista Capital
6		information services to multi		
7		site customers in North Amer.		
8				
9	Ecos IQ, Inc.	Formed in 2009 to acquire	100 by Advantage IQ	Subsidiary of
10		Ecos Consulting, Inc., an		Advantage IQ
11		energy efficiency solutions		
12		provider.		
13				
14	Avista Development, Inc.	Maintains an investment	100	Subsidiary of
15		portfolio of real estate and		Avista Capital
16		other investments.		
17				
18	Avista Energy, Inc.	Inactive	100	Subsidiary of
19				Avista Capital
20				
21	Avista Power, LLC	Inactive	100	Affiliate of
22				Avista Capital
23				
24	Avista Turbine Power, Inc.	Receives assignments of	100	Subsidiary of
25		purchase power agreements.		Avista Capital
26				
27	Avista Ventures, Inc.	Inactive	100	Subsidiary of

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	04/15/2011	End of 2010/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				Avista Capital
2				
3	Pentzer Corporation	Parent company of Bay Area	100	Subsidiary of
4		Manufacturing and Pentzer		Avista Capital
5		Venture Holdings.		
6				
7	Pentzer Venture Holdings	Inactive	100	Subsidiary of
8				Pentzer Corporation
9				
10	Bay Area Manufacturing	Holding Company	100	Subsidiary of
11				Pentzer Corporation
12				
13	Advanced Manufacturing and Development, Inc.	Performs custom sheet metal	82.95	Subsidiary of
14	dba Metalfx	manufacturing of electronic		Bay Area
15		enclosures, parts and systems		Manufacturing.
16		for the computer, telecom and		
17		medical industries. AM&D		
18		also has a wood products		
19		division.		
20				
21	Avista Receivables Corporation	Acquires and sells accounts	100	Subsidiary of
22		receivable of Avista Corp.		Avista Corp.
23				
24	Spokane Energy, LLC	Owns an electric capactiy	100	Affiliate of
25		contract.		Avista Corp.
26				
27				

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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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
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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Avista Capital II	An affiliated business trust	100	Affiliate of
2		formed by the Company.		Avista Corp.
3		Issued Pref. Trust Securities		
4				
5	Avista Northwest Resources, LLC	Formed in 2009 to own	100	Affiliate of
6		an interest in a venture		Avista Capital
7		fund investment		
8				
9	Steam Plant Square, LLC	Commercial office and retail	90	Affiliate of
10		leasing.		Avista Development
11				
12	Courtyard Office Center, LLC	Commercial office and retail	100	Affiliate of
13		leasing.		Avista Development
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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	04/15/2011	End of 2010/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	with responsibility 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 with responsibility for Transmission	D. F. Kopczynski	
21	and Distribution Operations		
22			
23	Vice President and Chief Counsel for Regulatory and	D. J. Meyer	
24	Governmental Affairs		
25			
26	Vice President, with responsibility for State and	K. O. Norwood	
27	Federal Regulation		
28			
29	Vice President, with responsibility for	R. D. Woodworth	
30	Sustainable Energy Solutions		
31			
32	Vice President, Finance	J. R. Thackston	
33			
34	Treasurer	D. C. Thoren	
35			
36	Vice President, Energy Resources	R. L. Storro	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/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	Brian W. Dunham (resigned 10/26/2010)	5721 SE Columbia Way, Suite 200, Vancouver, WA 98661
9		
10	Roy Lewis Eiguren (resigned 2/5/2011)	702 W. Idaho St., Suite 1100, Boise, ID 83702
11		
12	Jack W. Gustavel *** (retired 5/13/2010)	1260 Riverstone Dr., 3rd Floor, Coeur d' Alene, ID 83814
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 8650, Spokane, WA 99203
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 (effective 5/13/2010)	611 S. Congress Ave, Suite 125, Austin, TX 78704
25		
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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	04/15/2011	End of 2010/Q4

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

Does the respondent have formula rates?

[ ] Yes

[X] No

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

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	The Company has no formula rates.	
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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 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 rates				
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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) 04/15/2011	Year/Period of Report End of 2010/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

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

Line No.	Page No(s).	Schedule	Column	Line No
1		No formula rates		
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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	04/15/2011	End of 2010/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 106, 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. On December 30, 2010, Avista Corp., Avista Receivables Corporation (ARC), Bank of America, N.A. and Ranger Funding Company, LLC terminated a Receivables Purchase Agreement at the direction of the Company. ARC is a wholly owned, bankruptcy-remote subsidiary of the Company formed in 1997 for the purpose of acquiring or purchasing interests in certain accounts receivable, both billed and unbilled, of the Company. The Company elected to terminate the Receivables Purchase Agreement prior to its March 11, 2011 expiration date based on the Company's forecasted liquidity needs. The Receivables Purchase Agreement was originally entered into on May 29, 2002 (and has been renewed on an annual basis) and provided the Company with funds for general corporate needs. Under the Receivables Purchase Agreement, the Company could borrow up to $50.0 million based on calculations of eligible receivables. The Company did not borrow any funds under this revolving agreement in 2010.

At December 31, 2010, Avista Corp. had a committed line of credit agreement with various banks in the total amount of $320.0 million with an expiration date of April 5, 2011. Under the credit agreement, the Company could borrow or request the issuance of letters of credit in any combination up to $320.0 million. At December 31, 2010, the Company had borrowed $110.0 million under this committed line of credit and there were $27.1 million of letters of credit outstanding.

Additionally, the Company had a committed line of credit agreement with various banks in the total amount of $75.0 million with an expiration date of April 5, 2011.

In February 2011, Avista Corp. entered into a new committed line of credit 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.

The committed lines of credit are 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 lines of credit.

In December 2010, Avista Corp. issued $52.0 million of 3.89 percent First Mortgage Bonds due in 2020 and $35.0 million of 5.55 percent First Mortgage Bonds due in 2040. The total net proceeds from the sale of the new bonds of $86.6 million (net of placement agent fees and before Avista Corp.'s expenses) were used to redeem $45.0 million of 6.125 percent First Mortgage Bonds due in December 2013 and $30.0 million of 7.25 percent First Mortgage Bonds due in September 2013.

In December 2010, Avista Corp. issued $50.0 million of 1.68 percent First Mortgage Bonds (Bonds) due in 2013. The net proceeds from the issuance of the Bonds of $49.8 million (net of placement agent fees and before Avista Corp.'s expenses) were used to repay a portion of the borrowings outstanding under the Company's committed line of credit.

These debt issuance was approved by the respective regulatory commissions as follows:WUTC (Docket No. U-101722 Order No. 1); IPUC (Case No. AVU-U-10-02, Order No. 32120); and OPUC (Docket UF 4267, Order No. 10-461).

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 will 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 Consolidated Balance Sheet.

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 will 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 Consolidated Balance Sheet.

The Pollution Control Revenue Bonds refunded owere approved by the respective regulatory commissions as follows: WUTC (Docket No. UE-101615 Order No. 1); IPUC (Case No. AVU-U-08-03, Order No. 30674); and OPUC (Docket UF 4253, Order No. 10-424).

7. None
8. Average annual wage increases were 2.5% for non-exempt employees effective March 1, 2010. Average annual wage increases were 3.1% for exempt employees effective March 1, 2010. Officers received average increases of 3.8% effective March 1, 2010. Certain bargaining unit employees received increases of 2.0% effective March 1, 2010. For the majority of bargaining unit employees a new contract was implemented in October 2010, which provided for a 3.5% increase retroactive to April 1, 2010.
9. Reference is made to Note 22 of the Notes to Financial Statements.
10. None
11. Reserved
12. See page 123 of this report.
13. On May 13, 2010, the shareholders of Avista Corp. elected Rebecca A. Klein to serve as a director on the board. Jack W. Gustavel, a director whose term expired on May 13, 2010, retired from Avista Corp.'s Board of Directors as he has reached the mandatory retirement age of 70 as outlined in the Company's Bylaws. On October 26, 2010, Brian W. Dunham provided notification of his resignation from Avista Corp.'s Board of Directors. On February 4, 2011, Roy L. Eiguren provided notification of his resignation from Avista Corp.'s Board of Directors effective February 5, 2011.
14. Proprietary capital is not less than 30 percent.

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	04/15/2011	End of 2010/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	3,707,841,308	3,546,192,091
3	Construction Work in Progress (107)	200-201	60,766,153	57,217,478
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		3,768,607,461	3,603,409,569
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	1,284,830,029	1,219,877,922
6	Net Utility Plant (Enter Total of line 4 less 5)		2,483,777,432	2,383,531,647
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)		2,483,777,432	2,383,531,647
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		2,577,031	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		5,403,010	5,031,620
19	(Less) Accum. Prov. for Depr. and Amort. (122)		908,291	897,684
20	Investments in Associated Companies (123)		12,047,000	12,047,000
21	Investment in Subsidiary Companies (123.1)	224-225	77,733,569	81,243,239
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)		21,346,633	23,798,439
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		12,397,507	11,558,301
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		15,260,734	45,482,748
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		143,280,162	178,263,663
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		1,722,379	2,462,480
36	Special Deposits (132-134)		7,981,895	1,630,323
37	Working Fund (135)		762,784	848,613
38	Temporary Cash Investments (136)		17,455,810	652,010
39	Notes Receivable (141)		226,712	629,625
40	Customer Accounts Receivable (142)		197,906,612	188,271,550
41	Other Accounts Receivable (143)		8,919,486	6,484,963
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		3,846,839	3,710,770
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		211,095	101,231
45	Fuel Stock (151)	227	6,288,853	4,294,013
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	23,335,143	18,386,509
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/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	12,832
55	Gas Stored Underground - Current (164.1)		17,242,935	12,706,763
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		10,754,149	9,985,760
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	197,040
60	Rents Receivable (172)		1,488,593	553,237
61	Accrued Utility Revenues (173)		0	0
62	Miscellaneous Current and Accrued Assets (174)		213,064	454,418
63	Derivative Instrument Assets (175)		17,852,716	53,240,001
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		15,260,734	45,482,748
65	Derivative Instrument Assets - Hedges (176)		243,221	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		293,497,874	251,717,850
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		12,854,887	15,732,877
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	429,832,794	352,616,516
73	Prelim. Survey and Investigation Charges (Electric) (183)		3,946,461	3,346,452
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	17,414,947	26,105,547
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)		25,454,075	15,196,145
82	Accumulated Deferred Income Taxes (190)	234	119,988,041	91,975,547
83	Unrecovered Purchased Gas Costs (191)		-22,074,296	-39,952,004
84	Total Deferred Debits (lines 69 through 83)		587,416,909	465,021,080
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		3,510,549,408	3,278,534,240

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	04/15/2011	end of 2010/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	805,656,943	759,057,747
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	15,798,128	17,498,634
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	-6,137,359	-2,090,961
11	Retained Earnings (215, 215.1, 216)	118-119	326,861,303	295,862,243
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-24,343,433	-20,871,863
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)	-4,325,953	-2,350,286
16	Total Proprietary Capital (lines 2 through 15)		1,125,784,347	1,051,287,436
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,098,148,636	1,070,256,423
19	(Less) Reaquired Bonds (222)	256-257	0	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)		222,084	230,967
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		2,013,529	2,167,570
24	Total Long-Term Debt (lines 18 through 23)		1,147,904,191	1,119,866,820
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		4,974,661	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		2,684,975	1,650,500
29	Accumulated Provision for Pensions and Benefits (228.3)		161,188,441	123,281,094
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	2,916,673
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		30,984,511	2,871,255
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		52,705	0
34	Asset Retirement Obligations (230)		3,887,409	3,971,453
35	Total Other Noncurrent Liabilities (lines 26 through 34)		203,772,702	134,690,975
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		110,000,000	87,000,000
38	Accounts Payable (232)		121,798,025	114,930,110
39	Notes Payable to Associated Companies (233)		7,374,317	6,882,247
40	Accounts Payable to Associated Companies (234)		866,285	724,582
41	Customer Deposits (235)		7,958,557	8,140,853
42	Taxes Accrued (236)	262-263	-397,450	2,222,627
43	Interest Accrued (237)		11,290,059	13,476,434
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	04/15/2011	end of 2010/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)		32,330	147,574
48	Miscellaneous Current and Accrued Liabilities (242)		52,383,017	55,461,901
49	Obligations Under Capital Leases-Current (243)		195,575	0
50	Derivative Instrument Liabilities (244)		82,467,564	18,958,058
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		30,984,511	2,871,255
52	Derivative Instrument Liabilities - Hedges (245)		58,584	50,091
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		52,705	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		362,989,647	305,123,222
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		1,089,209	1,280,331
57	Accumulated Deferred Investment Tax Credits (255)	266-267	7,842,362	5,632,508
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	17,050,733	22,330,799
60	Other Regulatory Liabilities (254)	278	31,545,561	61,709,913
61	Unamortized Gain on Reaquired Debt (257)		2,655,731	2,957,426
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		369,622,132	348,074,981
64	Accum. Deferred Income Taxes-Other (283)		240,292,793	225,579,829
65	Total Deferred Credits (lines 56 through 64)		670,098,521	667,565,787
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		3,510,549,408	3,278,534,240

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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	1,602,043,842	1,516,973,753		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,175,254,099	1,100,224,196		
5	Maintenance Expenses (402)	320-323	48,270,267	50,846,769		
6	Depreciation Expense (403)	336-337	92,936,677	87,089,835		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	10,067,620	9,143,602		
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)		919,134	3,718,504		
13	(Less) Regulatory Credits (407.4)		11,804,920	10,397,806		
14	Taxes Other Than Income Taxes (408.1)	262-263	73,392,440	76,582,590		
15	Income Taxes - Federal (409.1)	262-263	10,616,573	30,223,259		
16	- Other (409.1)	262-263	469,639	2,111,405		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	41,454,197	23,050,105		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	1,521,709	6,214,995		
19	Investment Tax Credit Adj. - Net (411.4)	266	-177,672	-93,914		
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)		1,439,975,392	1,366,382,597		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		162,068,450	150,591,156		

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
1,069,954,147	951,029,259	532,089,695	565,944,494			2
						3
724,521,516	621,221,944	450,732,583	479,002,252			4
39,000,254	42,044,915	9,270,013	8,801,854			5
75,862,701	71,109,022	17,073,976	15,980,813			6
						7
8,110,496	7,467,875	1,957,124	1,675,727			8
99,047	99,047					9
						10
						11
-1,799,835	947,939	2,718,969	2,770,565			12
9,787,351	7,405,420	2,017,569	2,992,386			13
54,037,916	51,664,659	19,354,524	24,917,931			14
22,733,087	23,099,627	-12,116,514	7,123,632			15
686,110	1,263,060	-216,471	848,345			16
22,478,586	20,060,696	18,975,611	2,989,409			17
1,625,776	5,234,188	-104,067	980,807			18
-131,436	-44,606	-46,236	-49,308			19
						20
						21
						22
						23
						24
934,185,315	826,294,570	505,790,077	540,088,027			25
135,768,832	124,734,689	26,299,618	25,856,467			26

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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)		162,068,450	150,591,156		
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)		-10,997			
34	(Less) Expenses of Nonutility Operations (417.1)		5,458,722	5,249,706		
35	Nonoperating Rental Income (418)		-119,784	-3,024		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	6,092,992	827,451		
37	Interest and Dividend Income (419)		1,800,338	5,906,409		
38	Allowance for Other Funds Used During Construction (419.1)		3,352,964	3,078,244		
39	Miscellaneous Nonoperating Income (421)					
40	Gain on Disposition of Property (421.1)		402,632	54,105		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		6,059,423	4,613,479		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		3,938	-2,050		
44	Miscellaneous Amortization (425)		1,110,572	1,110,572		
45	Donations (426.1)		4,164,132	1,405,009		
46	Life Insurance (426.2)		2,236,551	1,336,173		
47	Penalties (426.3)		287,129	-19,900		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,167,774	1,347,809		
49	Other Deductions (426.5)		776,184	1,686,420		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		9,746,280	6,864,033		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	-9,752	-8,841		
53	Income Taxes-Federal (409.2)	262-263	1,419,985	-985,412		
54	Income Taxes-Other (409.2)	262-263	-188,221	-269,492		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	-1,578,031	-223,696		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	4,255,497	3,386,934		
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)		-4,611,516	-4,874,375		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		924,659	2,623,821		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		63,349,463	55,436,849		
63	Amort. of Debt Disc. and Expense (428)		893,123	2,109,201		
64	Amortization of Loss on Reaquired Debt (428.1)		3,530,313	3,572,357		
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)		883,444	2,144,504		
68	Other Interest Expense (431)		2,219,100	3,434,267		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		298,141	544,568		
70	Net Interest Charges (Total of lines 62 thru 69)		70,568,419	66,143,727		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		92,424,690	87,071,250		
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)		92,424,690	87,071,250		

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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	04/15/2011	End of 2010/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		294,314,125	251,930,211
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		86,331,698	86,243,799
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			-55,682,194	(44,360,374)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-55,682,194	(44,360,374)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		349,553	500,486
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		325,313,182	294,314,122
	APPROPRIATED RETAINED EARNINGS (Account 215)			

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)		326,861,303	295,862,243
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-20,871,863	(25,488,897)
50	Equity in Earnings for Year (Credit) (Account 418.1)		6,092,992	827,451
51	(Less) Dividends Received (Debit)			
52	Equity transaction of subsidiaries		-9,564,563	3,789,583
53	Balance-End of Year (Total lines 49 thru 52)		-24,343,434	(20,871,863)

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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)	92,424,690	87,071,250
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	103,004,297	96,233,438
5	Amortization of deferred power and natural gas costs	-9,795,050	51,358,730
6	Amortization of debt expense	4,414,553	5,672,674
7	Amortization of investment in exchange power	2,450,031	2,450,031
8	Deferred Income Taxes (Net)	36,084,184	9,011,417
9	Investment Tax Credit Adjustment (Net)	2,209,854	5,258,780
10	Net (Increase) Decrease in Receivables	-11,666,672	18,733,830
11	Net (Increase) Decrease in Inventory	-11,466,814	16,449,128
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	-1,486,305	-27,996,937
14	Net (Increase) Decrease in Other Regulatory Assets	5,858,734	-10,391,960
15	Net Increase (Decrease) in Other Regulatory Liabilities	-4,654,996	1,329,752
16	(Less) Allowance for Other Funds Used During Construction	3,352,964	3,078,244
17	(Less) Undistributed Earnings from Subsidiary Companies	6,092,992	827,452
18	Other (provide details in footnote):	-2,996,589	338,032
19			
20	Changes in other non-current assets and liabilities	-7,567,021	-20,200,944
21	Net change in receivables allowance	136,069	-2,133,833
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	187,503,009	229,277,692
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-206,800,158	-206,916,479
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)	-206,800,158	-206,916,479
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	592,582	128,775
38	Federal grant payments received	7,585,367	
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies	523,909	4,689,731
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	04/15/2011	End of 2010/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	-1,588,956	-1,000,477
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-199,687,256	-203,098,450
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	136,365,000	249,425,000
62	Preferred Stock		
63	Common Stock	46,235,329	2,621,946
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	Cash received for settlement of interest rate swap		10,776,222
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	205,600,329	262,823,168
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-110,129,764	-78,931,206
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Long-term debt and short-term borrowing issuance costs	-916,100	-3,726,398
78	Net Decrease in Short-Term Debt (c)		-163,000,000
79	Premium paid to repurchase long-term debt	-10,710,164	
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-55,682,184	-44,360,372
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	28,162,117	-27,194,808
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	15,977,870	-1,015,566
87			
88	Cash and Cash Equivalents at Beginning of Period	3,963,103	4,978,669
89			
90	Cash and Cash Equivalents at End of period	19,940,973	3,963,103

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/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 Commission 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. Avista Capital's subsidiaries include Advantage IQ, Inc. (Advantage IQ), a 76 percent owned subsidiary as of December 31, 2010. Advantage IQ is a provider of energy efficiency and other facility information and cost management programs and services for multi-site customers and utilities throughout North America.

Basis of Reporting

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

Use of Estimates

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

- determining the market value of energy commodity derivative assets and liabilities,
- pension and other postretirement benefit plan obligations,
- contingent liabilities,
- recoverability of regulatory assets,
- 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 our 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):

	2010	2009
Unbilled accounts receivable	$84,073	$89,558

Advertising Expenses

The Company expenses advertising costs as incurred. Advertising expenses were not a material portion of the Company's operating expenses in 2010 and 2009.

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:

	2010	2009
Ratio of depreciation to average depreciable property	2.84%	2.78%

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

- electric thermal production - 32 years,
- hydroelectric production - 74 years,
- electric transmission - 50 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):

	2010	2009
Utility taxes	$49,953	$56,818

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 currently 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:

	2010	2009
Effective AFUDC rate	8.25% (1)	8.22%

(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. See Note 20 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.

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 23 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 Washington Utilities and Transportation Commission (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.

NOTE 2. NEW ACCOUNTING STANDARDS

Effective January 1, 2010, the Company adopted Accounting Standards Update (ASU) No. 2009-16, "Transfers and Servicing" (ASC Topic 860). This ASU amends certain provisions of ASC 860 related to accounting for transfers of financial assets and a transferor's continuing involvement in transferred financial assets. In particular, the Company evaluated its accounts receivable sales financing facility (see Note 11) and determined that the transactions no longer meet the criteria of sales of financial assets. As such, any transactions will be accounted for as secured borrowings. During 2010, the Company did not borrow any funds under the revolving agreement. As such, the adoption of this ASU did not have any impact on the Company's financial condition, results of operations and cash flows.

Effective January 1, 2010, the Company adopted ASU No. 2009-17, "Consolidations (Topic 810) - Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities (VIEs)." This ASU carries forward the scope of ASC 810, with the addition of entities previously considered qualifying special-purpose entities, as the concept of these entities was eliminated in ASU No. 2009-16 (ASC 860). The amendments required the Company to reconsider previous conclusions relating to the consolidation of VIEs, whether the Company is the VIE's primary beneficiary, and what type of financial statement disclosures are required. As required by the FERC, the Company accounts for its investments in subsidiaries on the equity method rather than consolidating the assets, liabilities, revenues and expenses of subsidiaries, as required by U.S. GAAP. As such, the adoption of ASU No. 2009-17 did not have any effect on the Company's financial condition, results of operations and cash flows as reported in this report.

Effective January 1, 2010, the Company adopted ASU No. 2010-06, "Fair Value Measurements and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements." This ASU amends guidance related to the disclosures of fair value measurements. In particular, it amends ASC 820-10 to clarify existing disclosures and provides for further disaggregation within classes of assets and liabilities, and further disclosure about inputs and valuation techniques. It also requires disclosure of significant transfers between Level 1 and Level 2 and separate disclosure of purchases, sales, issuances and settlements in the reconciliation of Level 3 activity (this will be required beginning in 2011). See Note 18 for the Company's fair value disclosures.

NOTE 3. DISPOSITION OF AVISTA ENERGY

On June 30, 2007, Avista Energy and Avista Energy Canada completed the sale of substantially all of their contracts and ongoing operations to Shell Energy North America (U.S.), L.P. (Shell Energy), formerly known as Coral Energy Holding, L.P., as well as to certain other subsidiaries of Shell Energy. In connection with the transaction, Avista Energy and its affiliates entered into an Indemnification Agreement with Shell Energy and its affiliates. Under the Indemnification Agreement, Avista Energy and Shell Energy each agree to provide indemnification of the other and the other's affiliates for certain events and matters described in the purchase and sale agreement and certain other transaction agreements. Such events and matters include, but are not limited to, the refund proceedings arising out of the western energy markets in 2000 and 2001 (see Note 22), existing litigation, tax liabilities, and matters related to natural gas storage rights. In general, such indemnification is not required unless and until a party's claims exceed \$150,000 and is limited to an aggregate amount of \$30 million and a term of three years (except for agreements or transactions with terms longer than three years). These limitations do not apply to certain third party claims.

Avista Energy's obligations under the Indemnification Agreement are guaranteed by Avista Capital pursuant to a Guaranty dated June 30, 2007. This Guaranty is limited to an aggregate amount of \$30 million plus certain fees and expenses. The Guaranty will terminate April 30, 2011 except for claims made prior to termination. The Company has not recorded any liability related to this guaranty.

NOTE 4. ADVANTAGE IQ ACQUISITIONS

Effective July 2, 2008, Advantage IQ completed the acquisition of Cadence Network, a privately held, Cincinnati-based energy and expense management company. As consideration, the owners of Cadence Network received a 25 percent ownership interest in Advantage IQ. The total value of the transaction was \$37 million.

The acquisition of Cadence Network was funded with the issuance of Advantage IQ common stock. Under the transaction agreement, the previous owners of Cadence Network can exercise a right to have their shares of Advantage IQ common stock redeemed during July 2011 or July 2012 if Advantage IQ is not liquidated through either an initial public offering or sale of the business to a third party. Their redemption rights expire July 31, 2012. The redemption price would be determined based on the fair market value of Advantage IQ at the time of the redemption election as determined by certain independent parties. Additionally, the certain minority shareholders and option holders of Advantage IQ have the right to put their shares back to Advantage IQ at their discretion.
On August 31, 2009, Advantage IQ acquired substantially all of the assets and liabilities of Ecos Consulting, Inc. (Ecos), a Portland, Oregon-based energy efficiency solutions provider. Under the terms of the transaction, the assets and liabilities of Ecos were acquired by a wholly owned subsidiary of Advantage IQ.

On December 31, 2010, Advantage IQ acquired substantially all of the assets and liabilities of The Loyalton Group, a Minneapolis-based energy management firm known for its energy procurement and price risk management solutions.

In January 2011, Advantage IQ acquired substantially all of the assets and liabilities of Building Knowledge Networks, a Seattle-based real-time building energy management services provider.

NOTE 5. DERIVATIVES AND RISK MANAGEMENT

Energy Commodity Derivatives

Avista Corp. is exposed to market risks relating to changes in electricity and natural gas commodity prices and certain other fuel prices. Market risk is, in general, the risk of fluctuation in the market price of the commodity being traded and is influenced primarily by supply and demand. Market risk includes the fluctuation in the market price of associated derivative commodity instruments. 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 management. The Audit Committee of the Company's Board of Directors periodically reviews and discusses risk assessment and risk management policies, including 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 one hour up to multiple years.

Avista Corp. makes continuing projections of:

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

On the basis of these projections, 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. Forward natural gas contracts are typically for monthly delivery periods. 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
- sales of excess natural gas storage capacity.

Derivatives are recorded as either assets or liabilities on the balance sheet 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 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 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.

The following table presents the underlying energy commodity derivative volumes as of December 31, 2010 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
2011	949	1,144	35,324	41,593	267	142	13,426	46,525
2012	551	668	11,526	24,845	286	62	1,525	19,510
2013	368	-	6,008	6,275	286	-	1,500	1,125
2014	366	-	2,483	900	286	-	1,475	-
2015	379	-	675	-	286	-	-	-
Thereafter	1,315	-	-	-	1,017	-	-	-

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):

	2010	2009
Number of contracts	29	24
Notional amount (in United States dollars)	$10,916	$10,210
Notional amount (in Canadian dollars)	10,989	10,637
Derivative amount	116	(50)

Interest Rate Swap Agreements

Avista Corp. enters into forward-starting interest rate swap agreements to manage the risk associated with changes in interest rates and the impact on future interest payments. These interest rate swap agreements relate to the interest payments for anticipated debt issuances. These interest rate swap agreements are considered economic hedges against fluctuations in future cash flows associated with changes in interest rates.

The following table summarizes the interest rate swaps that the Company has entered into as of December 31, 2010 (dollars in thousands):

Entered	Notional	Number of Contracts	Mandatory Cash Settlement Date
May/June 2010	$ 50,000	2	July 2012

The Company did not have any interest rate swap contracts outstanding as of December 31, 2009. In September 2009, the Company cash settled interest rate swap contracts (notional amount of $200.0 million) and received a total of $10.8 million. The interest rate swap contracts were settled concurrently with the issuance of $250.0 million of First Mortgage Bonds (see Note 13). The settlement of the interest rate swaps was deferred as a regulatory liability (included as part of long-term debt) and is being amortized as a component of interest expense over the life of the associated debt issued in accordance with regulatory accounting practices.

Under the terms of the outstanding interest rate swap agreements, the value of the interest rate swaps is determined based upon Avista Corp. paying a fixed rate and receiving a variable rate based on LIBOR for a term of ten years. As of December 31, 2010, Avista Corp. had a long-term derivative asset and an offsetting regulatory liability of $0.1 million, as well as a long-term derivative liability and an offsetting regulatory asset of less than $0.1 million on the Balance Sheet in accordance with regulatory accounting practices. Upon settlement of the interest rate swaps, the regulatory asset or liability (included as part of long-term debt) will be 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, 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 assets - 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)

The following table presents the fair values and locations of derivative instruments recorded on the Balance Sheet as of December 31, 2009 (in thousands):

		Fair Value		
Derivative	Balance Sheet Location	Asset	Liability	Net Asset (Liability)
Foreign currency contracts	Derivative instrument liabilities - Hedges	$ -	$ (50)	$ (50)
Commodity contracts	Derivative instrument assets current	8,976	(1,219)	7,757
Commodity contracts	Long-term portion of derivative assets	53,765	(8,282)	45,483
Commodity contracts	Derivative instrument liabilities current	5,783	(21,870)	(16,087)
Commodity contracts	Long-term portion of derivative instrument liabilities	650	(3,521)	(2,871)
Total derivative instruments recorded on the balance sheet		$69,174	$(34,942)	$34,232

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 adverse 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 minimize capital requirements.

