THIS FILING IS	
Item 1: ☐ 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

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 2009/Q4

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

IDENTIFICATION

01 Exact Legal Name of Respondent Avista Corporation	02 Year/Period of Report End of 2009/Q4
03 Previous Name and Date of Change *(if name changed during year)*	/ /
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 1411 East Mission Avenue, Spokane, WA 99207	
05 Name of Contact Person Christy Burmeister-Smith	06 Title of Contact Person VP and Controller
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) ☐ An Original (2) ☒ A Resubmission	05/12/2010

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 Christy Burmeister-Smith	03 Signature Christy Burmeister-Smith	04 Date Signed *(Mo, Da, Yr)*
02 Title VP and Controller		05/12/2010

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

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2010	Year/Period of Report End of 2009/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".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Lines Added During the Year	424-425	
68	Substations	426-427	
69	Transactions with Associated (Affiliated) Companies	429	N/A
70	Footnote Data	450	
	Stockholders' Reports Check appropriate box: [X] Two copies will be submitted [ ] No annual report to stockholders is prepared		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2010	End of 2009/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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2010	End of 2009/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Avista Capital, Inc.	Parent company to the	100	
2		Company's subsidiaries.		
3				
4	Advantage IQ, Inc.	Provider of utility bill	74.36	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.		Advantage IQ
11				
12	Avista Development, Inc.	Maintains an investment	100	Subsidiary of
13		portfolio of real estate and		Avista Capital
14		other investments.		
15				
16	Avista Energy, Inc.	Inactive	100	Subsidiary of
17				Avista Capital
18				
19	Avista Power, LLC	Inactive	100	Affiliate of
20				Avista Capital
21				
22	Avista Turbine Power, Inc.	Receives assignments of	100	Subsidiary of
23		purchase power agreements.		Avista Capital
24				
25	Avista Ventures, Inc.	Inactive	100	Subsidiary of
26				Avista Capital
27				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Pentzer Corporation	Parent company of Bay Area	100	Subsidiary of
2		Manufacturing and Pentzer		Avista Capital
3		Venture Holdings.		
4				
5	Pentzer Venture Holdings	Inactive	100	Subsidiary of
6				Pentzer Corporation
7				
8	Bay Area Manufacturing	Holding Company	100	Subsidiary of
9				Pentzer Corporation
10				
11	Advanced Manufacturing and Development, Inc.	Performs custom sheet metal	82.95	Subsidiary of
12	dba Metalfx	manufacturing of electronic		Bay Area
13		enclosures, parts and systems		Manufacturing.
14		for the computer, telecom and		
15		medical industries. AM&D		
16		also has a wood products		
17		division.		
18				
19	Avista Receivables Corporation	Acquires and sells accounts	100	Subsidiary of
20		receivable of Avista Corp.		Avista Corp.
21				
22	Spokane Energy, LLC	Marketing of energy.	100	Affiliate of
23				Avista Corp.
24				
25	Avista Capital II	An affiliated business trust	100	Affiliate of
26		formed by the Company.		Avista Corp.
27		Issued Pref. Trust Securities		

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2010	Year/Period of Report End of 2009/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.
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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1				
2	Avista Northwest Resources, LLC	Formed in 2009 to own	100	Subsidiary of
3		an interest in a venture		Avista Capital
4		fund investment		
5				
6	Steam Plant Square, LLC	Commercial office and retail	90	Affiliate of
7		leasing.		Avista Development
8				
9	Courtyard Office Center	Commercial office and retail	100	Affiliate of
10		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	04/16/2010	End of 2009/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	Executive Vice President (Resigned 3/31/2009)	M. K. Malquist	
5			
6	Senior Vice President and Chief Financial Officer	M. T. Thies	
7			
8	Senior Vice President, General Counsel	M. M. Durkin	
9	and Chief Compliance Officer		
10			
11	Senior Vice President and Corporate Secretary	K. S. Feltes	
12	with responsibility for Human Resources		
13			
14	Vice President, Controller and	C. M. Burmeister-Smith	
15	Principal Accounting Officer		
16			
17	Vice President and Chief Information Officer	J. M. Kensok	
18			
19	Vice President with responsibility for Transmission	D. F. Kopczynski	
20	and Distribution Operations		
21			
22	Vice President and Chief Counsel for Regulatory and	D. J. Meyer	
23	Governmental Affairs		
24			
25	Vice President, with responsibility for State and	K. O. Norwood	
26	Federal Regulation		
27			
28	Vice President and Environmental Compliance Officer	D. P. Vermillion	
29			
30	Vice President of Finance and Treasurer	A. M. Wilson	
31	(Resigned 6/12/2009)		
32			
33	Vice President, with responsibility for	R. D. Woodworth	
34	Sustainable Energy Solutions		
35			
36	Vice President, Finance	J. R. Thackston	
37	(Effective 6/12/2009)		
38			
39	Treasurer	D. C. Thoren	
40	(Effective 6/12/2009)		
41			
42	Vice President, Energy Resources	R. L. Storro	
43	(Effective 1/1/2009)		
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	04/16/2010	End of 2009/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	5721 SE Columbia Way, Suite 200, Vancouver, WA 986661
9		
10	Roy Lewis Eiguren	702 W. Idaho St., Suite 1100, Boise, ID 83702
11		
12	Jack W. Gustavel ***	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
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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	04/16/2010	End of 2009/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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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2010	End of 2009/Q4

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

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?

[ ] Yes
[X] No

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

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	No formula rates				
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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	04/16/2010	End of 2009/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	04/16/2010	End of 2009/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. Avista Receivables Corporation (ARC) is a wholly owned, bankruptcy-remote subsidiary of Avista Corp. formed for the purpose of acquiring or purchasing interests in certain accounts receivable, both billed and unbilled, of the Company. Avista Corp., ARC and a third-party financial institution are parties to a Receivables Purchase Agreement, and on March 13, 2009 that agreement was amended to, among other things, extend the termination date to March 12, 2010. Under the Receivables Purchase Agreement, ARC can sell without recourse, and such financial institution will purchase, on a revolving basis, up to $85.0 million of those receivables. ARC is obligated to pay fees that approximate the purchaser's cost of issuing commercial paper equal in value to the interests in receivables sold. The amount of such fees is included in other operating expenses of Avista Corp. The Receivables Purchase Agreement has financial covenants, which are substantially the same as those of Avista Corp.'s committed lines of credit. Based on calculations of eligible receivables, ARC had the ability to sell up to $85.0 million of receivables under this revolving agreement at each of December 31, 2009 and December 31, 2008. There were not any accounts receivable sold under this revolving agreement as of December 31, 2009 and $17.0 million were sold as of December 31, 2008.

The Company has 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 can borrow or request the issuance of letters of credit in any combination up to $320.0 million. The Company had $87.0 million in borrowings outstanding under this committed line of credit as of December 31, 2009 and $250.0 million as of December 31, 2008. Total letters of credit outstanding were $28.4 million as of December 31, 2009 and $24.3 million as of December 31, 2008. The committed line of credit is secured by $320.0 million of non-transferable First Mortgage Bonds of the Company issued to the agent bank that would only become due and payable in the event, and then only to the extent, that the Company defaults on its obligations under the committed line of credit.

Additionally, the Company has 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 (entered in November 2009). The Compnay did not have any borrowings outstanding under this agreement at December 31, 2009. Avista Corp. may elect to increase the committed line of credit by up to $25.0 million under the same agreement. The committed line of credit is secured by $75.0 million of non-transferable First Mortgage Bonds of the Company issued to the agent bank that would only become due and payable in the event, and then only to the extent, that the Company defaults on its obligations under the committed line of credit. This credit agreement was approved by the respective regulatory commissions as follows: WUTC (Docket No. UE-081842); IPUC (Case No. AVU-U-08-02 Order No. 30673); and OPUC (Docket UF 4260).

On September 22, 2009, the Company issued $250.0 million of 5.125 percent First Mortgage Bonds due in 2022. The net proceeds from the issuance of $249.4 million (net of discounts and before Avista Corp.'s expenses) were used to retire variable rate short-term borrowings outstanding under our $320.0 million committed line of credit, and for general corporate purposes. This debt issuance was approved by the respective regulatory commissions as follows: WUTC (Docket No. UE-081842 Order No. 2); IPUC (Case No. AVU-U-08-01 Order No. 30670); and OPUC (Docket UF 4246(1) Order No. 08-542).

In 2004, the Company issued Junior Subordinated Debt Securities, with a principal amount of $61.9 million to AVA Capital Trust III, an affiliated business trust formed by the Company. Concurrently, AVA Capital Trust III issued $60.0 million of Preferred Trust Securities to third parties and $1.9 million of Common Trust Securities to the Company. On April 1, 2009, AVA Capital Trust III redeemed all of the Preferred Trust Securities issued to third parties with a principal balance of $60.0 million and all of the Common Trust Securities issued to the Company with a principal balance of $1.9 million. Concurrently, the Company redeemed the total amount outstanding of its Junior Subordinated Debt Securities, at 100 percent of the principal amount ($61.9 million) plus accrued interest held by AVA Capital Trust III. The Company's net redemption of $60.0 million was funded by borrowings under its $320.0 million committed line of credit agreement.

In December 2008, the City of Forsyth, Montana issued $17.0 million of its Pollution Control Revenue Refunding Bonds, Series 2008 (Avista Corp. Colstrip Project) due 2034 on behalf of Avista Corp. The proceeds of the Bonds were used to refund $17.0 million of Pollution Control Revenue Refunding Bonds, Series 1999B (Avista Corp. Colstrip Project) issued by the City of Forsyth, Montana on behalf of Avista Corp., which were subject to remarketing or refunding on December 31, 2008. In December 2009, Avista Corp. purchased the Bonds and expects that at a later date, subject to market conditions, the bonds will be refunded or remarketed to unaffiliated investors. Although Avista Corp. is now the holder of these Pollution Control Bonds, the bonds will not be cancelled but will remain outstanding under the City of Forsyth's indenture. However, so long as Avista Corp. is the holder, the bonds will not be reflected as an asset or a liability on Avista Corp.'s Consolidated Balance Sheet.

7. None

8. Average annual wage increases were 2.4% for non-exempt employees effective March 2, 2009. Average annual wage increases were 2.8% for exempt employees effective March 2, 2009. There were no wage increases for officers. Certain bargaining unit employees received increases ranging from 2.0% to 4.0% effective in March and April 2009.

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. Malyn K. Malquist, Excecutive Vice President, left the Company effective March 31, 2009.

Ann M. Wilson, Vice President of Finance and Treasurer, left the Company in June 2009.

On May 8, 2009, the Board of Directors of Avista Corporation elected Marc Racicot to serve as a director on the board effective August 1, 2009. Mr. Racicot will stand for election to the board at the next annual meeting of shareholders on May 13, 2010. Mr. Racicot was appointed to serve on the Energy, Environmental & Operations and Finance Committees of the board.

On May 18, 2009, Avista Corporation named Jason Thackston as Vice President of Finance effective June 12, 2009.

On May 18, 2009, Avista Corporation named Diane Thoren as Treasurer effective June 12, 2009.

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	04/16/2010	End of 2009/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	3,546,192,091	3,340,068,198
3	Construction Work in Progress (107)	200-201	57,217,478	75,568,224
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		3,603,409,569	3,415,636,422
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	1,219,877,922	1,142,578,137
6	Net Utility Plant (Enter Total of line 4 less 5)		2,383,531,647	2,273,058,285
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)		2,383,531,647	2,273,058,285
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		5,031,620	4,991,551
19	(Less) Accum. Prov. for Depr. and Amort. (122)		897,684	890,639
20	Investments in Associated Companies (123)		12,047,000	13,903,000
21	Investment in Subsidiary Companies (123.1)	224-225	81,243,239	77,487,962
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)		23,798,439	26,240,546
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		11,558,301	10,234,544
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		45,482,748	49,312,596
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		178,263,663	181,279,560
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		2,462,480	1,674,372
36	Special Deposits (132-134)		1,630,323	1,600,000
37	Working Fund (135)		848,613	619,853
38	Temporary Cash Investments (136)		652,010	2,684,444
39	Notes Receivable (141)		629,625	63,451
40	Customer Accounts Receivable (142)		188,271,550	207,867,900
41	Other Accounts Receivable (143)		6,484,963	6,188,617
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		3,710,770	5,844,603
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		101,231	120,021
45	Fuel Stock (151)	227	4,294,013	3,673,039
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	18,386,509	17,455,835
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

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	12,832	0
55	Gas Stored Underground - Current (164.1)		12,706,763	30,720,371
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		9,985,760	8,415,670
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		197,040	10,934
60	Rents Receivable (172)		553,237	646,271
61	Accrued Utility Revenues (173)		0	0
62	Miscellaneous Current and Accrued Assets (174)		454,418	194,919
63	Derivative Instrument Assets (175)		53,240,001	60,546,323
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		45,482,748	49,312,596
65	Derivative Instrument Assets - Hedges (176)		0	874,944
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		251,717,850	288,199,765
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		15,732,877	15,852,599
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	352,616,516	455,580,547
73	Prelim. Survey and Investigation Charges (Electric) (183)		3,346,452	3,088,816
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	26,105,547	32,008,980
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)		15,196,145	17,151,844
82	Accumulated Deferred Income Taxes (190)	234	91,975,547	131,055,525
83	Unrecovered Purchased Gas Costs (191)		-39,952,004	-18,646,016
84	Total Deferred Debits (lines 69 through 83)		465,021,080	636,092,295
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		3,278,534,240	3,378,629,905

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2010	end of 2009/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	759,057,747	755,903,119
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	17,498,634	19,170,532
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	-2,090,961	87,394
11	Retained Earnings (215, 215.1, 216)	118-119	295,862,243	253,478,332
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-20,871,863	-25,488,897
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)	-2,350,286	-6,092,318
16	Total Proprietary Capital (lines 2 through 15)		1,051,287,436	996,883,374
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,070,256,423	824,970,979
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	51,547,000	114,603,000
21	Other Long-Term Debt (224)	256-257	0	0
22	Unamortized Premium on Long-Term Debt (225)		230,967	239,850
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		2,167,570	1,752,256
24	Total Long-Term Debt (lines 18 through 23)		1,119,866,820	938,061,573
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		1,650,500	1,579,821
29	Accumulated Provision for Pensions and Benefits (228.3)		123,281,094	184,587,850
30	Accumulated Miscellaneous Operating Provisions (228.4)		2,916,673	2,936,173
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		2,871,255	7,140,857
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		3,971,453	4,208,327
35	Total Other Noncurrent Liabilities (lines 26 through 34)		134,690,975	200,453,028
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		87,000,000	250,000,000
38	Accounts Payable (232)		114,930,110	153,032,408
39	Notes Payable to Associated Companies (233)		6,882,247	2,854,178
40	Accounts Payable to Associated Companies (234)		724,582	737,710
41	Customer Deposits (235)		8,140,853	6,979,171
42	Taxes Accrued (236)	262-263	2,222,627	6,105,577
43	Interest Accrued (237)		13,476,434	10,871,471
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	04/16/2010	end of 2009/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)		147,574	0
48	Miscellaneous Current and Accrued Liabilities (242)		55,461,901	32,188,393
49	Obligations Under Capital Leases-Current (243)		0	75,206
50	Derivative Instrument Liabilities (244)		18,958,058	78,603,554
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		2,871,255	7,140,857
52	Derivative Instrument Liabilities - Hedges (245)		50,091	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		305,123,222	534,306,811
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		1,280,331	1,263,086
57	Accumulated Deferred Investment Tax Credits (255)	266-267	5,632,508	373,728
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	22,330,799	24,985,882
60	Other Regulatory Liabilities (254)	278	61,709,913	55,429,522
61	Unamortized Gain on Reaquired Debt (257)		2,957,426	3,237,373
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		348,074,981	334,892,041
64	Accum. Deferred Income Taxes-Other (283)		225,579,829	288,743,487
65	Total Deferred Credits (lines 56 through 64)		667,565,787	708,925,119
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		3,278,534,240	3,378,629,905

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2010	End of 2009/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	1,516,973,753	1,657,671,994		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,100,224,196	1,278,636,823		
5	Maintenance Expenses (402)	320-323	50,846,769	47,636,921		
6	Depreciation Expense (403)	336-337	87,089,835	82,388,834		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	9,143,602	7,905,829		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	99,047	99,047		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		3,718,504	382,274		
13	(Less) Regulatory Credits (407.4)		10,397,806	8,388,441		
14	Taxes Other Than Income Taxes (408.1)	262-263	76,582,590	72,057,352		
15	Income Taxes - Federal (409.1)	262-263	30,223,259	3,249,258		
16	- Other (409.1)	262-263	2,111,405	53,201		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	23,050,105	42,600,284		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	6,214,995	4,970,670		
19	Investment Tax Credit Adj. - Net (411.4)	266	-93,914	-49,308		
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)		1,366,382,597	1,521,601,404		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		150,591,156	136,070,590		

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2010	Year/Period of Report End of 2009/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

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

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
951,029,259	921,386,136	565,944,494	736,285,858			2
						3
621,221,944	624,698,493	479,002,252	653,938,330			4
42,044,915	40,308,817	8,801,854	7,328,104			5
71,109,022	67,721,188	15,980,813	14,667,646			6
						7
7,467,875	6,448,003	1,675,727	1,457,826			8
99,047	99,047					9
						10
						11
947,939	153,132	2,770,565	229,142			12
7,405,420	6,730,732	2,992,386	1,657,709			13
51,664,659	47,356,209	24,917,931	24,701,143			14
23,099,627	143,777	7,123,632	3,105,481			15
1,263,060	-192,188	848,345	245,389			16
20,060,696	36,623,690	2,989,409	5,976,594			17
5,234,188	4,711,220	980,807	259,450			18
-44,606		-49,308	-49,308			19
						20
						21
						22
						23
						24
826,294,570	811,918,216	540,088,027	709,683,188			25
124,734,689	109,467,920	25,856,467	26,602,670			26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2010	End of 2009/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)		150,591,156	136,070,590		
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)					
34	(Less) Expenses of Nonutility Operations (417.1)		5,249,706	3,869,058		
35	Nonoperating Rental Income (418)		-3,024	7,726		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	827,451	4,123,038		
37	Interest and Dividend Income (419)		5,906,409	10,085,671		
38	Allowance for Other Funds Used During Construction (419.1)		3,078,244	5,692,491		
39	Miscellaneous Nonoperating Income (421)			16,000		
40	Gain on Disposition of Property (421.1)		54,105	810,694		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		4,613,479	16,866,562		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		-2,050			
44	Miscellaneous Amortization (425)		1,110,572	1,110,571		
45	Donations (426.1)		1,405,009	956,059		
46	Life Insurance (426.2)		1,336,173	2,100,235		
47	Penalties (426.3)		-19,900	138,152		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,347,809	1,211,097		
49	Other Deductions (426.5)		1,686,420	-1,891,457		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		6,864,033	3,624,657		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	-8,841	547,911		
53	Income Taxes-Federal (409.2)	262-263	-985,412	2,415,034		
54	Income Taxes-Other (409.2)	262-263	-269,492	-288,122		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	-223,696	1,523,886		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	3,386,934	3,294,942		
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)		-4,874,375	903,767		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		2,623,821	12,338,138		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		55,436,849	62,954,659		
63	Amort. of Debt Disc. and Expense (428)		2,109,201	922,381		
64	Amortization of Loss on Reaquired Debt (428.1)		3,572,357	3,759,437		
65	(Less) Amort. of Premium on Debt-Credit (429)		8,883	8,885		
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		2,144,504	6,218,511		
68	Other Interest Expense (431)		3,434,267	5,554,756		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		544,568	4,611,851		
70	Net Interest Charges (Total of lines 62 thru 69)		66,143,727	74,789,008		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		87,071,250	73,619,720		
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)		87,071,250	73,619,720		

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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) 04/16/2010	Year/Period of Report End of 2009/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		251,930,211	219,765,445
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				(796,180)
15	TOTAL Debits to Retained Earnings (Acct. 439)			(796,180)
16	Balance Transferred from Income (Account 433 less Account 418.1)		86,243,799	69,496,682
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			-44,360,374	(37,070,823)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-44,360,374	(37,070,823)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		500,486	535,087
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		294,314,122	251,930,211

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2010	Year/Period of Report End of 2009/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)
	APPROPRIATED RETAINED EARNINGS (Account 215)			
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)		295,862,243	253,478,332
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-25,488,897	(14,672,673)
50	Equity in Earnings for Year (Credit) (Account 418.1)		827,451	4,123,038
51	(Less) Dividends Received (Debit)			
52	Equity transactions of subsidiaries		3,789,583	(14,939,262)
53	Balance-End of Year (Total lines 49 thru 52)		-20,871,863	(25,488,897)

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2010	Year/Period of Report End of 2009/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)	87,071,250	73,619,720
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	96,233,438	90,390,864
5	Amortization of deferred power and natural gas costs	51,358,730	45,835,653
6	Amortization of debt expense	5,672,674	4,672,935
7	Amortization of investment in exchange power	2,450,031	2,450,031
8	Deferred Income Taxes (Net)	9,011,417	41,798,683
9	Investment Tax Credit Adjustment (Net)	5,258,780	-49,308
10	Net (Increase) Decrease in Receivables	18,733,830	-116,961,581
11	Net (Increase) Decrease in Inventory	16,449,128	-18,855,778
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	-27,996,937	2,228,853
14	Net (Increase) Decrease in Other Regulatory Assets	-10,391,960	-20,468,183
15	Net Increase (Decrease) in Other Regulatory Liabilities	1,329,752	2,372,800
16	(Less) Allowance for Other Funds Used During Construction	3,078,244	5,692,491
17	(Less) Undistributed Earnings from Subsidiary Companies	827,452	4,123,038
18	Other (provide details in footnote):	338,032	601,532
19			
20	Changes in other non-current assets and liabilities	-20,200,944	-10,063,226
21	Net change in receivables allowance	-2,133,833	2,878,927
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	229,277,692	90,636,393
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-206,916,479	-219,796,264
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)	-206,916,479	-219,796,264
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	128,775	7,998,322
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies	4,689,731	1,191,118
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	04/16/2010	End of 2009/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		6,013
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	-1,000,477	2,006,496
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-203,098,450	-208,594,315
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	249,425,000	296,165,000
62	Preferred Stock		
63	Common Stock	2,621,946	28,564,671
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		250,000,000
67	Other (provide details in footnote):		
68	Cash received for settlement of interest rate swap agreements	10,776,222	
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	262,823,168	574,729,671
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-78,931,206	-401,855,029
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Long-term debt and short-term borrowing issuance costs	-3,726,398	-5,023,987
78	Net Decrease in Short-Term Debt (c)	-163,000,000	
79	Cash paid for settlement of interest rate swap agreements		-16,395,000
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-44,360,372	-37,070,823
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-27,194,808	114,384,832
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-1,015,566	-3,573,090
87			
88	Cash and Cash Equivalents at Beginning of Period	4,978,669	8,551,759
89			
90	Cash and Cash Equivalents at End of period	3,963,103	4,978,669

NOTES TO FINANCIAL STATEMENTS

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

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SEE PAGE 123 FOR REQUIRED INFORMATION.

NOTES TO FINANCIAL STATEMENTS

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Business

Avista Corporation (Avista Corp. or the Company) is an energy company engaged in the generation, transmission and distribution of energy, as well as other energy-related businesses. Avista Corp. generates, transmits and distributes electricity in parts of eastern Washington and northern Idaho. In addition, Avista Corp. has electric generating facilities in Montana and northern Oregon. Avista Corp. also provides natural gas distribution service in parts of eastern Washington and northern Idaho, as well as parts of northeast and southwest Oregon. Avista Capital, Inc. (Avista Capital), a wholly owned subsidiary of Avista Corp., is the parent company of all of the subsidiary companies including Avista Energy, Inc. (Avista Energy) and Advantage IQ, Inc. (Advantage IQ), a 74 percent owned subsidiary as of December 31, 2009. Avista Energy was an electricity and natural gas marketing, trading and resource management business. On June 30, 2007, Avista Energy completed the sale of substantially all of its contracts and ongoing operations. See Note 3 for further information. Advantage IQ is a provider of facility information and cost management services for multi-site customers throughout North America.

Accounting Standards Codification

In June 2009, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 168, "The Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles – a replacement of FASB Statement No. 162." This statement replaces all previously issued accounting standards and establishes the FASB Accounting Standards Codification (ASC). The ASC is the single source of authoritative nongovernmental accounting principles generally accepted in the United States of America (U.S. GAAP) and is effective for all interim and annual periods ending after September 15, 2009. All existing accounting standards documents were superseded. All other accounting literature not included in the ASC is considered nonauthoritative. The adoption of the ASC did not have any impact on the Company's financial condition, results of operations and cash flows, as the ASC did not change existing U.S. GAAP. The adoption of the ASC only resulted in changes to the Company's financial statement disclosure references. In order to facilitate the transition to the ASC, the Company has elected to show references to U.S. GAAP within this report prior to the ASC along with a parenthetical ASC reference.

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 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 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 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 by the FERC.

Operating Revenues
Revenues related to the sale of energy are generally 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 $89.6 million as of December 31, 2009 and $84.3 million (net of $11.4 million of unbilled receivables sold) as of December 31, 2008. See Note 5 for information related to the sale of accounts receivable.

Advertising Expenses
The Company expenses advertising costs as incurred. Advertising expenses were not a material portion of the Company's operating expenses in 2009 and 2008.

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 2.78 percent in 2009 and 2.77 percent in 2008.

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 - 51 years,
- electric distribution - 41 years, and
- natural gas distribution property - 53 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 $56.8 million in 2009 and $53.9 million in 2008.

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. In accordance with the uniform system of accounts 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 generally is permitted, under established regulatory rate practices, to recover the capitalized AFUDC, and a fair 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 generally does not occur until the related utility plant is placed in service and included in rate base. The effective AFUDC rate was 8.22 percent in 2009 and 8.2 percent in 2008. The Company's AFUDC rates do not exceed the maximum allowable rates as determined in accordance with the requirements of regulatory authorities.

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 of 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 21 for further information.

Earnings per Common Share Attributable to Avista Corporation
Basic earnings per common share attributable to Avista Corporation is computed by dividing net income attributable to Avista Corporation by the weighted average number of common shares outstanding for the period. Diluted earnings per common share attributable to Avista Corporation is calculated by dividing net income attributable to Avista Corporation (adjusted for the effect of potentially dilutive securities issued by subsidiaries) by diluted weighted average common shares outstanding during the period, including common stock equivalent shares outstanding using the treasury stock method, unless such shares are anti-dilutive. Common stock equivalent shares include shares issuable upon exercise of stock options and contingent stock awards. See Note 20 for earnings per common share calculations.

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. The following table presents the activity in the allowance for doubtful accounts during the years ended December 31 (dollars in thousands):

	2009	2008
Allowance as of the beginning of the year	$5,845	$2,966
Additions expensed during the year	5,160	6,336
Net deductions	(7,294)	(3,457)
Allowance as of the end of the year	$3,711	$5,845

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. Costs of depreciable units of property retired plus costs of removal less salvage are charged to accumulated depreciation.

Regulatory Deferred Charges and Credits
The Company prepares its financial statements in accordance with the provisions of SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation" (ASC 980) 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.

ASC 980 requires the Company to reflect the impact of regulatory decisions in its financial statements. ASC 980 requires 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 ASC 980 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.

The Company's primary regulatory assets include:

- power cost deferrals,

- investment in exchange power,
- regulatory asset for deferred income taxes,
- unamortized debt repurchase costs,
- assets offsetting net utility energy commodity derivative liabilities (see Note 6 for further information),
- expenditures for demand side management programs,
- expenditures for conservation programs,
- payments to the Coeur d'Alene Tribe for past water storage and the licensing of the Spokane River Project,
- certain expenditures for licensing hydroelectric generating facilities, and
- unfunded pensions and other postretirement benefits.

Regulatory liabilities include:

- utility plant retirement costs,
- natural gas deferrals, and
- liabilities offsetting net utility energy commodity derivative assets (see Note 6 for further information).

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 beginning 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 primary 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, 2008, the Company adopted the provisions of SFAS No. 157, "Fair Value Measurements" (ASC 820-10) related to its financial assets and liabilities and nonfinancial assets and liabilities measured at fair value on a recurring basis. In February 2008, the FASB issued Staff Position (FSP) No. 157-2, which deferred the effective date for certain portions of ASC 820-10 related to nonrecurring measurements of nonfinancial assets and liabilities. Effective January 1, 2009, the Company adopted those provisions of ASC 820-10. The adoption of the provisions of ASC 820-10 that became effective on January 1, 2008 and 2009, did not have a material impact on the Company's financial condition, results of operations and cash flows. However, the Company expanded disclosures for fair value measurements that became effective on January 1, 2008. There were no additional disclosures related to the provisions that became effective January 1, 2009. See Note 18 for the expanded disclosures.

Effective January 1, 2009, the Company adopted SFAS No. 141(R), "Business Combinations" (ASC 805-10) that replaces previous accounting guidance for business combinations and addresses the accounting for all transactions or other events in which an entity obtains control of one or more businesses. This statement requires the acquiring entity in a business combination to recognize the assets acquired, the liabilities assumed, and any noncontrolling interest in the transaction at the acquisition date, measured at their fair values as of that date, with limited exceptions.

Effective January 1, 2009, the Company adopted SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements - an amendment of ARB No. 51" (ASC 810-10). This statement amended previous accounting guidance to establish accounting and reporting standards for a noncontrolling (minority) interest in a subsidiary and for the deconsolidation of a subsidiary. This statement clarifies that a noncontrolling interest in a subsidiary is an ownership in the consolidated entity that should be reported as equity in the consolidated financial statements. The adoption of this statement had no material impact on the Company's financial condition and results of operations.

Effective January 1, 2009, the Company adopted SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities" (ASC 815-10) that requires disclosure of the fair value of derivative instruments and their gains and losses in a tabular format. The statement requires disclosure of derivative features that are related to credit risk. The Company expanded disclosures for derivatives and hedging activities. See Note 6 for the expanded disclosures.

Effective December 31, 2009, the Company adopted FSP FAS 132(R)-1, "Employers' Disclosures about Postretirement Benefit Plan Assets" (ASC 715-20) that amends FASB Statement No. 132(R) "Employers' Disclosures about Pensions and Other Postretirement Benefits" (ASC 715-20). This statement provides guidance on an employer's disclosures about plan assets of a defined benefit pension or other postretirement plan. The Company has expanded disclosures for its pension and other postretirement benefit plan assets in Note 9.

Effective June 30, 2009, the Company adopted FSP FAS 157-4, "Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly" (ASC 820-65-10-4) that provides guidance for determining fair values of financial instruments for which there is no active market or when quoted prices may represent distressed transactions. The guidance includes a reaffirmation of the need to use judgment in certain circumstances and requires expanded disclosures surrounding equity and debt securities. The adoption of this FSP did not have an impact on the Company's financial condition, results of operations and cash flows.

Effective June 30, 2009, the Company adopted SFAS No. 165, "Subsequent Events" (ASC 855-10). This statement established principles and requirements for subsequent events related to: 1) the period after the balance sheet date during which management of a reporting entity shall evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements; 2) the circumstances under which an entity shall recognize events or transactions occurring after the balance sheet date in its financial statements; and 3) the disclosures that an entity shall make about events or transactions that occurred after the balance sheet date. The Company evaluated subsequent events up to February 26, 2010 (the date the financial statements were available to be issued).