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, 2010 was $62.1 million. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2010, the Company would be required to post $42.1 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. Changes in market prices may dramatically alter the size of credit risk with counterparties, even when conservative credit limits are established. 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.

Should a counterparty, customer or supplier 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 some of its transactions on exchanges with clearing arrangements that essentially eliminate 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 utilities,
- electric generators and transmission providers,
- natural gas producers and pipelines,
- financial institutions, 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, either positively or negatively, because the counterparties may be similarly affected by changes in conditions.

As is common industry practice, Avista Corp. maintains margin agreements with certain counterparties. 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. Margin calls are periodically made and/or received by Avista Corp. Negotiating for collateral in the form of cash, letters of credit, or performance guarantees is common industry practice.

Cash deposits from counterparties totaled $1.2 million as of December 31, 2010 and $3.2 million as of December 31, 2009. These funds were held by Avista Corp. to mitigate the potential impact of counterparty default risk. These amounts are subject to return if conditions warrant because of continuing portfolio value fluctuations with those parties or substitution of non-cash collateral.

NOTE 6. JOINTLY OWNED ELECTRIC FACILITIES

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

	2010	2009
Utility plant in service	$336,796	$334,773
Accumulated depreciation	(219,770)	(209,587)

NOTE 7. ASSET RETIREMENT OBLIGATIONS

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

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

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

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

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

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

	2010	2009
Asset retirement obligation at beginning of year	$3,971	$4,208
New liability recognized	19	-
Liability adjustment due to revision in estimated cash flows	-	-
Liability settled	(460)	(499)
Accretion expense	357	262
Asset retirement obligation at end of year	$3,887	$3,971

NOTE 8. 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 $21 million in cash to the pension plan in 2010 and $48 million in 2009. The Company expects to contribute $26 million in cash to the pension plan in 2011.

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):

	2011	2012	2013	2014	2015	Total 2016-2020
Expected benefit payments	$19,343	$20,521	$21,824	$23,105	$24,620	$145,063

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.

In 2009, the Company reviewed the mortality table utilized in the actuarial calculations. The Company determined that the RP-2000 combined healthy mortality tables for males and females should be replaced with the RP-2000 combined healthy mortality tables for males and females projected to 2010 using scale AA. The change resulted in an increase of $6.6 million to the pension benefit obligation as of December 31, 2009.

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 twenty years, beginning in 1993.

The Company established 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):

	2011	2012	2013	2014	2015	Total 2016-2020
Expected benefit payments	$4,695	$4,495	$4,488	$4,489	$4,520	$22,439

The Company expects to contribute $4.7 million to other postretirement benefit plans in 2011, 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, 2010 and 2009 and the components of net periodic benefit costs for the years ended December 31, 2010 and 2009 (dollars in thousands):

	Pension		Other	
	2010	2009	2010	2009
Change in benefit obligation:				
Benefit obligation as of beginning of year	$378,235	$353,572	$39,560	$38,953
Service cost	11,609	10,496	684	803
Interest cost	23,231	21,770	2,624	2,364
Actuarial loss	38,547	9,610	21,657	1,676
Transfer of accrued vacation	-	-	367	98
Benefits paid	(18,131)	(17,213)	(4,553)	(4,334)
Benefit obligation as of end of year	$433,491	$378,235	$60,339	$39,560
Change in plan assets:				
Fair value of plan assets as of beginning of year	$272,732	$190,637	$20,394	$16,048
Actual return on plan assets	29,846	50,053	2,481	4,346
Employer contributions	21,000	48,000	-	-

Benefits paid	(16,866)	(15,958)	-	-
Fair value of plan assets as of end of year	$306,712	$272,732	$22,875	$20,394
Funded status	$(126,779)	$(105,503)	$(37,464)	$(19,166)
Unrecognized net actuarial loss	149,819	126,926	35,149	15,772
Unrecognized prior service cost	1,140	1,790	(1,154)	(1,303)
Unrecognized net transition obligation	-	-	1,011	1,516
Prepaid (accrued) benefit cost	24,180	23,213	(2,458)	(3,181)
Additional liability	(150,959)	(128,716)	(35,006)	(15,985)
Accrued benefit liability	$(126,779)	$(105,503)	$(37,464)	$(19,166)
Accumulated pension benefit obligation	$377,606	$331,081	-	-
Accumulated postretirement benefit obligation:				
For retirees			$27,921	$18,377
For fully eligible employees			$15,618	$9,290
For other participants			$16,800	$11,893
Included in accumulated comprehensive loss (income) (net of tax):				
Unrecognized net transition obligation	$ -	$ -	$ 657	$ 985
Unrecognized prior service cost	741	1,163	(750)	(847)
Unrecognized net actuarial loss	97,382	82,502	22,847	10,252
Total	98,123	83,665	22,754	10,390
Less regulatory asset	(92,570)	(80,041)	(23,981)	(11,664)
Accumulated other comprehensive loss (income)	$5,553	$3,624	$(1,227)	$(1,274)
Weighted average assumptions as of December 31:				
Discount rate for benefit obligation	5.69%	6.29%	5.50%	6.00%
Discount rate for annual expense	6.28%	6.25%	6.00%	6.25%
Expected long-term return on plan assets	7.75%	8.50%	7.75%	8.50%
Rate of compensation increase	4.72%	4.65%		
Medical cost trend pre-age 65 – initial			8.00%	8.50%
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%	8.50%
Medical cost trend post-age 65 – ultimate			6.00%	6.00%
Ultimate medical cost trend year post-age 65			2015	2015
Components of net periodic benefit cost:				
Service cost	$11,609	$10,496	$ 684	$ 803
Interest cost	23,231	21,770	2,624	2,364
Expected return on plan assets	(21,381)	(17,612)	(1,581)	(1,364)
Transition obligation recognition	-	-	505	505
Amortization of prior service cost	650	654	(149)	(149)
Net loss recognition	7,189	10,539	1,379	1,279
Net periodic benefit cost	$21,298	$25,847	$3,462	$3,438

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:

	2010	2009
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:

- current cost of reproducing a property less deterioration and functional economic obsolescence,
- capitalization of the property's net earnings power, and
- value indicated by recent sales of comparable properties in the market.

The market-related value of pension plan assets was determined as of December 31, 2010 and 2009.

The following table discloses by level within the fair value hierarchy (refer to Note 18 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:				
Fixed income 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

The following table discloses by level within the fair value hierarchy (refer to Note 18 for a description of the fair value hierarchy) of the pension plan's assets measured and reported as of December 31, 2009 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ 19	$ -	$ -	$ 19
Mutual funds:				
Fixed income securities	70,924	-	-	70,924
U.S. equity securities	87,562	-	-	87,562

International equity securities	46,548	-	-	46,548
Absolute return (1)	11,671	-	-	11,671
Commodities (2)	5,870	-	-	5,870
Common/collective trusts:				
Fixed income securities	-	14,840	-	14,840
U.S. equity securities	-	11,070	-	11,070
Absolute return (1)	-	-	844	844
Real estate	-	-	6,029	6,029
Partnership/closely held investments:				
Absolute return (1)	-	-	15,794	15,794
Private equity funds (3)	-	-	1,561	1,561
Total	$222,594	$25,910	$24,228	$272,732

(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 several 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, 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 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, 2009 (dollars in thousands):

	Common/collective trusts		Partnership/closely held investments	
	Absolute return	Real estate	Absolute return	Private equity funds
Balance, as of January 1, 2009	$2,351	$11,987	$13,983	$1,316
Realized gains (losses)	(415)	520	-	3
Unrealized gains (losses)	(21)	(4,310)	1,811	223
Purchases (sales), net	(1,071)	(2,168)	-	19
Balance, as of December 31, 2009	$ 844	$ 6,029	$15,794	$1,561

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 2010 and 2009.

The market-related value of other postretirement plan assets was determined as of December 31, 2010 and 2009.
The following table discloses by level within the fair value hierarchy (refer to Note 18 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:				
Debt securities	8,320	-	-	8,320
U.S. equity securities	6,986	-	-	6,986
International equity securities	5,572	-	-	5,572
Debt securities	37	-	-	37
U.S. equity securities	1,785	-	-	1,785
International equity securities	57	-	-	57
Total	$22,875	$ -	$ -	$22,875

The following table discloses by level within the fair value hierarchy (refer to Note 18 for a description of the fair value hierarchy) of other postretirement plan assets measured and reported as of December 31, 2009 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ 96	$ -	$ -	$ 96
Mutual funds:				
Debt securities	7,742	-	-	7,742
U.S. equity securities	5,927	-	-	5,927
International equity securities	5,077	-	-	5,077
Debt securities	25	-	-	25
U.S. equity securities	1,456	-	-	1,456
International equity securities	71	-	-	71
Total	$20,394	$ -	$ -	$20,394

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, 2010 by $5.2 million and the service and interest cost by $0.3 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, 2010 by $4.4 million and the service and interest cost by $0.2 million.

The Company has a salary deferral 401(k) plans that is a defined contribution plans and covers 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):

	2010	2009
Employer 401(k) matching contributions	$4,797	$4,439

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):

	2010	2009
Deferred compensation assets and liabilities	$9,285	$9,437

NOTE 9. ACCOUNTING FOR INCOME TAXES

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes and tax credit carryforwards.

As of December 31, 2010, the Company had $11.2 million of state tax credit carryforwards. State tax credits expire from 2015 to 2023. 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 examined the Company's 2008 or 2009 federal income tax returns. However, an estimate of the range of any such possible change cannot be made at this time. 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 2010 or 2009.

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):

	2010	2009
Regulatory assets for deferred income taxes	$90,025	$97,945

NOTE 10. ENERGY PURCHASE CONTRACTS

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

	2010	2009
Utility power resources	$649,408	$704,886

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):

	2011	2012	2013	2014	2015	Thereafter	Total
Power resources	$217,093	$159,409	$119,250	$105,974	$ 97,163	$ 666,752	$1,365,641
Natural gas resources	138,917	100,658	83,908	65,192	56,514	631,946	1,077,135
Total	$356,010	$260,067	$203,158	$171,166	$153,677	$1,298,698	$2,442,776

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):

	2011	2012	2013	2014	2015	Thereafter	Total
Contractual obligations	$21,551	$23,307	$22,643	$23,100	$24,525	$252,015	$367,141

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):

	2010	2009
PUD contract costs	$8,287	$12,633

Information as of December 31, 2010 pertaining to these PUD contracts is summarized in the following table (dollars in thousands):

	Company's Current Share of					Expiration Date
	Output	Kilowatt Capability	Annual Costs (1)	Debt Service Costs (1)	Bonds Outstanding	
Chelan County PUD:						
Rocky Reach Project	2.9%	37,000	$ 2,172	$1,013	$ 436	2011
Douglas County PUD:						
Wells Project	3.3%	28,000	1,734	698	3,773	2018
Grant County PUD:						
Priest Rapids and Wanapum Projects	3.3%	65,800	4,381	1,803	19,537	2055
Totals		130,800	$8,287	$3,514	$23,746	

(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 2010. 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):

	2011	2012	2013	2014	2015	Thereafter	Total
Minimum payments	$3,026	$2,590	$2,585	$2,557	$2,447	$28,026	$41,231

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

NOTE 11. ACCOUNTS RECEIVABLE FINANCING FACILITY

On December 30, 2010, Avista Corp., Avista Receivables Corporation (ARC), Bank of America, N.A. and Ranger Funding Company, LLC terminated a Receivables Purchase Agreement at the direction of the Company. ARC is a wholly owned, bankruptcy-remote subsidiary of the Company formed in 1997 for the purpose of acquiring or purchasing interests in certain accounts receivable, both billed and unbilled, of the Company. The Company elected to terminate the Receivables Purchase Agreement prior to its March 11, 2011 expiration date based on the Company's forecasted liquidity needs. The Receivables Purchase Agreement was originally entered into on May 29, 2002 (and has been renewed on an annual basis) and provided the Company with funds for general corporate needs. Under the Receivables Purchase Agreement, the Company could borrow up to $50.0 million based on calculations of eligible receivables. The Company did not borrow any funds under this revolving agreement in 2010.

NOTE 12. NOTES PAYABLE

At December 31, 2010, Avista Corp. had a committed line of credit agreement with various banks in the total amount of $320.0 million with an expiration date of April 5, 2011. Under the credit agreement, the Company could borrow or request the issuance of letters of credit in any combination up to $320.0 million. Additionally, the Company had a committed line of credit agreement with various banks in the total amount of $75.0 million with an expiration date of April 5, 2011.

In February 2011, Avista Corp. entered into a new committed line of credit 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.

The committed lines of credit are 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 lines of credit.

The committed line of credit agreements contain customary covenants and default provisions. The $320.0 million and $75.0 million credit agreements had a covenant that required the ratio of "earnings before interest, taxes, depreciation and amortization" to "interest expense" of Avista Corp. for the preceding twelve-month period at the end of any fiscal quarter to be greater than 1.6 to 1. As of December 31, 2010, the Company was in compliance with this covenant. The new $400.0 million committed line of credit does not have this covenant. The $320.0 million and $75.0 million credit agreements also had a covenant which did not permit the ratio of "consolidated total debt" to "consolidated total capitalization" of Avista Corp. to be greater than 70 percent at any time. As of December 31, 2010, the Company was in compliance with this covenant. Under the new $400.0 million committed line of credit, this ratio must not be greater than 65 percent at any time.

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 and for the years ended December 31 (dollars in thousands):

	2010	2009
Balance outstanding at end of period	$110,000	$ 87,000
Letters of credit outstanding at end of period	$ 27,126	$ 28,448
Average interest rate at end of period	0.57%	0.59%

NOTE 13. BONDS

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

Maturity Year	Description	Interest Rate	2010	2009
2010	Secured Medium-Term Notes	6.67%-8.02%	$ -	$ 35,000
2012	Secured Medium-Term Notes	7.37%	7,000	7,000
2013	First Mortgage Bonds (1)	6.13%	-	45,000
2013	First Mortgage Bonds (1)	7.25%	-	30,000
2013	First Mortgage Bonds (2)	1.68%	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 (1)	3.89%	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 (3)	(3)	66,700	66,700
2034	Secured Pollution Control Bonds (4)	(4)	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 (1)	5.55%	35,000	-
	Total secured long-term debt		1,178,700	1,151,700
2023	Unsecured Pollution Control Bonds	6.00%	4,100	4,100
	Settled interest rate swaps		(951)	(1,844)
	Secured Pollution Control Bonds held by Avista Corporation (3) (4)		(83,700)	(83,700)
	Total bonds		$1,098,149	$1,070,256

(1) In December 2010, Avista Corp. issued $52.0 million of 3.89 percent First Mortgage Bonds due in 2020 and $35.0 million of 5.55 percent First Mortgage Bonds due in 2040. The total net proceeds from the sale of the new bonds of $86.6 million (net of placement agent fees and before Avista Corp.'s expenses) were used to redeem $45.0 million of 6.125 percent First Mortgage Bonds due in December 2013 and $30.0 million of 7.25 percent First Mortgage Bonds due in September 2013. These First Mortgage Bonds were redeemed at par plus a make-whole redemption premium of $10.7 million. In accordance with regulatory accounting practices, the make-whole redemption premium will be amortized over the life of the new debt issued.

(2) In December 2010, Avista Corp. issued $50.0 million of 1.68 percent First Mortgage Bonds (Bonds) due in 2013. The net proceeds from the issuance of the Bonds of $49.8 million (net of placement agent fees and before Avista Corp.'s expenses) were used to repay a portion of the borrowings outstanding under the Company's committed line of credit.

(3) 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 will 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.

(4) 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 will 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.

The following table details future long-term debt maturities including advances from associated companies (see Note 14) (dollars in thousands):

	2011	2012	2013	2014	2015	Thereafter	Total
Debt maturities	$ -	$7,000	$50,000	$ -	$ -	$1,093,647	$1,150,647

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) 70 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, 2010, property additions and retired bonds would have allowed the Company to issue $795.3 million in aggregate principal amount of additional First Mortgage Bonds. However, using an interest rate of 8 percent on additional First Mortgage Bonds, and based on net earnings for the 12 months ended December 31, 2010, the net earnings test would limit the principal amount of additional bonds the Company could issue to $758.8 million.

See Note 12 for information regarding First Mortgage Bonds issued to secure the Company's obligations under its committed lines of credit agreements.

NOTE 14. 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:

	2010	2009
Low distribution rate	1.13%	1.22%
High distribution rate	1.41	3.06
Distribution rate at the end of the year	1.17	1.22

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 has 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 15. 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):

	2010	2009
Rental expense	$2,885	$3,244

Future minimum lease payments required under operating leases having initial or remaining noncancelable lease terms in excess of one year as of December 31, 2010 were as follows (dollars in thousands):

	2011	2012	2013	2014	2015	Thereafter	Total
Minimum payments required	$1,480	$1,317	$1,259	$1,260	$437	$2,498	$8,251

NOTE 16. GUARANTEES

The Company has guaranteed the payment of distributions on, and redemption price and liquidation amount for, the Preferred Trust Securities issued by its affiliate, Avista Capital II, to the extent that this entity has funds available for such payments from its debt securities.

The output from the Lancaster Plant was contracted to Avista Turbine Power, Inc. (ATP), an affiliate of Avista Energy, through 2026 under a power purchase agreement (PPA). The majority of the rights and obligations of this PPA were conveyed to Shell Energy through the end of 2009. Beginning in January 2010, the rights and obligations under the PPA were conveyed to Avista Corp. Effective December 1, 2010, the PPA was assigned to Avista Corp. Prior to the assignment, Avista Corp. had provided Rathdrum Power LLC, the owner of the Lancaster Plant, a guarantee under which Avista Corp. has guaranteed ATP's performance under the PPA. This guarantee was terminated in connection with the assignment of the PPA to Avista Corp.

In connection with the transaction, on June 30, 2007, Avista Energy and its affiliates entered into an Indemnification Agreement with Shell Energy and its affiliates. Under the Indemnification Agreement, Avista Energy and Shell Energy each agree to provide indemnification of the other and the other's affiliates for certain events and matters described in the purchase and sale agreement entered into on April 16, 2007 and certain other transaction agreements. Such events and matters include, but are not limited to, the refund proceedings arising out of the western energy markets in 2000 and 2001 (see Note 22), existing litigation, tax liabilities, and matters related to storage rights at Jackson Prairie. In general, such indemnification is not required unless and until a party's claims exceed $150,000 and is limited to an aggregate amount of $30 million and a term of three years (except for agreements or transactions with terms longer than three years). These limitations do not apply to certain third party claims.

Avista Energy's obligations under the Indemnification Agreement are guaranteed by Avista Capital pursuant to a Guaranty dated June 30, 2007. This Guaranty is limited to an aggregate amount of $30 million plus certain fees and expenses. The Guaranty will terminate April 30, 2011 except for claims made prior to termination. The Company has not recorded any liability related to this guaranty.

NOTE 17. PREFERRED STOCK-CUMULATIVE (SUBJECT TO MANDATORY REDEMPTION)

The Company has 10 million authorized shares of preferred stock. The Company did not have any preferred stock outstanding as of December 31, 2010 and 2009.

NOTE 18. FAIR VALUE

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. 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):

	2010		2009	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Bonds	$1,099,100	$1,139,765	$1,072,100	$1,079,857
Advances from associated companies	51,547	37,114	51,547	43,534

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

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. U.S. GAAP defines a fair value hierarchy that 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, 2010 and 2009 at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Counterparty Netting (1)	Total
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 (3)	1,854	-	-	-	1,854
Equity securities (3)	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
December 31, 2009					
Assets:					
Energy commodity derivatives	$ -	$11,898	$57,276	$(15,934)	$ 53,240
Deferred compensation assets:					
Fixed income securities (3)	2,011	-	-	-	2,011
Equity securities (3)	5,863	-	-	-	5,863
Total	$7,874	$11,898	$57,276	$(15,934)	$61,114
Liabilities:					
Energy commodity derivatives	$ -	$27,086	$7,806	$(15,934)	$18,958
Foreign currency derivatives	-	50	-	-	50
Total	$ -	$27,136	$7,806	$(15,934)	$19,008

(1) The Company is permitted to net derivative assets and derivative liabilities 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 5 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 $1.2 million as of December 31, 2010 and $1.6 million as of December 31, 2009.

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	
	2010	2009	2010	2009
Balance as of January 1	$57,276	$68,047	$(7,806)	$(16,085)
Total gains or losses (realized/unrealized):				
Included in net income	-	-	-	-
Included in other comprehensive income	-	-	-	-
Included in regulatory assets/liabilities (1)	(34,943)	(7,202)	1,209	7,747
Purchases, issuances, and settlements, net	(2,594)	(3,569)	317	532
Transfers to other categories	-	-	-	-
Ending balance as of December 31	$19,739	$57,276	$(6,280)	$(7,806)

(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.

NOTE 19. 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. The Company originally entered into a sales agency agreement to issue up to 1,250,000 shares of its common stock in December 2009. Shares issued under sales agency agreements were as follows in the years ended December 31:

	2010	2009

Shares issued under sales agency agreement	2,054,110	-

NOTE 20. 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. In May 2010, the Company's shareholders approved an additional 1 million shares of Company common stock to be made available for grant under this plan. However, as of December 31, 2010, the Company has not received approvals from regulatory agencies to add these 1 million share to the 1998 plan. The Company has available a maximum of 3.5 million shares of its common stock for grant under the 1998 Plan. As of December 31, 2010, 0.5 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, 2010, 1.9 million shares were remaining for grant under this plan.

Stock Compensation

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

	2010	2009
Stock-based compensation expense	$4,916	$2,906
Income tax benefits	1,720	1,017

Stock Options

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

	2010	2009
Number of shares under stock options:		
Options outstanding at beginning of year	523,973	748,673
Options granted	-	-
Options exercised	(101,649)	(200,225)
Options canceled	(220,650)	(24,475)
Options outstanding and exercisable at end of year	201,674	523,973
Weighted average exercise price:		
Options exercised	$11.51	$13.83
Options canceled	$22.60	$22.69
Options outstanding and exercisable at end of year	$11.53	$16.30
Cash received from options exercised (in thousands)	$2,179	$2,770
Intrinsic value of options exercised (in thousands)	$1,006	$1,180
Intrinsic value of options outstanding (in thousands)	$2,217	$2,774

Information for options outstanding and exercisable as of December 31, 2010 is as follows:

Range of Exercise Prices	Number of Shares	Weighted Average Exercise Price	Weighted Average Remaining Life (in years)
$10.17-$12.41	186,674	$10.97	1.4

$15.88-$19.34	6,000	15.88	1.4
$20.11-$23.00	9,000	20.11	0.4
Total	201,674	$11.53	1.4

As of December 31, 2010 and 2009, 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, 2010 was 1.3 years. The following table summarizes restricted stock activity for the years ended December 31:

	2010	2009
Unvested shares at beginning of year	71,904	55,939
Shares granted	43,800	44,400
Shares cancelled	-	(10,000)
Shares vested	(31,570)	(18,435)
Unvested shares at end of year	84,134	71,904
Weighted average fair value at grant date	$19.80	$18.18
Unrecognized compensation expense at end of year (in thousands)	$735	$668
Intrinsic value, unvested shares at end of year (in thousands)	$1,895	$1,552
Intrinsic value, shares vested during the year (in thousands)	$682	$345

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 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. 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:

	2010	2009
Risk-free interest rate	1.4%	1.3%
Expected life, in years	3	3
Expected volatility	27.8%	25.8%
Dividend yield	4.6%	3.6%

Weighted average grant date fair value (per share)	$15.30	$17.22

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

The following summarizes performance share activity:

	2010	2009
Opening balance of unvested performance shares	300,601	252,923
Performance shares granted	168,700	163,900
Performance shares canceled	-	(43,758)
Performance shares vested	(143,601)	(72,464)
Ending balance of unvested performance shares	325,700	300,601
Intrinsic value of unvested performance shares (in thousands)	$7,335	$6,490
Unrecognized compensation expense (in thousands)	$2,330	$2,453

The weighted average remaining vesting period for the Company's performance shares outstanding as of December 31, 2010 was 1.5 years. Unrecognized compensation expense as of December 31, 2010 will be recognized during 2011 and 2012. The following summarizes the impact of the market condition on the vested performance shares:

	2010	2009
Performance shares vested	143,601	72,464
Impact of market condition on shares vested	21,540	(72,464)
Shares of common stock earned	165,141	-
Intrinsic value of common stock earned (in thousands)	$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, 2010 and 2009, the Company had recognized compensation expense and a liability of $0.9 million and $0.4 million related to the dividend component of performance share grants.

NOTE 21. 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. After consultation with legal counsel, the Company accrues a loss contingency if it is probable that an asset is impaired or a liability has been incurred and the amount of the loss or impairment can be reasonably estimated. 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, California Parties 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 and the FERC's denial of rehearing requests, the Company does not expect that this proceeding will have any material adverse 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 adverse 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. That filing was accepted in orders issued by the FERC in January 2006 and November 2006. In June 2009, the FERC reversed, in part, its previous decision and ordered a compliance filing requiring an adjustment to the return on investment component of Avista Energy's cost filing. That compliance filing was made in July 2009. In March 2010, the California AG, the CPUC, PG&E, and SCE filed a protest and comments on Avista Energy's compliance filing. In April 2010, Avista Energy filed a response and corrected a technical error from its July 2009 filing. The correction increased its cost filing claim. The California AG, CPUC, PG&E and SCE filed an answer and protest to this filing in April 2010, which Avista Energy answered in June 2010. In July 2010, the same parties again opposed Avista Energy's cost filing, and Avista Energy answered that protest. The revised compliance filing is pending before the FERC.

The CalISO continues to work on its compliance filing for the Refund Period, which will show "who owes what to whom." In April 2010 and May 2010, the CalISO and CalPX, respectively, filed updated compliance reports concerning preparatory re-run activity. The CalPX filing requested guidance from the FERC on issues related to completing the final determination of "who owes what to whom." The CalPX supplemented its compliance filing in October 2010. In June 2010, Avista Energy filed comments with the FERC asking the FERC to assist the parties in bringing this matter to a close by expeditiously: 1) approving the compliance filings made by the CalISO and the CalPX; 2) ruling on the outstanding issues presented by the CalPX; and 3) setting milestones for next steps regarding the final compliance filing.

In July 2010, the CalISO filed its 45th status report on the California recalculation process confirming that the calculations related to fuel cost allowance offsets and emission offsets are complete, and identifying several open issues related to the refund rerun calculations that need to be resolved by the FERC. The CalISO states that it will need to revise certain calculations related to cost-recovery offsets and interest calculations. In addition, the CalISO stated that it is in the process of making adjustments to the CalISO data to remove refunds associated with sales made by non-jurisdictional entities. The CalISO also says that it will need to work with parties to the various global settlements to make appropriate adjustments to the CalISO's data in order to properly reflect those adjustments. In a March 2010 filing, the CalISO stated that it does not intend to make any compliance filing until, *inter alia*, the FERC resolves issues related to the Ninth Circuit's remand regarding possible remedies for alleged tariff violations pursuant to Federal Power Act (FPA) section 309, prior to the refund effective date in this proceeding (discussed below).

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. As of December 31, 2010, 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. Petitions for rehearing were denied in April 2009. In July 2009, Avista Energy and Avista Corp. filed a motion at the FERC, asking that the companies be dismissed from any further proceedings arising under section 309 pursuant to the remand. The filing pointed out that section 309 relief is based on tariff violations of the seller, and as to Avista Energy and Avista Corp., these allegations had already been fully adjudicated in the proceeding that gave rise to the Agreement in Resolution, discussed above. There, the FERC absolved both companies of all allegations of market manipulation or wrongdoing that would justify or permit FPA sections 206 or 309 remedies during 2000 and 2001. In November 2009, the FERC issued an order establishing an evidentiary hearing before an administrative law judge to address the issues remanded by the Ninth Circuit without addressing the Company's pending motion. In December 2009, the Company again brought the issue to the FERC's attention but its motion remains pending, as do a number of rehearing requests regarding the November 2009 hearing order. In September 2010, the FERC issued a "Supplemental Order Soliciting Comments" on the scope of the hearing. The Company responded in filings made on September 22, 2010 and October 6, 2010, and the parties are awaiting further rulings by the FERC before the hearing commences.

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 will have a material adverse effect on its financial condition, results of operations or cash flows. 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. Requests by various parties for rehearing on this ruling were denied in April 2009.