In June 2009, the FASB issued SFAS No. 166, "Accounting for Transfers of Financial Assets an amendment of FASB Statement No. 140" (ASC 860). This statement amends certain provisions of SFAS No. 140 (ASC 860) related to accounting for transfers of financial assets and a transferor's continuing involvement in transferred financial assets. The Company was required to adopt this statement effective January 1, 2010. The Company is evaluating the impact this statement will have on its financial condition, results of operations and cash flows. In particular, the Company is evaluating its accounts receivable sales (see Note 5) to determine whether or not the transactions meet the criteria of sales of financial assets. If the transactions did not meet the criteria, the transactions would be accounted for as secured borrowings. As of December 31, 2009, the Company had not sold any accounts receivable under the revolving agreement. The Company will finalize its evaluation during the first quarter of 2010 to determine the impact of adoption, if any, on its financial condition, results of operations and cash flows.

In June 2009, the FASB issued SFAS No. 167, "Amendments to FASB Interpretation No. 46(R)" (ASC 810). This statement carries forward the scope of FASB Interpretation No. 46(R) (ASC 810), with the addition of entities previously considered qualifying special-purpose entities, as the concept of these entities was eliminated in SFAS No. 166 (ASC 860). The amendments will significantly affect the overall consolidation analysis of variable interest entities (VIE). The amendments will require the Company to reconsider previous conclusions relating to the consolidation of VIEs, including whether an entity is a VIE, whether the Company is the VIE's primary beneficiary, and what type of financial statement disclosures are required. The Company was required to adopt this statement effective January 1, 2010. The Company is evaluating the impact this statement will have on its financial condition, results of operations and cash flows. The Company will finalize its evaluation during the first quarter of 2010 to determine the impact of adoption, if any, on its financial condition, results of operations and cash flows.

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.

Certain assets of Avista Energy with a net book value of approximately $30 million were not sold or liquidated. These primarily include natural gas storage and deferred income tax assets. The Company expects that the natural gas storage will ultimately be transferred to Avista Corp., subject to future regulatory approval. There is also a power purchase agreement, related to a 270 MW natural gas-fired combined cycle combustion turbine plant located in Idaho (Lancaster Plant). The Lancaster Plant is owned by an unrelated third-party and all of the output from the plant is contracted to Avista Turbine Power, Inc. (an affiliate of Avista Energy) through 2026. The majority of the rights and obligations of the power purchase agreement were conveyed to Shell Energy through the end of 2009. The rights and obligations of power purchase agreement were conveyed to Avista Corp. in January 2010.

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 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. As of February 26, 2010, neither party has made any claims under the Indemnification Agreement or 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.

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 for $8.9 million. Under the terms of the transaction, the assets and liabilities of Ecos were acquired by a wholly owned subsidiary of Advantage IQ.

NOTE 5. ACCOUNTS RECEIVABLE SALE

Avista Receivables Corporation (ARC) is a wholly owned, bankruptcy-remote subsidiary of Avista Corp. formed for the purpose of acquiring or purchasing interests in certain accounts receivable, both billed and unbilled, of the Company. Avista Corp., ARC and a third-party financial institution are parties to a Receivables Purchase Agreement, and on March 13, 2009 that agreement was amended to, among other things, extend the termination date to March 12, 2010. Under the Receivables Purchase Agreement, ARC can sell without recourse, and such financial institution will purchase, on a revolving basis, up to $85.0 million of those receivables. ARC is obligated to pay fees that approximate the purchaser's cost of issuing commercial paper equal in value to the interests in receivables sold. The amount of such fees is included in other operating expenses of Avista Corp. The Receivables Purchase Agreement has financial covenants, which are substantially the same as those of Avista Corp.'s committed lines of credit (see Note 12). Based on calculations of eligible receivables, ARC had the ability to sell up to $85.0 million of receivables under this revolving agreement at each of December 31, 2009 and December 31, 2008. There were not any accounts receivable sold under this revolving agreement as of December 31, 2009 and $17.0 million were sold as of December 31, 2008.

NOTE 6. 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.

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 gas supply requirements unhedged for purchase in short-term and spot markets. Natural gas resource optimization activities include:

- wholesale market sales of surplus gas supplies,
- purchases and sales of natural gas to use underutilized pipeline capacity, 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.

Substantially all forward contracts to purchase or sell power and natural gas are recorded as assets or liabilities at market value with an offsetting regulatory asset or liability. Contracts that are not considered derivatives under ASC 815 are generally 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, 2009 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
2010	760	568	26,699	1,210	1,381	49	5,051	-
2011	401	138	10,477	-	286	31	467	-
2012	366	-	4,128	-	287	-	-	-
2013	368	-	1,575	-	286	-	-	-
2014	366	-	-	-	286	-	-	-
Thereafter	1,694	-	-	-	1,303	-	-	-

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. In early 2009, Avista Corp. implemented a process to economically hedge a portion of the foreign currency risk by purchasing Canadian currency 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. As of December 31, 2009, the Company had a current derivative liability for foreign currency hedges of less than $0.1 million. As of December 31, 2009, the Company had entered into 24 Canadian currency forward contracts with a notional amount of $10.2 million ($10.6 million Canadian).

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. 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). These settlements of the interest rate swaps were deferred as a regulatory liability (included as part of long-term debt) and will be amortized as a component of interest expense over the life of the associated debt issued in accordance with regulatory accounting practices. The Company did not have any interest rate swap contracts outstanding as of December 31, 2009.

Derivative Instruments Summary

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 derivative instrument assets	53,765	(8,282)	45,483
Commodity contracts	Derivative instrument liabilities current	5,783	(21,870)	(16,087)
Commodity contracts	Long-term 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, 2009 was $11.8 million. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2009, the Company would be required to post $3.4 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 $3.2 million as of December 31, 2009 and $0.2 million as of December 31, 2008. 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 7. 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 was $334.8 million and accumulated depreciation was $209.6 million as of December 31, 2009. The Company's share of utility plant in service for Colstrip was $330.9 million and accumulated depreciation was $204.0 million as of December 31, 2008.

NOTE 8. 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):

	2009	2008
Asset retirement obligation at beginning of year	$4,208	$3,990
New liability recognized	-	-
Liability adjustment due to revision in estimated cash flows	-	-
Liability settled	(499)	(29)
Accretion expense	262	247
Asset retirement obligation at end of year	$3,971	$4,208

NOTE 9. 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 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 $48 million in cash to the pension plan in 2009 and $28 million in 2008. The Company expects to contribute $21 million to the pension plan in 2010.

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 $18.6 million in 2010, $19.4 million in 2011, $20.5 million in 2012, $21.7 million in 2013 and $23.0 million in 2014. For the ensuing five years (2015 through 2019), the Company expects that benefit payments under the pension plan and the SERP will total $136.3 million.

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.

In 2008, the rates at which participants are assumed to retire by age were analyzed based upon historical trends and future projections. The Company revised the rates to assume that a greater percentage of participants would retire between the ages of 55 and 65. The assumed rates were revised to range from 5 percent to 40 percent and 100 percent at age 65. The previous rates ranged from 2 percent to 30 percent and 100 percent at age 65. The change resulted in an increase of $11.0 million to the pension benefit obligation as of December 31, 2008.

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 employees' 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 be $4.1 million in 2010, $3.9 million in 2011, $3.7 million in 2012, $3.6 million in 2013 and $3.5 million in 2014. For the ensuing five years (2015 through 2019), the Company expects that benefit payments under other postretirement benefit plans will total $16.4 million. The Company expects to contribute $4.1 million to other postretirement benefit plans in 2010, 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, 2009 and 2008 and the components of net periodic benefit costs for the years ended December 31, 2009 and 2008 (dollars in thousands):

	Pension		Other	
	2009	2008	2009	2008
Change in benefit obligation:				
Benefit obligation as of beginning of year	$353,572	$323,090	$38,953	$34,352
Service cost	10,496	10,209	803	772
Interest cost	21,770	20,812	2,364	2,371
Actuarial loss	9,610	17,041	1,676	5,611
Transfer of accrued vacation	-	-	98	365
Benefits paid	(17,213)	(17,580)	(4,334)	(4,518)
Benefit obligation as of end of year	$378,235	$353,572	$39,560	$38,953
Change in plan assets:				
Fair value of plan assets as of beginning of year	$190,637	$242,561	$16,048	$22,718
Actual return on plan assets	50,053	(63,575)	4,346	(6,670)
Employer contributions	48,000	28,000	-	-

Benefits paid	(15,958)	(16,349)	-	-
Fair value of plan assets as of end of year	$272,732	$190,637	$20,394	$16,048
Funded status	$(105,503)	$(162,935)	$(19,166)	$(22,905)
Unrecognized net actuarial loss	126,926	160,280	15,772	18,357
Unrecognized prior service cost	1,790	2,444	(1,303)	(1,452)
Unrecognized net transition obligation	-	-	1,516	2,021
Prepaid (accrued) benefit cost	23,213	(211)	(3,181)	(3,979)
Additional liability	(128,716)	(162,724)	(15,985)	(18,926)
Accrued benefit liability	$(105,503)	$(162,935)	$(19,166)	$(22,905)
Accumulated pension benefit obligation	$294,649	$307,413	-	-
Accumulated postretirement benefit obligation:				
For retirees			$18,377	$18,821
For fully eligible employees			$9,290	$8,903
For other participants			$11,893	$11,229
Included in accumulated comprehensive loss (income) (net of tax):				
Unrecognized net transition obligation	$ -	$ -	$ 985	$1,313
Unrecognized prior service cost	1,163	1,589	(847)	(943)
Unrecognized net actuarial loss	82,502	104,182	10,252	11,932
Total	83,665	105,771	10,390	12,302
Less regulatory asset	(80,041)	(98,850)	(11,664)	(13,131)
Accumulated other comprehensive loss (income)	$3,624	$6,921	$(1,274)	$ (829)
Weighted average assumptions as of December 31:				
Discount rate for benefit obligation	6.29%	6.25%	6.00%	6.25%
Discount rate for annual expense	6.25%	6.34%	6.25%	6.20%
Expected long-term return on plan assets	8.50%	8.50%	8.50%	8.50%
Rate of compensation increase	4.65%	4.72%		
Medical cost trend pre-age 65 – initial			8.50%	9.00%
Medical cost trend pre-age 65 – ultimate			5.00%	5.00%
Ultimate medical cost trend year pre-age 65			2017	2017
Medical cost trend post-age 65 – initial			8.50%	9.00%
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	$10,496	$10,209	$ 803	$ 772
Interest cost	21,770	20,812	2,364	2,371
Expected return on plan assets	(17,612)	(21,138)	(1,364)	(1,931)
Transition obligation recognition	-	-	505	505
Amortization of prior service cost	654	654	(149)	(149)
Net loss recognition	10,539	3,345	1,279	575
Net periodic benefit cost	$25,847	$13,882	$3,438	$2,143

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 plan, 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 of December 31, 2009 and 2008 as indicated in the table below:

	2009	2008
Equity securities	51%	50%
Debt securities	31%	30%
Real estate	5%	5%
Absolute return	10%	12%
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, 2009 and 2008.

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, 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 market-related value of other postretirement plan assets was determined as of December 31, 2009 and 2008.

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, 2009 by $2.1 million and the service and interest cost by $0.2 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, 2009 by $1.9 million and the service and interest cost by $0.2 million.

The Company has a salary deferral 401(k) plan that is a defined contribution plan 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 $4.4 million in 2009 and $4.3 million in 2008.

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. At December 31, 2009 and 2008, there were deferred compensation assets of $9.4 million and $8.8 million included in other special funds and corresponding deferred compensation liabilities of $9.4 million and $8.8 million included in other deferred credits on the Balance Sheets.

NOTE 10. 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, 2009, the Company had $11.6 million of state tax credit carryforwards. State tax credits expire from 2015 to 2021. 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 federal income tax return. This examination could result in a change in the liability for uncertain tax positions. 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 state income taxes could result in any adjustments that would be significant to the financial statements.

In August 2005, the Treasury Department issued regulations and the IRS issued a revenue ruling that affects the tax treatment by Avista Corp. of certain indirect overhead expenses. Avista Corp. had previously made a tax election to currently deduct certain indirect overhead costs, starting with the 2002 tax return, that were capitalized for financial accounting purposes. This election allowed Avista Corp. to take tax deductions resulting in a total reduction of approximately $40 million in current tax liabilities for 2002, 2003 and 2004. These current tax benefits were deferred on the balance sheet and did not affect net income.

On the basis of the revenue ruling and related regulations, the IRS disallowed the tax deduction of indirect overhead expenses during their examination of the Company's 2001, 2002 and 2003 federal income tax returns. The Company believed that the tax deductions claimed on tax returns were appropriate based on the applicable statutes and regulations in effect at the time. Avista Corp. appealed the proposed IRS adjustment in April 2006. The Company repaid a portion of the previous tax deductions through tax payments in 2005, 2006 and 2008.

On September 10, 2008, the Company entered into a Settlement Agreement with the Appeals Division of the IRS that resolved all items noted during their audit of the Company's 2001 through 2003 tax years, including, among other things, indirect overhead expenses. The agreement was reviewed and approved by the Joint Committee on Taxation, and a settlement payment was received in December 2008. The original IRS disallowance and the Company's appeal of the indirect overhead issue caused a delay in associated tax refunds for net operating losses that were carried back to several earlier years. The final settlement with the IRS freed up the refund years and set the amount owed for the 2001-2003 tax years. The net result was a refund to the Company of $14.7 million, plus interest of $5.7 million.

The Company had net regulatory assets of $97.9 million at December 31, 2009 and $115.0 million at December 31, 2008 related to the probable recovery of certain deferred income tax liabilities from customers through future rates.

NOTE 11. 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, which are included in operation expenses in the Statements of Income, were $704.9 million in 2009 and $951.4 million in 2008. 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):

	2010	2011	2012	2013	2014	Thereafter	Total
Power resources	$220,286	$133,287	$104,716	$ 79,543	$70,605	$485,980	$1,094,417
Natural gas resources	146,321	93,609	62,084	44,375	44,424	431,904	822,717
Total	$366,607	$226,896	$166,800	$123,918	$115,029	$917,884	$1,917,134

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 generally 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 expenses associated with these agreements are reflected as operation expenses and maintenance expenses in the Statements of Income. The following table details future contractual commitments for these agreements (dollars in thousands):

	2010	2011	2012	2013	2014	Thereafter	Total
Contractual obligations	$46,773	$55,084	$48,457	$52,181	$53,211	$573,643	$829,349

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. The cost of power obtained under the contracts, including payments made when a facility is not operating, is included in operation expenses in the Statements of Income. Expenses under these PUD contracts were $12.6 million in 2009 and $14.9 million in 2008. Information as of December 31, 2009 pertaining to these PUD contracts is summarized in the following table (dollars in thousands):

	Company's Current Share of					
	Output	Kilowatt Capability	Annual Costs (1)	Debt Service Costs (1)	Bonds Outstanding	Expiration Date
Chelan County PUD:						
Rocky Reach Project	2.9%	37,000	$ 1,658	$883	$ 909	2011
Douglas County PUD:						
Wells Project	3.5%	30,000	1,609	698	3,728	2018
Grant County PUD:						
Priest Rapids Project	3.3%	31,500	4,377	726	7,854	2055
Wanapum Project (2)	7.4%	76,800	4,989	2,394	13,554	2055
Totals		175,300	$12,633	$4,701	$26,045	

(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 the year 2009. Debt service costs are included in annual costs.

(2) A previous contract expired on October 31, 2009. A new contract was completed in 2001 with an expiration date of 2055. Beginning in November 2009, the Company's rights to the output were reduced from 8.2 percent to 3.3 percent. Under the new contract the Company has the rights to the output but not the obligation to take the output. In September of each year the Company is required to determine if it will take the output for the subsequent year.

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):

	2010	2011	2012	2013	2014	Thereafter	Total
Minimum payments	$2,985	$2,926	$2,500	$2,496	$2,368	$30,777	$44,052

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

NOTE 12. NOTES PAYABLE

Avista Corp. has 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 can borrow or request the issuance of letters of credit in any combination up to $320.0 million. Total letters of credit outstanding were $28.4 million as of December 31, 2009 and $24.3 million as of December 31, 2008. The committed line of credit is secured by $320.0 million of non-transferable First Mortgage Bonds of the Company issued to the agent bank that would only become due and payable in the event, and then only to the extent, that the Company defaults on its obligations under the committed line of credit.

Additionally, the Company has 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. Avista Corp. may elect to increase the committed line of credit by up to $25.0 million under the same agreement. The committed line of credit is secured by $75.0 million of non-transferable First Mortgage Bonds of the Company issued to the agent bank that would only become due and payable in the event, and then only to the extent, that the Company defaults on its obligations under the committed line of credit.

The committed line of credit agreements contain customary covenants and default provisions, including a covenant requiring 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, 2009, the Company was in compliance with this covenant with a ratio of 4.23 to 1. The committed line of credit agreements also have a covenant which does 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, 2009, the Company was in compliance with this covenant with a ratio of 53.6 percent.

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):

	2009	2008
Balance outstanding at end of period	$ 87,000	$250,000
Maximum balance outstanding during the period	$275,000	$250,000
Average balance outstanding during the period	$186,474	$ 48,426
Average interest rate during the period	0.65%	3.04%
Average interest rate at end of period	0.59%	0.81%

NOTE 13. BONDS

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

Maturity Year	Description	Interest Rate	2009	2008
2010	Secured Medium-Term Notes	6.67%-8.02%	$ 35,000	$ 35,000
2012	Secured Medium-Term Notes	7.37%	7,000	7,000
2013	First Mortgage Bonds	6.13%	45,000	45,000
2013	First Mortgage Bonds	7.25%	30,000	30,000
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
2022	First Mortgage Bonds (1)	5.13%	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 (2)	(2)	66,700	66,700
2034	Secured Pollution Control Bonds (3)	(3)	17,000	17,000
2035	First Mortgage Bonds	6.25%	150,000	150,000
2037	First Mortgage Bonds	5.70%	150,000	150,000
	Total secured bonds		1,151,700	901,700
2023	Unsecured Pollution Control Bonds	6.00%	4,100	4,100
	Interest rate swaps		(1,844)	(14,129)
	Total		1,153,956	891,671
	Secured Pollution Control Bonds held by Avista Corporation (2) (3)		(83,700)	(66,700)
	Total bonds		$1,070,256	$824,971

(1) In September 2009, the Company issued $250.0 million of 5.125 percent First Mortgage Bonds due in 2022.
(2) On December 31, 2008, $66.7 million of the City of Forsyth, Montana Pollution Control Revenue Refunding Bonds, Series 1999A (Avista Corporation Colstrip Project) due 2032 were remarketed. Avista Corp. purchased these Pollution Control Bonds and expects that at a later date, subject to market conditions, these bonds will be remarketed to unaffiliated investors or refunded by a new issue. Although Avista Corp. is now the holder of these Pollution Control Bonds, the bonds will not be cancelled but will remain outstanding under the City of Forsyth's indenture. However, so long as Avista Corp. is the holder, the bonds will not be reflected as an asset or a liability on Avista Corp.'s Balance Sheet.

(3) In December 2008, the City of Forsyth, Montana issued $17.0 million of its Pollution Control Revenue Refunding Bonds, Series 2008 (Avista Corp. Colstrip Project) due 2034 on behalf of Avista Corp. The proceeds of the Bonds were used to refund $17.0 million of Pollution Control Revenue Refunding Bonds, Series 1999B (Avista Corp. Colstrip Project) issued by the City of Forsyth, Montana on behalf of Avista Corp., which were subject to remarketing or refunding on December 31, 2008. In December 2009, Avista Corp. purchased the Bonds and expects that at a later date, subject to market conditions, the bonds will be refunded or remarketed to unaffiliated investors. Although Avista Corp. is now the holder of these Pollution Control Bonds, the bonds will not be cancelled but will remain outstanding under the City of Forsyth's indenture. However, so long as Avista Corp. is the holder, 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):

	2010	2011	2012	2013	2014	Thereafter	Total
Debt maturities	$35,000	$ -	$7,000	$75,000	$ -	$1,006,647	$1,123,647

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; provided, however, that 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, 2009, property additions and retired bonds would have entitled the Company to issue $668.5 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, 2009, the net earnings test would limit the principal amount of additional bonds the Company could issue to $607.5 million.

See Note 12 for information regarding First Mortgage Bonds issued to secure the Company's obligations under its $320.0 million and $75.0 million committed line of credit agreements.

NOTE 14. ADVANCES FROM ASSOCIATED COMPANIES

In 2004, the Company issued Junior Subordinated Debt Securities, with a principal amount of $61.9 million to AVA Capital Trust III, an affiliated business trust formed by the Company. Concurrently, AVA Capital Trust III issued $60.0 million of Preferred Trust Securities to third parties and $1.9 million of Common Trust Securities to the Company. On April 1, 2009, AVA Capital Trust III redeemed all of the Preferred Trust Securities issued to third parties with a principal balance of $60.0 million and all of the Common Trust Securities issued to the Company with a principal balance of $1.9 million. Concurrently, the Company redeemed the total amount outstanding of its Junior Subordinated Debt Securities, at 100 percent of the principal amount ($61.9 million) plus accrued interest held by AVA Capital Trust III. The Company's net redemption of $60.0 million was funded by borrowings under its $320.0 million committed line of credit agreement.

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 annual distribution rate paid during 2009 ranged from 1.22 percent to 3.06 percent. As of December 31, 2009, the annual distribution rate was 1.22 percent. 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 $3.2 million in 2009 and $2.0 million in 2008. Future minimum lease payments required under operating leases having initial or remaining noncancelable lease terms in excess of one year as of December 31, 2009 were as follows (dollars in thousands):

	2010	2011	2012	2013	2014	Thereafter	Total
Minimum payments required	$1,275	$1,198	$1,093	$1,079	$1,077	$2,630	$8,351

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 is contracted to Avista Turbine Power, Inc. (ATP), an affiliate of Avista Energy, through 2026 under a power purchase agreement. Avista Corp. has provided Rathdrum Power LLC, the owner of the Lancaster Plant, a guarantee under which Avista Corp. has guaranteed ATP's performance under the power purchase agreement. The majority of the rights and obligations of this agreement were conveyed to Shell Energy through the end of 2009. Beginning in January 2010, the rights and obligations under the power purchase agreement were conveyed 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, 2009 and 2008.

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, 2009 and 2008 (dollars in thousands):

	2009		2008	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Bonds	$1,072,100	$1,079,857	$839,100	$875,451
Advances from associated companies	51,547	43,534	113,403	102,027

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. Level 3 instruments include those that may be more structured or otherwise tailored to the Company's needs.

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, 2009 and 2008 at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Counterparty Netting (1)	Total
December 31, 2009					
Assets:					
Energy commodity derivatives	$ -	$11,898	$57,276	$(15,934)	$53,240
Deferred compensation assets:					
Fixed income securities (2)	2,011	-	-	-	2,011
Equity securities (2)	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
December 31, 2008					
Assets:					
Energy commodity derivatives	$ -	$40,104	$68,047	$(47,604)	$60,547
Deferred compensation assets:					
Fixed income securities (2)	1,889	-	-	-	1,889
Equity securities (2)	5,101	-	-	-	5,101
Interest rate swaps	-	875	-	-	875
Total	$6,990	$40,979	$68,047	$(47,604)	$68,412
Liabilities:					
Energy commodity derivatives	$ -	$110,123	$16,085	$(47,604)	$78,604

(1) The Company is permitted to net derivative assets and derivative liabilities when a legally enforceable master netting agreement exists.
(2) These assets are trading securities.

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 6 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 $1.6 million as of December 31, 2009 and $1.8 million as of December 31, 2008.

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	
	2009	2008	2009	2008
Balance as of January 1	$68,047	$98,943	$(16,085)	$(36,506)
Total gains or losses (realized/unrealized):				
Included in net income	-	-	-	-
Included in other comprehensive income	-	-	-	-
Included in regulatory assets/liabilities (1)	(7,202)	(22,586)	7,747	18,715
Purchases, issuances, and settlements, net	(3,569)	(8,310)	532	1,706
Transfers to other categories	-	-	-	-
Ending balance as of December 31	$57,276	$68,047	$(7,806)	$(16,085)

(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 December 2009, the Company entered into an amended and restated sales agency agreement with a sales agent to issue up to 1.25 million shares of its common stock from time to time. The Company originally entered into a sales agency agreement to issue up to 2 million shares of its common stock in December 2006. In 2008, the Company issued 750,000 shares of its common stock under this sales agency agreement. The Company did not issue any shares under this sales agency agreement in 2009.

NOTE 20. EARNINGS PER COMMON SHARE ATTRIBUTABLE TO AVISTA CORPORATION

The following table presents the computation of basic and diluted earnings per common share attributable to Avista Corporation for the years ended December 31 (in thousands, except per share amounts):

	2009	2008
Numerator:		
Net income attributable to Avista Corporation	$87,071	$73,620
Subsidiary earnings adjustment for dilutive securities	(114)	(249)
Adjusted net income attributable to Avista Corporation for computation of diluted earnings per common share	$86,957	$73,371
Denominator:		
Weighted-average number of common shares outstanding-basic	54,694	53,637
Effect of dilutive securities:		
Contingent stock awards	163	213
Stock options	85	178
Weighted-average number of common shares outstanding-diluted	54,942	54,028
Earnings per common share attributable to Avista Corporation:		
Basic	$1.59	$1.37
Diluted	$1.58	$1.36

Total stock options outstanding excluded in the calculation of diluted earnings per common share attributable to Avista Corporation were 218,450 for 2009 and 250,950 for 2008. These stock options were excluded from the calculation because they were antidilutive based on the fact that the exercise price of the stock options was higher than the average market price of Avista Corp. common stock during the respective period.

NOTE 21. STOCK COMPENSATION PLANS

1998 Plan

In 1998, the Company adopted, and shareholders approved, the Long-Term Incentive Plan (1998 Plan). Under the 1998 Plan, certain key employees, officers and non-employee directors of the Company and its subsidiaries may be granted stock options, stock appreciation rights, stock awards (including restricted stock) and other stock-based awards and dividend equivalent rights. The Company has available a maximum of 3.5 million shares of its common stock for grant under the 1998 Plan. As of December 31, 2009, 0.7 million shares were remaining for grant under this plan.

2000 Plan

In 2000, the Company adopted a Non-Officer Employee Long-Term Incentive Plan (2000 Plan), which was not required to be approved by shareholders. The provisions of the 2000 Plan are essentially the same as those under the 1998 Plan, except for the exclusion of non-employee directors and executive officers of the Company. The Company has available a maximum of 2.5 million shares of its common stock for grant under the 2000 Plan. However, the Company currently does not plan to issue any further options or securities under the 2000 Plan. As of December 31, 2009, 1.7 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 of $2.9 million for 2009 and $3.0 million for 2008. The total income tax benefit recognized in the Statements of Income was $1.0 million for 2009 and $1.1 million for 2008.

Stock Options

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

	2009	2008
Number of shares under stock options:		

Options outstanding at beginning of year	748,673	1,411,911
Options granted	-	-
Options exercised	(200,225)	(582,238)
Options canceled	(24,475)	(81,000)
Options outstanding and exercisable at end of year	523,973	748,673
Weighted average exercise price:		
Options exercised	$13.83	$13.91
Options canceled	$22.69	$21.70
Options outstanding and exercisable at end of year	$16.30	$15.85
Intrinsic value of options exercised (in thousands)	$1,180	$4,248
Intrinsic value of options outstanding (in thousands)	$2,774	$2,643

Information for options outstanding and exercisable as of December 31, 2009 is as follows:

Range of Exercise Prices	Number of Shares	Weighted Average Exercise Price	Weighted Average Remaining Life (in years)
$10.17-$12.41	285,323	$11.11	2.4
$15.88-$19.34	11,200	16.56	2.0
$20.11-$23.00	213,050	22.46	0.9
$26.59-$28.47	14,400	27.69	0.2
Total	523,973	$16.30	1.7

Total cash received from the exercise of stock options was $2.8 million for 2009 and $8.1 million for 2008. As of December 31, 2009 and 2008, 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, 2009 was one year. The following table summarizes restricted stock activity for the years ended December 31:

	2009	2008
Unvested shares at beginning of year	55,939	28,137
Shares granted	44,400	43,400
Shares cancelled	(10,000)	(1,230)
Shares vested	(18,435)	(14,368)
Unvested shares at end of year	71,904	55,939
Weighted average fair value at grant date	$18.18	$20.05
Unrecognized compensation expense at end of year (in thousands)	$668	$691
Intrinsic value, unvested shares at end of year (in thousands)	$1,552	$1,084
Intrinsic value, shares vested during the year (in thousands)	$345	$293

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:

	2009	2008
Risk-free interest rate	1.3%	2.2%
Expected life, in years	3	3
Expected volatility	25.8%	20.2%
Dividend yield	3.6%	2.8%
Weighted average grant date fair value (per share)	$17.22	$16.96

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

The following summarizes performance share activity:

	2009	2008
Opening balance of unvested performance shares	252,923	207,841
Performance shares granted	163,900	170,100
Performance shares canceled	(43,758)	(5,239)
Performance shares vested	(72,464)	(119,779)
Ending balance of unvested performance shares	300,601	252,923
Intrinsic value of unvested performance shares (in thousands)	$6,490	$4,902
Unrecognized compensation expense (in thousands)	$2,453	$2,227

The weighted average remaining vesting period for the Company's performance shares outstanding as of December 31, 2009 was 1.5 years. Unrecognized compensation expense as of December 31, 2009 will be recognized during 2010 and 2011. The following summarizes the impact of the market condition on the vested performance shares:

	2009	2008
Performance shares vested	72,464	119,779
Impact of market condition on shares vested	(72,464)	21,560
Shares of common stock earned	-	141,339
Intrinsic value of common stock earned (in thousands)	$ -	$2,739

In 2009 and 2008, the number of performance shares vested was adjusted by (100) percent and 18 percent based on the performance condition achieved. 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, 2009 and 2008, the Company had recognized compensation expense and a liability of $0.3 million and $0.5 million related to the dividend component of performance share grants.

NOTE 22. 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 these proceedings, the Company intends to vigorously protect and defend its interests and pursue its rights. However, no assurance can be given as to the ultimate outcome of any particular matter because litigation and other contested proceedings are inherently subject to numerous uncertainties. For matters that affect Avista Corp.'s operations, the Company intends to seek, to the extent appropriate, recovery of incurred costs through the ratemaking process.

Federal Energy Regulatory Commission Inquiry

In April 2004, the Federal Energy Regulatory Commission (FERC) approved the contested Agreement in Resolution of Section 206 Proceeding (Agreement in Resolution) between Avista Corp., Avista Energy and the FERC's Trial Staff which stated that there was: (1) no evidence that any executives or employees of Avista Corp. or Avista Energy knowingly engaged in or facilitated any improper trading strategy during 2000 and 2001; (2) no evidence that Avista Corp. or Avista Energy engaged in any efforts to manipulate the western energy markets during 2000 and 2001; and (3) no finding that Avista Corp. or Avista Energy withheld relevant information from the FERC's inquiry into the western energy markets for 2000 and 2001 (Trading Investigation). The Attorney General of the State of California (California AG), the California Electricity Oversight Board, 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. The Company has not accrued a liability related to this matter.