In May 2009, the California AG filed a complaint against both Avista Energy and Avista Corp. seeking refunds on sales made to CERS during the period January 18, 2001 to June 20, 2001 under section 309 of the FPA (the Brown Complaint). The sales at issue are limited in scope and are duplicative of claims already at issue in the Pacific Northwest proceeding, discussed above. In August 2009, the City of Tacoma and the Port of Seattle filed a motion asking the FERC to summarily re-price sales of energy in the Pacific Northwest during 2000 and 2001. In October 2009, Avista Corp. filed, as part of the Transaction Finality Group, an answer to that motion and, in addition, made its own recommendations for further proceedings in this docket. Those pleadings are pending before the FERC.

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, if refunds were ordered by the FERC, could be liable to make payments, but also could be entitled to receive refunds from other FERC-jurisdictional entities. The opportunity to make claims against entities not subject to the FERC's jurisdiction may be limited based on existing law. 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 or could be entitled to receive. 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 but directing sellers to re-file certain transaction summaries. It was not clear that Avista Corp. and its subsidiaries were subject to this directive but the Company took the conservative approach and re-filed certain transaction summaries in June and July of 2002. 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, but did not order any refunds, leaving it to the FERC to consider appropriate remedial options.

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 will be allowed 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 particular, the parties were directed to address whether the seller at any point reached a 20 percent generation market share threshold, and if the seller did reach a 20 percent market share, whether other factors were present to indicate that the seller did not have the ability to exercise market power. The California AG, CPUC, PG&E, and SCE filed their testimony in July 2009. Avista Corp. and Avista Energy's answering testimony was filed in September 2009. On the same day, the FERC staff filed its answering testimony taking the position that, using the test the FERC directed to be applied in this proceeding, neither Avista Corp. nor Avista Energy had market power for the period in question. Cross answering testimony and rebuttal testimony were filed in November 2009. In January 2010, Avista Corp. and Avista Energy filed a motion for summary disposition, as did other parties to the proceeding. 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." Briefs on exceptions were filed in April 2010 and briefs opposing exceptions were filed in May 2010.

Based on information currently known to the Company's management, the fact that neither Avista Corp. nor Avista Energy ever reached a 20 percent generation market share during 2000 or 2001 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 adverse 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. Under the settlement, Avista Corp.'s portion of payment (which was accrued in the second quarter of 2010) to the plaintiffs was not material to its financial condition, results of operations or cash flows. The plaintiffs have indicated that they will contest the existence of any settlement, and will file a response to the motion, with the matter to be decided by the court. 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 adverse 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), which is expected to be finalized in the first half of 2011. The actual cleanup, if any, will not occur until the RI/FS is complete. 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. However, there is currently not enough information to allow the Company to assess the probability or amount of a liability, if any, being incurred. The Company

has accrued 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 under one FERC license 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 FERC issued a new 50-year license for the Spokane River Project in June 2009. 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 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. The EPA, the City of Post Falls and the Hayden Area Regional Sewer Board are currently in settlement negotiations in an attempt to resolve the appeal.

The Company is implementing the environmental and operational conditions required in the license for the Spokane River Project. The estimated cost to implement the license conditions, which is the result of more than a dozen separate settlements, is $334 million over the 50-year license term. This will increase the Spokane River Project's cost of power by about 40 percent, while decreasing annual generation by approximately one-half of one percent. Costs to implement mitigation measures related to the TMDL are not included in these cost estimates. 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 Department of Environmental Quality (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 opening and modification of possibly 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 over the next several years. In March 2010, the FERC approved the GSCP addendum of preliminary design for alternative abatement measures. In May 2010, the Company initiated preliminary feasibility assessments for several alternative abatement measures, the results of which are anticipated in March 2011. 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 will help the Company and other parties determine the best use of funds toward continuing fish passage efforts or other bull trout population enhancement measures. In the fall of 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 2011.

In January 2010, the USFWS proposed to revise its 2005 designation of critical habitat for the bull trout. The proposed revisions include the lower Clark Fork River as critical habitat. In April 2010, the Company submitted comments recommending the lower Clark Fork River be excluded from critical habitat designation based in part on the extensive bull trout recovery efforts the Company is already undertaking. 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 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 commenced the remedial investigation during the fourth quarter of 2010, which is expected to be completed in 2011. There is currently not enough information to allow the Company to assess the probability or amount of a liability, if any, being incurred.

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 allege 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 allege 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 addition to economic and non-economic damages, plaintiffs also seek damages for loss of consortium, attorney's fees and costs, prejudgment interest and punitive damages. Trial has been scheduled to begin in September 2011. The case is in the early stage of discovery and plaintiffs have not yet provided a statement specifying damages. Because the resolution of this claim remains uncertain, legal counsel cannot express an opinion on the extent, if any, of the Company's liability. However, based on information currently known to the Company's management, the Company does not expect this complaint will have a material adverse effect on its financial condition, results of operations or cash flows.

Natural Gas Line Safety Complaint
In June 2010, the WUTC staff filed a complaint against the Company related to a natural gas explosion and fire that occurred in Odessa, Washington in December 2008 that injured two people. The WUTC staff alleges certain violations related to the installation of the low pressure natural gas distribution line, as well as the removal of the line following the explosion and fire. The WUTC staff made recommendations of fines that could exceed $1.1 million and that the Company implement certain measures to ensure compliance with WUTC laws and rules. In January 2011, the Company filed a settlement agreement with the WUTC that was approved by the WUTC in February 2011, and resolved all issues in this matter. As part of the settlement agreement, the Company accrued a fine of $0.2 million. In the fourth quarter of 2010, the Company reached separate legal settlement with the injured individuals in an amount that was not material to the Company's financial condition, results of operations or cash flows.

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. Because the resolution of this issue remains uncertain, legal counsel cannot express an opinion on the extent, if any, of the Company's liability. However, based on information currently known to the Company's management, the Company does not expect this complaint will have a material adverse 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 expired on March 26, 2010. A new agreement was reached in October 2010 (expiring 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 adverse 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 22. 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):

	2010	2009
Information service contract payments	$13,426	$15,529

Minimum contractual obligations under the Company's information services contracts are $12.8 million in 2011, $11.8 million in 2012, $9.3 million in 2013, $7.5 million in 2014 and $7.0 million in each of 2015, 2016 and 2017.

NOTE 23. 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 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 will resume in 2011. The Company must make a filing (no sooner than June 2011), to allow all interested parties the opportunity to review the ERM, and make recommendations to the WUTC related to the continuation, modification or elimination of the ERM.

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. In June 2007, the IPUC approved continuation of the PCA mechanism with an annual rate adjustment provision. These annual October 1 rate adjustments recover or rebate power costs deferred during the preceding July-June twelve-month period.

The following table shows activity in deferred power costs for Washington and Idaho during 2008, 2009 and 2010 (dollars in thousands):

	Washington	Idaho	Total
Deferred power costs as of January 1, 2009	$36,952	$20,655	$57,607
Activity from January 1 – December 31, 2009:			
Power costs deferred	-	17,985	17,985
Interest and other net additions	879	388	1,267
Recovery of deferred power costs through retail rates	(31,567)	(17,521)	(49,088)
Deferred power costs as of December 31, 2009	6,264	21,507	27,771
Activity from January 1 – December 31, 2010:			
Power costs deferred	-	9,768	9,768
Interest and other net additions	538	26	564
Recovery of deferred power costs through retail rates	(6,802)	(12,996)	(19,798)
Deferred power costs as of December 31, 2010	$ -	$18,305	$18,305

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 $22.1 million as of December 31, 2010 and $40.0 million as of December 31, 2009.

General Rate Cases

The following is a summary of the Company's authorized rates of return in each jurisdiction:

Jurisdiction and service	Implementation Date	Authorized Overall Rate of Return	Authorized Return on Equity	Authorized Equity Level
Washington electric and natural gas	December 2010	7.91%	10.2%	46.5%
Idaho electric and natural gas	October 2010	(1)	(1)	(1)
Oregon natural gas	November 2009	8.19%	10.1%	50.0%

(1) The rate adjustment implemented on October 1, 2010 resulting from the Idaho electric and natural gas general rate case settlement did not have a specific authorized rate of return, return on equity or equity level. The prior rate case settlement implemented in August 2009 had an authorized rate of return of 8.55 percent, a return on equity of 10.5 percent and authorized equity level of 50.0 percent.

Washington General Rate Cases

In December 2009, the WUTC issued an order on Avista Corp.'s electric and natural gas rate general rate cases that were filed with the WUTC in January 2009. The WUTC approved a base electric rate increase for the Company's Washington customers of 2.8 percent, which was designed to increase annual revenues by $12.1 million. Base natural gas rates for the Company's Washington customers increased by an average of 0.3 percent, which was designed to increase annual revenues by $0.6 million. The new electric and natural gas rates became effective on January 1, 2010. In this general rate case order, the WUTC did not allow the Company to include the costs associated with the power purchase agreement for the Lancaster Plant in rates. The Company subsequently filed for and received approval for deferred accounting treatment for these net costs.

In August 2010, the Company entered into an all-party settlement agreement that resolved all issues with respect to its general rate case filed with the WUTC in March 2010. This settlement agreement was approved by the WUTC in November 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. As part of the settlement, the parties agreed that the Company would not file a general rate case in the Washington jurisdiction before April 1, 2011.

The parties agreed that recovery of the deferred net costs associated with the power purchase agreement for the Lancaster Plant were limited to $6.8 million for 2010. These net deferred costs will be recovered over a five-year amortization period with a rate of return on the unamortized balance. The parties agreed that the costs for the Lancaster Plant for 2011 and going forward are reasonable and should be recovered in rates.

As part of the settlement related to the 2010 Lancaster Plant deferred net costs, the parties agreed that there would be no deferrals under the ERM for 2010 in either the surcharge or rebate direction. For 2010, the Company received all of the benefit from the amount of power supply costs below the level in retail rates in Washington. Deferrals under the ERM will resume in 2011.

Idaho General Rate Cases

In June 2009, the Company entered into an all-party settlement stipulation in its electric and natural gas general rate cases that were filed with the IPUC in January 2009. This settlement stipulation was approved by the IPUC in July 2009. The new electric and natural gas rates became effective on August 1, 2009. As agreed to in the settlement, base electric rates for the Company's Idaho customers increased by an average of 5.7 percent, which was designed to increase annual revenues by $12.5 million. Offsetting the base electric rate increase was an overall 4.2 percent decrease in the PCA surcharge, which was designed to decrease annual PCA revenues by $9.3 million, resulting in a net increase in annual revenues of $3.2 million. Base natural gas rates for the Company's Idaho customers increased by an average of 2.1 percent, which was designed to increase annual revenues by $1.9 million. Offsetting the natural gas rate increase for residential customers was an equivalent PGA decrease of 2.1 percent. Large general services customers received a PGA decrease of 2.4 percent and interruptible services customers received a PGA decrease of 2.8 percent. The overall PGA decrease resulted in a $2.0 million decrease in annual PGA revenues, resulting in a net decrease in annual revenues of $0.1 million. The PGAs are designed to pass through changes in natural gas costs to customers with no change in gross margin or net income.

In September 2010, the IPUC approved a settlement agreement with respect to 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 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 will increase on October 1, 2011 and October 1, 2012 as the deferred state income tax balance is amortized to zero.

Oregon General Rate Cases

In September 2009, the Company entered into an all-party settlement stipulation in its general rate case that was filed with the OPUC in June 2009. This settlement stipulation was approved by the OPUC in October 2009. The new natural gas rates became effective on November 1, 2009. As agreed to in the settlement, base natural gas rates for Oregon customers increased by an average of 7.1 percent, which was designed to increase annual revenues by $8.8 million.

In February 2011, the Company entered into an all-party settlement stipulation in its general rate case that was filed with the OPUC in September 2010. The settlement, which is subject to approval by the OPUC, 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 would become effective March 15, 2011, with the remaining increase effective June 1, 2011. The settlement is based on an overall rate of return of 8.0 percent, with a common equity ratio of 50.0 percent and a 10.1 percent return on equity. The Company's original request was for an overall rate increase of 5.6 percent, designed to increase annual revenues by $5.4 million. The Company's original request was based on an overall rate of return of 8.61 percent, with a common equity ratio of 50.8 percent and a 10.9 percent return on equity.

NOTE 24. SUPPLEMENTAL CASH FLOW INFORMATION (in thousands)

	2010	2009
Cash paid for interest	$68,638	$58,197
Cash paid for income taxes	10,641	22,695
Other Cash Flows from Operating Activities:		
Power and natural gas deferrals	$1,383	$(216)
Change in special deposits	(6,352)	(30)
Change in other current assets	(1,509)	(1,923)
Non-cash stock compensation	3,603	2,596
Gain on sale of assets	(122)	(89)

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	04/15/2011	End of 2010/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		(6,092,318)		
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value		3,742,032		
4	Total (lines 2 and 3)		3,742,032		
5	Balance of Account 219 at End of Preceding Quarter/Year		(2,350,286)		
6	Balance of Account 219 at Beginning of Current Year		(2,350,286)		
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value		(1,975,667)		
9	Total (lines 7 and 8)		(1,975,667)		
10	Balance of Account 219 at End of Current Quarter/Year		(4,325,953)		

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			(6,092,318)		
2					
3			3,742,032		
4			3,742,032	87,071,250	90,813,282
5			(2,350,286)		
6			(2,350,286)		
7					
8			(1,975,667)		
9			(1,975,667)	92,424,690	90,449,023
10			(4,325,953)		

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	04/15/2011	End of 2010/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)	3,676,391,997	2,796,018,893
4	Property Under Capital Leases	7,203,329	
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	3,683,595,326	2,796,018,893
9	Leased to Others		
10	Held for Future Use	2,218,041	2,033,223
11	Construction Work in Progress	60,766,153	39,513,487
12	Acquisition Adjustments	22,027,941	
13	Total Utility Plant (8 thru 12)	3,768,607,461	2,837,565,603
14	Accum Prov for Depr, Amort, & Depl	1,284,830,029	969,323,143
15	Net Utility Plant (13 less 14)	2,483,777,432	1,868,242,460
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	1,238,948,043	960,938,591
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	24,281,139	8,384,552
22	Total In Service (18 thru 21)	1,263,229,182	969,323,143
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	21,600,847	
33	Total Accum Prov (equals 14) (22,26,30,31,32)	1,284,830,029	969,323,143

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
712,126,860				168,246,244	3
1,619,845				5,583,484	4
					5
					6
					7
713,746,705				173,829,728	8
					9
184,818					10
4,365,975				16,886,691	11
22,027,941					12
740,325,439				190,716,419	13
268,765,035				46,741,851	14
471,560,404				143,974,568	15
					16
					17
246,503,255				31,506,197	18
					19
					20
660,933				15,235,654	21
247,164,188				46,741,851	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
21,600,847					32
268,765,035				46,741,851	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	04/15/2011	End of 2010/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	44,478,295	152,088
4	(303) Miscellaneous Intangible Plant	3,968,847	174,780
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	48,447,142	326,868
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	2,230,746	
9	(311) Structures and Improvements	124,903,704	344,352
10	(312) Boiler Plant Equipment	166,294,776	2,460,691
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	48,239,041	42,045
13	(315) Accessory Electric Equipment	26,930,014	3,545
14	(316) Misc. Power Plant Equipment	15,650,932	23,630
15	(317) Asset Retirement Costs for Steam Production	585,276	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	384,834,489	2,874,263
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	56,519,003	845
28	(331) Structures and Improvements	40,656,073	1,839,019
29	(332) Reservoirs, Dams, and Waterways	117,796,318	5,443,778
30	(333) Water Wheels, Turbines, and Generators	141,170,373	8,413,432
31	(334) Accessory Electric Equipment	34,096,337	108,176
32	(335) Misc. Power PLant Equipment	7,318,628	17,928
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)	399,556,294	15,823,178
36	D. Other Production Plant		
37	(340) Land and Land Rights	903,118	5,988
38	(341) Structures and Improvements	15,743,240	400,035
39	(342) Fuel Holders, Products, and Accessories	21,064,681	105,457
40	(343) Prime Movers	21,876,780	
41	(344) Generators	198,781,330	790,153
42	(345) Accessory Electric Equipment	15,994,108	1,101,775
43	(346) Misc. Power Plant Equipment	1,389,422	198,568
44	(347) Asset Retirement Costs for Other Production	351,682	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	276,104,361	2,601,976
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,060,495,144	21,299,417

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			44,074,880		3
			4,143,627		4
555,503			48,218,507		5
					6
					7
350			2,230,396		8
107,595			125,140,461		9
7,694,060			161,061,407		10
					11
			48,281,086		12
			26,933,559		13
19,580			15,654,982		14
			585,276		15
7,821,585			379,887,167		16
					17
					18
					19
					20
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					25
					26
			56,519,848		27
193,647			42,301,445		28
3,263,452			119,976,644		29
7,744			149,576,061		30
395,703			33,808,810		31
			7,336,556		32
			1,999,562		33
					34
3,860,546			411,518,926		35
					36
3,938			905,168		37
6,880			16,136,395		38
17,815			21,152,323		39
			21,876,780		40
2,837,690			196,733,793		41
319,179			16,776,704		42
9,099			1,578,891		43
			351,682		44
3,194,601			275,511,736		45
14,876,732			1,066,917,829		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	04/15/2011	End of 2010/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	16,092,056	3,623,034
49	(352) Structures and Improvements	16,040,755	752,665
50	(353) Station Equipment	177,678,840	17,804,118
51	(354) Towers and Fixtures	17,113,029	7,792
52	(355) Poles and Fixtures	131,611,436	3,628,228
53	(356) Overhead Conductors and Devices	106,341,896	1,893,064
54	(357) Underground Conduit	2,605,488	
55	(358) Underground Conductors and Devices	2,330,071	
56	(359) Roads and Trails	1,872,246	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	471,685,817	27,708,901
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	4,336,127	1,086,034
61	(361) Structures and Improvements	14,029,847	495,999
62	(362) Station Equipment	93,198,468	4,866,342
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	214,302,534	15,321,278
65	(365) Overhead Conductors and Devices	139,008,612	13,271,577
66	(366) Underground Conduit	74,816,416	2,986,849
67	(367) Underground Conductors and Devices	123,155,633	7,118,187
68	(368) Line Transformers	169,574,920	10,887,227
69	(369) Services	115,182,247	5,077,737
70	(370) Meters	45,007,149	1,348,471
71	(371) Installations on Customer Premises		
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	29,342,489	2,503,071
74	(374) Asset Retirement Costs for Distribution Plant	129,707	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,022,084,149	64,962,772
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	
87	(390) Structures and Improvements	3,432,419	188,676
88	(391) Office Furniture and Equipment	1,163,669	834,808
89	(392) Transportation Equipment	11,406,205	5,023,432
90	(393) Stores Equipment	383,459	6,918
91	(394) Tools, Shop and Garage Equipment	3,455,055	38,717
92	(395) Laboratory Equipment	1,467,560	29,070
93	(396) Power Operated Equipment	25,194,583	12,328,274
94	(397) Communication Equipment	39,099,709	2,662,744
95	(398) Miscellaneous Equipment	8,849	
96	SUBTOTAL (Enter Total of lines 86 thru 95)	85,736,189	21,112,639
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)	85,736,189	21,112,639
100	TOTAL (Accounts 101 and 106)	2,688,448,441	135,410,597
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)	2,688,448,441	135,410,597

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
			19,715,090		48
207,863			16,585,557		49
2,683,011			192,799,947		50
			17,120,821		51
127,134			135,112,530		52
75,173			108,159,787		53
			2,605,488		54
			2,330,071		55
			1,872,246		56
					57
3,093,181			496,301,537		58
					59
497			5,421,664		60
4,197			14,521,649		61
969,057			97,095,753		62
					63
312,503			229,311,309		64
563,810			151,716,379		65
39,206			77,764,059		66
509,604			129,764,216		67
1,944,378			178,517,769		68
83,212			120,176,772		69
300,610			46,055,010		70
					71
					72
78,012			31,767,548		73
			129,707		74
4,805,086			1,082,241,835		75
					76
					77
					78
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					80
					81
					82
					83
					84
					85
			124,681		86
32,336			3,588,759		87
7,620			1,990,857		88
846,401			15,583,236		89
			390,377		90
236,208			3,257,564		91
368,969			1,127,661		92
2,616,792			34,906,065		93
400,936			41,361,517		94
381			8,468		95
4,509,643			102,339,185		96
					97
					98
4,509,643			102,339,185		99
27,840,145			2,796,018,893		100
					101
					102
					103
27,840,145			2,796,018,893		104

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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	193,588
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22				
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47	Total			2,033,223

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	04/15/2011	End of 2010/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	State of Washington	
2	NE Sub-Increase Capacity	1,216,991
3	SGDP Pullman Smart Grid Demonstration Project	1,474,917
4	Minor Projects (232) Under $1,000,000	3,164,510
5		
6	State of Idaho	
7	Appleway Sub-Rebuild	1,639,907
8	Minor Projects (132) under $1,000,000	1,501,439
9		
10	Common -WA & ID	
11	Appleway Sub-Rebuild	1,168,858
12	Idaho Road Sub	1,199,560
13	Colstrip Capital Additions	1,397,988
14	Noxon Rapids Unit 2 Runner Upgrade	5,109,642
15	Noxon Rapids Unit 4 Runner Upgrade	1,522,833
16	Nine Mile Redevelopment	1,761,235
17	Microwave Replacement With Fiber	2,764,603
18	Clark Fork Implement PME Agreement	5,623,561
19	Spokane River Implementation (PM&E)	1,840,951
20	Transportation Equipment	956,888
21	Minor Projects (206) Under $1,000,000	7,169,604
22		
23	Common -WA/ID/OR	
24	Minor Projects (0) Under $1,000,000	
25		
26		
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42		
43	TOTAL	39,513,487

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	04/15/2011	End of 2010/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	910,060,974	910,060,974		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	69,003,315	69,003,315		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	1,031,516	1,031,516		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	-268,779	-268,779		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	69,766,052	69,766,052		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	17,368,623	17,368,623		
13	Cost of Removal	2,651,566	2,651,566		
14	Salvage (Credit)	1,268,366	1,268,366		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	18,751,823	18,751,823		
16	Other Debit or Cr. Items (Describe, details in footnote):	-136,612	-136,612		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	960,938,591	960,938,591		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	256,610,251	256,610,251		
21	Nuclear Production				
22	Hydraulic Production-Conventional	102,530,485	102,530,485		
23	Hydraulic Production-Pumped Storage				
24	Other Production	62,516,258	62,516,258		
25	Transmission	165,976,498	165,976,498		
26	Distribution	327,916,454	327,916,454		
27	Regional Transmission and Market Operation				
28	General	45,388,645	45,388,645		
29	TOTAL (Enter Total of lines 20 thru 28)	960,938,591	960,938,591		

Schedule Page: 219 Line No.: 8 Column: c

Includes: Accumulated provision of non-recoverable plant of $290,798.
Also includes FAS 143 depreciation of $22,019.

Schedule Page: 219 Line No.: 16 Column: c

Change in Removal Work in Process of <$136,612>

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	04/15/2011	End of 2010/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		187,935,344
3	Avista Capital - Equity in Earnings			-107,001,757
4	OCI Investment in Subs			
5	Avista Capital - Other Changes in Net Investment			
6	Avista Capital - Other Changes in Net Investment			
7	Avista Capital - Other Changes in Net Investment			309,652
8				
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41				
42	Total Cost of Account 123.1 $ 0		TOTAL	81,243,239

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
	-10,915,535	177,019,809		2
6,092,992		-100,908,756		3
				4
				5
				6
	1,312,864	1,622,516		7
				8
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				41
6,092,992	-9,602,671	77,733,569		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	04/15/2011	End of 2010/Q4

MATERIALS AND SUPPLIES

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

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	4,294,013	6,288,853	(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)	12,289,004	15,715,351	(1)
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	2,161,593	2,314,543	(1)
8	Transmission Plant (Estimated)	55,859	91,697	(1)
9	Distribution Plant (Estimated)	280,550	320,705	(1)
10	Regional Transmission and Market Operation Plant (Estimated)			(1),(2)
11	Assigned to - Other (provide details in footnote)	3,599,503	4,892,847	(1),(2)
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	18,386,509	23,335,143	
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)	12,832		
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	22,693,354	29,623,996	

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.: 10 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 Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	Horizon Wind Interconnect	88,688	186200	27,345	186210
23	Avista - Pomeroy Area Interconnect	46,211	186200	46,211	186210
24	BP Wind Interconnect	19,557	186200	19,557	186210
25	PPM Energy Wind Interconnect	39,332	186200		186210
26	Martinsdale Wind Interconnect	2,879	186200	2,578	186210
27	Palouse Wind Interconnect	48,020	186200		186210
28	Avista - Nine Mile Upgrade	209	186200		186210
29	Avista - Noxon Upgrade	5,290	186200		186210
30	United Renew Interconnect	3,683	186200		186210
31	Exergy Dev Inter 50MW		186200		186210
32	Exergy Dev Inter 2 100MW		186200		186210
33					
34					
35					
36					
37					
38					
39					
40					

Schedule Page: 231 Line No.: 22 Column: b
Total Charges Incurred Life to Date.

Schedule Page: 231 Line No.: 22 Column: d
Total Reimbursements Received Life to Date.

Schedule Page: 231 Line No.: 23 Column: b
Total Charges Incurred Life to Date.

Schedule Page: 231 Line No.: 23 Column: d
Total Reimbursements Received Life to Date.

Schedule Page: 231 Line No.: 24 Column: b
Total Charges Incurred Life to Date.

Schedule Page: 231 Line No.: 24 Column: d
Total Reimbursements Received 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.: 26 Column: d
Total Reimbursements Received 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.

Schedule Page: 231 Line No.: 30 Column: b
Total Charges Incurred Life to Date.

Schedule Page: 231 Line No.: 31 Column: b
Total Charges Incurred Life to Date.

Schedule Page: 231 Line No.: 32 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) 04/15/2011	Year/Period of Report End of 2010/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	1,418,256		926	472,752	945,504
2	Guaranteed Residual Value-Airplane					
3	Reg Asset Post Ret Liab	141,084,843	37,899,909			178,984,752
4	Regulatory Asset FAS109 Utility Plant	82,355,236		283	6,778,073	75,577,163
5	Regulatory Asset Lancaster Generation		6,686,667			6,686,667
6	Regulatory Asset FAS109 DSIT Non Plant	2,387,826		283	232,356	2,155,470
7	Regulatory Asset FAS109 DFIT State Tax Cr	6,248,158		283	196,871	6,051,287
8	Regulatory Asset FAS109 WNP3	7,128,805		283	737,483	6,391,322
9	Regulatory Asset- Spokane River Relicense	802,034		407	22,200	779,834
10	Regulatory Asset- Spokane River PM&E	443,350	279,160			722,510
11	Regulatory Asset- Lake CDA Fund	10,062,735		407	203,006	9,859,729
12	Regulatory Asset- Lake CDA IPA Fund		2,000,000			2,000,000
13	Reg Assets- Decouplings Surcharge	378,929	92,730			471,659
14	Regulatory Asset ID DSIT Amort		299,605			299,605
15	Regulatory Asset AMR					
16	Regulatory Asset RTO Deposits- ID	141,611		560	70,806	70,805
17	Regulatory Asset BPA Residential Exchange		663,953			663,953
18	Regulatory Asset ERM Approved for Recovery	6,233,995		557	6,233,995	
19	ID Wind Gen AFUDC	120,476	119,124			239,600
20	Regulatory Asset Wartsila Units	1,765,181		407	337,788	1,427,393
21	MTM St Regulatory Asset	8,331,750	40,559,323			48,891,073
22	MTM Lt Regulatory Asset		15,723,775			15,723,775
23	Regulatory Asset FAS143 Asset Retirement Obligation	3,130,245		111	65,214	3,065,031
24	Reg Asset AN- CDA Lake Settlement	37,202,198	3,183,778			40,385,976
25	Reg Asset WA-CDA Lake Settlement	1,553,548		407	45,042	1,508,506
26	Regulatory Asset Workers Comp	2,921,174	9,586			2,930,760
27	CS2 Lev Ret	1,504,659		407	60,300	1,444,359
28	Regulatory Asset ID PCA Deferral 1	10,457,471	4,280,973			14,738,444
29	Regulatory Asset ID PCA Deferral 2		3,566,306			3,566,306
30	Regulatory Asset ID PCA Deferral 3	11,049,788		557	11,049,788	
31	Reg Asset-Future Payments- Lake CDA	4,000,000		182	4,000,000	
32	DSM Asset	11,894,248	4,251,311		11,894,248	4,251,311
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44	TOTAL	352,616,516	119,616,200		42,399,922	429,832,794

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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	04/15/2011	End of 2010/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	254,614		407	299,390	-44,776
4	WA Deferred Power Costs	29,449			29,449	
5	WA ERM YTD Company Band	-3,037,637	3,037,637			
6	WA ERM YTD Contra Account	3,037,637			3,037,637	
7	Regulatory Asset RTO Deposit	237,321		560	158,214	79,107
8	Regulatory Asset-Mt lease pymt	2,434,617		540	360,684	2,073,933
9	Regulatory Asset-Mt lease pymt	4,736,376		540	676,632	4,059,744
10	Colstrip Common Fac.	2,355,642		406		2,355,642
11	Regulatory Asset- COLS	584,330		506	584,330	
12	Guaranteed Residual Value-Plane	2,916,673			2,916,673	
13	Prepaid airplane Lease LT	28,743	584,448			613,191
14	Misc DD- airplane lease cap		48,316			48,316
15	Payroll Accrual			VAR		
16						
17	Plant Allocation of clearing jr	2,837,265		VAR	1,551,959	1,285,306
18	Misc DD- IR Swaps		52,705	VAR		52,705
19	Misc Error Suspense	-15,154	455,407			440,253
20						
21	Renewable Energy-Cert Fees	174,000		557		174,000
22	Misc susp acct-non w/o	47,415			47,415	
23	Unamortized A/R sale	35,445			35,445	
24						
25	Intangible Pension Asset					
26						
27	Nez Perce Settlement	176,385		557	5,212	171,173
28	Misc Deferred Debit Centralia	678,434			678,434	
29						
30	Long Term Note Rec acct	277,158	282,270	143		559,428
31	Reg Asset ID-Lake Cdal	315,120		506	13,115	302,005
32	ID Panhandle Forest Use Permit	226,097			45,080	181,017
33	Credit Union Labor and Exp	20,275	40,836			61,111
34						
35	Horizon Wind Interco	47,020	14,323			61,343
36						
37						
38	Reclass IPA acct deposit	2,000,000			2,000,000	
39	Reclass Idaho Clk Fork Relic	976,731			260,633	716,098
40	Noxon Living Facility Exp	67,001			67,001	
41	Dry Creek Transport					
42						
43	PG & E Canada to N Cal trans	867,043	19,130			886,173
44	Misc Work Orders <$50,000	-71,696	98,013	VAR		26,317
45	Subsidiary Billings	87,699		VAR	54,323	33,376
46	"Null" Projects directly to 186	12,645			8,188	4,457
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	26,105,547				17,414,947

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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	Regulatory Assets Consv	229,213			229,213	
3	Regulatory Assets Consv	63,569	2,049,197			2,112,766
4	Regulatory Assets Consv	2,072,766			2,072,766	
5	Regulatory Assets Consv	152,407			101,144	51,263
6	Regulatory Assets Consv	139,945			139,945	
7						
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46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	26,105,547				17,414,947

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	04/15/2011	End of 2010/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		5,391,537	11,937,146
3			
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	5,391,537	11,937,146
9	Gas		
10		-267,754	777,990
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15	-267,754	777,990
17	Other	86,851,764	107,272,905
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	91,975,547	119,988,041

Notes

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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	04/15/2011	End of 2010/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 Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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
57,119,723	805,656,943			84,134	1,665,853	2
						3
57,119,723	805,656,943			84,134	1,665,853	4
						5
						6
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/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	15,798,128
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40	TOTAL	15,798,128

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	04/15/2011	End of 2010/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 - Public issue	-6,137,359
2		
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21		
22	TOTAL	-6,137,359

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

Capital stock expense activity, 2010

Beginning balance	$(2,090,960)
Issuance of common stock	558,660
Repurchase of common stock	209,498
Excess tax benefits on stock compensation	(404,293)
Stock compensation accrual	(4,410,265)
Ending balance	$(6,137,359)

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

Footnote Linked. See note on 254, 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	04/15/2011	End of 2010/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 - 7.37% DUE 5/10/2012	7,000,000	49,114
4	FMBS - SERIES A - 7.39% DUE 5/11/2018	7,000,000	54,364
5	FMBS - SERIES A - 7.45% DUE 6/11/2018	15,500,000	170,597
6	FMBS - SERIES A - 7.18% DUE 8/11/2023	7,000,000	54,364
7	KETTLE FALLS P C REV BONDS DUE 14	4,100,000	135,855
8	ADVANCE ASSOCIATED-AVISTA CAPITAL II (ToPRS)	51,547,000	1,296,086
9	FMBS - 6.37% SERIES C	25,000,000	158,304
10	FMBS - 5.45% SERIES	90,000,000	1,432,081
11	FMBS - 6.25% SERIES	150,000,000	2,713,435
12	FMBS - 5.70% SERIES	150,000,000	4,924,304
13	FMBS - 5.95% SERIES	250,000,000	3,081,419
14	FMBS - 5.125% SERIES	250,000,000	2,859,788
15	FMBS - 1.68% SERIES	50,000,000	296,372
16	FMBS - 3.89% SERIES	52,000,000	375,867
17	FMBS - 5.55% SERIES	35,000,000	252,988
18	COLSTRIP 2010A PCRBs DUE 2032	66,700,000	
19	COLSTRIP 2010B PCRBs DUE 2034	17,000,000	
20	INTEREST RATE SWAPS		
21	SERIES C SET UP		666,169
22			
23			
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31			
32			
33	TOTAL	1,234,347,000	18,571,585

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	04/15/2011	End of 2010/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
05-10-1993	5-10-2012	05-10-1993	5-10-2012	7,000,000	515,900	3
05-11-1993	05-11-2018	05-11-1993	05-11-2018	7,000,000	517,300	4
06-09-1993	06-11-2018	06-09-1993	06-11-2018	15,500,000	1,154,750	5
08-12-1993	08-11-2023	08-12-1993	08-11-2023	7,000,000	502,600	6
07-29-1993	12-01-2023	07-29-1993	12-01-2023	4,100,000	246,000	7
06-03-1997	06-01-2037	06-03-1997	06-01-2037	51,547,000	685,019	8
06-19-1998	06-19-2028	06-19-1998	06-19-2028	25,000,000	1,592,500	9
11-18-2004	12-01-2019	11-18-2004	12-01-2019	90,000,000	4,905,000	10
11-17-2005	12-01-2035	11-17-2005	12-01-2035	150,000,000	9,375,000	11
12-15-2006	07-01-2037	12-15-2006	07-01-2037	150,000,000	8,550,000	12
04-02-2008	06-01-2018	04-02-2008	06-01-2018	250,000,000	14,875,000	13
09-22-2009	04-01-2022	09-22-2009	04-01-2022	250,000,000	12,812,500	14
12-30-2010	12-30-2013	12-30-2010	12-30-2013	50,000,000	840,000	15
12-20-2010	12-20-2020	12-20-2010	12-20-2020	52,000,000	2,022,800	16
12-20-2010	12-20-2040	12-20-2010	12-20-2040	35,000,000		17
12-15-2010	10-1-2034	12-15-2010	10-1-2034	66,700,000		18
12-15-2010	3-1-2034	12-15-2010	3-1-2034	17,000,000		19
Various	Various	Various	Various	-951,364		20
6-15-1998	6-15-2013	6-15-1998	6-15-2013			21
						22
						23
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				1,233,395,636	59,083,919	33

Schedule Page: 256 Line No.: 18 Column: f

Please see footnotes to financial statements at page 122. These bonds do not appear in the balance sheet total of long term debt

Schedule Page: 256 Line No.: 19 Column: f

Please see footnotes to financial statements at page 122. These bonds do not appear in the balance sheet total of long term debt

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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)	92,424,690
2		
3		
4	Taxable Income Not Reported on Books	
5		4,217,908
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		98,555,448
11	Federal Income Tax	11,848,337
12	Deferred Income Tax	34,098,960
13	Investment Tax Credit	291,967
14	Income Recorded on Books Not Included in Return	
15		4,872,900
16	Equity in Sub Earnings	-6,092,992
17	Corporated Overhead Unallocated Subs	537,773
18		
19	Deductions on Return Not Charged Against Book Income	
20		-201,378,590
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	39,376,401
28	Show Computation of Tax:	
29	State Tax @ 2% Less Idaho ITC	469,639
30	Federal Tax Net income less state tax	39,846,040
31		
32	Federal Tax @35%	13,946,114
33	Prior years tax return, misc true ups	-1,967,645
34	Cabinet Gorge Tax Credit	-130,132
35	Total Federal Expense	11,848,337
36		
37		
38		
39		
40		
41		
42		
43		
44		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/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				
3	Income Tax 2006	-23,788,097		-2,700,913		
4	Income Tax 2007	-454,486		-728,828		
5	Income Tax 2008	10,768,896		-1,293,655		
6	Income Tax 2009	-18,895,541		13,198,286		
7	Income Tax (Current)			12,116,921	23,841,641	
8	Retained Earnings					
9	Prior Retained Earnings	-5,015,936				-4,773,830
10	Prior Retained Earnings	-2,127,838				2,127,838
11	Prior Retained Earnings	-1,435,621				1,435,621
12	Prior Retained Earnings	-1,210,371				1,210,371
13	Current Retained Earnings			-386,409		
14	Total Federal	-16,380,262		20,205,402	23,841,641	
15						
16	STATE OF WASHINGTON:					
17	Property Tax (2009)	7,086,606		-736,257	6,342,069	
18	Property Tax (2010)			8,027,008		
19	Excise Tax (2005)	91,452		-91,452		
20	Excise Tax (2006)	-464				
21	Excise Tax (2007)	400,000		121,563	400,000	
22	Excise Tax (2009)	2,265,543		-20,970	2,244,573	
23	Excise Tax (2010)			22,135,679	19,553,738	
24	Natural Gas Use Tax	15,109		34,014	41,293	
25	Municipal Occupation Tax	2,435,373		20,011,536	19,792,188	
26	Sales & Use Tax (2006)	-8,173				
27	Sales & Use Tax (2009)	84,190			84,190	
28	Sales & Use Tax (2010)			855,271	805,723	
29	Motor Vehicle Tax (2010)			26,109	26,109	
30	Total Washington	12,369,636		50,362,501	49,289,883	
31						
32	STATE OF IDAHO:					
33	Income Tax (2006)	346,389				
34	Income Tax (2007)	-104,516				
35	Income Tax (2008)	-101,560			-202,872	
36	Income Tax (2009)	-290,110		-5,421		
37	Income Tax (2010)			293,319	600,000	
38	Property Tax (2009)	1,958,891		-2,930	1,954,314	
39	Property Tax (2010)			4,636,980	2,324,276	
40	Motor Vehicle Tax (2010)			4,722	4,722	
41	TOTAL	2,222,627		94,953,802	97,573,879	

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
25,778,732						2
-26,489,010					-2,700,913	3
-1,183,314		-524,756			-204,072	4
9,475,241		-904,526			-389,129	5
-5,697,255		-714,210			13,912,496	6
-11,724,719		22,794,744			-10,677,823	7
						8
-9,789,766						9
						10
						11
						12
-386,409					-386,409	13
-20,016,500		20,651,252			-445,850	14
						15
						16
8,281		-530,742			-205,515	17
8,027,008		6,148,008			1,879,000	18
		102,921			-194,373	19
-464						20
121,563					121,563	21
		-18,691			-2,279	22
2,581,941		16,730,929			5,404,751	23
7,830		6,417			27,596	24
2,654,720		14,849,283			5,162,252	25
-8,173						26
						27
49,548					855,271	28
					26,109	29
13,442,254		37,288,125			13,074,375	30
						31
						32
346,389						33
-104,516						34
101,312						35
-295,531		-4,337			-1,084	36
-306,681		494,532			-201,213	37
1,647					-2,930	38
2,312,704		3,829,944			807,037	39
					4,722	40
-397,450		75,375,276			19,578,526	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	04/15/2011	End of 2010/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	Sales & Use Tax (2005)	436				
2	Sales & Use Tax (2008)	4,348		1		-4,349
3	Sales & Use Tax (2009)	4,150			8,497	4,349
4	Sales & Use Tax (2010)			83,354	75,412	
5	Irrigation Credits (2009)	444		-444		
6	KWH Tax (2009)	16,185		817	17,002	
7	KWH Tax (2010)			313,304	285,450	
8	Franchise Tax (2009)	1,703,625			1,703,625	
9	Franchise Tax (2010)			4,148,926	2,651,701	
10	Total Idaho	3,538,282		9,472,628	9,422,127	
11						
12	STATE OF MONTANA:					
13	Income Tax (2006)	520,245				
14	Income Tax (2008)	-180,574			-180,574	
15	Income Tax (2009)	-209,972		4,524	-205,273	
16	Income Tax (2010)			196,651	370,000	
17	Property Tax (2009)	3,084,410		-9,620	3,075,220	
18	Property Tax (2010)			6,614,757	3,314,570	
19	Colstrip Generation Tax			3,129	3,129	
20	KWH Tax (2009)	220,298		-481	219,818	
21	KWH Tax (2010)			1,114,299	864,778	
22	Motor Vehicle Tax (2010)			4,675	4,675	
23	Consumer Council Tax	3		7,070	1,737	
24	Public Commission Tax	808		1,293	2,091	
25	Total Montana	3,435,218		7,936,297	7,470,171	
26						
27	STATE OF OREGON:					
28	Income Tax (2006)	266,087			-34,444	
29	Income Tax (2007)	-5				-241,886
30	Income Tax (2008)	109,583				241,886
31	Income Tax (2009)	-368,312		-249,611	-280,000	
32	Income Tax (2010)			228,576	215,000	
33	Property Tax (2009)	-1,317,390		1,747,230	3,182	
34	Property Tax (2010)			1,751,024	3,931,888	
35	Motor Vehicle Tax (2010)			2,475	2,475	
36	BETC Credit (2006 & Prior)	-420,805				
37	BETC Credit (2007)	243,353				
38	BETC Credit (2008)	-40,383				
39	BETC Credit (2009)	-91,881		-297		
40	BETC Credit (2010)			-68,844		
41	TOTAL	2,222,627		94,953,802	97,573,879	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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				
(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)	Line No.
436						1
						2
2						3
7,942					83,354	4
					-444	5
		817				6
27,854		313,304				7
						8
1,497,225		3,011,831			1,137,095	9
3,588,783		7,646,091			1,826,537	10
						11
						12
520,245						13
						14
-175		4,524				15
-173,349		196,651				16
-430		-183,863			174,243	17
3,300,187		6,789,000			-174,243	18
		3,129				19
					-481	20
249,521		1,113,819			481	21
					4,675	22
5,336		8,340			-1,270	23
9		22			1,271	24
3,901,344		7,931,622			4,676	25
						26
						27
300,531						28
-241,891						29
351,469						30
-337,923		-62,403			-187,208	31
13,576		57,143			171,433	32
426,658		922,031			825,199	33
-2,180,864		926,276			824,748	34
					2,475	35
-420,805						36
243,353						37
-40,383						38
-92,178					-297	39
-68,844					-68,844	40
-397,450		75,375,276			19,578,526	41

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.
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3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to 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	Glendale Regulatory Cr. 2008	-210,889				
2	Glendate Regulatory Cr. 2009	70,289				
3	Franchise Tax (2006)	755				-755
4	Franchise Tax (2008)	30,327				-30,327
5	Franchise Tax (2009)	996,981			998,078	1,097
6	Franchise Tax (2010)			3,598,576	2,724,573	29,986
7	Total Oregon	-732,290		7,009,129	7,560,752	1
8						
9	STATE OF CALIFORNIA:					
10	Income Tax (2005)	-1,869			3,342	
11	Income Tax (2006)	-314				
12	Income Tax (2009)	-2,400		1,600		
13	Income Tax (2010)				2,400	
14	Total California	-4,583		1,600	5,742	
15						
16	MISCELLANEOUS STATES:					
17	Income Tax (2008)					-1
18	Income Tax (2010)			-17,884		
19	Total Misc States			-17,884		-1
20						
21	COUNTY & MUNICIPAL					
22	WA Renewable Energy			-39,290	-39,290	
23	Misc.	-3,374		23,419	22,853	
24	Total County	-3,374		-15,871	-16,437	
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	2,222,627		94,953,802	97,573,879	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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				
(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)	Line No.
-210,889						1
70,289						2
						3
						4
						5
903,988					3,598,576	6
-1,283,913		1,843,047			5,166,082	7
						8
						9
-5,211						10
-314						11
-800					1,600	12
-2,400						13
-8,725					1,600	14
						15
						16
-1						17
-17,884					-17,884	18
-17,885					-17,884	19
						20
						21
					-39,290	22
-2,808		15,139			8,280	23
-2,808		15,139			-31,010	24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
-397,450		75,375,276			19,578,526	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	04/15/2011	End of 2010/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		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%						
6		5,308,088	190	2,256,090			
7							
8	TOTAL	5,308,088		2,256,090			
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Gas Propertry (100%	324,420			411	46,236	
11							
12	TOTAL PROPERTY	324,420				46,236	
13							
14							
15							
16							
17							
18							
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47							
48							

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
7,564,178			6
			7
7,564,178			8
			9
278,184			10
			11
278,184			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
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			46
			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	04/15/2011	End of 2010/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	Balance at Beginning of Year	DEBITS		Credits	Balance at End of Year
			Contra Account	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Defer Gas Exchange (253028)	2,119,525			130,435	2,249,960
2						
3	Centralia Environmental (253110)	966,323	421	966,323		
4	Rathdrum Refund (253120)	341,042	550	33,822		307,220
5	NE Tank Spil (253130)	87,105			1	87,106
6	Bills Pole Rentals (253140)	215,203			7,938	223,141
7	CR-CS2 GE LTSA (253150)	2,412,558	232	2,412,558		
8	DOC EECE Grant				900,017	900,017
9	DOC EECE Admin Fee				100,000	100,000
10	IR Swaps (254170)				126,864	126,864
11						
12	Sale/Leaseback on Bldg (253850)	522,912	931	261,456		261,456
13						
14	Defer Comp Retired Execs (253900)	119,174	431,232	25,218		93,956
15	Defer Comp Active Execs (253910)	9,436,629	128	151,516		9,285,113
16	Executive Incent Plan (253920)	140,000				140,000
17	Unbilled Revenue (253990)	5,970,328	908	2,694,428		3,275,900
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	22,330,799		6,545,321	1,265,255	17,050,733

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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	04/15/2011	End of 2010/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	255,283,307	15,267,229	
3	Gas	76,033,192	12,627,052	
4	Other	16,758,482	4,248,441	
5	TOTAL (Enter Total of lines 2 thru 4)	348,074,981	32,142,722	
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	348,074,981	32,142,722	
10	Classification of TOTAL			
11	Federal Income Tax	337,008,658	32,142,722	
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) 04/15/2011	Year/Period of Report End of 2010/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
					-16,612,764	253,937,772	2
					-874,213	87,786,031	3
-201,483			-7,092,889			27,898,329	4
-201,483			-7,092,889		-17,486,977	369,622,132	5
							6
							7
							8
-201,483			-7,092,889		-17,486,977	369,622,132	9
							10
-201,483			-7,092,889		-17,486,977	358,555,809	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	04/15/2011	End of 2010/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Electric	45,107,264	1,785,900	415,630
4		-1,259,488		
5		402,332		
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	44,250,108	1,785,900	415,630
10	Gas			
11	Gas	-12,851,902	5,061,282	-226,664
12		-21,363		
13		-69,458		
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	-12,942,723	5,061,282	-226,664
18	Other	194,272,444	-63,966	4,016,875
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	225,579,829	6,783,216	4,205,841
20	Classification of TOTAL			
21	Federal Income Tax	221,346,023	6,783,216	4,205,841
22	State Income Tax	4,233,806		
23	Local Income Tax			

NOTES

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)	
[redacted]							1
							2
167,220					-1,494,390	45,150,364	3
						-1,259,488	4
						402,332	5
							6
							7
							8
167,220					-1,494,390	44,293,208	9
[redacted]							10
-2,642			-189,419			-7,377,179	11
						-21,363	12
						-69,458	13
							14
							15
							16
-2,642			-189,419			-7,468,000	17
			-13,275,982			203,467,585	18
164,578			-13,465,401		-1,494,390	240,292,793	19
[redacted]							20
164,578			-13,465,401		-1,494,390	236,058,987	21
						4,233,806	22
							23

NOTES (Continued)

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Idaho Investment Tax Credit (254005)	11,603,723	190	470,351		11,133,372
2	Oregon BETC Credit (254010)				104,733	104,733
3	Noxon, ITC (254025)	1,441,110			595,399	2,036,509
4	Defer Gas Exchange (254028)					
5	Oregon Commercial Fee (254120)				116,233	116,233
6	FAS 109 Invest Credit (254180)	174,684	190	24,900		149,784
7	Nez Perce (254220)	748,388	557	22,008		726,380
8	Oregon Senate Bill (254250)	1,789,652			755,285	2,544,937
9	Reg liability CCX CR ID (254300)	340,512	407	340,512		
10	Accrue Lake CDA IPA int (254325)	64,410	407	64,410		
11	Idaho DSIT Amort				14,713,202	14,713,202
12	BPA Res Exch Regulatory Liab (254345)	2,900,393	407	2,900,393		
13	Unrealized Currency Exchange (254399)	35,548	143	9,259		26,289
14	Reg Liability Other (254700)					
15	Mark to Market ST (254740)		245	5,878		-5,878
16	Mark to Market FAS133 (254750)	42,611,493	244,175	42,611,493		
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	TOTAL	61,709,913		46,449,204	16,284,852	31,545,561

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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	296,626,659	315,648,544
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	265,219,243	273,953,602
5	Large (or Ind.) (See Instr. 4)	114,792,344	107,741,463
6	(444) Public Street and Highway Lighting	6,702,211	6,607,434
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales	999,779	1,075,772
10	TOTAL Sales to Ultimate Consumers	684,340,236	705,026,815
11	(447) Sales for Resale	256,319,131	198,516,063
12	TOTAL Sales of Electricity	940,659,367	903,542,878
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	940,659,367	903,542,878
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	567,270	651,836
18	(453) Sales of Water and Water Power	281,752	381,238
19	(454) Rent from Electric Property	2,797,559	2,742,428
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	113,233,443	34,534,405
22	(456.1) Revenues from Transmission of Electricity of Others	12,414,756	9,176,474
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	129,294,780	47,486,381
27	TOTAL Electric Operating Revenues	1,069,954,147	951,029,259

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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
3,618,328	3,791,369	315,282	313,884	2
				3
3,100,156	3,176,670	39,489	39,276	4
2,099,333	1,947,553	1,376	1,394	5
26,114	26,021	449	444	6
				7
				8
12,458	13,371	86	81	9
8,856,389	8,954,984	356,682	355,079	10
6,251,508	4,737,063			11
15,107,897	13,692,047	356,682	355,079	12
				13
15,107,897	13,692,047	356,682	355,079	14

Line 12, column (b) includes $ -2,124,891 of unbilled revenues.

Line 12, column (d) includes -40,411 MWH relating to unbilled revenues

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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	3,517,184	276,489,736	300,814	11,692	0.0786
3	2 Residential Service					
4	3 Residential Service					
5	12 Res. & Farm Gen. Service	65,742	7,484,692	12,638	5,202	0.1138
6	15 MOPS II Residential					
7	22 Res. & Farm Lg. Gen. Service	50,727	3,902,949	111	457,000	0.0769
8	30 Pumping-Special					
9	32 Res. & Farm Pumping Service	12,761	1,065,213	1,719	7,424	0.0835
10	48 Res. & Farm Area Lighting	4,583	1,041,194			0.2272
11	49 Area Lighting-High-Press.	272	74,519			0.2740
12	56 Centralia Refund					
13	95 Wind Power		174,658			
14	72 Residential Service					
15	73 Residential Service					
16	74 Residential Service					
17	76 Residential Service					
18	77 Residential Service					
19	58A Tax Adjustment		-43,206			
20	58 Tax Adjustment		7,853,937			
21	SubTotal	3,651,269	298,043,692	315,282	11,581	0.0816
22	Residential-Unbilled	-32,941	-1,417,033			0.0430
23	Total Residential Sales	3,618,328	296,626,659	315,282	11,476	0.0820
24						
25	COMMERCIAL SALES (442)					
26	2 General Service					
27	3 General Service					
28	11 General Service	650,954	67,512,245	34,025	19,132	0.1037
29	12 Res. & Farm Gen. Service					
30	16 MOPS II Commercial					
31	19 Contract-General Service					
32	21 Large General Service	2,018,544	162,022,602	4,406	458,135	0.0803
33	25 Extra Lg. Gen. Service	349,655	19,451,763	13	26,896,538	0.0556
34	28 Contract-Extra Large Serv					
35	31 Pumping Service	85,336	6,323,302	1,045	81,661	0.0741
36	47 Area Lighting-Sod. Vap	6,524	1,310,852			0.2009
37	49 Area Lighting-High-Press.	2,417	524,548			0.2170
38	56 Centralia Refune					
39	95 Wind Power		61,793			
40	74 Large General Service					
41	TOTAL Billed	15,148,308	942,784,258	356,682	42,470	0.0622
42	Total Unbilled Rev.(See Instr. 6)	-40,411	-2,124,891	0	0	0.0526
43	TOTAL	15,107,897	940,659,367	356,682	42,357	0.0623

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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		-43,632			
5	58 Tax Adjustment		9,229,653			
6	SubTotal	3,113,430	266,393,126	39,489	78,843	0.0856
7	Commercial-Unbilled	-13,274	-1,173,883			0.0884
8	Total Commercial	3,100,156	265,219,243	39,489	78,507	0.0856
9						
10	INDUSTRIAL SALES (442)					
11	2 General Service					
12	3 General Service					
13	8 Lg Gen Time of Use					
14	11 General Service	6,453	690,349	233	27,695	0.1070
15	12 Res. & Farm Gen. Service					
16	21 Large General Service	163,672	12,941,031	185	884,714	0.0791
17	25 Extra Lg. Gen. Service	1,844,277	94,156,743	18	102,459,833	0.0511
18	28 Contract - Extra Large Service	1,409	336,574	1	1,409,000	0.2389
19	29 Contract Lg. Gen. Service					
20	30 Pumping Service - Special	20,983	1,292,810	34	617,147	0.0616
21	31 Pumping Service	52,604	4,069,893	755	69,674	0.0774
22	32 Pumping Svc Res & Firm	3,912	295,851	150	26,080	0.0756
23	47 Area Lighting-Sod. Vap.	227	41,377			0.1823
24	49 Area Lighting - High-Press	50	10,069			0.2014
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		-1,200			
33	58 Tax Adjustment		598,734			
34	SubTotal	2,093,587	114,433,959	1,376	1,521,502	0.0547
35	Industrial-Unbilled	5,746	358,385			0.0624
36	Total Industrial	2,099,333	114,792,344	1,376	1,525,678	0.0547
37						
38	STREET AND HWY LIGHTING (444)					
39	6 Mercury Vapor St. Ltg.					
40	7 HP Sodium Vap. St. Ltg					
41	TOTAL Billed	15,148,308	942,784,258	356,682	42,470	0.0622
42	Total Unbilled Rev.(See Instr. 6)	-40,411	-2,124,891	0	0	0.0526
43	TOTAL	15,107,897	940,659,367	356,682	42,357	0.0623

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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					
2	41 Co-Owned St. Lt. Service	222	39,659	16	13,875	0.1786
3	42 Co-Owned St. Lt. Service	20,332	5,837,670	368	55,250	0.2871
4	High-Press. Sod. Vap.					
5	43 Cust-Owned St. Lt. Energy	9	875	1	9,000	0.0972
6	and Maint. Service					
7	44 Cust-Owned St. Lt. Energy	856	123,696	28	30,571	0.1445
8	and Maint. Svce - High-Pres					
9	Sodium Vapor					
10	45 Cust. Owned St. Lt. Energy Svc	1,301	85,586	6	216,833	0.0658
11	46 Cust. Owned St. Lt. Energy Svc	3,336	294,670	30	111,200	0.0883
12	58A Tax Adjustment		-622			
13	58 Tax Adjustment		213,037			
14	SubTotal	26,056	6,594,571	449	58,031	0.2531
15	Street & Hwy Lighting-Unbilled	58	107,640			1.8559
16	Total Street & Hwy Lighting	26,114	6,702,211	449	58,160	0.2567
17						
18	OTHER SALES TO PUBLIC					
19	(445)					
20	None					
21						
22	INTERDEPARTMENTAL SALES	12,458	999,779	86	144,860	0.0803
23	58 Tax Adjustment					
24	Total Interdepartmental	12,458	999,779	86	144,860	0.0803
25						
26	SALES FOR RESALE (447)					
27	61 Sales to Other Utilities (NDA)	6,251,508	256,319,131			0.0410
28						
29						
30	Total Sales for Resale	6,251,508	256,319,131			0.0410
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	15,148,308	942,784,258	356,682	42,470	0.0622
42	Total Unbilled Rev.(See Instr. 6)	-40,411	-2,124,891	0	0	0.0526
43	TOTAL	15,107,897	940,659,367	356,682	42,357	0.0623

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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	BC Transmission Corp.	SF	Tariff 9			
2	BNP Paribas Energy Trading GP	SF	Tariff 9			
3	BP Corporation North America, Inc.	SF	ISDA			
4	BP Energy Company	SF	Tariff 9			
5	Barclays Bank PLC	SF	Tariff 9			
6	Barclays Bank PLC	SF	ISDA			
7	Black Hills Power, Inc.	SF	Tariff 9			
8	Bonneville Power Administration	LF	Tariff 8			
9	Bonneville Power Administration	LF	ACS-06			
10	Bonneville Power Administration	IF	ACS-06			
11	Bonneville Power Administration	IF	ACS-06			
12	Bonneville Power Administration	SF	Tariff 9			
13	Bonneville Power Administration	LF	Tariff 12			
14	Burbank, City of	SF	Tariff 9			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
24		821		821	1
3,800		119,350		119,350	2
			3,190,831	3,190,831	3
729,793		31,366,477		31,366,477	4
90,975		3,364,934		3,364,934	5
			90,224	90,224	6
1,600		54,200		54,200	7
30,419		1,028,648		1,028,648	8
6,478		203,909		203,909	9
5,835		191,439		191,439	10
1,909		26,233		26,233	11
284,083		10,873,211		10,873,211	12
4		168		168	13
200		7,700		7,700	14
0	0	0	0	0	
6,251,508	6,702,608	220,613,706	29,002,817	256,319,131	
6,251,508	**6,702,608**	**220,613,706**	**29,002,817**	**256,319,131**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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	Cargill Power Markets, LLC	SF	Tariff 9			
2	Chelan County PUD No. 1	SF	Tariff 9			
3	Citigroup Energy, Inc.	SF	Tariff 9			
4	Clatskanie Peoples PUD	SF	Tariff 9			
5	Conoco Phillips	SF	Tariff 9			
6	Conoco Phillips	SF	Tariff 9			
7	DB Energy Trading, LLC	SF	Tariff 9			
8	Douglas County PUD No. 1	SF	Tariff 9			
9	EDF Trading North America	SF	Tariff 9			
10	Endure Energy, LLC	SF	Tariff 9			
11	Eugene Water & Electric Board	SF	Tariff 9			
12	Grant County PUD No. 2	SF	Tariff 9			
13	Grant County PUD No. 2	LF	Tariff 12			
14	Grant County PUD No. 2	SF	Tariff 10			
	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) 04/15/2011	Year/Period of Report End of 2010/Q4

SALES FOR RESALE (Account 447) (Continued)

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

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

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)

5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.