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.

The CalISO continues to work on its compliance filing for the Refund Period, which will show "who owes what to whom." In May 2009, the CalISO filed its 43rd status report on the California recalculation process confirming that the preparatory and the FERC refund recalculations are complete (as are calculations related to fuel cost allowance offsets, emission offsets, cost-recovery offsets, and the majority of the interest calculations). Once the FERC rules on several open issues, the CalISO states that it intends to: (1) perform the necessary adjustment to remove refunds associated with non-jurisdictional entities and allocate that shortfall to net refund recipients; and (2) work with the parties to the various global settlements to make appropriate adjustments to the CalISO's data in order to properly reflect those adjustments. After completing these calculations, the CalISO states that it intends to make a compliance filing with the FERC that presents the final financial position of each party that participated in its markets during the Refund Period.

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, 2009, Avista Energy's accounts receivable outstanding related to defaulting parties in California were fully offset by reserves for uncollected amounts and funds collected from 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 Federal Power Act (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.

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. As such, the Company has not accrued a liability related to this matter.

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 for rehearing 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 non-jurisdictional entities 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. The Company has not accrued a liability related to this matter.

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 are 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 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, Avista Energy does not have market power. Cross answering testimony and rebuttal testimony were filed in November 2009. A hearing is expected to commence in April 2010.

Based on information currently known to the Company's management and the fact that neither Avista Corp. nor Avista Energy ever reached a 20 percent generation market share during 2000 or 2001, the Company does not expect that this matter will have a material adverse effect on its financial condition, results of operations or cash flows. The Company has not accrued any liability related to this matter.

Colstrip Generating Project Complaints
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. The trial is set to begin in May 2011. Because the resolution of this complaint 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. The Company has not accrued a liability related to this matter.

Harbor Oil Inc. Site
Avista Corp. used Harbor Oil Inc. (Harbor Oil) for the recycling of waste oil and non-PCB transformer oil in the late 1980s and early 1990s. In June 2005, the Environmental Protection Agency (EPA) Region 10 provided notification to Avista Corp. and several other parties, as customers of Harbor Oil, that the EPA had determined that hazardous substances were released at the Harbor Oil site in Portland, Oregon and that Avista Corp. and several other parties may be liable for investigation and cleanup of the site under the Comprehensive Environmental Response, Compensation, and Liability Act, commonly referred to as the federal "Superfund" law, which provides for joint and several liability. The initial indication from the EPA is that the site may be contaminated with PCBs, petroleum hydrocarbons, chlorinated solvents and heavy metals. Six potentially responsible parties, including Avista Corp., signed an Administrative Order on Consent with the EPA on May 31, 2007 to conduct a remedial investigation and feasibility study (RI/FS). The total cost of the RI/FS is estimated to be $1.5 million and it is expected that it will be completed by early 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. Other than its share of the RI/FS, the Company has not accrued a liability related to this matter.

Lake Coeur d'Alene

In July 1998, the United States District Court for the District of Idaho issued its finding that the Coeur d'Alene Tribe (the Tribe) owns, among other things, portions of the bed and banks of Lake Coeur d'Alene (Lake) lying within the current boundaries of the Tribe's reservation lands. The United States District Court decision was affirmed by the United States Court of Appeals for the Ninth Circuit and the United States Supreme Court in June 2001. This ownership decision resulted in, among other things, Avista Corp. being liable to the Tribe for water storage on the Tribe's land and for the use of the Tribe's reservation lands under Section 10(e) of the Federal Power Act (Section 10(e) payments). The Company's Post Falls Hydroelectric Generating Station (Post Falls) controls the water level in the Lake for portions of the year (including portions of the lakebed owned by the Tribe).

In December 2008, Avista Corp., the Tribe and the United States Department of Interior (DOI) finalized an agreement regarding a range of issues related to Post Falls and the Lake. The agreement establishes the amount of past and future compensation Avista Corp. will pay for Section 10(e) payments and issues related to licensing of the Company's hydroelectric generating facilities located on the Spokane River (see Spokane River Licensing below).

Avista Corp. agreed to compensate the Tribe a total of $39 million ($25 million paid in 2008, $10 million paid in 2009 and $4 million to be paid in 2010) for trespass and Section 10(e) payments for past storage of water for the period from 1907 through 2007. Avista Corp. agreed to compensate the Tribe for future storage of water through Section 10(e) payments of $0.4 million per year beginning in 2008 and continuing through the first 20 years of the new license and $0.7 million per year through the remaining term of the license.

In addition to Section 10(e) payments, Avista Corp. agreed to make annual payments over the life of the new FERC license to fund a variety of protection, mitigation and enhancement measures on the Coeur d'Alene Reservation required under Section 4(e) of the Federal Power Act. These payments involve creation of a Coeur d'Alene Reservation Trust Restoration Fund (the Trust Fund). Annual payments from the Company to the Trust Fund for protection, mitigation and enhancement measurements commenced with the issuance of the new FERC license in June 2009 and total $100 million over the 50-year license term.

The WUTC and IPUC approved deferral and future recovery of amounts paid to the Tribe and the Trust Fund through general rate cases in 2009.

On January 27, 2009, the Public Counsel Section of the Washington Attorney General's Office (Public Counsel) filed a Petition for Judicial Review (in Thurston County Superior Court) of the WUTC's December 2008 order approving the Company's general rate case settlement. Public Counsel raised a number of issues that were previously argued before the WUTC. These include whether the recovery of settlement costs associated with resolving the dispute with the Tribe would constitute illegal "retroactive ratemaking" (the Washington portion of these costs was $25.2 million). Public Counsel also questioned whether the WUTC's decision to entertain supplemental testimony to update the Company's filing for power supply costs during the course of the proceedings was appropriate. Finally, Public Counsel argued that the settlement improperly included advertising costs, dues and donations, and certain other expenses. The appeal itself did not prevent the new rates from going into effect.

On December 18, 2009, the Thurston County Superior Court affirmed the decision of the WUTC and rejected the arguments of Public Counsel, with the exception of disallowing $0.1 million of miscellaneous expenses, including charitable donations. Public Counsel has until March 4, 2010 to further appeal the WUTC's decision.

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, which have a total present capability of 144.1 MW) 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 single 50-year license for the Spokane River Project on June 18, 2009.

The license incorporated the 4(e) conditions that were included in the December 2008 Settlement Agreement with the DOI and the 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. Various issues that were appealed under the Washington 401 Water Quality Certification were subsequently resolved through settlement.

As part of the Settlement Agreement with the Washington Department of Ecology (DOE), the Company is currently engaged with the DOE and the EPA Total Maximum Daily Load (TMDL) process for the Spokane River and Lake Spokane, the reservoir created by Long Lake Dam. On February 12, 2010, the DOE submitted the TMDL for the EPA's review and approval. Once the TMDL process is completed, and the Company's level of responsibility related to low dissolved oxygen in Lake Spokane is established, the Company will identify potential mitigation measures. It is not possible to provide cost estimates at this time because the mitigation measures have not been fully indentified or approved by the DOE. It is also possible the TMDL will be appealed by one or more parties if it is approved by the EPA.

The Company has begun implementing the environmental and operational conditions required in the license for the Spokane River Project. The estimated cost to implement the license conditions for the five hydroelectric plants 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 the licensing of the Spokane River Project.

Clark Fork Settlement Agreement
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") with 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 provides 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 addendum to the GSCP. The GSCP addendum abandons the existing concept to reopen the two diversion tunnels and requires the Company to evaluate a variety of smaller capacity options to abate TDG over the next several years. The addendum was filed with the FERC in October 2009 and is pending approval.

In 1999, the USFWS listed bull trout as threatened under the Endangered Species Act. The Clark Fork Settlement Agreement describes programs intended to 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 initiated a contractor selection process for the design of a permanent upstream passage facility at Cabinet Gorge. On January 13, 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. The USFWS is accepting public comment on the proposed revisions until March 15, 2010. The Company is reviewing the proposed revisions.

Air Quality
The Company must be in compliance with requirements under the Clean Air Act and Clean Air Act Amendments for its thermal generating plants. The Company continues to monitor legislative developments at both the state and national level for the potential of further restrictions on sulfur dioxide, nitrogen oxide and carbon dioxide, as well as other greenhouse gas and mercury emissions.

In 2006, the Montana Department of Environmental Quality (Montana DEQ) adopted final rules for the control of mercury emissions from coal-fired plants. The new rules set strict mercury emission limits by 2010, and put in place a recurring ten-year review process to ensure facilities are keeping pace with advancing technology in mercury emission control. The rules also provide for temporary alternate emission limits provided certain provisions are met, and they allocate mercury emission credits in a manner that rewards the cleanest facilities.

Compliance with new and proposed requirements and possible additional legislation or regulations results in increases to capital expenditures and operating expenses for expanded emission controls at the Company's thermal generating facilities. The Company, along with the other owners of Colstrip, completed the first phase of testing on two mercury control technologies. The joint owners of Colstrip believe, based upon current results, that the plant will be able to comply with the Montana law without utilizing the temporary alternate emission limit provision. Current estimates indicate that the Company's share of installation capital costs will be $1.4 million and annual operating costs will increase by $1.5 million (began in late-2009). The Company will continue to seek recovery, through the ratemaking process, of the costs to comply with various air quality requirements.

Aluminum Recycling Site
In October 2009, the Company (through its subsidiary Pentzer Corporation) received notice from the DOE proposing to find Pentzer

liable for a release of hazardous substances under the Model Toxics Control Act (MTCA), under Washington state law. The subject property 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 that property maintained piles of aluminum "black dross," which can be designated as a state-only dangerous waste in Washington State. Operators placed a portion of the aluminum dross pile on the site owned by Pentzer Corporation. The Company 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, the Company received notice from the DOE that it had been designated as a potentially liable party for any hazardous substances located on this site. 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 not accrued a liability related to this matter.

Collective Bargaining Agreements

As of December 31, 2009, the Company's collective bargaining agreement with the International Brotherhood of Electrical Workers represented approximately 45 percent of all of Avista Corp.'s employees. The agreement with the local union in Washington and Idaho representing the majority (approximately 90 percent) of the bargaining unit employees expires on March 26, 2010. Two local agreements in Oregon, which cover approximately 50 employees, expire in April 2010. Negotiations are currently ongoing for these labor agreements.

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 in-depth 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 have and have not agreed to a settlement and 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.

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, been listed as "threatened" or been petitioned for listing. Thus far, measures adopted and implemented have had minimal impact on the Company.

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 potentially adversely affect the energy production of the Company's Cabinet Gorge and Noxon Rapids hydroelectric facilities. The state of Idaho is conducting an adjudication in northern Idaho, which will ultimately include both 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 participating in these extensive adjudication processes, which are unlikely to be concluded in the foreseeable future.

NOTE 23. INFORMATION SERVICES CONTRACTS

The Company has information services contracts that expire at various times through 2012. Total payments under these contracts were $15.5 million in 2009 and $15.4 million in 2008. The majority of the costs are included in operation expenses in the Statements of Income. Minimum contractual obligations under the Company's information services contracts are $13.2 million in 2010, $12.9 million in 2011, and $12.2 million in 2012. 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.

NOTE 24. 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 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. The Company must make a filing (no sooner than January 1, 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 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 and 2009 (dollars in thousands):

	Washington	Idaho	Total
Deferred power costs as of December 31, 2007	$58,524	$21,163	$79,687
Activity from January 1 – December 31, 2008:			
Power costs deferred	7,049	10,029	17,078
Interest and other net additions	2,231	1,153	3,384
Recovery of deferred power costs through retail rates	(30,852)	(11,690)	(42,542)
Deferred power costs as of December 31, 2008	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

In February 2010, the WUTC approved the Company's request to eliminate the existing ERM surcharge. The surcharge was eliminated because the previous balance of deferred power costs has been substantially recovered. This will result in an overall rate reduction of 7 percent for the Company's Washington customers with no impact on income from operations or net income.

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 for the prior year, 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 $40.0 million as of December 31, 2009 and $18.6 million as of December 31, 2008.

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	January 2010	8.25%	10.2%	46.5%
Idaho electric and natural gas	August 2009	8.55%	10.5%	50.0%
Oregon natural gas	November 2009	8.19%	10.1%	50.0%

Washington General Rate Cases

As approved by the WUTC, on January 1, 2008, electric rates for the Company's Washington customers increased by an average of 9.4 percent, which was designed to increase annual revenues by $30.2 million. As part of this general rate increase, the base level of power supply costs used in the ERM calculations was updated. Also, on January 1, 2008, natural gas rates increased by an average of 1.7 percent, which was designed to increase annual revenues by $3.3 million.

In September 2008, Avista Corp. entered into a settlement stipulation in its general rate case that was filed with the WUTC in March 2008. This settlement stipulation was approved by the WUTC in December 2008. The new electric and natural gas rates became effective on January 1, 2009. As agreed to in the settlement, base electric rates for the Company's Washington customers increased by an average of 9.1 percent, which was designed to increase annual revenues by $32.5 million. Base natural gas rates for the Company's Washington customers increased by an average of 2.4 percent, which was designed to increase annual revenues by $4.8 million.

On January 27, 2009, Public Counsel filed a Petition for Judicial Review (in Thurston County Superior Court) of the WUTC's December 2008 order approving Avista Corp.'s multiparty settlement. Public Counsel raised a number of issues that were previously argued before the WUTC. These included whether the recovery of settlement costs associated with resolving the dispute with the Coeur d'Alene Tribe would constitute illegal "retroactive ratemaking" (the Washington portion of these costs was $25.2 million). Public Counsel also questioned whether the WUTC's decision to entertain supplemental testimony by the Company to update its filing for power supply costs during the course of the proceedings was appropriate. Finally, Public Counsel argued that the settlement improperly included advertising costs, dues and donations, and certain other expenses. The appeal itself did not prevent the new rates from going into effect.

On December 18, 2009, the Thurston County Superior Court affirmed the decision of the WUTC and rejected the arguments of Public Counsel, with the exception of disallowing $0.1 million of miscellaneous expenses, including charitable donations. Public Counsel has until March 4, 2010 to further appeal the WUTC's decision.

On December 22, 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 is 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 is designed to increase annual revenues by $0.6 million. The new electric and natural gas rates became effective on January 1, 2010.

Following the execution of a partial settlement stipulation in September 2009, Avista Corp. revised downward its electric rate increase request from $69.8 million to $37.5 million, primarily due to the decline in the wholesale prices of electricity and natural gas. Avista Corp. also reduced its natural gas request from $4.9 million to $2.8 million. Under the partial settlement stipulation, the Company reached agreement with the other settling parties on issues in the areas of cost of capital, power supply, rate spread and rate design, and funding under the Low-Income Ratepayer Assistance Program. The WUTC approved this partial settlement stipulation in its order on December 22, 2009.

The WUTC did not allow Avista Corp. to include the costs associated with the power purchase agreement for the Lancaster Plant in rates, indicating the Company did not demonstrate compliance with certain requirements necessary for immediate inclusion in rates. However, the WUTC directed Avista Corp. to file to defer costs associated with the Lancaster Plant, with a carrying charge, for potential recovery in a future rate proceeding if the Company demonstrates that it has satisfied these requirements. The Company's proposed deferred accounting treatment for the net costs associated with the Lancaster Plant was approved by the WUTC in February 2010. The net costs associated with the power purchase agreement for the Lancaster Plant account for approximately half of the difference between the Company's revised electric rate increase request of $37.5 million and the $12.1 million increase approved by the WUTC.

The WUTC also did not allow for certain pro forma future capital additions to rate base, as well as certain increases in labor costs, tree trimming costs and information systems costs. These costs account for the majority of the remaining difference between the Company's revised electric rate increase request and the amount approved by the WUTC.