10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
140,852		5,140,867		5,140,867	1
10,625		377,290		377,290	2
234,625		7,907,682		7,907,682	3
1,448		48,620		48,620	4
70,606		2,830,042		2,830,042	5
	122,640			122,640	6
24,600		727,878		727,878	7
8,100		275,940		275,940	8
400		19,300		19,300	9
2,768		99,458		99,458	10
9,762		328,783		328,783	11
26,530		887,004		887,004	12
2		78		78	13
	2,103			2,103	14
0	0	0	0	0	
6,251,508	6,702,608	220,613,706	29,002,817	256,319,131	
6,251,508	**6,702,608**	**220,613,706**	**29,002,817**	**256,319,131**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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	Iberdrola Renewables, Inc.	SF	Tariff 9			
2	Idaho Power Company	SF	Tariff 9			
3	Idaho Power Company	LF	Tariff 12			
4	J. Aron & Company	SF	Tariff 9			
5	J. Aron & Company	SF	ISDA			
6	JP Morgan Ventures Energy	SF	Tariff 9			
7	JP Morgan Ventures Energy	SF	ISDA			
8	Macquarie Energy, LLC	SF	Tariff 9			
9	Modesto Irrigation District	SF	Tariff 9			
10	Morgan Stanley	SF	ISDA			
11	Morgan Stanley	SF	ISDA			
12	NaturEner Power Watch, LLC	SF	Tariff 9			
13	NaturEner Power Watch, LLC	LF	Tariff 12			
14	NaturEner Power Watch, LLC	SF	Tariff 9			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/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.
607,789		23,914,898		23,914,898	1
14,836		522,560		522,560	2
130		4,392		4,392	3
10,000		512,500		512,500	4
			715,697	715,697	5
153,758		6,001,526		6,001,526	6
			431,777	431,777	7
187,391		6,572,910		6,572,910	8
6,372		213,857		213,857	9
362,854		15,478,962		15,478,962	10
			119,007	119,007	11
22,876		754,489		754,489	12
1		41		41	13
			5,002	5,002	14
0	0	0	0	0	
6,251,508	6,702,608	220,613,706	29,002,817	256,319,131	
6,251,508	**6,702,608**	**220,613,706**	**29,002,817**	**256,319,131**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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	NaturEner Power Watch, LLC	SF	Tariff 9			
2	NaturEner Power Watch, LLC	SF	Tariff 9			
3	NaturEner Power Watch, LLC	SF	Tariff 9			
4	NorthWestern Energy LLC	IF	Tariff 10			
5	NorthWestern Energy LLC	IF	Tariff 10			
6	NorthWestern Energy LLC	IF	Tariff 9			
7	NorthWestern Energy LLC	SF	Tariff 9			
8	NorthWestern Energy LLC	LF	Tariff 12			
9	NorthWestern Energy LLC	LF	Tariff 9			
10	NorthWestern Energy LLC	SF	Tariff 9			
11	Okanogan County PUD	SF	Tariff 9			
12	Pacific NW Generating Coop	SF	Tariff 9			
13	PacifiCorp	SF	Tariff 9			
14	PacifiCorp	LF	Tariff 12			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
	140,400			140,400	1
	551,282			551,282	2
			70,000	70,000	3
	3,256,935			3,256,935	4
			984,000	984,000	5
29,368		986,685		986,685	6
121,607		5,030,599		5,030,599	7
94		3,256		3,256	8
8,131		248,341		248,341	9
	230			230	10
7,595		262,856		262,856	11
1,852		42,316		42,316	12
128,378		4,219,541		4,219,541	13
472		15,946		15,946	14
0	0	0	0	0	
6,251,508	6,702,608	220,613,706	29,002,817	256,319,131	
6,251,508	**6,702,608**	**220,613,706**	**29,002,817**	**256,319,131**	

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	04/15/2011	End of 2010/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	PacifiCorp	LF	Tariff 9			
2	Peaker LLC	LF	Tariff 9			
3	Pend Oreille Public Utility District	LF	Tariff 10			
4	Pend Oreille Public Utility District	LF	Tariff 9			
5	Pend Oreille Public Utility District	SF	Tariff 9			
6	Pend Oreille Public Utility District	SF	Tariff10			
7	Portland General Electric Company	SF	Tariff 9			
8	Portland General Electric Company	LF	Tariff 12			
9	Portland General Electric Company	SF	Tariff 9			
10	Powerex	SF	Tariff 9			
11	Powerex	SF	Tariff 9			
12	Powerex	SF	Tariff 9			
13	PPL EnergyPlus, LLC	SF	Tariff 10			
14	PPL EnergyPlus, LLC	SF	Tariff 9			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
5,174		158,035		158,035	1
	1,748,695			1,748,695	2
	419,372			419,372	3
8,317		283,256		283,256	4
42,950		1,329,497		1,329,497	5
	35,972			35,972	6
40,050		1,289,090		1,289,090	7
64		2,216		2,216	8
	850			850	9
327,442		11,413,514		11,413,514	10
	53,970			53,970	11
			21,169	21,169	12
	286,521			286,521	13
129,240		4,638,272		4,638,272	14
0	0	0	0	0	
6,251,508	6,702,608	220,613,706	29,002,817	256,319,131	
6,251,508	**6,702,608**	**220,613,706**	**29,002,817**	**256,319,131**	

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	04/15/2011	End of 2010/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	PPL EnergyPlus, LLC	LF	Tariff 9			
2	Public Service of Colorado	SF	Tariff 9			
3	Puget Sound Energy	LF	Tariff 9			
4	Puget Sound Energy	SF	Tariff 9			
5	Puget Sound Energy	LF	Tariff 12			
6	Rainbow Energy Marketing	SF	Tariff 9			
7	Redding, City of	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	Sempra Energy Trading	SF	Tariff 9			
14	Sempra Energy Trading	SF	ISDA			
	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	04/15/2011	End of 2010/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
18,480		564,412		564,412	1
3,600		124,720		124,720	2
23,654		722,447		722,447	3
142,045		6,031,398		6,031,398	4
69		2,500		2,500	5
47,393		1,292,140		1,292,140	6
1,376		53,552		53,552	7
85,284		3,095,708		3,095,708	8
2		45		45	9
642,458		27,761,301		27,761,301	10
8,798		157,228		157,228	11
17,361		604,728		604,728	12
46,848		2,142,123		2,142,123	13
			50,769	50,769	14
0	0	0	0	0	
6,251,508	6,702,608	220,613,706	29,002,817	256,319,131	
6,251,508	**6,702,608**	**220,613,706**	**29,002,817**	**256,319,131**	

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	04/15/2011	End of 2010/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	Shell Energy N.A.	SF	Tariff 9			
2	Shell Energy N.A.	SF	ISDA			
3	Shell Energy N.A.	SF	Tariff 9			
4	Sierra Pacific Power Company	SF	Tariff 9			
5	Sierra Pacific Power Company	LF	Tariff 12			
6	Snohomish County PUD	SF	Tariff 9			
7	Sovereign Power	LF	Tariff 10			
8	Sovereign Power	LF	Tariff 9			
9	Tacoma Power	SF	Tariff 9			
10	Tacoma Power	LF	Tariff 12			
11	Tacoma Power	SF	Tariff 10			
12	Tenaska Power Services Co.	SF	Tariff 9			
13	The Energy Authority	SF	Tariff 9			
14	TransAlta Energy Marketing	SF	Tariff 9			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
1,050,124		41,910,567		41,910,567	1
			218,140	218,140	2
	2,200			2,200	3
40,726		736,431		736,431	4
27		1,061		1,061	5
5,455		186,680		186,680	6
	80,368			80,368	7
15,902		504,545		504,545	8
3,117		77,658		77,658	9
3		59		59	10
	1,070			1,070	11
400		14,000		14,000	12
6,667		235,258		235,258	13
189,141		7,070,961		7,070,961	14
0	0	0	0	0	
6,251,508	6,702,608	220,613,706	29,002,817	256,319,131	
6,251,508	**6,702,608**	**220,613,706**	**29,002,817**	**256,319,131**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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	Turlock Irrigation District	SF	Tariff 9			
2	IntraCompany Wheeling	LF				
3	IntraCompany Generation	LF				
4	Revenue Adjustment	AD				
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**

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

SALES FOR RESALE (Account 447) (Continued)

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

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

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)

5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.

10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
400		14,200		14,200	1
		-22,469,603	22,469,603		2
			631,350	631,350	3
-1			5,248	5,248	4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
0	0	0	0	0	
6,251,508	6,702,608	220,613,706	29,002,817	256,319,131	
6,251,508	**6,702,608**	**220,613,706**	**29,002,817**	**256,319,131**	

Schedule Page: 310 Line No.: 3 Column: b
SWAP

Schedule Page: 310 Line No.: 6 Column: b
SWAP

Schedule Page: 310 Line No.: 8 Column: b
BPA Contract Terminates September 30, 2011.

Schedule Page: 310 Line No.: 9 Column: b
BPA Contract Terminates January 1, 2036.

Schedule Page: 310 Line No.: 13 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.1 Line No.: 13 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.2 Line No.: 3 Column: b
NWPP Reserve Sharing Sales

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

Schedule Page: 310.2 Line No.: 7 Column: b
SWAP

Schedule Page: 310.2 Line No.: 11 Column: b
SWAP

Schedule Page: 310.2 Line No.: 13 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.2 Line No.: 14 Column: b
Loss Return

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

Schedule Page: 310.3 Line No.: 3 Column: b
Bundled Transmission

Schedule Page: 310.3 Line No.: 4 Column: b
Capacity Sale expires January 6, 2011

Schedule Page: 310.3 Line No.: 5 Column: b
Bundled Transmission - Capacity Sale expires January 6, 2011.

Schedule Page: 310.3 Line No.: 6 Column: b
Contract terminates January 6, 2011.

Schedule Page: 310.3 Line No.: 8 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.3 Line No.: 9 Column: b
NorthWestern Energy LLC sale expires October 31, 2013.

Schedule Page: 310.3 Line No.: 14 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.4 Line No.: 1 Column: b
PacifiCorp sale terminates October 31, 2013.

Schedule Page: 310.4 Line No.: 2 Column: b
Peaker, LLC capacity contract terminates December 31, 2016.

Schedule Page: 310.4 Line No.: 3 Column: b
Contract expires 09/30/2014

Schedule Page: 310.4 Line No.: 4 Column: b
Contract expires 9/30/2014.

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

Schedule Page: 310.4 Line No.: 12 Column: b
Bundled Transmission

Schedule Page: 310.5 Line No.: 1 Column: b
PPL sale terminates October 31, 2013.

Schedule Page: 310.5 Line No.: 3 Column: b

Puget Sound Energy sale terminates October 31, 2013.

Schedule Page: 310.5 Line No.: 5 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.: 2 Column: b

SWAP

Schedule Page: 310.6 Line No.: 5 Column: b

NWPP Reserve Sharing Sales

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

Sovereign Power contract terminates 1-31-2015

Schedule Page: 310.6 Line No.: 8 Column: b

Sovereign Power Contract terminates 1-31-2015

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

NWPP Reserve Sharing Sales

Schedule Page: 310.7 Line No.: 2 Column: a

Intracompany Wheeling

Schedule Page: 310.7 Line No.: 2 Column: b

IntraCompany Wheeling terminates 09/30/2023.

Schedule Page: 310.7 Line No.: 3 Column: a

Intracompany Generation - Sale of Ancillary Services

Schedule Page: 310.7 Line No.: 3 Column: b

IntraCompany Generation - Sale of Ancillary Services.

Schedule Page: 310.7 Line No.: 4 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	04/15/2011	End of 2010/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	536,766	514,450
5	(501) Fuel	28,352,582	22,358,344
6	(502) Steam Expenses	4,265,708	2,614,109
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	838,347	699,318
10	(506) Miscellaneous Steam Power Expenses	2,468,855	2,783,706
11	(507) Rents	15,498	29,773
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	36,477,756	28,999,700
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	501,359	500,139
16	(511) Maintenance of Structures	610,113	546,526
17	(512) Maintenance of Boiler Plant	4,899,998	5,457,086
18	(513) Maintenance of Electric Plant	645,697	2,565,316
19	(514) Maintenance of Miscellaneous Steam Plant	661,490	937,372
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	7,318,657	10,006,439
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	43,796,413	39,006,139
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	2,349,973	2,278,227
45	(536) Water for Power	900,793	815,150
46	(537) Hydraulic Expenses	5,932,977	4,390,300
47	(538) Electric Expenses	5,726,408	5,604,151
48	(539) Miscellaneous Hydraulic Power Generation Expenses	733,429	630,038
49	(540) Rents	6,529,629	6,068,605
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	22,173,209	19,786,471
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	376,904	249,607
54	(542) Maintenance of Structures	522,921	343,445
55	(543) Maintenance of Reservoirs, Dams, and Waterways	1,290,854	646,541
56	(544) Maintenance of Electric Plant	1,789,839	1,937,827
57	(545) Maintenance of Miscellaneous Hydraulic Plant	177,024	1,835,745
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	4,157,542	5,013,165
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	26,330,751	24,799,636

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	04/15/2011	End of 2010/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	873,063	846,899
63	(547) Fuel	115,449,329	68,656,659
64	(548) Generation Expenses	2,463,056	2,215,456
65	(549) Miscellaneous Other Power Generation Expenses	505,589	456,697
66	(550) Rents	33,433	-33,811
67	TOTAL Operation (Enter Total of lines 62 thru 66)	119,324,470	72,141,900
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	798,646	775,889
70	(552) Maintenance of Structures	8,426	1,850
71	(553) Maintenance of Generating and Electric Plant	1,691,146	1,893,421
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	116,403	100,412
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	2,614,621	2,771,572
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	121,939,091	74,913,472
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	277,079,128	303,784,778
77	(556) System Control and Load Dispatching	555,351	528,673
78	(557) Other Expenses	126,323,056	69,198,479
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	403,957,535	373,511,930
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	596,023,790	512,231,177
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,210,636	2,436,974
84	(561) Load Dispatching	2,192,996	2,224,918
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	272,063	190,291
94	(563) Overhead Lines Expenses	447,185	543,042
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	17,742,126	13,350,741
97	(566) Miscellaneous Transmission Expenses	1,617,125	1,387,100
98	(567) Rents	120,946	152,055
99	TOTAL Operation (Enter Total of lines 83 thru 98)	24,603,077	20,285,121
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	665,430	566,082
102	(569) Maintenance of Structures	275,169	330,766
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	1,157,114	1,127,999
108	(571) Maintenance of Overhead Lines	1,751,805	1,528,641
109	(572) Maintenance of Underground Lines	11,590	17,566
110	(573) Maintenance of Miscellaneous Transmission Plant	-2,754	38,785
111	TOTAL Maintenance (Total of lines 101 thru 110)	3,858,354	3,609,839
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	28,461,431	23,894,960

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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	1,495,137	1,367,048
135	(581) Load Dispatching		
136	(582) Station Expenses	715,019	546,953
137	(583) Overhead Line Expenses	1,402,987	1,577,717
138	(584) Underground Line Expenses	581,320	710,346
139	(585) Street Lighting and Signal System Expenses	226,745	218,441
140	(586) Meter Expenses	1,773,001	1,619,021
141	(587) Customer Installations Expenses	790,470	861,022
142	(588) Miscellaneous Expenses	6,426,792	5,871,255
143	(589) Rents	294,788	375,764
144	TOTAL Operation (Enter Total of lines 134 thru 143)	13,706,259	13,147,567
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	1,261,570	1,326,210
147	(591) Maintenance of Structures	396,786	280,729
148	(592) Maintenance of Station Equipment	785,071	1,030,655
149	(593) Maintenance of Overhead Lines	7,948,732	6,823,635
150	(594) Maintenance of Underground Lines	845,853	1,067,148
151	(595) Maintenance of Line Transformers	1,094,896	1,040,344
152	(596) Maintenance of Street Lighting and Signal Systems	652,322	638,654
153	(597) Maintenance of Meters	138,937	160,883
154	(598) Maintenance of Miscellaneous Distribution Plant	270,915	315,281
155	TOTAL Maintenance (Total of lines 146 thru 154)	13,395,082	12,683,539
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	27,101,341	25,831,106
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	592,956	567,832
160	(902) Meter Reading Expenses	2,739,310	2,624,185
161	(903) Customer Records and Collection Expenses	7,798,575	8,243,568
162	(904) Uncollectible Accounts	1,674,638	2,735,983
163	(905) Miscellaneous Customer Accounts Expenses	131,019	244,871
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	12,936,498	14,416,439

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	04/15/2011	End of 2010/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	27,971,131	25,449,316
169	(909) Informational and Instructional Expenses	874,830	67,743
170	(910) Miscellaneous Customer Service and Informational Expenses	168,978	146,608
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	29,014,939	25,663,667
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	4,734	506,252
176	(913) Advertising Expenses	452	114,294
177	(916) Miscellaneous Sales Expenses	192,237	307,957
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	197,423	928,503
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	25,316,910	22,474,374
182	(921) Office Supplies and Expenses	4,127,587	3,928,835
183	(Less) (922) Administrative Expenses Transferred-Credit	50,151	49,301
184	(923) Outside Services Employed	15,053,420	11,313,636
185	(924) Property Insurance	1,300,926	1,283,269
186	(925) Injuries and Damages	5,380,816	3,543,277
187	(926) Employee Pensions and Benefits	1,098,670	1,053,264
188	(927) Franchise Requirements	6,027	6,704
189	(928) Regulatory Commission Expenses	5,550,292	4,999,707
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	204,098	264,628
192	(930.2) Miscellaneous General Expenses	3,269,466	3,129,106
193	(931) Rents	872,289	393,144
194	TOTAL Operation (Enter Total of lines 181 thru 193)	62,130,350	52,340,643
195	Maintenance		
196	(935) Maintenance of General Plant	7,655,998	7,960,364
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	69,786,348	60,301,007
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	763,521,770	663,266,859

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	04/15/2011	End of 2010/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	IF	WSPP			
3	BP Energy Comp	SF	WSPP			
4	Barclays Bank PLC	SF	WSPP			
5	Black Creek Hydro	LU	FERC #1			
6	BNP Paribas Energy	SF	WSPP			
7	Bonneville Power Administration	LF	WNP#3 Agr.			
8	Bonneville Power Administration	SF	WSPP			
9	Bonneville Power Administration	EX	PNCA			
10	Bonneville Power Administration	SF	Tariff #8			
11	Bonneville Power Administration	OS	BPA OATT			
12	Bonneville Power Administration	SF	BPA OATT			
13	Calpine Energy Services	SF	WSPP			
14	California Independent System Operator	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	04/15/2011	End of 2010/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
					7,357,836	7,357,836	1
219,000				7,555,500		7,555,500	2
353,924				13,794,676		13,794,676	3
16,452				721,300		721,300	4
10,438				233,903		233,903	5
3,000				35,950		35,950	6
406,710				13,920,036		13,920,036	7
66,184				1,739,345		1,739,345	8
	700	700		2,338		2,338	9
37,161				1,166,693		1,166,693	10
				244,700	824,256	1,068,956	11
14,796				317,730	-79,214	238,516	12
50							13
3,215							14
8,441,791	650,299	649,168	9,510,548	256,938,753	10,629,829	277,079,130	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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	Cargill Power Markets	SF	WSPP			
2	City of Spokane	LU	PURPA			
3	Chelan County PUD	LU	Rocky Reach			
4	Chelan County PUD	SF	WSPP			
5	Citigroup Energy	SF	WSPP			
6	Clatskanie PUD	SF	WSPP			
7	Conoco Phillips	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	WSPP			
12	Douglas County PUD No. 1	EX	305			
13	DB Energy Trading LLC	SF	WSPP			
14	Eagle Energy Partners	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)	
57,779				1,847,465		1,847,465	1
52,519				2,054,628		2,054,628	2
144,508				2,171,979		2,171,979	3
6,605				186,374		186,374	4
118,775				3,954,104		3,954,104	5
2,287				86,575		86,575	6
44							7
211,599				1,399,720		1,399,720	8
17,613				334,029		334,029	9
23,296			9,496,248			9,496,248	10
22,170				827,513		827,513	11
	114,405	114,285		1,553,363	3,458	1,556,821	12
7,200				189,200		189,200	13
400				13,900		13,900	14
8,441,791	650,299	649,168	9,510,548	256,938,753	10,629,829	277,079,130	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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	Endure Energy	SF	WSPP			
2	Eugene Water & Electric Board	SF	WSPP			
3	Ford Hydro Limited Partnership	LU	PURPA			
4	Grant County PUD No. 2	LU	Wanapum			
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	Hydro Technology Systems	LU	PURPA			
10	Idaho Power Company	SF	WSPP			
11	Inland Power & Light Company	RQ	208			
12	Iberdrola Renewables	SF	WSPP			
13	Jim White	LU	PURPA			
14	John Day Hydro	LU	PURPA			
	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	04/15/2011	End of 2010/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)	
2,264				89,326		89,326	1
7,400				257,380		257,380	2
2,939				186,068		186,068	3
136,440				-1,227,586		-1,227,586	4
151,949				5,608,844		5,608,844	5
12,614				392,112		392,112	6
					3,415	3,415	7
192,996				5,653,029		5,653,029	8
7,869				405,179		405,179	9
2,205				83,125		83,125	10
104				6,239		6,239	11
336,690				13,358,966		13,358,966	12
967				90,807		90,807	13
2,013				90,814		90,814	14
8,441,791	650,299	649,168	9,510,548	256,938,753	10,629,829	277,079,130	

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	J P Morgan Ventures Energy LLC	SF	WSPP			
2	J P Morgan Ventures Energy LLC	LU	PPM Energy			
3	Mirant Energy Trading	LU	WSPP			
4	Morgan Stanley Capital Group	IF	WSPP			
5	Morgan Stanley Capital Group	SF	WSPP			
6	Macquarie Energy LLC	SF	ISDA			
7	NaturEner Power Watch	SF	WSPP			
8	Northpoint Energy Solutions	SF	WSPP			
9	NorthWestern Energy LLC	SF	WSPP			
10	Okanogan County PUD No. 1	SF	WSPP			
11	PPL Energy Plus	SF	WSPP			
12	PacifiCorp	SF	WSPP			
13	Pacific NW Gen Corp	SF	WSPP			
14	Pend Oreille County PUD No. 1	SF	Pend O'			
	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	04/15/2011	End of 2010/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)	
15,602				452,806		452,806	1
73,276				3,016,499		3,016,499	2
							3
656,992				20,191,554		20,191,554	4
100,717				3,458,919		3,458,919	5
66,331				2,141,800		2,141,800	6
13							7
307				7,571		7,571	8
39,954				1,403,589		1,403,589	9
57,242				1,535,964		1,535,964	10
1,724,322				54,745,622		54,745,622	11
51,782				1,653,589		1,653,589	12
8,439				183,000		183,000	13
26,339				861,345		861,345	14
8,441,791	650,299	649,168	9,510,548	256,938,753	10,629,829	277,079,130	

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	04/15/2011	End of 2010/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	Pend Oreille County PUD No. 1	SF	Pend O'			
2	Phillips Ranch	LU	PURPA			
3	Portland General Electric Company	EX	304			
4	Portland General Electric Company	EX	178			
5	Portland General Electric Company	SF	WSPP			
6	Potlatch Corporation	LU	PURPA			
7	Powerex Corp	SF	WSPP			
8	Powerex Corp	SF	WSPP			
9	Public Service Co of Colorado	SF	WSPP			
10	Puget Sound Energy	SF	WSPP			
11	Rainbow Energy Marketing Corp	SF	WSPP			
12	Sacramento Municipal Utility District	SF	WSPP			
13	Seattle City Light	EX	WSPP			
14	Seattle City Light	SF	WSPP			
	Total					

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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)	
77,301	9,354	7,851		2,014,636	-359	2,014,277	1
65				4,169		4,169	2
	10,379	10,347					3
	430,075	430,785			46,035	46,035	4
6,883				228,158		228,158	5
436,153				18,719,687		18,719,687	6
			14,300			14,300	7
73,148				3,544,975		3,544,975	8
800				35,300		35,300	9
27,014				926,051		926,051	10
116,026				3,569,684		3,569,684	11
1,200				33,000		33,000	12
	85,200	85,200		1,074,040		1,074,040	13
56,214				1,666,086		1,666,086	14
8,441,791	650,299	649,168	9,510,548	256,938,753	10,629,829	277,079,130	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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	Sempra Energy Trading	SF	WSPP			
2	Sheep Creek Hydro	LU	PURPA			
3	Shell Energy	SF	ISDA			
4	Shell Energy	SF	WSPP			
5	Southern California Edison Co.	SF	WSPP			
6	Snohomish County PUD No. 1	SF	WSPP			
7	Sovereign Power	IF	Sovereign			
8	Stimson Lumber	IU	PURPA			
9	Tacoma Power	SF	WSPP			
10	Tacoma Power	SF	WSPP			
11	The Energy Authority	SF	WSPP			
12	TransAlta Energy Marketing	SF	WSPP			
13	IntraCompany Generation Services	OS	OATT			
14	Avista Turbine Power	LF	Lancaster			
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	POWER EXCHANGES MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	COST/SETTLEMENT OF POWER Energy Charges ($) (k)	COST/SETTLEMENT OF POWER Other Charges ($) (l)	COST/SETTLEMENT OF POWER Total (j+k+l) of Settlement ($) (m)	Line No.
99,159				5,424,668		5,424,668	1
7,097				301,525		301,525	2
					2,357,890	2,357,890	3
473,149				18,266,097		18,266,097	4
610				20,380		20,380	5
23,105				689,820		689,820	6
7,404				232,201		232,201	7
35,845				1,964,160		1,964,160	8
30,606				939,913		939,913	9
							10
10,529				296,901		296,901	11
76,072				3,194,228		3,194,228	12
				631,350		631,350	13
1,304,090				22,201,691		22,201,691	14
8,441,791	650,299	649,168	9,510,548	256,938,753	10,629,829	277,079,130	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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	Rathdrum Power LLC	LF	Lancaster			
2	Other - Inadvertent Interchange	EX				
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
105,830				1,962,451		1,962,451	1
	186				116,512	116,512	2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
8,441,791	650,299	649,168	9,510,548	256,938,753	10,629,829	277,079,130	

Schedule Page: 326 Line No.: 1 Column: a

Fianncial Swap

Schedule Page: 326 Line No.: 9 Column: a

Non Monetary

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.: 12 Column: a

Non Monetary

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

Non Monetary

Schedule Page: 326.4 Line No.: 1 Column: a

Non Monetary

Schedule Page: 326.4 Line No.: 4 Column: a

Non Monetary

Schedule Page: 326.5 Line No.: 3 Column: a

Financial Swap

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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	04/15/2011	End of 2010/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 Classifi-cation (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	Grant County Public Utility District	Bonneville Power Administration	NorthWestern Montana	LFP
11	Bonneville Power Administration	Bonneville Power Administration	Idaho Power Company	NF
12	Bonneville Power Administration	Bonneville Power Administration	Avista Corporation	NF
13	Bonneville Power Administration	Bonneville Power Administration	Avista Corporation	SFP
14	Bonneville Power Administration	Bonneville Power Administration	Idaho Power Company	SFP
15	Idaho Power Company	Grant County Public Utility Distr	Idaho Power Company	NF
16	Idaho Power Company	PacifiCorp	Idaho Power Company	NF
17	Idaho Power Company	Avista Corporation	Idaho Power Company	NF
18	Idaho Power Company	Idaho Power Company	Bonneville Power Administration	NF
19	Idaho Power Company	Bonneville Power Administration	Idaho Power Company	NF
20	Idaho Power Company	NorthWestern Montana	Idaho Power Company	NF
21	Idaho Power Company	Chelan Public Utility District	Idaho Power Company	NF
22	Idaho Power Company	Bonneville Power Administration	Idaho Power Company	SFP
23	Idaho Power Company	Avista Corporation	Bonneville Power Administration	SFP
24	Idaho Power Company	Idaho Power Company	Bonneville Power Administration	SFP
25	Idaho Power Company	Portland General Electric	Idaho Power Company	SFP
26	Idaho Power Company	NorthWestern Montana	Idaho Power Company	SFP
27	Idaho Power Company	PacifiCorp	Idaho Power Company	SFP
28	NorthWestern Energy	NorthWestern Montana	Bonneville Power Administration	NF
29	PacifiCorp	PacifiCorp	Bonneville Power Administration	NF
30	PacifiCorp	PacifiCorp	NorthWestern Montana	NF
31	PacifiCorp	PacifiCorp	Idaho Power Company	NF
32	PacifiCorp	PacifiCorp	Bonneville Power Administration	NF
33	Powerex	NorthWestern Montana	Bonneville Power Administration	NF
34				
	TOTAL			

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
FERC No. 182	Dry Creek Walla Wall	Dry Gulch	20	50,244	50,244	1
FERC Trf No. 8	Chelan-Stratford 115	Stratford 115kV SS		173,230	173,230	2
FERC Trf No. 8	Chelan-Stratford 115	Stratford 115kV SS		173,230	173,230	3
FERC No. 104	Stratford Substation	Coulee Cy/Wilson Crk	25	68,582	68,582	4
FERC Trf No. 8	Westside	Little Falls	2	2,409	2,409	5
FERC Trf No. 8	Bell Substation	Post Falls	3	3,014	3,014	6
FERC Trf No. 8	Bell Substation	BKR/OPT/EFM/LIB	4	5,599	5,599	7
FERC Trf No. 8				1,760,718	1,760,718	8
FERC No. 155	Sunset-Westside 115k	Westside	23	141,498	141,498	9
FERC Trf No. 8	BPATPUD	Burke		40,299	40,299	10
FERC Trf No. 8				7,848	7,848	11
FERC Trf No. 8						12
FERC Trf No. 8						13
FERC Trf No. 8				56,829	56,829	14
FERC Trf No. 8				1,930	1,930	15
FERC Trf No. 8				3,071	3,071	16
FERC Trf No. 8				480	480	17
FERC Trf No. 8				13,749	13,749	18
FERC Trf No. 8				19,942	19,942	19
FERC Trf No. 8				325	325	20
FERC Trf No. 8				400	400	21
FERC Trf No. 8				122,163	122,163	22
FERC Trf No. 8				6,168	6,168	23
FERC Trf No. 8				62,115	62,115	24
FERC Trf No. 8				280	280	25
FERC Trf No. 8				406	406	26
FERC Trf No. 8				10,837	10,837	27
FERC Trf No. 8				290	290	28
FERC Trf No. 8				2,620	2,620	29
FERC Trf No. 8						30
FERC Trf No. 8				1,519	1,519	31
FERC Trf No. 8				21	21	32
FERC Trf No. 8				4,455	4,455	33
						34
			77	**2,918,232**	**2,918,232**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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.
217,930			217,930	1
182,990			182,990	2
182,990			182,990	3
23,750			23,750	4
21,346			21,346	5
16,517			16,517	6
46,982			46,982	7
8,435,924			8,435,924	8
127,506		32,088	159,594	9
240,000			240,000	10
	45,473		45,473	11
	5,343		5,343	12
1,292			1,292	13
339,572			339,572	14
	10,561		10,561	15
	22,973		22,973	16
	2,770		2,770	17
	65,128		65,128	18
	109,850		109,850	19
	1,908		1,908	20
	2,308		2,308	21
569,078			569,078	22
27,133			27,133	23
354,398			354,398	24
1,601			1,601	25
2,322			2,322	26
59,072			59,072	27
	1,673		1,673	28
	36,349		36,349	29
	12		12	30
	37,103		37,103	31
	577		577	32
	33,432		33,432	33
				34
11,450,739	**931,928**	**32,088**	**12,414,755**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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	Powerex	Idaho Power Company	Bonneville Power Administration	NF
2	Powerex	Bonneville Power Administration	Idaho Power Company	NF
3	Powerex	Bonneville Power Administration	Idaho Power Company	SFP
4	Puget Sound Energy	Idaho Power Company	Bonneville Power Administration	NF
5	Puget Sound Energy	NorthWestern Montana	Puget Sound Energy	NF
6	Puget Sound Energy	NorthWestern Montana	Bonneville Power Administration	NF
7	Puget Sound Energy	Bonneville Power Administration	Idaho Power Company	NF
8	Puget Sound Energy	NorthWestern Montana	Bonneville Power Administration	SFP
9	Portland General Electric	NorthWestern Montana	Portland General Electric	NF
10	Portland General Electric	NorthWestern Montana	Bonneville Power Administration	NF
11	Portland General Electric	NorthWestern Montana	Portland General Electric	SFP
12	Morgan Stanley Capital Group	Avista Corporation	Bonneville Power Administration	NF
13	Morgan Stanley Capital Group	Bonneville Power Administration	Idaho Power Company	NF
14	Morgan Stanley Capital Group	NorthWestern Montana	Chelan Public Utility District	NF
15	Morgan Stanley Capital Group	NorthWestern Montana	Portland General Electric	NF
16	Morgan Stanley Capital Group	NorthWestern Montana	Idaho Power Company	NF
17	Morgan Stanley Capital Group	NorthWestern Montana	Grant County Public Utility Distr	NF
18	Morgan Stanley Capital Group	Idaho Power Company	Bonneville Power Administration	NF
19	Morgan Stanley Capital Group	NorthWestern Montana	Bonneville Power Administration	NF
20	Morgan Stanley Capital Group	Idaho Power Company	Chelan Public Utility District	NF
21	Sierra Pacific Power Company	Bonneville Power Administration	Idaho Power Company	NF
22	Cargill Power Markets	NorthWestern Montana	Bonneville Power Administration	NF
23	Cargill Power Markets	Idaho Power Company	Bonneville Power Administration	NF
24	Cargill Power Markets	Bonneville Power Administration	Idaho Power Company	NF
25	Cargill Power Markets	Bonneville Power Administration	Idaho Power Company	SFP
26	Cargill Power Markets	NorthWestern Montana	Bonneville Power Administration	SFP
27	Cargill Power Markets	NorthWestern Montana	PacifiCorp	SFP
28	Rainbow Energy Marketing Corp	Bonneville Power Administration	Idaho Power Company	NF
29	Rainbow Energy Marketing Corp	NorthWestern Montana	Idaho Power Company	NF
30	Coral Power	NorthWestern Montana	Chelan Public Utility District	NF
31	Coral Power	Chelan Public Utility District	Idaho Power Company	NF
32	Coral Power	Chelan Public Utility District	NorthWestern Montana	NF
33	Coral Power	Bonneville Power Administration	Idaho Power Company	NF
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
FERC Trf No. 8				277	277	1
FERC Trf No. 8				2,632	2,632	2
FERC Trf No. 8				1,600	1,600	3
FERC Trf No. 8				5	5	4
FERC Trf No. 8				22	22	5
FERC Trf No. 8				21,798	21,798	6
FERC Trf No. 8				148	148	7
FERC Trf No. 8				15,779	15,779	8
FERC Trf No. 8				4,760	4,760	9
FERC Trf No. 8				1,544	1,544	10
FERC Trf No. 8						11
FERC Trf No. 8				25	25	12
FERC Trf No. 8				993	993	13
FERC Trf No. 8				10,323	10,323	14
FERC Trf No. 8				20	20	15
FERC Trf No. 8				196	196	16
FERC Trf No. 8				383	383	17
FERC Trf No. 8				1,560	1,560	18
FERC Trf No. 8				7,458	7,458	19
FERC Trf No. 8				1,371	1,371	20
FERC Trf No. 8				1,165	1,165	21
FERC Trf No. 8				1,998	1,998	22
FERC Trf No. 8				2,980	2,980	23
FERC Trf No. 8				6,530	6,530	24
FERC Trf No. 8				18,025	18,025	25
FERC Trf No. 8				2,368	2,368	26
FERC Trf No. 8				400	400	27
FERC Trf No. 8				80	80	28
FERC Trf No. 8				263	263	29
FERC Trf No. 8				3,126	3,126	30
FERC Trf No. 8				50	50	31
FERC Trf No. 8				1,704	1,704	32
FERC Trf No. 8				89	89	33
						34
			77	**2,918,232**	**2,918,232**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	1,906		1,906	1
	19,610		19,610	2
9,230			9,230	3
	29		29	4
	133		133	5
	133,484		133,484	6
	869		869	7
70,000			70,000	8
	30,588		30,588	9
	9,548		9,548	10
4,639			4,639	11
	331		331	12
	6,849		6,849	13
	69,460		69,460	14
	133		133	15
	1,282		1,282	16
	2,594		2,594	17
	10,660		10,660	18
	50,123		50,123	19
	9,363		9,363	20
	6,866		6,866	21
	12,115		12,115	22
	20,337		20,337	23
	31,362		31,362	24
96,638			96,638	25
13,660			13,660	26
2,308			2,308	27
	462		462	28
	1,517		1,517	29
	21,583		21,583	30
	288		288	31
	9,913		9,913	32
	528		528	33
				34
11,450,739	**931,928**	**32,088**	**12,414,755**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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	Coral Power	Idaho Power Company	Chelan Public Utility District	NF
2	PPL Energy Plus, LLC	NorthWestern Montana	Bonneville Power Administration	NF
3	PPL Energy Plus, LLC	NorthWestern Montana	Idaho Power Company	NF
4	PPL Energy Plus, LLC	NorthWestern Montana	Grant County Public Utility Distr	NF
5	TransAlta Energy Marketing (U.S.) Inc.	Idaho Power Company	Bonneville Power Administration	NF
6	TransAlta Energy Marketing (U.S.) Inc.	Bonneville Power Administration	Idaho Power Company	NF
7	NaturEner USA	NorthWestern Montana	Bonneville Power Administration	NF
8	NaturEner USA	NorthWestern Montana	Portland General Electric	NF
9	NaturEner USA	Bonneville Power Administration	NorthWestern Montana	SFP
10	NaturEner USA	NorthWestern Montana	Bonneville Power Administration	SFP
11	NaturEner USA	NorthWestern Montana	Portland General Electric	SFP
12	Grant County Public Utility District	Avista Corporation	Grant County Public Utility Distr	NF
13	Grant County Public Utility District	NorthWestern Montana	Bonneville Power Administration	SFP
14				
15				
16				
17				
18				
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33				
34				
	TOTAL			

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
FERC Trf No. 8				70	70	1
FERC Trf No. 8				520	520	2
FERC Trf No. 8				1,931	1,931	3
FERC Trf No. 8				465	465	4
FERC Trf No. 8				73	73	5
FERC Trf No. 8				1,553	1,553	6
FERC Trf No. 8				2,833	2,833	7
FERC Trf No. 8				3,277	3,277	8
FERC Trf No. 8				17,366	17,366	9
FERC Trf No. 8				1,453	1,453	10
FERC Trf No. 8				1,456	1,456	11
FERC Trf No. 8						12
FERC Trf No. 8				43,292	43,292	13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			77	2,918,232	2,918,232	

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.
	473		473	1
	3,000		3,000	2
	11,142		11,142	3
	2,683		2,683	4
	474		474	5
	10,996		10,996	6
	22,551		22,551	7
	37,350		37,350	8
206,718			206,718	9
16,673			16,673	10
33,149			33,149	11
	15,866		15,866	12
147,321			147,321	13
				14
				15
				16
				17
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				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
11,450,739	**931,928**	**32,088**	**12,414,755**	

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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	04/15/2011	End of 2010/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Bonneville Power Admin	LFP			1,172,536			1,172,536
2	Bonneville Power Admin	LFP			11,183,568		1,786,922	12,970,490
3	Bonneville Power Admin	LFP			788,565			788,565
4	Bonneville Power Admin	FNS			1,065,965		162,596	1,228,561
5	Bonneville Power Admin	OS					24,360	24,360
6	Bonneville Power Admin	NF	64,578	64,578		280,267	-1,954	278,313
7	Grant PUD	LFP					9,285	9,285
8	Kootenai Electric Coop	LFP			45,222			45,222
9	Northern Lights	LFP			138,670			138,670
10	NorthWestern Energy	NF	49,063	49,063		193,321	16,411	209,732
11	Northwestern Energy	SFP			127,589			127,589
12	Portland General Elec	LFP			642,989			642,989
13	Portland General Elec	NF	510	510		713		713
14	Puget Sound Energy	NF	38,234	38,234		87,187		87,187
15	Rainbow Energy Mkt	NF						
16	Seattle City Light	NF	6,905	6,905		9,241		9,241
	TOTAL		163,769	163,769	15,165,104	579,405	1,997,620	17,742,129

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Snohomish PUD	NF						
2	Tacoma Power	NF	4,479	4,479		8,676		8,676
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		163,769	163,769	15,165,104	579,405	1,997,620	17,742,129

FOOTNOTE DATA

Schedule Page: 332 Line No.: 2 Column: a

Ancillary Services

Schedule Page: 332 Line No.: 4 Column: a

Ancillary Services

Schedule Page: 332 Line No.: 5 Column: a

Use of Facilities

Schedule Page: 332 Line No.: 6 Column: a

Ancillary Services

Schedule Page: 332 Line No.: 7 Column: a

Use of Facilities

Schedule Page: 332 Line No.: 10 Column: a

Ancillary Services

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	04/15/2011	End of 2010/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	511,266
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	113,998
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	1,360,951
6	Community Relations	615,508
7	Education and Informational	37,192
8	Other Miscellaneous General Expenses	37,208
9	Directors fees and expenses	593,343
10		
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46	TOTAL	3,269,466

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	04/15/2011	2010/Q4

FOOTNOTE DATA

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

Schedule Page: 335 Line No.: 5

Vendor	Purpose	Amount
VENDORS LESS THAN $5,000		97,601
ADVENTURES IN ADVERTISING	Miscellaneous	13729
AMERICAN GAS ASSOCIATION	Miscellaneous	0
AMERICAN STOCK TRANSFER & TRUST CO	General Services	4692.55
AZAR'S FOOD SERVICES	Miscellaneous	6226
BANK OF NY - PERSHING	Miscellaneous	5411
BNY MELLON	Postage	4013.18
BOARDVANTAGE INC	Subscriptions	22476.08
BROADRIDGE ICS	General Services	56609.82
CHIPMAN MOVING & STORAGE (SPOKANE) INC	Employee Relocation	5719.99
CITIBANK NA	Miscellaneous	46978.62
CORP CREDIT CARD	Telecommunication Use	93610.91
CORPORATE EXECUTIVE BOARD	Subscriptions	9087.29
CUTAWAY MEDIA	Miscellaneous	17374.97
DAVID D HOLMES	Employee Misc Expenses	5157.61
DAVIS HIBBITTS & MIDGHALL INC	Professional Services	19131.15
DESAUTEL HEGE COMMUNICATIONS	Professional Services	43867
DEZDA FINN PROPERTIES LLC	Employee Relocation	5631
ENTERPRISE RENT A CAR	Printing	6063
ENTERPRISE SEATTLE FOUNDATION	Miscellaneous	5000
GARD COMMUNICATIONS	Professional Services	53689
HANNA & ASSOCIATES INC	Advertising Expenses	6189.04
J D POWER AND ASSOCIATES	Professional Services	17326.32
KLUNDT HOSMER DESIGN	Professional Services	23690.86
MARKET DECISIONS CORPORATION	Professional Services	17911
MELLON INVESTOR SERVICES LLC	Miscellaneous	124151.67
MICHAEL G ANDREA	Employee Misc Expenses	13867
MICHAEL J FAULKENBERRY	Employee Misc Expenses	0
MOODYS INVESTORS SERVICE	Miscellaneous	71471.07
NYSE MARKET INC	General Services	36816.99
OLSTEN	Workforce - Contract	3904.8
PATRICIA A NEWMANN	Professional Services	8604.54
RHT ENERGY SOLUTIONS	Professional Services	0
ROGER D WOODWORTH	Office Supplies	4840.31
STANDARD & POORS	Miscellaneous	72895
STEVE L VINCENT	Office Supplies	260.94
STRATEGIC RESEARCH ASSOCIATES	Professional Services	4548
SYSTRENDS USA	General Services	9350
THE BANK OF NEW YORK MELLON	Miscellaneous	14212.74
THE BANK OF NEW YORK MELLON TRUST CO	Miscellaneous	5054
THE DAVENPORT HOTEL	Miscellaneous	17885
THE LAUREL HILL ADVISORY GROUP LLC	General Services	5432.87

THINKING CAP	Miscellaneous	5963
WASHINGTON ROUNDTABLE	Miscellaneous	3725.88
WASHINGTON STATE UNIVERSITY	Miscellaneous	24365.13
WILMINGTON TRUST COMPANY	Miscellaneous	3609.65

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

Schedule Page: 335 Line No.: 9

Directors	**2010 Expenses**
Vendor Name	
HEIDI B STANLEY	$73,765
BRIAN W DUNHAM	$32,068
MARC F RACICOT	$36,307
ERIK J ANDERSON	$74,672
KRISTIANNE BLAKE	$62,858
REBECCA A KLEIN	$32,711
JOHN F KELLY	$71,066
MICHAEL L NOEL	$50,929
R JOHN TAYLOR	$76,745
ROY EIGUREN	$74,057
SCOTT L MORRIS	$8,165

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	04/15/2011	End of 2010/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			4,383,334		4,383,334
2	Steam Production Plant	10,491,685				10,491,685
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	8,447,346				8,447,346
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	8,974,310			2,450,031	11,424,341
7	Transmission Plant	9,750,937				9,750,937
8	Distribution Plant	28,359,278				28,359,278
9	Regional Transmission and Market Operation					
10	General Plant	2,979,759				2,979,759
11	Common Plant-Electric	6,859,386		1,277,131		8,136,517
12	TOTAL	75,862,701		5,660,465	2,450,031	83,973,197

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	04/15/2011	End of 2010/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	50,517	65.00	-5.00	2.28	S1.5	17.88
15	312	76,878	60.00	-10.00	2.70	R1	18.57
16	314	18,669	50.00	-10.00	3.39	O1	28.07
17	315	9,389	55.00	-5.00	2.49	S1.5	20.78
18	316	8,839	50.00		2.26	R2	15.88
19	Subtotal	164,292					
20							
21	Colstrip No. 4						
22	311	49,668	65.00	-5.00	2.35	S1.5	21.32
23	312	50,137	60.00	-10.00	2.83	R1	23.84
24	314	16,304	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	4,213	50.00		2.46	R3	19.98
27	Subtotal	127,028					
28							
29	Kettle Falls						
30	310	148	35.00		2.19	SQ	
31	311	24,955	65.00	-5.00	2.34	S1.5	20.59
32	312	41,358	60.00	-10.00	3.31	R1	22.43
33	314	13,308	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	93,211					
37							
38	HYDRO PLANT						
39	Cabinet Gorge						
40	330	7,725	75.00		2.75	R3	67.57
41	331	10,670	110.00	-5.00	1.62	R0.5	56.19
42	332	31,134	100.00		1.79	R1.5	77.96
43	333	37,441	60.00	-5.00	2.59	R1.5	52.14
44	334	5,457	45.00		1.43	R2.5	16.54
45	335	2,625	65.00		0.13	R1	1.20
46	336	1,099	60.00		2.05	S2.5	17.49
47	Subtotal	96,151					
48							
49	Noxon Rapids						
50	330	29,974	75.00		2.83	R3	69.37

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	13,935	110.00	-5.00	1.77	R0.5	81.53
13	332	32,298	100.00		1.79	R1.5	75.35
14	333	75,263	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	169,274					
19							
20	Post Falls						
21	330	2,732	75.00		3.79	R3	56.46
22	331	1,345	110.00	-5.00	0.36	R0.5	56.29
23	332	6,317	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	13,567					
28							
29	Long Lake						
30	330	418	75.00		5.68	R3	45.63
31	331	2,195	110.00	-5.00	0.12	R0.5	15.32
32	332	16,638	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	31,427					
37							
38	Little Falls						
39	330	4,217	75.00		7.03	R3	56.31
40	331	1,185	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	2,027	45.00		0.93	R2.5	12.81
44	335	144	65.00		1.18	R1	19.46
45	Subtotal	16,610					
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	7,126	100.00		1.20	R1.5	76.61

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	04/15/2011	End of 2010/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	333	1,186	60.00	-5.00	0.90	R1.5	6.67
13	334	4,268	45.00		1.85	R2.5	37.00
14	335	107	65.00		2.30	R1	51.46
15	Subtotal	13,335					
16							
17	Nine Mile						
18	330	11	75.00		4.59	R3	34.35
19	331	3,943	110.00	-5.00	2.35	R0.5	80.39
20	332	13,350	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	30,490					
26							
27	Monroe Street						
28	331	8,444	110.00	-5.00	1.82	R0.5	109.02
29	332	8,047	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	29,285					
35							
36	OTHER PRODUCTION						
37	Northeast Turbine						
38	341	365			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	1,158	40.00		8.54	S1.5	11.83
43	346	300			1.24	SQ	
44	Subtotal	13,550					
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	04/15/2011	End of 2010/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	5	40.00		4.48	S1.5	28.83
20	Subtotal	9,169					
21							
22	Boulder Park						
23	341	1,164			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	32,300					
30							
31	Coyote Springs 2						
32	341	11,349			2.76	SQ	
33	342	19,128	55.00		2.85	R3	44.23
34	344	116,984	45.00		2.92	R3	41.58
35	345	12,701	40.00		3.10	S1.5	32.07
36	346	1,271			2.76	SQ	
37	Subtotal	161,433					
38							
39	Solar Power	64					
40	Subtotal	64					
41	TRANSMISSION PLANT						
42	350	15,286	75.00		1.28	R4	53.27
43	352	16,586	60.00	-5.00	1.61	R4	44.73
44	353	192,800	47.00	-15.00	2.39	R3	31.13
45	354	17,121	70.00	-20.00	1.87	S3	43.89
46	355	135,113	60.00	-30.00	1.84	R3	37.27
47	356	108,160	60.00	-10.00	1.93	R3	43.30
48	357	2,605	60.00		1.58	R4	52.84
49	358	2,330	55.00		1.73	S3	41.27
50	359	1,872	65.00		1.65	R4	45.05

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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/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	491,873					
13	DISTRIBUTION PLANT						
14	360	1,026					
15	361	14,522	55.00	-10.00	1.80	R3	35.51
16	362	97,096	42.00	-10.00	2.60	R1.5	28.26
17	364	229,311	50.00	-25.00	2.66	R2.5	34.66
18	365	151,716	50.00	-15.00	2.46	R2.5	35.35
19	366	77,764	45.00	-10.00	2.71	R3	36.09
20	367	129,764	28.00	-15.00	6.38	L4	23.05
21	368	178,518	44.00	-5.00	2.00	R2	27.21
22	369	120,177	60.00	-15.00	1.63	R3	38.01
23	370	46,055	38.00		2.39	S1	33.72
24	373	15,406	32.00	-15.00	1.08	R2.5	8.68
25	373.4	16,361	32.00	-5.00	2.82	R2.5	18.79
26	Subtotal	1,077,716					
27							
28	GENERAL PLANT						
29	390.1	3,589	55.00	-5.00	1.85	S2	20.91
30	391.1	1,991	5.00		17.67	SQ	3.80
31	393	390	25.00		2.25	SQ	22.97
32	394	3,258	20.00		4.22	SQ	10.35
33	395	1,128	15.00		7.72	SQ	7.82
34	397	41,361	15.00		5.40	SQ	5.17
35	398	8	10.00		2.37	SQ	7.80
36	Subtotal	51,725					
37							
38	MISC POWER						
39	392	2,739	11.00	10.00	3.70	S3	
40	396	2,266	15.00	10.00	5.40	L2	
41	Subtotal	5,005					
42							
43							
44							
45							
46							
47							
48							
49							
50							

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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	2,687,844					
18							
19							
20							
21							
22							
23							
24							
25							
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27							
28							
29							
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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	04/15/2011	End of 2010/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.	2,247,187	345,541	2,592,728	
5					
6					
7					
8					
9	Washington Utilities and Transportation				
10	Commission: includes annual fee and various				
11	other electric dockets	907,189	285,206	1,192,395	
12					
13	Includes annual fee and various other natural				
14	gas dockets	421,053	127,029	548,082	
15					
16	Idaho Public Utilities Commission				
17	Includes annual fee and various other electric				
18	dockets	505,813	190,597	696,410	
19					
20	Includes annual fee and various other natural				
21	gas dockets	170,468	96,189	266,657	
22					
23	Public Utility Commission of Oregon				
24	Includes annual fees and various other natural				
25	gas dockets	566,667	61,737	628,404	
26					
27	Not directly assigned electric		1,068,709	1,068,709	
28	Not directly assigned natural gas		411,641	411,641	
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	4,818,377	2,586,649	7,405,026	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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	2,592,728					4
							5
							6
							7
							8
							9
							10
Electric	928	1,192,395					11
							12
							13
Gas	928	548,082					14
							15
							16
							17
Electric	928	696,410					18
							19
							20
Gas	928	266,657					21
							22
							23
							24
Gas	928	628,404					25
							26
Electric	928	1,068,709					27
Gas	928	411,641					28
							29
							30
							31
							32
							33
							34
							35
							36
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							41
							42
							43
							44
							45
		7,405,026					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	04/15/2011	End of 2010/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	9,728,684		
4	Transmission	2,565,620		
5	Regional Market			
6	Distribution	4,154,967		
7	Customer Accounts	6,114,360		
8	Customer Service and Informational	634,361		
9	Sales	129,785		
10	Administrative and General	13,792,391		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	37,120,168		
12	Maintenance			
13	Production	2,450,204		
14	Transmission	882,225		
15	Regional Market			
16	Distribution	4,078,389		
17	Administrative and General			
18	TOTAL Maintenance (Total of lines 13 thru 17)	7,410,818		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	12,178,888		
21	Transmission (Enter Total of lines 4 and 14)	3,447,845		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	8,233,356		
24	Customer Accounts (Transcribe from line 7)	6,114,360		
25	Customer Service and Informational (Transcribe from line 8)	634,361		
26	Sales (Transcribe from line 9)	129,785		
27	Administrative and General (Enter Total of lines 10 and 17)	13,792,391		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	44,530,986	9,702,484	54,233,470
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply	844,328		
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution	3,563,152		
37	Customer Accounts	2,641,759		
38	Customer Service and Informational	330,534		
39	Sales	49,990		
40	Administrative and General	4,840,841		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	12,270,604		
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	598,383		

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	04/15/2011	End of 2010/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	2,516,984		
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	3,115,367		
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)	844,328		
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)	598,383		
57	Distribution (Lines 36 and 48)	6,080,136		
58	Customer Accounts (Line 37)	2,641,759		
59	Customer Service and Informational (Line 38)	330,534		
60	Sales (Line 39)	49,990		
61	Administrative and General (Lines 40 and 49)	4,840,841		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	15,385,971	7,515,613	22,901,584
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	59,916,957	17,218,097	77,135,054
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	29,478,679	6,478,172	35,956,851
69	Gas Plant	5,935,086	1,304,281	7,239,367
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	35,413,765	7,782,453	43,196,218
72	Plant Removal (By Utility Departments)			
73	Electric Plant	1,309,103	280,493	1,589,596
74	Gas Plant	96,345	20,643	116,988
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	1,405,448	301,136	1,706,584
77	Other Accounts (Specify, provide details in footnote):			
78	Stores Expense (163)	1,698,876	-1,698,876	
79	Preliminary Survey and Investigation (183)	36,969		36,969
80	Small Tool Expense (184)	4,157,526	-4,157,526	
81	Miscellaneous Deferred Debits (186)	772,896		772,896
82	Merchandising Expenses (416)	288,382		288,382
83				
84	Expenditures of Certain Civic, Political and Related Activiti	532,655		532,655
85	Employee Incentive Plan (232380)	5,917,714	-5,917,714	
86	DSM Tarrif Rider and Payroll Equalization Liab. (242600, 2427	16,506,045	-14,809,334	1,696,711
87	Incentive/ Stock Compensation (238000)	76,010		76,010
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	29,987,073	-26,583,450	3,403,623
96	TOTAL SALARIES AND WAGES	126,723,243	-1,281,764	125,441,479