The partial settlement stipulation (as approved by the WUTC on December 22, 2009) is based on an overall rate of return of 8.25 percent with a common equity ratio of 46.5 percent and a 10.2 percent return on equity. The Company's original request was based on a proposed overall rate of return of 8.68 percent with a common equity ratio of 47.5 percent and an 11.0 percent return on equity.

Idaho General Rate Cases

In August 2008, the Company entered into an all-party settlement stipulation in its general rate case that was filed with the IPUC in April 2008. This settlement stipulation was approved by the IPUC in September 2008. The new electric and natural gas rates became effective on October 1, 2008. As agreed to in the settlement, base electric rates for the Company's Idaho customers increased by an average of 12.0 percent, which was designed to increase annual revenues by $23.2 million. Base natural gas rates for the Company's Idaho customers increased by an average of 4.7 percent, which was designed to increase annual revenues by $3.9 million.

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 received a PGA decrease of 2.4 percent and interruptible services 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.

Oregon General Rate Cases

As approved by the OPUC in March 2008, natural gas rates for the Company's Oregon customers increased 0.4 percent effective April 1, 2008 (designed to increase annual revenues by $0.5 million) and increased an additional 1.1 percent effective November 1, 2008 (designed to increase annual revenues by an additional $1.4 million).

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 is designed to increase annual revenues by $8.8 million.

NOTE 25. SUPPLEMENTAL CASH FLOW INFORMATION

(dollars in thousands)

	2009	2008
Cash paid for interest	$58,197	$76,434
Cash paid for income taxes	$22,695	$8,116
Other Cash Flows from Operating Activities:		
Power and natural gas deferrals	$(216)	$(2,736)
Change in special deposits	$(30)	$4,068

Change in other current assets	$(1,923)	$(2,149)
Non-cash stock compensation	$2,596	$2,541
Gain on sale of assets	$(89)	$(1,123)

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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	04/16/2010	End of 2009/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		(12,781,264)		
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value		6,688,946		
4	Total (lines 2 and 3)		6,688,946		
5	Balance of Account 219 at End of Preceding Quarter/Year		(6,092,318)		
6	Balance of Account 219 at Beginning of Current Year		(6,092,318)		
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value		3,742,032		
9	Total (lines 7 and 8)		3,742,032		
10	Balance of Account 219 at End of Current Quarter/Year		(2,350,286)		

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2010	Year/Period of Report End of 2009/Q4

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1	(6,826,222)		(19,607,486)		
2	10,656,750		10,656,750		
3	(3,830,528)		2,858,418		
4	6,826,222		13,515,168	73,619,720	87,134,888
5			(6,092,318)		
6			(6,092,318)		
7					
8			3,742,032		
9			3,742,032	87,071,250	90,813,282
10			(2,350,286)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2010	End of 2009/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)	3,520,534,663	2,678,537,207
4	Property Under Capital Leases	1,903,329	
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	3,522,437,992	2,678,537,207
9	Leased to Others		
10	Held for Future Use	1,631,351	1,457,302
11	Construction Work in Progress	57,217,478	42,232,962
12	Acquisition Adjustments	22,122,748	
13	Total Utility Plant (8 thru 12)	3,603,409,569	2,722,227,471
14	Accum Prov for Depr, Amort, & Depl	1,219,877,922	917,624,851
15	Net Utility Plant (13 less 14)	2,383,531,647	1,804,602,620
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	1,174,736,479	910,060,974
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	24,651,168	7,563,877
22	Total In Service (18 thru 21)	1,199,387,647	917,624,851
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	20,490,275	
33	Total Accum Prov (equals 14) (22,26,30,31,32)	1,219,877,922	917,624,851

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2010	Year/Period of Report End of 2009/Q4

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
688,622,700				153,374,756	3
1,619,845				283,484	4
					5
					6
					7
690,242,545				153,658,240	8
					9
174,049					10
4,524,629				10,459,887	11
22,122,748					12
717,063,971				164,118,127	13
258,391,573				43,861,498	14
458,672,398				120,256,629	15
					16
					17
236,976,472				27,699,033	18
					19
					20
924,826				16,162,465	21
237,901,298				43,861,498	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
20,490,275					32
258,391,573				43,861,498	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [ ] An Original (2) [X] A Resubmission	05/12/2010	End of 2009/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	15,629,982	28,848,313
4	(303) Miscellaneous Intangible Plant	3,474,009	494,838
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	19,103,991	29,343,151
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	2,231,688	
9	(311) Structures and Improvements	124,816,325	129,197
10	(312) Boiler Plant Equipment	162,892,531	3,935,651
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	47,684,556	1,148,746
13	(315) Accessory Electric Equipment	26,371,619	564,179
14	(316) Misc. Power Plant Equipment	15,474,936	191,965
15	(317) Asset Retirement Costs for Steam Production	585,276	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	380,056,931	5,969,738
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	55,860,497	658,506
28	(331) Structures and Improvements	39,908,000	765,660
29	(332) Reservoirs, Dams, and Waterways	117,490,242	306,076
30	(333) Water Wheels, Turbines, and Generators	123,875,342	17,876,895
31	(334) Accessory Electric Equipment	31,487,985	2,708,041
32	(335) Misc. Power PLant Equipment	6,288,495	1,117,996
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)	376,910,123	23,433,174
36	D. Other Production Plant		
37	(340) Land and Land Rights	903,118	
38	(341) Structures and Improvements	15,617,416	125,824
39	(342) Fuel Holders, Products, and Accessories	21,064,681	
40	(343) Prime Movers	21,876,780	
41	(344) Generators	197,970,615	810,715
42	(345) Accessory Electric Equipment	15,829,566	222,469
43	(346) Misc. Power Plant Equipment	1,344,105	45,317
44	(347) Asset Retirement Costs for Other Production	351,682	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	274,957,963	1,204,325
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,031,925,017	30,607,237

Name of Respondent Avista Corporation	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/12/2010	Year/Period of Report End of 2009/Q4

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

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

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

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

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
					2
			44,478,295		3
			3,968,847		4
			48,447,142		5
					6
					7
942			2,230,746		8
41,818			124,903,704		9
533,406			166,294,776		10
					11
594,261			48,239,041		12
5,784			26,930,014		13
15,969			15,650,932		14
			585,276		15
1,192,180			384,834,489		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			56,519,003		27
17,587			40,656,073		28
			117,796,318		29
581,864			141,170,373		30
99,689			34,096,337		31
87,863			7,318,628		32
			1,999,562		33
					34
787,003			399,556,294		35
					36
			903,118		37
			15,743,240		38
			21,064,681		39
			21,876,780		40
			198,781,330		41
57,927			15,994,108		42
			1,389,422		43
			351,682		44
57,927			276,104,361		45
2,037,110			1,060,495,144		46

Name of Respondent Avista Corporation	This Report Is: (1) ☐ An Original (2) ☒ A Resubmission	Date of Report (Mo, Da, Yr) 05/12/2010	Year/Period of Report End of 2009/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	15,595,500	496,556
49	(352) Structures and Improvements	15,750,369	290,386
50	(353) Station Equipment	172,929,491	6,687,685
51	(354) Towers and Fixtures	17,098,314	14,715
52	(355) Poles and Fixtures	128,285,893	3,424,336
53	(356) Overhead Conductors and Devices	103,930,504	2,428,936
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)	460,397,876	13,342,614
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	4,068,189	267,938
61	(361) Structures and Improvements	12,262,082	1,767,765
62	(362) Station Equipment	86,204,015	7,460,205
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	196,776,445	17,752,502
65	(365) Overhead Conductors and Devices	129,268,022	9,985,456
66	(366) Underground Conduit	71,349,434	3,517,231
67	(367) Underground Conductors and Devices	115,565,756	8,098,244
68	(368) Line Transformers	159,545,964	12,119,967
69	(369) Services	110,109,363	5,149,552
70	(370) Meters	44,273,042	1,673,893
71	(371) Installations on Customer Premises		
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	27,761,029	1,687,359
74	(374) Asset Retirement Costs for Distribution Plant	129,707	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	957,313,048	69,480,112
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	2,174,744	1,258,965
88	(391) Office Furniture and Equipment	718,653	445,016
89	(392) Transportation Equipment	9,481,838	2,232,469
90	(393) Stores Equipment	327,794	55,665
91	(394) Tools, Shop and Garage Equipment	3,353,108	101,947
92	(395) Laboratory Equipment	1,389,374	78,186
93	(396) Power Operated Equipment	21,732,539	4,321,967
94	(397) Communication Equipment	36,464,026	2,663,059
95	(398) Miscellaneous Equipment	2,781	6,068
96	SUBTOTAL (Enter Total of lines 86 thru 95)	75,769,538	11,163,342
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)	75,769,538	11,163,342
100	TOTAL (Accounts 101 and 106)	2,544,509,470	153,936,456
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)	2,544,509,470	153,936,456

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
			16,092,056		48
			16,040,755		49
1,938,336			177,678,840		50
			17,113,029		51
98,793			131,611,436		52
17,544			106,341,896		53
			2,605,488		54
			2,330,071		55
			1,872,246		56
					57
2,054,673			471,685,817		58
					59
			4,336,127		60
			14,029,847		61
465,752			93,198,468		62
					63
226,413			214,302,534		64
244,866			139,008,612		65
50,249			74,816,416		66
508,367			123,155,633		67
2,091,011			169,574,920		68
76,668			115,182,247		69
939,786			45,007,149		70
					71
					72
105,899			29,342,489		73
			129,707		74
4,709,011			1,022,084,149		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			124,681		86
1,290			3,432,419		87
			1,163,669		88
308,102			11,406,205		89
			383,459		90
			3,455,055		91
			1,467,560		92
859,923			25,194,583		93
27,376			39,099,709		94
			8,849		95
1,196,691			85,736,189		96
					97
					98
1,196,691			85,736,189		99
9,997,485			2,688,448,441		100
					101
					102
					103
9,997,485			2,688,448,441		104

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2010	End of 2009/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	1,457,302
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22				
23				
24				
25				
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27				
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46				
47	Total			1,457,302

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2010	End of 2009/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	Transportation Equipment	2,792,027
3	Minor Projects (37) under $1,000,000	3,824,985
4		
5	State of Idaho	
6	Transportation Equipment	1,132,768
7	Minor Projects (17) under $1,000,000	2,153,017
8		
9	Common WA & ID	
10	Nez Perce /Grangeville Capacitor Banks	1,450,146
11	CS2 Capital Improvements	4,522,884
12	Noxon Rapids Unit 2 Runner Upgrade	1,846,097
13	Noxon Rapids Unit 3 Runner Upgrade	4,874,351
14	Clark Fork Implement PME Agreement	4,388,527
15	Transportation Equipment	1,175,440
16	Productivity Initiative	2,616,353
17	Minor Projects (68) Under $1,000,000	11,456,367
18		
19	Common-WA/ID/OR	
20	Minor Projects (0) Under $1,000,000	
21		
22		
23		
24		
25		
26		
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41		
42		
43	TOTAL	42,232,962

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2010	End of 2009/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	856,572,707	856,572,707		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	65,856,676	65,856,676		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	993,144	993,144		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	463,364	463,364		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	67,313,184	67,313,184		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	9,996,542	9,996,542		
13	Cost of Removal	5,023,358	5,023,358		
14	Salvage (Credit)	1,015,075	1,015,075		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	14,004,825	14,004,825		
16	Other Debit or Cr. Items (Describe, details in footnote):	179,908	179,908		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	910,060,974	910,060,974		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	246,871,127	246,871,127		
21	Nuclear Production				
22	Hydraulic Production-Conventional	98,008,475	98,008,475		
23	Hydraulic Production-Pumped Storage				
24	Other Production	54,250,986	54,250,986		
25	Transmission	158,504,412	158,504,412		
26	Distribution	306,761,947	306,761,947		
27	Regional Transmission and Market Operation	45,664,027	45,664,027		
28	General				

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2010	Year/Period of Report End of 2009/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)
29	TOTAL (Enter Total of lines 20 thru 28)	910,060,974	910,060,974		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2010	End of 2009/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		184,251,609
3	Avista Capital - Equity in Earnings			-99,660,867
4	OCI Investment in Subs			
5	Avista Capital - Other Changes in Net Investment			-7,748,538
6	Avista Capital - Other Changes in Net Investment			645,758
7	Avista Capital - Other Changes in Net Investment			
8				
9				
10				
11				
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39				
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41				
42	Total Cost of Account 123.1 $ 0		TOTAL	77,487,962

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2010	Year/Period of Report End of 2009/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

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

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
	3,683,735	187,935,344		2
827,452	-8,168,341	-107,001,757		3
				4
	7,748,538			5
	-645,758			6
	309,652	309,652		7
				8
				9
				10
				11
				12
				13
				14
				15
				16
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				41
827,452	2,927,826	81,243,239		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	04/16/2010	End of 2009/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)	3,673,039	4,294,013	(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)	10,461,384	12,289,004	(1)
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	2,106,403	2,161,593	(1)
8	Transmission Plant (Estimated)	27,135	55,859	(1)
9	Distribution Plant (Estimated)	227,359	280,550	(1)
10	Regional Transmission and Market Operation Plant (Estimated)			(1),(2)
11	Assigned to - Other (provide details in footnote)	4,633,554	3,599,503	(1),(2)
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	17,455,835	18,386,509	
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)	21,128,874	22,693,354	

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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					
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21	**Generation Studies**				
22	Horizon Wind Interconnect	74,365	186200	27,345	186210
23	Avista - Reardan Project	47,480	186200		
24	Avista - Garfield Project	6,270	186200		
25	BP Wind Interconnect	5,039	186200	5,039	186210
26	PPM Energy Wind Interconnect	11,874	186200		
27	Avista - Grangeville Wind	5,060	186200	5,060	186210
28	Martinsdale Wind Interconnect	2,155	186200		
29	Palouse Wind Interconnect	1,851	186200		
30	Kellogg Biomass Interconnect	3,088	186200		
31	ADAGE Biomass Interconnect	9,811	186200		
32	Hawkstone Solar Interconnect	210	186200		
33	RES Tekoa Wind Interconnect	515	186200		
34	ADAGE Deary Biomass	209	186200		
35					
36					
37					
38					
39					
40					

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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	1,891,008		926,107	472,752	1,418,256
2	Guaranteed Residual Value-Airplane	2,936,173		186,228	2,936,173	
3	Reg Asset Post Ret Liab	172,277,747		228	31,192,904	141,084,843
4	Regulatory Asset FAS109 Utility Plant	99,465,025		283	17,109,789	82,355,236
5	Regulatory Asset FAS109 DSIT Non Plant	3,306,888		283	919,062	2,387,826
6	Regulatory Asset FAS109 DFIT State Tax Cr	4,568,230	1,679,928			6,248,158
7	Regulatory Asset FAS109 WNP3	7,866,287		283	737,482	7,128,805
8	Regulatory Asset- Spokane River Relicense		802,034			802,034
9	Regulatory Asset- Spokane River PM&E		443,350			443,350
10	Regulatory Asset- Lake CDA Fund		10,062,735			10,062,735
11	Reg Assets- Decouplings Surcharge	479,593		407	100,664	378,929
12	Regulatory Asset AMR	(252,769)	252,769			
13	Regulatory Asset RTO Deposits- ID	212,417		560	70,806	141,611
14	Regulatory Asset BPA Residential Exchange	249,229			249,229	
15	Regulatory Asset ERM Approved for Recovery	29,728,184		407,419	23,494,189	6,233,995
16	ID Wind Gen AFUDC	35,194	85,282			120,476
17	Regulatory Asset Wartsila Units	2,325,253		407	560,072	1,765,181
18	MTM St Regulatory Asset	60,228,970		244	51,897,220	8,331,750
19	Regulatory Asset FAS143 Asset Retirement Obligation	3,335,279		230,124	205,034	3,130,245
20	Reg Asset AN- CDA Lake Settlement	41,733,385		407,419	4,531,187	37,202,198
21	Reg Asset WA-CDA Lake Settlement		1,553,548			1,553,548
22	Regulatory Asset Workers Comp	3,097,168		242	175,994	2,921,174
23	CS2 Lev Ret	1,442,335	62,324			1,504,659
24	Regulatory Asset ID PCA Deferral 1		10,457,471			10,457,471
25	Regulatory Asset ID PCA Deferral 2	17,080,994		557,419	17,080,994	
26	Regulatory Asset ID PCA Deferral 3	3,573,957	7,475,831			11,049,788
27	Reg Asset-Future Payments- Lake CDA		4,000,000			4,000,000
28	DSM Asset		11,894,248			11,894,248
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44	TOTAL	455,580,547	48,769,520		151,733,551	352,616,516