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	04/15/2011	End of 2010/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	33,088,760
389	Land and Land Rights	5,288,514
390	Structures and Improvements	59,082,583
391	Office Furniture and Equipment	35,855,609
392	Transportation Equipment	9,005,542
393	Stores Equipment	1,480,701
394	Tools, Shop & Garage Equipment	4,664,596
395	Laboratory Equipment	573,784
396	Power Operated Equipment	2,384,859
397	Communications Equipment	21,621,565
398	Miscellaneous Equipment	412,287
399	Asset Retirement Cost	370,928
	Total Common Plant	173,829,729
	Const. Work in Progress	16,886,691
	Total Utility Plant	190,716,420
	Acc. Prov. for Dep. & Amort.	46,741,851
	Net Utility Plant	143,974,569

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	1,118,953	592,956	525,998	#of cust @ yr end
902	Meter reading expenses	4,207,359	2,598,717	1,608,642	#of cust @ yr end
903	Cust rec & collection expenses	13,160,557	7,176,227	5,984,329	#of cust @ yr end
903.90-99	A/R misc fees	426,347	340,822	85,525	net direct plant
904	Uncollectible accounts	3,160,171	1,674,638	1,485,533	#of cust @ yr end
905	Misc cust acct expenses	247,244	131,019	116,225	#of cust @ yr end
907	Cust srvc & Info exp supervision	0	0	0	#of cust @ yr end
908	Cust assistance exp	980,345	605,497	374,847	#of cust @ yr end
909	Info & instruct advert	1,508,278	842,202	666,076	#of cust @ yr end

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	318,612	168,978	149,634	#of cust @ yr end
911	Sales expense sprvsn	0	0	0	#of cust @ yr end
912	Demo and selling expenses	10,622	4,734	5,927	#of cust @ yr end
913	Advertising expenses	732	452	280	#of cust @ yr end
916	Misc sales expenses	311,235	192,237	118,998	#of cust @ yr end
920	Admin & gen salaries	32,531,389	23,603,594	8,927,794	four factor
921	Office supplies & expenses	5,489,199	3,964,539	1,524,660	four factor
922	Admin expenses tranf-cred	3,438	2,556	883	four factor
923	Outside srvcs employed	20,319,181	14,669,258	5,649,923	four factor
924	Property insurance	1,507,926	1,088,617	419,309	four factor
925	Injuries and damages	6,302,224	4,698,609	1,603,615	four factor
926	Employee pensions & benefits	47,334,327	34,290,934	13,043,392	four factor
927	Franchise requirement	0	0	0	four factor
928	Regulatory commission expenses	1,491,104	1,077,199	413,905	four factor
929	Duplicate charges-credit	0	0	0	four factor
930.1	General advertising expenses	281,990	203,858	78,131	four factor
930.2	Misc general expenses	3,858,816	2,818,869	1,039,948	four factor
931	Rents	1,072,579	777,341	295,238	four factor
935	Maint of general plant	8,171,994	5,961,093	2,210,901	four factor
403	Depreciation	9,392,046	6,859,385	2,532,661	four factor
404	Amort of LTD term plant	6,070,782	4,383,336	1,687,446	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 Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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	622	MW	126,180			
2	Reactive Supply and Voltage						
3	Regulation and Frequency Response	219,874	MWh	32,981	70,621	MW	631,350
4	Energy Imbalance				966	MW	4,159,507
5	Operating Reserve - Spinning	54,117	MWh	529,652	57,448	MWh	528,859
6	Operating Reserve - Supplement	49,243	MWh	406,544	21,667	MWh	226,622
7	Other	1,317,784	MW	11,780,987	1,317,784	MW	11,780,987
8	Total (Lines 1 thru 7)	1,641,640		12,876,344	1,468,486		17,327,325

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) 04/15/2011	Year/Period of Report End of 2010/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	2,388	7	1800	1,487	306	190	38	405	57
2	February	2,296	2	800	1,257	248	190	36	601	59
3	March	2,008	10	800	1,293	266	201	33	248	225
4	Total for Quarter 1	6,692			4,037	820	581	107	1,254	341
5	April	2,169	1	900	1,268	232	209	22	460	171
6	May	1,959	7	800	1,193	244	210	44	312	299
7	June	2,252	28	1700	1,292	229	203	44	528	118
8	Total for Quarter 2	6,380			3,753	705	622	110	1,300	588
9	July	2,319	26	1700	1,492	260	212	40	355	120
10	August	2,305	5	1700	1,490	253	207	25	355	238
11	September	1,882	29	1800	1,173	189	200	37	320	188
12	Total for Quarter 3	6,506			4,155	702	619	102	1,030	546
13	October	2,165	24	1900	1,124	207	197	21	637	198
14	November	2,461	24	1800	1,619	350	190	31	302	282
15	December	2,299	5	1800	1,444	288	190	25	377	42
16	Total for Quarter 4	6,925			4,187	845	577	77	1,316	522
17	Total Year to Date/Year	26,503			16,132	3,072	2,399	396	4,900	1,997

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	04/15/2011	End of 2010/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	2,061,174
4	Nuclear	
5	Hydro-Conventional	3,493,588
6	Hydro-Pumped Storage	
7	Other	1,686,988
8	Less Energy for Pumping	
9	Net Generation (Enter Total of lines 3 through 8)	7,241,750
10	Purchases	8,441,791
11	Power Exchanges:	
12	Received	650,299
13	Delivered	649,168
14	Net Exchanges (Line 12 minus line 13)	1,131
15	Transmission For Other (Wheeling)	
16	Received	2,918,232
17	Delivered	2,918,232
18	Net Transmission for Other (Line 16 minus line 17)	
19	Transmission By Others Losses	
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	15,684,672

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	8,856,389
23	Requirements Sales for Resale (See instruction 4, page 311.)	
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	6,251,508
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	10,733
27	Total Energy Losses	566,042
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	15,684,672

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	04/15/2011	End of 2010/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	1,327,445	448,076	1,526	7	1800
30	February	1,199,451	436,865	1,383	23	0800
31	March	1,313,274	535,803	1,348	10	0800
32	April	1,318,158	579,345	1,286	6	0900
33	May	1,167,464	443,620	1,245	6	0900
34	June	1,261,626	566,083	1,344	28	1700
35	July	1,444,136	650,286	1,552	26	1700
36	August	1,282,393	487,071	1,556	5	1700
37	September	1,262,155	561,087	1,210	3	1700
38	October	1,277,014	517,792	1,301	25	1900
39	November	1,406,544	548,097	1,704	23	1900
40	December	1,425,012	477,383	1,597	16	1800
41	TOTAL	15,684,672	6,251,508			

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	04/15/2011	End of 2010/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)	307			51		
7	Plant Hours Connected to Load	6416			19		
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	22			1		
12	Net Generation, Exclusive of Plant Use - KWh	1661182000			687000		
13	Cost of Plant: Land and Land Rights	0			157277		
14	Structures and Improvements	11348799			365280		
15	Equipment Costs	150084441			13193240		
16	Asset Retirement Costs	351682			0		
17	Total Cost	161784922			13715797		
18	Cost per KW of Installed Capacity (line 17/5) Including	563.7105			221.9385		
19	Production Expenses: Oper, Supv, & Engr	786563			29139		
20	Fuel	61382688			62238		
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	2064950			21774		
26	Misc Steam (or Nuclear) Power Expenses	49443			3668		
27	Rents	67255			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	614377			5468		
30	Maintenance of Structures	0			462		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	1148793			86863		
33	Maintenance of Misc Steam (or Nuclear) Plant	3485			34034		
34	Total Production Expenses	66117554			243646		
35	Expenses per Net KWh	0.0398			0.3547		
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	11356459	0	0	12130	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1020000	0	0	1020000	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	5.405	0.000	0.000	5.131	0.000	0.000
41	Average Cost of Fuel per Unit Burned	5.405	0.000	0.000	5.131	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	5.299	0.000	0.000	5.030	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.037	0.000	0.000	0.091	0.000	0.000
44	Average BTU per KWh Net Generation	6973.000	0.000	0.000	18010.000	0.000	0.000

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	04/15/2011	End of 2010/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
50			227			147			6
7402			8759			144			7
50			222			149			8
50			222			0			9
50			222			0			10
31			210			2			11
312276000			1748898000			10719000			12
941300			1289095			621682			13
24955417			100185043			3258386			14
68107702			191134566			56779395			15
450687			134589			0			16
94455106			292743293			60659463			17
1863.0198			1254.2558			364.3211			18
355493			180662			24385			19
11953801			16398780			545160			20
0			0			0			21
587712			3677996			0			22
0			0			0			23
0			0			0			24
801210			37137			150490			25
318820			2060904			181761			26
0			15498			0			27
0			0			0			28
123849			323810			407			29
133844			476268			4566			30
1757762			3142265			108557			31
253104			392594			0			32
321102			340421			30670			33
16606697			27046335			1045996			34
0.0532			0.0155			0.0976			35
Wood	Gas		Coal	Oil		Gas			36
Tons	MCF		Tons	Bbls		MCF			37
434622	5506	0	1075160	1627	0	120297	0	0	38
8500000	1020000	0	16855667	140000	0	1020000	0	0	39
27.431	5.384	0.000	15.123	85.581	0.000	4.532	0.000	0.000	40
27.431	5.384	0.000	15.123	85.581	0.000	4.532	0.000	0.000	41
3.230	5.278	0.000	0.900	14.420	0.000	4.443	0.000	0.000	42
0.038	0.063	0.000	0.009	0.000	0.000	0.051	0.000	0.000	43
11848.000	0.000	0.000	10368.000	0.000	0.000	11447.000	0.000	0.000	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	04/15/2011	End of 2010/Q4

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	514			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	10938000			0		
13	Cost of Plant: Land and Land Rights	144733			0		
14	Structures and Improvements	1163930			0		
15	Equipment Costs	31136453			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	32445116			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	1318.9072			0.0000		
19	Production Expenses: Oper, Supv, & Engr	24057			0		
20	Fuel	527656			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	76531			0		
26	Misc Steam (or Nuclear) Power Expenses	20097			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	3876			0		
30	Maintenance of Structures	3346			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	333801			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	39498			0		
34	Total Production Expenses	1028862			0		
35	Expenses per Net KWh	0.0941			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	107278	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1020000	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	4.919	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	4.919	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	4.822	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.048	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	10004.000	0.000	0.000	0.000	0.000	0.000

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	04/15/2011	End of 2010/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
0	0	0	16
0	0	0	17
0.0000	0.0000	0.0000	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
									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

Name of Respondent Avista Corporation	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report 2010/Q4

FOOTNOTE DATA

Schedule Page: 402 Line No.: -1 Column: b

Operated by Portland General Electric.

Schedule Page: 402 Line No.: -1 Column: e

Joint project operated by PPL Montana 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	04/15/2011	End of 2010/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	10.20
6	Net Peak Demand on Plant-Megawatts (60 minutes)	16	15
7	Plant Hours Connect to Load	8,626	8,435
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	105,901,000	71,163,000
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	8,047,296	7,126,169
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)	29,285,307	14,353,474
21	Cost per KW of Installed Capacity (line 20 / 5)	1,978.7370	1,407.2033
22	Production Expenses		
23	Operation Supervision and Engineering	31	7
24	Water for Power	0	0
25	Hydraulic Expenses	391	0
26	Electric Expenses	492,429	502,096
27	Misc Hydraulic Power Generation Expenses	17,848	37,301
28	Rents	0	0
29	Maintenance Supervision and Engineering	1,573	11,672
30	Maintenance of Structures	2,150	11,935
31	Maintenance of Reservoirs, Dams, and Waterways	99,293	50,642
32	Maintenance of Electric Plant	76,018	50,104
33	Maintenance of Misc Hydraulic Plant	13,608	4,061
34	Total Production Expenses (total 23 thru 33)	703,341	667,818
35	Expenses per net KWh	0.0066	0.0094

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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
261	545	90	6
8,758	6,686	7,028	7
			8
255	562	87	9
134	262	60	10
11	12	5	11
941,484,000	1,503,127,000	479,748,000	12
			13
10,573,152	35,831,527	1,597,959	14
10,670,126	13,934,921	2,194,764	15
31,133,950	32,298,217	16,637,951	16
45,523,191	92,841,623	12,176,179	17
1,098,564	225,369	0	18
0	0	0	19
98,998,983	175,131,657	32,606,853	20
373.5811	364.4021	465.8122	21
			22
102,869	115,030	11,187	23
0	0	0	24
1,164	6,210	9,270	25
1,044,638	1,192,827	626,390	26
128,782	280,202	75,344	27
111	0	0	28
26,904	55,878	13,852	29
127,897	232,209	39,984	30
95,711	451,694	48,350	31
424,579	411,518	182,349	32
11,474	-50,770	13,265	33
1,964,129	2,694,798	1,019,991	34
0.0021	0.0018	0.0021	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	04/15/2011	End of 2010/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)	23	18
7	Plant Hours Connect to Load	8,696	8,760
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	18	18
10	(b) Under the Most Adverse Oper Conditions	18	14
11	Average Number of Employees	2	2
12	Net Generation, Exclusive of Plant Use - Kwh	101,430,000	90,272,000
13	Cost of Plant		
14	Land and Land Rights	33,429	3,076,554
15	Structures and Improvements	3,943,110	1,345,554
16	Reservoirs, Dams, and Waterways	13,350,064	6,317,496
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)	30,512,568	13,911,583
21	Cost per KW of Installed Capacity (line 20 / 5)	1,155.7791	939.9718
22	Production Expenses		
23	Operation Supervision and Engineering	350	20,124
24	Water for Power	0	0
25	Hydraulic Expenses	9,635	0
26	Electric Expenses	616,984	598,189
27	Misc Hydraulic Power Generation Expenses	33,207	37,566
28	Rents	0	0
29	Maintenance Supervision and Engineering	17,070	15,647
30	Maintenance of Structures	38,766	15,202
31	Maintenance of Reservoirs, Dams, and Waterways	68,735	395,688
32	Maintenance of Electric Plant	102,820	76,479
33	Maintenance of Misc Hydraulic Plant	4,710	10,023
34	Total Production Expenses (total 23 thru 33)	892,277	1,168,918
35	Expenses per net KWh	0.0088	0.0129

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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
7,015	0	0	7
			8
35	0	0	9
26	0	0	10
5	0	0	11
200,463,000	0	0	12
			13
4,325,371	0	0	14
1,184,974	0	0	15
5,065,501	0	0	16
6,142,651	0	0	17
0	0	0	18
0	0	0	19
16,718,497	0	0	20
522.4530	0.0000	0.0000	21
			22
241	0	0	23
0	0	0	24
8,977	0	0	25
598,139	0	0	26
47,518	0	0	27
721,398	0	0	28
18,331	0	0	29
54,553	0	0	30
24,029	0	0	31
246,604	0	0	32
4,827	0	0	33
1,724,617	0	0	34
0.0086	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	04/15/2011	End of 2010/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 Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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	04/15/2011	End of 2010/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	9.0	3,462,000	9,169,338
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
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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) 04/15/2011	Year/Period of Report End of 2010/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.
1,273,519	165,454	193,539	31,859	Nat Gas		1
						2
						3
						4
						5
						6
						7
						8
						9
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						45
						46

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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 Structure	LENGTH (Pole miles) (In the case of 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		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	26.00		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	104.00		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		2
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	33

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
	136,038	70,092	206,130					1
								2
	9,590,915	96,902,738	106,493,653	372,527	471,803		844,330	3
								4
1272 ACSS	17,913	1,316,679	1,334,592					5
1272 ACSS								6
1272 ACSS								7
1272 ACSS	30,323	3,273,923	3,304,246					8
1272 ACSS								9
1590 ACSS								10
1590 ACSR	798,609	36,029,040	36,827,649		290,623		290,623	11
1272 ACSS								12
1272 McMAL	456,162	7,277,307	7,733,469	80,720	23,853		104,573	13
1590 ACSS	570,207	47,543,332	48,113,539	193	263		456	14
1272 ACSR								15
954 McMAL	671,047	17,987,859	18,658,906	6,480	96,311		102,791	16
954 McMAL	125,876	1,091,601	1,217,477	443	4,884		5,327	17
954 McMAL								18
954 McMAL	162,052	2,604,949	2,767,001	4,727	341,862		346,589	19
1272 McMAL								20
1272 McMAL	86,228	3,698,377	3,784,605	312	18,466		18,778	21
1272 McMAL								22
1272 McMAL	623,984	6,923,451	7,547,435	2,412	301,328		303,740	23
1272 McMAL								24
1272 McMAL	872,150	8,067,903	8,940,053	240	895		1,135	25
1272 McMAL								26
1272 McMAL	70,781	2,572,506	2,643,287		21,415		21,415	27
1272 McMAL								28
1272 McMAL		19,521	19,521					29
1272 McMAL								30
1272 McMAL	231,334	3,308,408	3,539,742	1,780	74,884		76,664	31
1272 McMAL	120,779	510,225	631,004		3,556		3,556	32
1590 ACSR	106,581	2,546,756	2,653,337	1,420	8,677		10,097	33
1272 McMAL	155,590	1,297,751	1,453,341	251	1,065		1,316	34
	595,789	29,323,495	29,919,284	54,948	301,903	86,240	443,091	35
	15,422,358	272,365,913	287,788,271	526,453	1,961,788	86,240	2,574,481	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	04/15/2011	End of 2010/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	No additions during 2010						
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
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21							
22							
23							
24							
25							
26							
27							
28							
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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	04/15/2011	End of 2010/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
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									44

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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	110.00	13.80	
5	Beacon	Trnsm. & Distr Unatt	230.00	115.00	13.80
6	Boulder	Trnsm. Unattended	230.00	115.00	13.80
7	Chester	Distr. Unattended	115.00	13.80	
8	Chewelah 115Kv	Distr. Unattended	115.00	13.80	
9	Colbert	Distr. Unattended	115.00	13.80	
10	College & Walnut	Distr. Unattended	115.00	13.80	
11	Colville 115Kv	Distr. Unattended	115.00	13.80	
12	Critchfield	Distr. Unattended	115.00	13.80	
13	Deer Park	Dist. Unattended	115.00	13.80	
14	Dry Creek	Transm. Unattended	230.00	115.00	13.80
15	Dry Gulch	Distr. Unattended	115.00	13.80	
16	East Colfax	Distr. Unattended	115.00	13.80	
17	East Farms	Distr. Unattended	115.00	13.80	
18	Fort Wright	Distr. Unattended	115.00	13.80	
19	Francis and Cedar	Distr. Unattended	115.00	13.80	
20	Gifford	Distr. Unattended	115.00	34.00	
21	Glenrose	Distr. Unattended	115.00	13.80	
22	Greenwood	Distr. Unattended	115.00	13.80	
23	Hallett & White	Distr. Unattended	115.00	13.80	
24	Indian Trail	Dist. Unattended	115.00	13.80	
25	Industrial Park	Dist. Unattended	115.00	13.80	
26	Kettle Falls	Distr. Unattended	115.00	13.80	
27	Lee & Reynolds	Distr. Unattended	115.00	13.80	
28	Liberty Lake	Distr. Unattended	115.00	13.80	
29	Little Falls 115/34Kv	Distr. Unattended	115.00	34.00	
30	Lyons & Standard	Distr. Unattended	115.00	13.80	
31	Mead	Distr. Unattended	115.00	13.80	
32	Metro	Distr. Unattended	115.00	13.80	
33	Milan	Distr. Unattended	115.00	13.80	
34	Millwood	Dist. Unattended	115.00	13.80	
35	Ninth & Central	Distr. Unattended	115.00	13.80	
36	Northeast	Distr. Unattended	115.00	13.80	
37	Northwest	Distr. Unattended	115.00	13.80	
38	Opportunity	Dist. Unattended	115.00	13.80	
39	Othello	Distr. Unattended	115.00	13.80	
40	Post Street	Distr. Unattended	115.00	13.80	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Number of Units (j)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT 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 Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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	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	Waikiki	Distr. Unattended	115.00	13.80	
14	West Side	Trans. Unattended	230.00	115.00	13.80
15	Other: 72substa less than 10MVA	Distr. Unattended			
16					
17	STATE OF IDAHO				
18	Appleway	Dist. Unattended	115.00	13.80	
19	Avondale	Dist. Unattended	115.00	13.80	
20	Benewah	Trans. Unattended	230.00	115.00	13.80
21	Big Creek	Distr. Unattended	115.00	13.80	
22	Blue Creek	Distr. Unattended	115.00	13.80	
23	Bunker Hill Limited	Distr. Unattended	115.00	13.80	
24	Cabinet Gorge (Switchyard)	Trans. Unattended	230.00	115.00	13.80
25	Clark Fork	Distr. Unattended	115.00	21.80	
26	Coeur d'Alene 15th Ave	Distr. Unattended	115.00	13.80	
27	Cottonwood	Distr. Unattended	115.00	24.90	
28	Dalton	Distr. Unattended	115.00	13.80	
29	Grangeville	Distr. Unattended	115.00	13.80	
30	Holbrook	Distr. Unattended	115.00	13.80	
31	Huetter	Distr. Unattended	115.00	13.80	
32	Idaho Road	Distr Unattended	115.00	13.80	
33	Juliaetta	Distr. Unattended	115.00	13.80	
34	Kamiah	Dist. Unattended	115.00	13.80	
35	Kooskia	Distr. Unattended	115.00	13.80	
36	Lolo	Tran & Dist Unattnd	230.00	115.00	13.80
37	Moscow	Distr. Unattended	115.00	13.80	
38	Moscow 230Kv	Tran & Dist Unattnd	230.00	115.00	13.80
39	North Moscow	Distr. Unattended	115.00	13.80	
40	North Lewiston 230kV	Trans Unattended	230.00	115.00	13.80

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/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
24	2		Frcd Oil & Air Fan	2	40	2
30	2		Two Stage Fan	2	60	3
24	2		Two Stage Fan	2	40	4
150	1		Two Stage Fan		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
24	2		Two Stage Fan	2	40	13
250	2					14
189	136	3				15
						16
						17
30	2		Two Stage Fan	2	50	18
12	1		Two Stage Fan	1	20	19
75	1		Two Stage Fan & Caps	223	125	20
17	2		Portable Fan	2	22	21
20	3	1				22
12	1		Frcd Air Fan	1	26	23
75	1		Two Stage Fan	1	125	24
10	1		Frcd Air Fan	1	13	25
36	2		Two Stage Fan	2	60	26
12	1		Two Stage Fan	1	20	27
24	2		FrcOil/Air2StgFan	2	40	28
25	4		FrcdOil/Air/Pt Fan&C	17	34	29
12	1		Two Stage Fan	1	20	30
12	1		Two Stage Fan	1	20	31
12	1		Two Stage Fan	1	20	32
12	1		Frcd Oil & Air Fan	1	20	33
12	1		Two Stage Fan	1	20	34
15	3		Frcd Air Fan	2	20	35
262	3		Frcd Oil/Air/Two Stg	1	270	36
24	2		FrOil/Air/2Stg Fan	2	40	37
137	2	1	Capacitors	48		38
12	1		Two Stage Fan	1	20	39
250	1	1	Capacitors	48		40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	North Lewiston	Distr. Unattended	115.00	13.80	
2	Oden	Distr. Unattended	115.00	21.80	
3	Oldtown	Distr. Unattended	115.00	21.80	
4	Orofino	Distr. Unattended	115.00	13.80	
5	Osburn	Distr. Unattended	115.00	13.80	
6	Pine Creek	Tran & Dist Unattnd	230.00	115.00	13.80
7	Pleasant View	Distr. Unattended	115.00	13.80	
8	Plummer	Dist Unattended	115.00	13.80	
9	Post Falls	Distr. Unattended	115.00	13.80	
10	Potlatch	Distr. Unattended	115.00	13.80	
11	Prarie	Distr. Unattended	115.00	13.80	
12	Priest River	Distr. Unattended	115.00	20.80	
13	Rathdrum	Trans & Distr Unattd	230.00	115.00	13.80
14	Sagle	Dist. Unattended	115.00	20.80	
15	Sandpoint	Distr. Unattended	115.00	20.80	
16	South Lewiston	Distr. Unattended	115.00	13.80	
17	Sweetwater	Distr. Unattended	115.00	24.90	
18	St. Maries	Distr. Unattended	115.00	23.90	
19	Tenth & Stewart	Distr. Unattended	115.00	13.80	
20	Wallace	Distr. Unattended	115.00	13.80	
21	Other: 28 substa less than 10 MVA	Distr. Unattended			
22					
23	STATE OF MONTANA				
24	1 substation less than 10 MVA	Distr. Unattended			
25					
26	SUBSTA. @ GENERATING PLANTS				
27	STATE OF WASHINGTON				
28	Boulder Park	Trans. Attended	115.00	13.80	
29	Kettle Falls	Trans. Attended	115.00	13.80	
30	Long Lake	Trans. Attended	115.00	4.00	4.00
31	Nine Mile	Trans. Attended	115.00	13.80	2.30
32	Little Falls	Trans. Attended	115.00	4.00	
33	Northeast	Trans. Attended	115.00	13.80	
34	Post Street	Trans. Attended	13.80	4.00	35.00
35					
36	STATE OF IDAHO				
37	Cabinet Gorge (HED)	Trans. Attended	230.00	13.80	
38	Post Falls	Trans. Attended	115.00	2.30	
39	Rathdrum	Trans. Attended	115.00	13.80	
40	STATE OF MONTANA				

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
10	3					1
10	1		Frcd Air Fan		13	2
18	2		Frcd Air Fan	2	22	3
20	2		Frcd Oil & Air Fan	1	28	4
12	1		Portable Fan	1	15	5
262	3		Capacitors	48		6
12	1		Two Stage Fan	1	20	7
12	1		Two Stage Fan	1	20	8
18	1		Two Stage Fan	1	30	9
15	2		Portable Fan	2	19	10
12	1		Frcd Oil & Air Fan	1	20	11
10	1	1	Frcd Air Fan	1	13	12
474	4		Frcd Oil & Air Fan	50	490	13
12	1		Two Stage Fan	1	20	14
30	3		Frcd Air Fan	3	38	15
27	4		Port Fan/FrcdOil/Air	4	39	16
12	1		Frcd Oil & Air Fan	1	20	17
24	2		Two Stage Fan	2	40	18
30	2		Frcd Oil/Air/Two Stg	2	50	19
10	3					20
77	45					21
						22
						23
5	1					24
						25
						26
						27
36	1		Two Stage Fan	1	60	28
34	1	1	Two Stage Fan	1	62	29
80	4	1				30
24	2		Frcd Oil & Air Fan	1	40	31
24	2		Frcd Oil & Air Fan	2	40	32
36	1		Two Stage Fan	1	60	33
2						34
						35
						36
300	6	1	Frcd Oil and Air Fan	2	30	37
16	2		Frcd Air/Oil/Air Fan	2	21	38
114	2	3	Two Stage Fan	2	190	39
						40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Noxon	Trans. Attended	230.00	13.80	
2					
3	STATE OF OREGON				
4	Coyote Springs II	Trans. Attended	500.00	13.80	18.00
5					
6	SUMMARY:				
7	Washington:				
8	4 subs	Trans. Unattended			
9	119subs	Distr. Unattended			
10	1 subs	Tran & Dist Unattnd			
11	7 subs	Trans. Attended			
12	Idaho:				
13	3 subs	Trans. Unattended			
14	63 subs	Distr. Unattended			
15	4 subs	Tran & Dist Unattnd			
16	3 subs	Trans. Attended			
17	Montana: 1 sub	Trans. Attended			
18	1 sub	Distr. Unattended			
19	Oregon: 1 sub	Trans. Unattended			
20	System: 207 subs				
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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.
495	9	2	Two Stage Fan	1	595	1
						2
						3
213	1	1	Two Stage fan	1	355	4
						5
						6
						7
850						8
1200						9
536						10
269						11
						12
400						13
669						14
1135						15
430						16
555						17
5						18
213						19
6201						20
						21
						22
						23
						24
						25
						26
						27
						28
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IDAHO PUBLIC
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AVU-E

Avista Corp.