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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) 04/16/2010	Year/Period of Report End of 2009/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

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

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1						
2	Colstrip Common Fac.	1,110,999				1,110,999
3	Regulatory Asset-Decoupling def	589,937			335,323	254,614
4	WA Deferred Power Costs	7,223,823			7,194,374	29,449
5	WA ERM YTD Company Band	4,000,000			7,037,637	-3,037,637
6	WA ERM YTD Contra Account	-4,000,000	7,037,637			3,037,637
7	Regulatory Asset ROT Deposit	395,534			158,213	237,321
8	Regulatory Asset-Mt lease pymt	2,795,301			360,684	2,434,617
9	Regulatory Asset-Mt lease pymt	5,413,008			676,632	4,736,376
10	Colstrip Common Fac.	2,355,642				2,355,642
11	Regulatory Asset- COLS	738,101			153,771	584,330
12	Guaranteed Residual Value-Plane		2,916,673			2,916,673
13	Prepaid airplane Lease LT		28,743			28,743
14						
15	Payroll Accrual					
16						
17	Plant Allocation of clearing jr	2,172,024	665,241			2,837,265
18						
19	Misc Error Suspense	12,457			27,611	-15,154
20						
21	Renewable Energy-Cert Fees		174,000			174,000
22	Misc susp acct-non w/o	28,327	19,088			47,415
23	Unamortized A/R sale	25,767	9,678			35,445
24						
25	Intangible Pension Asset					
26						
27	Nez Perce Settlement	181,597			5,212	176,385
28	Misc Deferred Debit Centralia	675,990	2,444			678,434
29						
30	Long Term Note Rec acct		277,158			277,158
31	Reg Asset ID-Lake Cdal		315,120			315,120
32	ID Panhandle Forest Use Permit	224,337	1,760			226,097
33	Metro-Sunset 115KV TE					
34						
35	UPRR Permit Conv	350,163			350,163	
36	Insurance Recvy CDA Lake					
37	Corp reorg stk iss. costs	118,086			118,086	
38	Reclass IPA acct deposit		2,000,000			2,000,000
39	Reclass Idaho Clk Fork Relic		976,731			976,731
40	Noxon Living Facility Exp		67,001			67,001
41	Dry Creek Transport	366,206			366,206	
42						
43	PG & E Canada to N Cal trans	493,607	373,436			867,043
44	Misc Work Orders <$50,000	115,729			120,130	-4,401
45	Subsidiary Billings	2,067,825			1,980,126	87,699
46	"Null" Projects directly to 186	-345,705	358,350			12,645
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	32,008,980				26,105,547

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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	1,283,765			1,054,552	229,213
3	Regulatory Assets Consv	-87,884	151,453			63,569
4	Regulatory Assets Consv	3,003,183			930,417	2,072,766
5	Regulatory Assets Consv	253,551			101,144	152,407
6	Regulatory Assets Consv	447,610			307,665	139,945
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45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	32,008,980				26,105,547

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2010	Year/Period of Report End of 2009/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		15,824,253	5,391,537
3			
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	15,824,253	5,391,537
9	Gas		
10		2,255,652	-267,754
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15	2,255,652	-267,754
17	Other	112,975,620	86,851,764
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	131,055,525	91,975,547

Notes

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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_COM	200,000,000		
5				
6				
7	Account 204 - Preferred Stock Issued	10,000,000		
8				
9				
10	Cumulative			
11				
12				
13	TOTAL_PRE	10,000,000		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2010	End of 2009/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
54,836,781	759,057,747					2
				71,904	1,307,215	3
54,836,781	759,057,747			71,904	1,307,215	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	04/16/2010	End of 2009/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	17,498,634
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40	TOTAL	17,498,634

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2010	End of 2009/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	
2	CAP STOCK EXP - COMMON PUBLIC ISSUE	13,301,168
3	TAX BENEFIT - OPTIONS EXERCISED	-5,683,807
4	STOCK COMP INCENTIVE ACCRUAL	-10,272,805
5	STOCK COMP - SUBS	-849,764
6	SHARE WITHHOLDING	1,414,247
7		
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21		
22	TOTAL	-2,090,961

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2010	End of 2009/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 C - 8.02% DUE 10/26/2010	25,000,000	868,814
2	FMBS - SERIES C - 6.37% DUE 06/18/2028	25,000,000	346,953
3	FMBS - SERIES A - 6.67% DUE 7/12/2010	5,000,000	725,545
4	FMBS - SERIES A - 7.37% DUE 5/10/2012	7,000,000	1,276,997
5	FMBS - SERIES A - 7.39% DUE 5/11/2018	7,000,000	1,282,247
6	FMBS - SERIES A - 7.45% DUE 6/11/2018	15,500,000	2,311,037
7	FMBS - SERIES A - 7.53% DUE 05/05/2023	5,500,000	1,005,723
8	FMBS - SERIES A - 7.54% DUE 5/05/2023	1,000,000	183,178
9	FMBS - SERIES A - 7.18% DUE 8/11/2023	7,000,000	54,364
10	FMBS - SERIES B - 6.9% DUE 07/01/2010	5,000,000	37,944
11	COLSTRIP 1999B PCBS DUE 2034	17,000,000	4,051,718
12	COLSTRIP 1999A PCBS DUE 2032	66,700,000	3,330,522
13	FMBS - 6.125% DUE 09-01-2013	45,000,000	1,870,964
14	KETTLE FALLS P C REV BONDS DUE 14	4,100,000	282,248
15	5.45% SERIES DUE 12-01-2019	90,000,000	1,432,081
16	FMBS - 6.25% DUE 12-01-35	150,000,000	-2,137,016
17	FMBS - 5.70% DUE 07-01-2037	150,000,000	8,663,162
18	5.95% SERIES DUE 06-01-2018	250,000,000	19,476,419
19	7.25% FMB'S DUE 2013	30,000,000	420,306
20	5.125% SERIES DUE 04-01-2022	250,000,000	-7,701,222
21	ADVANCE ASSOCIATED-AVISTA CAPITAL II (ToPRS)	51,547,000	-1,203,914
22	INTEREST RATE SWAPS		
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	1,207,347,000	36,578,070

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.
10-26-1999	10-26-2010			25,000,000	2,005,000	1
06-19-1998	06-19-2028			25,000,000	1,592,500	2
07-12-1993	07-12-2010			5,000,000	333,500	3
05-10-1993	05-10-2012			7,000,000	515,900	4
05-11-1993	05-11-2018			7,000,000	517,300	5
06-09-1993	06-11-2018			15,500,000	1,154,750	6
05-06-1993	05-05-2023			5,500,000	414,150	7
05-07-1993	05-05-2023			1,000,000	75,400	8
08-12-1993	08-11-2023			7,000,000	502,600	9
06-09-1995	07-01-2010			5,000,000	345,000	10
03-01-1994	03-01-2034				61,675	11
03-01-1994	06-01-2032					12
09-08-2003	09-01-2013			45,000,000	2,756,250	13
12-01-1993	12-01-2023			4,100,000	246,000	14
11-18-2004	12-01-2019			90,000,000	4,905,000	15
11-17-2005	12-01-2035			150,000,000	9,375,000	16
12-15-2006	07-01-2037			150,000,000	8,550,000	17
04-02-2008	06-01-2018			250,000,000	14,875,000	18
12-16-2008	12-16-2013			30,000,000	2,175,000	19
09-22-2009	04-01-2022			250,000,000	12,812,500	20
06-03-1997	06-01-2037			51,547,000	952,275	21
				-1,843,577		22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				1,121,803,423	64,164,800	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	04/16/2010	End of 2009/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)	87,071,250
2		
3		
4	Taxable Income Not Reported on Books	
5		1,911,534
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		102,619,036
11	Federal Income Tax	28,968,355
12	Deferred Income Tax	13,224,479
13	Investment Tax Credit	2,017,491
14	Income Recorded on Books Not Included in Return	
15		60,745,269
16	Equity in Sub Earnings (Income)/Loss	827,452
17	Corporated Overhead Unallocated Subs	769,980
18		
19	Deductions on Return Not Charged Against Book Income	
20		229,909,385
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	
28	Show Computation of Tax:	
29	State Tax @2% Less Idaho ITC	2,111,405
30	Federal Tax Net Income, less State Tax	68,701,962
31		
32	Federal Tax @ 35%	24,045,687
33	Prior years tax return, revenue agent reports & misc true ups	6,601,983
34	Kettle Falls & Cabinet Gorge tax credit	1,679,315
35	Total Federal Tax Expense	28,968,355
36		
37		
38		
39		
40		
41		
42		
43		
44		

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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) 04/16/2010	Year/Period of Report End of 2009/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	-18,141,202		992,601	6,639,496	
4	Income Tax 2007	-2,300,314		-151,670	-1,997,498	
5	Income Tax 2008	-11,031,901		13,123,056	-8,677,741	
6	Income Tax (Current)			12,352,670	31,248,211	
7	Retained Earnings					
8	Prior Retained Earnings	-5,013,521		-2,415		
9	Prior Retained Earnings	-2,127,838				
10	Prior Retained Earnings	-1,435,621				
11	Current Retained Earnings			-1,210,371		
12	Total Federal	-14,271,665		25,103,871	27,212,468	
13						
14	STATE OF WASHINGTON:					
15	Property Tax (2008)	7,771,174		-1,318,164	6,453,010	
16	Property Tax (2009)			7,086,952		-346
17	Excise Tax (2005)	91,452				
18	Excise Tax (2006)	-464				
19	Excise Tax (2007)	400,000				
20	Excise Tax (2008)	2,485,298		-11,891	2,473,407	
21	Excise Tax (2009)			25,168,760	22,903,217	
22	Natural Gas Use Tax	33,215		47,598	65,704	
23	Municipal Occupation Tax	2,614,786		23,012,125	23,191,538	
24	Sales & Use Tax (2006)	-7,943		-295	-65	
25	Sales & Use Tax (2007)	13,643			13,643	
26	Sales & Use Tax (2008)	50,265			50,265	
27	Sales & Use Tax (2009)			868,665	784,475	
28	Motor Vehicle Tax (2009)			15,574	15,574	
29	Total Washington	13,451,426		54,869,324	55,950,768	-346
30						
31	STATE OF IDAHO:					
32	Income Tax (2006)	487,826			141,437	
33	Income Tax (2007)	-104,516				
34	Income Tax (2008)	-443,776		342,216		
35	Income Tax (2009)			469,890	760,000	
36	Property Tax (2008)	2,512,135		-157,401	2,354,513	-221
37	Property Tax (2009)			3,937,283	1,956,011	-22,381
38	Motor Vehicle Tax (2009)			9,347	9,347	
39	Sales & Use Tax (2005)	436				
40	Sales & Use Tax (2007)	-13		13		
41	TOTAL	6,105,577		104,962,934	108,845,885	1

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
-23,788,097		-100,641			1,093,242	3
-454,486		98,001			-249,670	4
10,768,896		135,923			12,987,133	5
-18,895,541		13,438,692			-1,086,022	6
						7
-5,015,936					-2,415	8
-2,127,838						9
-1,435,621						10
-1,210,371					-1,210,371	11
-16,380,262		13,571,975			11,531,897	12
						13
						14
		-1,059,373			-258,791	15
7,086,606		5,405,952			1,681,000	16
91,452						17
-464						18
400,000						19
		-16,589			4,698	20
2,265,543		17,235,991			7,932,769	21
15,109					47,598	22
2,435,373		15,480,504			7,531,621	23
-8,173					-295	24
						25
						26
84,190					868,665	27
					15,574	28
12,369,636		37,046,485			17,822,839	29
						30
						31
346,389						32
-104,516						33
-101,560		313,024			29,192	34
-290,110		380,356			89,534	35
		-57,910			-99,491	36
1,958,891		3,206,068			731,215	37
					9,347	38
436						39
					13	40
2,222,627		66,499,694			38,463,240	41

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2010	Year/Period of Report End of 2009/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 (2008)	23,236			18,888	
2	Sales & Use Tax (2009)			129,709	125,559	
3	Irrigation Credits (2009)			444		
4	KWH Tax (2008)	21,255		-5,595	15,660	
5	KWH Tax (2009)			338,888	322,703	
6	Franchise Tax (2008)	1,673,763			1,673,763	
7	Franchise Tax (2009)			4,511,633	2,808,008	
8	Total Idaho	4,170,346		9,576,427	10,185,889	-22,602
9						
10	STATE OF MONTANA:					
11	Income Tax (2006)	520,245				
12	Income Tax (2007)	-59,435			-59,435	
13	Income Tax (2008)	-347,781		167,207		
14	Income Tax (2009)			315,028	525,000	
15	Property Tax (2008)	3,336,316		-8,185	3,328,131	
16	Property Tax (2009)			6,173,166	3,088,756	
17	Colstrip Generation Tax			3,222	3,222	
18	KWH Tax (2008)	267,227			267,227	
19	KWH Tax (2009)			1,008,877	788,579	
20	Motor Vehicle Tax (2009)			4,068	4,068	
21	Consumer Council Tax	24,450		-20,548	3,899	
22	Public Commission Tax	6		5,907	5,105	
23	Total Montana	3,741,028		7,648,742	7,954,552	
24						
25	STATE OF OREGON:					
26	Income Tax (2006)	266,087				
27	Income Tax (2007)	-5				
28	Income Tax (2008)	-549,586		324,299	-334,870	
29	Income Tax (2009)			161,688	530,000	
30	Property Tax (2008)	-1,010,000		1,004,692	-5,308	
31	Property Tax (2009)			1,764,096	3,081,486	
32	Motor Vehicle Tax (2009)			486	486	
33	BETC Credit (2006 & Prior)	-498,457		77,652		
34	BETC Credit (2007)	209,659		33,694		
35	BETC Credit (2008)	-46,847		6,464		
36	BETC Credit (2009)			-91,881		
37	Glendale Regulatory Cr. 2008	-351,469		140,580		
38	Glendate Regulatory Cr. 2009			70,289		
39	Franchise Tax (2006)	755				
40	Franchise Tax (2008)	996,390			966,063	
41	TOTAL	6,105,577		104,962,934	108,845,885	1

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2010	Year/Period of Report End of 2009/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
4,348						1
4,150					129,709	2
444		444				3
		-5,595				4
16,185		338,888				5
						6
1,703,625		2,955,248			1,556,385	7
3,538,282		7,130,523			2,445,904	8
						9
						10
520,245						11
						12
-180,574		167,207				13
-209,972		315,028				14
		-8,185				15
3,084,410		6,173,166				16
		3,222				17
						18
220,298		1,008,877				19
					4,068	20
3		-20,548				21
808		5,907				22
3,435,218		7,644,674			4,068	23
						24
						25
266,087						26
-5						27
109,583		-1			324,300	28
-368,312		87,446			74,242	29
		79,000			925,692	30
-1,317,390		939,758			824,338	31
					486	32
-420,805					77,652	33
243,353					33,694	34
-40,383					6,464	35
-91,881					-91,881	36
-210,889					140,580	37
70,289					70,289	38
755						39
30,327						40
2,222,627		66,499,694			38,463,240	41