IDAHO

Annual Electric Report

2010

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	April 15, 2011	December 31, 2010

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

Line No.	Item (a)	Total (b)	Electric (c)
1	UTILITY PLANT		
2	In Service		
3	Plant in Service (Classified)	1,098,601,839	940,368,099
4	Property Under Capital Leases	499,951	0
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Investment in Kettle Falls		
8	TOTAL (Enter Total of lines 3 thru 7)	1,099,101,790	940,368,099
9	Leased to Others		
10	Held for Future Use	347,171	162,353
11	Construction Work in Progress	3,427,363	3,322,305
12	Acquisition Adjustments	0	0
13	TOTAL Utility Plant (Enter Total of lines 8 thru 12)	1,102,876,324	943,852,757
14	Accum. Prov. for Depr., Amort., & Depl.	0	0
15	Net Utility Plant (Enter total of line 13 less 14)	1,102,876,324	943,852,757
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION		
17	In Service:		
18	Depreciation		
19	Amort. and Depl. of Producing Nat. Gas Land and Land Rights		
20	Accumulated Depreciation - Kettle Falls		
21	Amort. of Other Utility Plant		
22	TOTAL in Service (Enter Total of lines 18 thru 21)		
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	TOTAL Leased to Others (Enter Total of lines 24 and 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	TOTAL Held for Future Use (Ent. Tot. of lines 28 and 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort. of Plant Acquisition Adjustment	0	0
33	TOTAL Accumulated Provisions (Should agree with line 14 above) (Enter Total of lines 22, 26, 30, 31, and 32)	0	0

State of Idaho

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	April 15, 2011	December 31, 2010

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

Gas *(d)*	Other (Specify) *(e)*	Other (Specify) *(f)*	Other (Specify) *(g)*	Common *(h)*	Line No.
					1
					2
147,704,562				10,529,178	3
403,189				96,762	4
					5
					6
					7
148,107,751				10,625,940	8
					9
184,818					10
91,253				13,805	11
					12
148,383,822				10,639,745	13
0					14
148,383,822				10,639,745	15
					16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
0				0	33

State of Idaho

Name of Respondent 2 Avista Corp.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) April 15, 2011	Year of Report December 31, 2010

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, 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 Accounts 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. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
5. Classify Account106 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) reversals of tentative distributions of prior year of unclassified retirements. Attach supplemental statement showing the account distributions of these tentative classifications in columns (c) and (d), including the

Line No.	Account (a)	Balance at 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	-	-
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	10,609,425	-
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	-	-
9	(311) Structures and Improvements	-	-
10	(312) Boiler Plant Equipment	-	-
11	(313) Engines and Engine Driven Generators	-	-
12	(314) Turbogenerator Units	-	-
13	(315) Accessory Electric Equipment	-	-
14	(316) Misc. Power Plant Equipment	-	-
15	(317) Asset Retirement Costs for Steam Production	-	-
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	-	-
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	6,612,042	845
28	(331) Structures and Improvements	10,935,190	583,860
29	(332) Reservoirs, Dams, and Waterways	35,805,181	359,633
30	(333) Water Wheels, Turbines, and Generators	39,674,285	-
31	(334) Accessory Electric Equipment	6,135,145	38,174
32	(335) Misc. Power Plant Equipment	2,816,522	10,330
33	(336) Roads, Railroads, and Bridges	1,098,564	-
34	(337) Asset Retirement Costs for Hydraulic Production	-	-
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	103,076,929	992,842
36	D. Other Production Plant		
37	(340) Land and Land Rights	621,682	-
38	(341) Structures and Improvements	3,255,691	9,576
39	(342) Fuel Holders, Products and Accessories	1,700,144	105,457
40	(343) Prime Movers	3,658,328	-
41	(344) Generators	48,858,107	208,506
42	(345) Accessory Electric Equipment	2,552,284	40,149

State of Idaho

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	April 15, 2011	December 31, 2010

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

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.

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

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

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
-		-	-	(301)	2
-		-	10,609,425	(302)	3
-		-	-	(303)	4
-	-	-	10,609,425		5
					6
					7
-		-	-	(310)	8
-		-	-	(311)	9
-		-	-	(312)	10
-		-	-	(313)	11
-		-	-	(314)	12
-		-	-	(315)	13
-		-	-	(316)	14
-		-	-	(317)	15
-	-	-	-		16
					17
-	-	-	-	(320)	18
-	-	-	-	(321)	19
-	-	-	-	(322)	20
-	-	-	-	(323)	21
-	-	-	-	(324)	22
-	-	-	-	(325)	23
-	-	-	-	(326)	24
-	-	-	-		25
					26
-	-	-	6,612,887	(330)	27
40,649	-	-	11,478,401	(331)	28
33,755	-	-	36,131,059	(332)	29
-	-	-	39,674,285	(333)	30
397	-	-	6,172,922	(334)	31
-	-	-	2,826,852	(335)	32
-	-	-	1,098,564	(336)	33
-	-	-	-	(337)	34
74,801	-	-	103,994,970		35
					36
-	-	-	621,682	(340)	37
6,880	-	-	3,258,387	(341)	38
17,815	-	-	1,787,786	(342)	39
-	-	-	3,658,328	(343)	40
-	-	-	49,066,613	(344)	41
25,282	-	-	2,567,151	(345)	42

Name of Respondent	This Report Is:	State of Idaho Date of Report (Mo, Da, Yr)	State of Idaho Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	April 15, 2011	December 31, 2010

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, 106)

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)
43	(346) Misc. Power Plant Equipment	-	-
44	(347) Asset Retirement Costs for Other Production	-	-
45	TOTAL Other Production Plant (Enter Total of lines 37 thru 45)	60,646,236	363,688
46	TOTAL Production Plant (Enter Total of lines 16, 25, 35, and 45)	163,723,165	1,356,530
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	5,102,164	3,224,148
49	(352) Structures and Improvements	8,168,941	639,977
50	(353) Station Equipment	73,254,097	7,181,239
51	(354) Towers and Fixtures	556,655	-
52	(355) Poles and Fixtures	46,998,860	1,159,731
53	(356) Overhead Conductors and Devices	28,717,494	577,790
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 (Enter Total of lines 48 thru 57)	164,172,213	12,782,885
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	964,029	1,058,943
61	(361) Structures and Improvements	4,459,230	47,749
62	(362) Station Equipment	32,441,214	923,563
63	(363) Storage Battery Equipment	-	-
64	(364) Poles, Towers, and Fixtures	84,265,495	5,973,191
65	(365) Overhead Conductors and Devices	56,557,145	3,440,951
66	(366) Underground Conduit	28,604,017	1,083,790
67	(367) Underground Conductors and Devices	44,433,568	1,909,537
68	(368) Line Transformers	59,369,276	1,950,082
69	(369) Services	43,861,626	1,409,005
70	(370) Meters	28,502,816	277,626
71	(371) Installations on Customer Premises	-	-
72	(372) Leased Property on Customer Premises	-	-
73	(373) Street Lighting and Signal Systems	12,901,950	495,553
74	(374) Asset Retirement Costs for Distribution Plant	-	-
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	396,360,366	18,569,990
76	5. GENERAL PLANT		
77	(389) Land and Land Rights	101,907	-
78	(390) Structures and Improvements	1,351,622	120,820
79	(391) Office Furniture and Equipment	-	-
80	(392) Transportation Equipment	2,094,468	888,227
81	(393) Stores Equipment	14,745	-
82	(394) Tools, Shop and Garage Equipment	432,865	-
83	(395) Laboratory Equipment	144,113	-
84	(396) Power Operated Equipment	6,763,612	2,045,775
85	(397) Communication Equipment	4,219,718	97,503
86	(398) Miscellaneous Equipment	2,299	-
87	SUBTOTAL (Enter Total of lines 77 thru 86)	15,125,349	3,152,325
88	(399) Other Tangible Property	-	-
89	(399.1) Asset Retirement Costs for General Plant	-	-
90	TOTAL General Plant (Enter Total of lines 87 and 90)	15,125,349	3,152,325
91	TOTAL (Accounts 101 and 106)	749,990,518	35,861,730
92	(102) Electric Plant Purchased	-	-
93	(Less) (102) Electric Plant Sold	-	
94	(103) Experimental Plant Unclassified	-	-
95	TOTAL Electric Plant in Service	749,990,518	35,861,730

Name of Respondent	This Report Is:	Date of Report	State of Idaho Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) April 15, 2011	December 31, 2010

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

Retirements *(d)*	Adjustments *(e)*	Transfers *(f)*	Balance at End of Year *(g)*		Line No.
-	-	-	-	(346)	43
-	-	-	-	(347)	44
49,977	-	-	60,959,947		45
124,778	-	-	164,954,917		46
					47
-	-	-	8,326,312	(350)	48
207,863	-	-	8,601,055	(352)	49
1,368,084	-	-	79,067,252	(353)	50
-	-	-	556,655	(354)	51
43,616	-	-	48,114,975	(355)	52
56,869	-	-	29,238,415	(356)	53
-	-	-	-	(357)	54
-	-	-	-	(358)	55
-	-	-	1,374,002	(359)	56
-	-	-	-	(359.1)	57
1,676,432	-	-	175,278,666		58
					59
497	-	-	2,022,475	(360)	60
-	-	-	4,506,979	(361)	61
49,131	-	-	33,315,646	(362)	62
-	-	-	-	(363)	63
110,803	-	-	90,127,883	(364)	64
155,274	-	-	59,842,822	(365)	65
14,849	-	(4,432)	29,668,526	(366)	66
86,890	-	-	46,256,215	(367)	67
57,688	-	-	61,261,670	(368)	68
31,748	-	-	45,238,883	(369)	69
-	-	-	28,780,442	(370)	70
-	-	-	-	(371)	71
-	-	-	-	(372)	72
36,248	-	-	13,361,255	(373)	73
-	-	-	-	(374)	74
543,128	-	(4,432)	414,382,796		75
					76
-	-	-	101,907	(389)	77
18,418	-	-	1,454,024	(390)	78
-	-	-	-	(391)	79
232,727	-	-	2,749,968	(392)	80
-	-	-	14,745	(393)	81
35,180	-	-	397,685	(394)	82
39,986	-	-	104,127	(395)	83
235,378	-	-	8,574,009	(396)	84
-	-	-	4,317,221	(397)	85
-	-	-	2,299	(398)	86
561,689	-	-	17,715,985		87
-	-	-	-	(399)	88
-	-	-	-	(399.1)	89
561,689	-	-	17,715,985		90
2,906,027	-	(4,432)	782,941,789		91
-	-	-	-	(102)	92
			-		93
-	-	-	-	(103)	94
2,906,027	-	(4,432)	782,941,789		95

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	April 15, 2011	Dec. 31, 2010

ELECTRIC OPERATING REVENUES (Account 400)

1. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.

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 previous year (columns (c), (e), and (g), are not derived from previously reported figures, explain any inconsistencies in a footnote.

Line No.	Title of Account (a)	OPERATING REVENUES Amount for Year (b)	Amount for Previous Year (c)
1	Sales of Electricity		
2	(440) Residential Sales	100,732,420	101,397,475
3	(442) Commercial and Industrial Sales (3)		
4	Small (or Commercial)	82,538,298	81,073,948
5	Large (or Industrial)	64,194,131	62,109,598
6	(444) Public Street and Highway Lighting	2,250,093	2,126,115
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales	187,603	178,951
10	TOTAL Sales to Ultimate Consumers	249,902,545 (1)	246,886,087
11	(447) Sales for Resale	89,301,585	69,738,693
12	TOTAL Sales of Electricity	339,204,130	316,624,780
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Provision for Refunds	339,204,130	316,624,780
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	219,901	242,635
18	(453) Sales of Water and Water Power	98,162	133,929
19	(454) Rent from Electric Property	892,796	897,391
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	39,445,502	12,080,448
22	(456.1) Revenues from Transmission of Electricty of Others	4,325,301	3,223,695
23			
24			
25			
26	TOTAL Other Operating Revenues	44,981,662	16,578,098
27	TOTAL Electric Operating Revenues	$384,185,792	$333,202,878

State of Idaho

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ELECTRIC OPERATING REVENUES (Account 400) (Continued)

4. 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 classifcation 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.)

5. See page 108, Important Changes During Year, for important new territory added and important rate increases or decreases.

6. For lines 2, 4, 5, and 6, see page 304 for amounts relating to unbilled revenue by accounts.

7. Include unmetered sales. Provide details of such sales in a foonote.

MEGAWATT HOURS SOLD		AVG. NO. OF CUSTOMERS PER MONTH		
Amount for Year (d)	Amount for Previous Year (e)	Number for Year (f)	Number for Previous Year (g)	Line No.
				1
1,179,482	1,224,836	105,286	104,609	2
				3
987,327	1,010,376	16,573	16,484	4
1,210,786	1,198,407	476	486	5
8,888	8,847	124	123	6
				7
				8
2,250	2,226	28	25	9
3,388,733 (2)	3,444,692	122,487	121,727	10
2,178,025	1,664,130			11
5,566,758	5,108,822	122,487	121,727	12
				13
5,566,758	5,108,822	122,487	121,727	14

(1) Includes $264,324 of unbilled revenues.

(2) Includes -6,915 MWH relating to unbilled revenues.

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

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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 customers, average kWh per customer, and average revenue per kWh, excluding data 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 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 (cents) per KWH Sold (f)
1	**RESIDENTIAL SALES (440)**					
2	1 Residential Service	1,147,627	95,391,528	100,132	11,461	8.31
3	2 Residential Service					
4	3 Residential Service					
5	12 Res. & Farm Gen. Service	20,313	2,234,808	4,524	4,490	11.00
6	22 Res. & Farm Lg. Gen. Service	12,906	937,332	29	445,034	7.26
7	30 Pumping-Special					
8	32 Res. & Farm Pumping Service	3,343	309,449	601	5,562	9.26
9	48 Res. & Farm Area Lighting	1,203	257,723			21.42
10	49 Area Lighting-High-Press.	272	74,519			27.40
11	56 Centralia Credit					
12	95 Wind Power		50,423			
13	73 Residential					
14	74 Residential Service					
15	76 Residential Service					
16	77 Residential Service					
17	79 Residential Service					
18	58 Tax Adjustment		1,339,351			
19	Total	1,185,664	100,595,133	105,286	11,261	8.54
20	Residential-Unbilled	(6,182)	137,287			
21	**COMMERCIAL SALES (442)**					
22	2 General Service					
23	3 General Service					
24	11 General Service	288,916	28,273,712	14,774	19,556	9.79
25	19 Contract-General Service					
26	21 Large General Service	608,442	46,632,753	1,330	457,475	7.66
27	25 Extra Lg. Gen. Service	64,519	3,527,048	3	21,506,333	5.47
28	28 Contract-Extra Large Service					
29	31 Pumping Service	25,302	2,027,443	466	54,296	8.01
30	47 Area Lighting-Sod. Vap.	938	139,309			14.85
31	49 Area Lighting-High-Press.	2,417	524,548			21.70
32	56 Centralia Credit					
33	95 Wind Power		9,008			
34	73 General Service					
35	74 Large General Service					
36	75 Large General Service					
37	76 Large General Service					
38	77 General Service					
39	79 Area Light-High Press.					
40	58 Tax Adjustment		1,572,523			
41	Total	990,534	82,706,344	16,573	59,768	8.36
42	Commercial-Unbilled	(3,207)	(168,046)			
43	Total Billed	2,176,198	183,301,477	121,859		8.42
44	Total Unbilled Rev. (See Instr. 6)	-9,389	-30,759	0		0.33
45	TOTAL	2,166,809	183,270,718	121,859		8.46

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2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," page 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 (cents) per KWH Sold (f)
1	**INDUSTRIAL SALES (442)**					
2	2 General Service					
3	3 General Service					
4	8 Lg Gen Time of Use					
5	11 General Service	3,640	376,434	132	27,576	10.34
6	21 Large General Service	78,120	5,969,925	79	988,861	7.64
7	25 Extra Lg. Gen. Service	1,101,060	55,526,233	6	183,510,000	5.04
8	28 Contract-Extra Large Service					
9	29 Contract Lg. Gen. Service					
10	30 Pumping Service -Special					
11	31 Pumping Service	22,985	1,825,711	217	105,922	7.94
12	32 Pumping Svc Res & Frm	2,433	183,884	42	57,929	7.56
13	47 Area Lighting-Sod. Vap.	53	7,371			13.91
14	49 Area Lighting-High-Press.	50	10,069			20.14
15	56 Centralia Credit					
16	72 General Service					
17	73 General Service					
18	74 Large General Service					
19	75 Large General Service					
20	76 Pumping Service					
21	77 General Service					
22	78 Lg Gen Tim of Use					
23	58 Tax Adjustment		70,321			
24	Total	1,208,341	63,969,948	476	2,538,532	5.30
25	Industrial-Unbilled	2,445	224,183	0		
26						
27	**STREET AND HWY LIGHTING (444)**					
28	11 General Service					
29	41 Co.-Owned St. Lt. Service	115	18,095	5	23,000	15.73
30	42 Co.-Owned St. Lt. Service	6844	1,962,290	89	76,899	28.67
31	High-Press. Sod. Vap.					
32	43 Cust.-Owned St. Lt. Energy	9	875	1	9,000	9.72
33	and Maint. Service					
34	44 Cust.-Owned St. Lt. Energy	588	89,180	15	39,200	15.17
35	and Maint. Svce.-High-					
36	Press. Sod. Vap.					
37	45 Cust.Owned St. Lt. Energy Service	281	18,383	3	93,667	6.54
38	46 Cust.Owned St. Lt. Energy Service	1,022	88,774	11	92,909	8.69
39	High-Press. Sod. Vap.					
40	56 Centralia Credit					
41	58 Tax Adjustment		35,756			
42	Total	8,859	2,213,353	124	71,444	7.40
43	Street and Hwy Lighting-Unbilled	29	36,740			
44	Total Billed	3,393,398	249,484,778	122,459		7.35
45	Total Unbilled Rev. (See Instr. 6)	-6,915	230,164	0		(3.33)
46	TOTAL	3,386,483	249,714,942	122,459		7.37

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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 customers, average kWh per customer, and average revenue per kWh, excluding data 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 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.
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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 (cents) per KWH Sold (f)
1	**OTHER SALES TO PUBLIC**					
2	**AUTHORITIES (445)**					
3	None					
4						
5	**INTERDEPARTMENTAL**					
6	**SALES (448)**	2,250	187,603	28	80,357	8.34
7	58 Tax Adjustment					
8	Total	2,250	187,603	28	80,357	8.34
9						
10	**SALES FOR RESALE (447) (1)**					
11	61 Sales to Other Utilities - ID	2,178,025	89,301,585			
12						
13						
14						
14	Total	2,178,025	89,301,585			
15						
16						
17	Note: Sch. 61 is a state assigned rate schedule for Sales/Resale					
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39	Total Billed	5,573,673	338,973,966	122,487	45,504	6.08
40	Total Unbilled Rev.	(6,915)	230,164	0		(3.33)
41	TOTAL	5,566,758	339,204,130	122,487	45,448	6.09

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Prior Year (c)
1	(1) POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	213	-
5	(501) Fuel	3,311,212	-
6	(502) Steam Expenses	-	-
7	(503) Steam from Other Sources	-	-
8	(Less) (504) Steam Transferred-Cr.	-	-
9	(505) Electric Expenses	-	589
10	(506) Miscellaneous Steam Power Expenses	31,054	26,653
11	(507) Rents	-	-
12	(509) Allowances	-	-
13	TOTAL Operation (Enter Total of Lines 4 thru 11)	3,342,478	27,242
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	18,709	680
16	(511) Maintenance of Structures	-	-
17	(512) Maintenance of Boiler Plant	(10)	-
18	(513) Maintenance of Electric Plant	-	-
19	(514) Maintenance of Miscellaneous Steam Plant	(11)	-
20	TOTAL Maintenance (Enter Total of Lines 14 thru 18)	18,688	680
21	TOTAL Power Production Expenses-Steam Plant (Enter Total of lines 12 and 19)	3,361,166	27,922
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 liens 23 thru 31)	-	-
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 34 thru 38)	-	-
41	TOTAL Power Production Expenses-Nuclear Power(Enter total of lines 32 and 39)	-	-
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	819,028	798,300
45	(536) Water for Power	313,836	286,362
46	(537) Hydraulic Expenses	2,078,409	1,867,708
47	(538) Electric Expenses	1,661,890	1,645,377
48	(539) Miscellaneous Hydraulic Power Generation Expenses	192,708	167,116
49	(540) Rents	2,035,361	2,145,975
50	TOTAL Operation (Enter Total of lines 43 thru 48)	7,101,233	6,910,838

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
50	C. Hydraulic Power Generation (Continued)		
51	Maintenance		
52	(541) Maintenance Supervision and Engineering	117,797	87,034
53	(542) Maintenance of Structures	143,177	103,726
54	(543) Maintenance of Reservoirs, Dams, and Waterways	511,137	267,952
55	(544) Maintenance of Electric Plant	577,529	848,660
56	(545) Maintenance of Miscellaneous Hydraulic Plant	78,868	75,554
57	TOTAL Maintenance (Enter Total of lines 52 thru 56)	1,428,508	1,382,925
58	TOTAL Power Production Expenses-Hydraulic Power (Enter total of lines 49 and 57)	8,529,740	8,293,763
59	D. Other Power Generation		
60	Operation		
61	(546) Operation Supervision and Engineering	25,065	38,150
62	(547) Fuel	14,903,439	2,627,749
63	(548) Generation Expenses	150,490	110,412
64	(549) Miscellaneous Other Power Generation Expenses	265,880	267,663
65	(550) Rents	(11,784)	(11,914)
66	TOTAL Operation (Enter Total of lines 61 thru 65)	15,333,090	3,032,060
67	Maintenance		
68	(551) Maintenance Supervision and Engineering	54,912	41,886
69	(552) Maintenance of Structures	4,566	1,169
70	(553) Maintenance of Generating and Electric Plant	108,558	118,078
71	(554) Maintenance of Miscellaneous Other Power Generation Plant	33,497	42,205
72	TOTAL Maintenance (Enter Total of lines 68 thru 71)	201,533	203,338
73	TOTAL Power Production Expenses-Other Power (Enter Total of lines 66 and 72)	15,534,623	3,235,398
74	E. Other Power Supply Expenses		
75	(555) Purchased Power	96,534,368	106,719,593
76	(556) System Control and Load Dispatching	193,484	185,723
77	(557) Other Expenses	47,480,397	12,543,494
78	TOTAL Other Power Supply Expenses (Enter Total of lines 75 thru 77)	144,208,249	119,448,809
79	TOTAL Power Production Expenses (Enter Total of lines 20, 40, 58, 73 and 78)	171,633,778	131,005,893
80	2. TRANSMISSION EXPENSES		
81	Operation		
82	(560) Operation Supervision and Engineering	772,139	852,402
83	(561) Load Dispatching	752,070	769,280
84	(561.1) Load Dispatching Reliability	-	-
85	(561.2) Load Dispatching Monitor and Operate Transmission System	-	-
86	(561.3) Load Dispatching Transmission Service and Sched	-	-
87	(561.4) Scheduling Sysemt Control and Dispatch Services	-	-
88	(561.5) Reliability, Planning and Standards Development	-	-
89	(561.6) Transmission Service Studies	-	-
90	(561.7) Generation Interconnection Studies	-	-
91	(561.8) Reliability, Planning and Standards Development Services	-	-
92	(562) Station Expenses	116,548	69,316
93	(563) Overhead Line Expenses	327,794	79,442
94	(564) Underground Line Expenses	-	-
95	(565) Transmission of Electricity by Others	6,181,357	4,690,115
96	(566) Miscellaneous Transmission Expenses	571,167	484,611
97	(567) Rents	12,092	26,811
98	TOTAL Operation (Enter Total of lines 82 thru 89)	8,733,166	6,971,978
99	Maintenance		
100	(568) Maintenance Supervision and Engineering	197,276	166,195
101	(569) Maintenance of Structures	112,182	120,137
102	(570) Maintenance of Station Equipment	384,083	416,494
103	(571) Maintenance of Overhead Lines	1,007,373	1,005,428
104	(572) Maintenance of Underground Lines	134	3,892
105	(573) Maintenance of Miscellaneous Transmission Plant	3,149	16,288
106	TOTAL Maintenance (Enter Total of lines 92 thru 97)	1,704,197	1,728,436
107	TOTAL Transmission Expenses (Enter Total of lines 90 and 98)	10,437,363	8,700,413
108	3. DISTRIBUTION EXPENSES		
109	Operation		
110	(580) Operation Supervision and Engineering	544,983	484,527

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES

Line No.	Account (a)	Amount for Current Year (b)	Amount for Prior Year (c)
103	3. DISTRIBUTION EXPENSES (Continued)		
104	(581) Load Dispatching	-	-
105	(582) Station Expenses	255,535	218,337
106	(583) Overhead Line Expenses	430,850	548,930
107	(584) Underground Line Expenses	221,579	252,091
108	(585) Street Lighting and Signal System Expenses	182,248	172,955
109	(586) Meter Expenses	223,838	139,228
110	(587) Customer Installations Expenses	399,146	401,850
111	(588) Miscellaneous Distribution Expenses	1,705,994	1,780,724
112	(589) Rents	87,090	89,562
113	TOTAL Operation (Enter Total of lines 102 thru 112)	4,051,263	4,088,203
114	Maintenance		
115	(590) Maintenance Supervision and Engineering	429,059	461,079
116	(591) Maintenance of Structures	152,578	103,495
117	(592) Maintenance of Station Equipment	203,062	365,933
118	(593) Maintenance of Overhead Lines	2,850,672	2,618,661
119	(594) Maintenance of Underground Lines	277,358	286,540
120	(595) Maintenance of Line Transformers	434,393	261,020
121	(596) Maintenance of Street Lighting and Signal Systems	212,900	190,439
122	(597) Maintenance of Meters	24,206	38,336
123	(598) Maintenance of Miscellaneous Distribution Plant	41,510	79,238
124	TOTAL Maintenance (Enter Total of lines 115 thru 123)	4,625,739	4,404,741
125	TOTAL Distribution Expenses (Enter Total of lines 113 and 124)	8,677,002	8,492,944
126	4. CUSTOMER ACCOUNTS EXPENSES		
127	Operation		
128	(901) Supervision	203,657	194,693
129	(902) Meter Reading Expenses	437,260	362,283
130	(903) Customer Records and Collection Expenses	2,651,726	2,709,234
131	(904) Uncollectible Accounts	575,171	938,087
132	(905) Miscellaneous Customer Accounts Expenses	45,000	83,959
133	TOTAL Customer Accounts Expenses (Enter Total of lines 128 thru 132)	3,912,813	4,288,255
134	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
135	Operation		
136	(907) Supervision	-	-
137	(908) Customer Assistance Expenses	7,760,232	5,867,133
138	(909) Informational and Instructional Expenses	297,416	17,264
139	(910) Miscellaneous Customer Service and Informational Expenses	58,037	50,267
140	TOTAL Cust. Service and Informational Expenses (Enter Total of lines 136 thru 139)	8,115,686	5,934,664
141	6. SALES EXPENSES		
142	Operation		
143	(911) Supervision	-	-
144	(912) Demonstrating and Selling Expenses	1,626	173,500
145	(913) Advertising Expenses	155	39,188
146	(916) Miscellaneous Sales Expenses	15,864	38,600
147	TOTAL Sales Expenses (Enter Total of lines 143 thru 146)	17,646	251,288
148	7. ADMINISTRATIVE AND GENERAL EXPENSES		
149	Operation		
150	(920) Administrative and General Salaries	8,513,036	8,148,288
151	(921) Office Supplies and Expenses	1,386,720	1,379,591
152	(Less) (922) Administrative expenses Transferred-Credit	(16,287)	(17,312)

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES

Line No.	Account (a)	Amount for Current Year (b)	Amount for Prior Year (c)
153	7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)		
154	(923) Outside Services Employed	5,043,643	3,972,670
155	(924) Property Insurance	437,241	450,607
156	(925) Injuries and Damages	1,808,492	1,243,326
157	(926) Employee Pensions and Benefits	343,886	338,615
158	(927) Franchise Requirements	6,027	6,704
159	(928) Regulatory Commission Expenses	1,927,019	1,698,820
160	(Less) (929) Duplicate Charges-Cr.	-	-
161	(930.1) General Advertising Expenses	67,411	84,243
162	(930.2) Miscellaneous General Expenses	1,044,972	1,019,353
163	(931) Rents	252,531	100,527
164	TOTAL Operation (Enter Total of lines 150 thru 163)	20,814,691	18,425,432
165	Maintenance		
166	(935) Maintenance of General Plant	1,929,813	2,102,635
167	TOTAL Administrative and General Expenses (Enter Total of lines 164 and 166)	22,744,504	20,528,067
168	TOTAL Electric Operation and Maintenance Expenses (Enter Total of lines 79,99,125,133,140,147,and 167)	225,538,791	179,201,524

NUMBER OF ELECTRIC DEPARTMENT EMPLOYEES

1. The data on number of employees should be reported for the payroll period ending nearest to October 31, or any payroll period ending 60 days before or after October 31.
2. If the respondent's payroll for the reporting period includes any special construction personnel, include such employees on line 3, and show the number of such special construction employees in a footnote.
3. The number of employees assignable to the electric department from joint functions of combination utilities may be determined by estimate, on the basis of employee equivalents. Show the estimated number of equivalent employees attributed to the electric department from joint functions.

1 Payroll Period Ended (Date) December 31, 2010		
2 Total Regular Full-Time Employees	85	83
3 Total Part-Time and Temporary Employees	1	2
4 Allocation of General Employees	126	128
5 Total Employees (See Note 1)	212	213