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2010	Year/Period of Report End of 2009/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)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year	Taxes Paid During Year	Adjust- ments
		Taxes Accrued (Account 236)	Prepaid Taxes (Include in Account 165)			
	(a)	(b)	(c)	(d)	(e)	(f)
1	Franchise Tax (2009)			4,284,846	3,287,865	
2	Total Oregon	-983,473		7,776,905	7,525,722	
3						
4	STATE OF CALIFORNIA:					
5	Income Tax (2005)	-1,869				
6	Income Tax (2006)	-314				
7	Income Tax (2007)	-3,200		800		2,400
8	Income Tax (2008)			2,400		-2,400
9	Income Tax (2009)				2,400	
10	Total California	-5,383		3,200	2,400	
11						
12	MISCELLANEOUS STATES:					
13	Income Tax (2007)					
14	Income Tax (2008)	-1		1		
15	Total Misc States	-1		1		
16						
17	COUNTY & MUNICIPAL					
18	WA Renewable Energy			-8,863	-8,863	
19	Misc.	3,299		-6,673	22,949	22,949
20	Total County	3,299		-15,536	14,086	22,949
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	6,105,577		104,962,934	108,845,885	1

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2010	End of 2009/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
996,981		-166			4,285,012	1
-732,290		1,106,037			6,670,868	2
						3
						4
-1,869						5
-314						6
					800	7
					2,400	8
-2,400						9
-4,583					3,200	10
						11
						12
						13
						14
						15
						16
						17
					-8,863	18
-3,374					-6,673	19
-3,374					-15,536	20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
2,222,627		66,499,694			38,463,240	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	04/16/2010	End of 2009/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			236000	5,308,088			
7							
8	TOTAL			5,308,088			
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Gas Property (100%	373,728			411400	49,308	
11							
12	TOTAL PROPERTY	373,728				49,308	
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
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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
5,308,088			6
			7
5,308,088			8
			9
324,420			10
			11
324,420			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
			32
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			45
			46
			47
			48

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2010	Year/Period of Report End of 2009/Q4

OTHER DEFFERED CREDITS (Account 253)

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

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Defer Gas Exchange(253028)				2,119,525	2,119,525
2	Pacificorp Capacitor (253080)	4,686	456	4,686		
3	Centralia Environmental (253110)	963,886			2,437	966,323
4	Rathdrum Refund (253120)	374,864	550	33,822		341,042
5	NE Tank Spil (253130)	98,607	550	11,502		87,105
6	Bills Pole Rentals (253140)	211,620			3,583	215,203
7	CR-CS2 GE LTSA (253150)	4,739,221	232	2,326,663		2,412,558
8	IR Swaps (254170)	568,713	176	568,713		
9	Regulatory Accruals(253650)	4,000,000	232	4,000,000		
10	Sale/Leaseback on Bldg (253850)	784,368	931	261,456		522,912
11	Clark Fork Relicensing (253890)	-1,223,720			1,223,720	
12	Defer Comp Retired Execs (253900)	180,448	431,232	61,274		119,174
13	Defer Comp Active Execs (253910)	8,807,721			628,908	9,436,629
14	Executive Incent Plan (253920)	140,000				140,000
15	Unbilled Revenue (253990)	5,335,468			634,860	5,970,328
16						
17						
18						
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46						
47	TOTAL	24,985,882		7,268,116	4,613,033	22,330,799

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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	252,105,800	15,828,047	936,721
3	Gas	70,244,199	7,534,446	
4	Other	12,542,042	4,128,701	
5	TOTAL (Enter Total of lines 2 thru 4)	334,892,041	27,491,194	936,721
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	334,892,041	27,491,194	936,721
10	Classification of TOTAL			
11	Federal Income Tax	323,825,718	27,491,194	936,721
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) 04/16/2010	Year/Period of Report End of 2009/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits Account Credited (g)	Debits Amount (h)	Credits Account Debited (i)	Credits Amount (j)	Balance at End of Year (k)	Line No.
							1
		190	11,713,819			255,283,307	2
-116,953		190	1,628,500			76,033,192	3
87,739						16,758,482	4
-29,214			13,342,319			348,074,981	5
							6
							7
							8
-29,214			13,342,319			348,074,981	9
							10
-29,214			13,342,319			337,008,658	11
						11,066,323	12
							13

NOTES (Continued)

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	48,019,117	-3,135,591	301,512
4		31,845		
5		402,332		
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	48,453,294	-3,135,591	301,512
10	Gas			
11	Gas	-6,439,429	-6,495,357	-143,255
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	-6,439,429	-6,495,357	-143,255
18	Other	246,729,622	-864,923	
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	288,743,487	-10,495,871	158,257
20	Classification of TOTAL			
21	Federal Income Tax	279,078,915	-10,495,871	158,257
22	State Income Tax	9,664,572		
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					
		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)	Balance at End of Year (k)	Line No.
							1
							2
541,021	15,771					45,107,264	3
		182	1,291,333			-1,259,488	4
						402,332	5
							6
							7
							8
541,021	15,771		1,291,333			44,250,108	9
							10
172,486	232,857					-12,851,902	11
		190	21,363			-21,363	12
		283	69,458			-69,458	13
							14
							15
							16
172,486	232,857		90,821			-12,942,723	17
-301,246	3,372,019	182,190	47,988,448	283	69,458	194,272,444	18
412,261	3,620,647		49,370,602		69,458	225,579,829	19
							20
412,261	3,620,647		43,939,836		69,458	221,346,023	21
			5,430,766			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) 04/16/2010	Year/Period of Report End of 2009/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Idaho Investment Tax Credit (254005)	8,354,865			3,248,858	11,603,723
2	Oregon BETC Credit (254010)	128,992	190	128,992		
3	Noxon, ITC (254025)				1,441,110	1,441,110
4	Defer Gas Exchange (254028)	1,597,806	142,495	1,597,806		
5	FAS 109 Invest Tax Credit (254180)	201,240	190	26,556		174,684
6	Nez Perce (254220)	770,396	557	22,008		748,388
7	Oregon Senate Bill (254250)	1,450,000	407	662,125	1,001,777	1,789,652
8	Reg liability CCX CR ID (254300)	754,484	407	413,972		340,512
9	Accrue Lake CDA IPA int (254325)				64,410	64,410
10	BPA Res Exch Regulatory Liab (254345)				2,900,393	2,900,393
11	Unrealized Currency Exchange (254399)				35,548	35,548
12	Reg Liability Other (254700)					
13	Mark to Market ST (254740)					
14	Mark to Market FAS133 (254750)	42,171,739			439,754	42,611,493
15						
16						
17						
18						
19						
20						
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22						
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25						
26						
27						
28						
29						
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40						
41	TOTAL	55,429,522		2,851,459	9,131,850	61,709,913

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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	315,648,544	279,640,876
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	273,953,602	247,713,799
5	Large (or Ind.) (See Instr. 4)	107,741,463	101,785,110
6	(444) Public Street and Highway Lighting	6,607,434	5,961,756
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales	1,075,772	980,339
10	TOTAL Sales to Ultimate Consumers	705,026,815	636,081,880
11	(447) Sales for Resale	198,516,063	224,672,881
12	TOTAL Sales of Electricity	903,542,878	860,754,761
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	903,542,878	860,754,761
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	651,836	570,818
18	(453) Sales of Water and Water Power	381,238	306,684
19	(454) Rent from Electric Property	2,742,428	2,774,767
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	34,534,405	47,550,273
22	(456.1) Revenues from Transmission of Electricity of Others	9,176,474	9,428,833
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	47,486,381	60,631,375
27	TOTAL Electric Operating Revenues	951,029,259	921,386,136

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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
3,791,369	3,743,696	313,884	311,381	2
				3
3,176,670	3,187,832	39,276	39,075	4
1,947,553	2,058,527	1,394	1,388	5
26,021	25,757	444	434	6
				7
				8
13,371	13,507	80	74	9
8,954,984	9,029,319	355,078	352,352	10
4,737,063	3,566,073			11
13,692,047	12,595,392	355,078	352,352	12
				13
13,692,047	12,595,392	355,078	352,352	14

Line 12, column (b) includes $ 6,581,138 of unbilled revenues.

Line 12, column (d) includes 52,131 MWH relating to unbilled revenues

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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	3,634,114	290,440,480	299,715	12,125	0.0799
3	2 Residential Service					
4	3 Residential Service					
5	12 Res. & Farm Gen. Service	66,429	7,593,985	12,365	5,372	0.1143
6	15 MOPS II Residential					
7	22 Res. & Farm Lg. Gen. Service	49,691	3,926,588	103	482,437	0.0790
8	30 Pumping-Special					
9	32 Res. & Farm Pumping Service	14,132	1,183,579	1,701	8,308	0.0838
10	48 Res. & Farm Area Lighting	4,690	1,073,658			0.2289
11	49 Area Lighting-High-Press.	281	72,087			0.2565
12	56 Centralia Refund					
13	95 Wind Power		174,792			
14	72 Residential Service					
15	73 Residential Service					
16	74 Residential Service					
17	76 Residential Service					
18	77 Residential Service					
19	58A Tax Adjustment		-46,918			
20	58 Tax Adjustment		8,292,835			
21	SubTotal	3,769,337	312,711,086	313,884	12,009	0.0830
22	Residential-Unbilled	22,032	2,937,458			0.1333
23	Total Residential Sales	3,791,369	315,648,544	313,884	12,079	0.0833
24						
25	COMMERCIAL SALES (442)					
26	2 General Service					
27	3 General Service					
28	11 General Service	664,262	68,279,239	33,746	19,684	0.1028
29	12 Res. & Farm Gen. Service					
30	16 MOPS II Commercial					
31	19 Contract-General Service					
32	21 Large General Service	2,029,033	164,397,447	4,496	451,297	0.0810
33	25 Extra Lg. Gen. Service	360,289	20,172,762	13	27,714,538	0.0560
34	28 Contract-Extra Large Serv					
35	31 Pumping Service	93,901	6,933,108	1,021	91,970	0.0738
36	47 Area Lighting-Sod. Vap	6,648	1,342,337			0.2019
37	49 Area Lighting-High-Press.	2,383	491,797			0.2064
38	56 Centralia Refune					
39	95 Wind Power		59,072			
40	74 Large General Service					
41	TOTAL Billed	13,639,916	896,961,740	355,078	38,414	0.0658
42	Total Unbilled Rev.(See Instr. 6)	52,131	6,581,138	0	0	0.1262
43	TOTAL	13,692,047	903,542,878	355,078	38,561	0.0660

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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	75 Large General Service					
2	76 Large General Service					
3	77 General Service					
4	58A Tax Adjustment		-46,808			
5	58 Tax Adjustment		9,499,450			
6	SubTotal	3,156,516	271,128,404	39,276	80,368	0.0859
7	Commercial-Unbilled	20,154	2,825,198			0.1402
8	Total Commercial	3,176,670	273,953,602	39,276	80,881	0.0862
9						
10	INDUSTRIAL SALES (442)					
11	2 General Service					
12	3 General Service					
13	8 Lg Gen Time of Use					
14	11 General Service	6,552	688,918	232	28,241	0.1051
15	12 Res. & Farm Gen. Service					
16	21 Large General Service	166,637	12,928,178	192	867,901	0.0776
17	25 Extra Lg. Gen. Service	1,677,279	86,076,255	20	83,863,950	0.0513
18	28 Contract - Extra Large Service	68	219,109			3.2222
19	29 Contract Lg. Gen. Service					
20	30 Pumping Service - Special	23,689	1,544,497	34	696,735	0.0652
21	31 Pumping Service	57,865	4,455,491	759	76,238	0.0770
22	32 Pumping Svc Res & Firm	5,235	396,960	157	33,344	0.0758
23	47 Area Lighting-Sod. Vap.	232	39,472			0.1701
24	49 Area Lighting - High-Press	51	9,435			0.1850
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		-1,124			
33	58 Tax Adjustment		564,062			
34	SubTotal	1,937,608	106,922,981	1,394	1,389,963	0.0552
35	Industrial-Unbilled	9,945	818,482			0.0823
36	Total Industrial	1,947,553	107,741,463	1,394	1,397,097	0.0553
37						
38	STREET AND HWY LIGHTING (444)					
39	6 Mercury Vapor St. Ltg.					
40	7 HP Sodium Vap. St. Ltg					
41	TOTAL Billed	13,639,916	896,961,740	355,078	38,414	0.0658
42	Total Unbilled Rev.(See Instr. 6)	52,131	6,581,138	0	0	0.1262
43	TOTAL	13,692,047	903,542,878	355,078	38,561	0.0660

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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	219	39,152	16	13,688	0.1788
3	42 Co-Owned St. Lt. Service	20,309	5,938,023	363	55,948	0.2924
4	High-Press. Sod. Vap.					
5	43 Cust-Owned St. Lt. Energy	9	847	1	9,000	0.0941
6	and Maint. Service					
7	44 Cust-Owned St. Lt. Energy	843	116,215	28	30,107	0.1379
8	and Maint. Svce - High-Pres					
9	Sodium Vapor					
10	45 Cust. Owned St. Lt. Energy Svc	1,329	89,708	6	221,500	0.0675
11	46 Cust. Owned St. Lt. Energy Svc	3,312	297,106	30	110,400	0.0897
12	58A Tax Adjustment		-664			
13	58 Tax Adjustment		127,047			
14	SubTotal	26,021	6,607,434	444	58,606	0.2539
15	Street & Hwy Lighting-Unbilled					
16	Total Street & Hwy Lighting	26,021	6,607,434	444	58,606	0.2539
17						
18	OTHER SALES TO PUBLIC					
19	(445)					
20	None					
21						
22	INTERDEPARTMENTAL SALES	13,371	1,075,772	80	167,138	0.0805
23	58 Tax Adjustment					
24	Total Interdepartmental	13,371	1,075,772	80	167,138	0.0805
25						
26	SALES FOR RESALE (447)					
27	61 Sales to Other Utilities (NDA)	4,737,063	198,516,063			0.0419
28						
29						
30	Total Sales for Resale	4,737,063	198,516,063			0.0419
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	13,639,916	896,961,740	355,078	38,414	0.0658
42	Total Unbilled Rev.(See Instr. 6)	52,131	6,581,138	0	0	0.1262
43	TOTAL	13,692,047	903,542,878	355,078	38,561	0.0660

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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) 04/16/2010	Year/Period of Report End of 2009/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	BC Transmission Corp.	SF	Tariff 12			
2	Barclays Bank PLC	SF	WSPP-C			
3	Barclays Bank PLC	SF	ISDA			
4	Black Hills Power, Inc.	SF	WSPP-C			
5	BP Corporation North America, Inc.	SF	ISDA			
6	BP Energy Company	SF	WSPP-C			
7	Bonneville Power Administration	LF	Tariff 8			
8	Bonneville Power Administration	LF	BPA OATT			
9	Bonneville Power Administration	SF	WSPP-C			
10	Bonneville Power Administration	SF	Tariff 12			
11	Cargill Power Markets, LLC	SF	WSPP-C			
12	Cargill Power Markets, LLC	SF	Tariff 9			
13	Chelan County PUD No. 1	SF	WSPP-C			
14	Citigroup Energy, Inc.	SF	WSPP-C			
	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	04/16/2010	End of 2009/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.
20		434		434	1
297,334		13,046,048		13,046,048	2
			-189,600	-189,600	3
400		15,600		15,600	4
			1,113,659	1,113,659	5
434,981		23,779,454		23,779,454	6
33,894		1,195,985		1,195,985	7
1,184		36,734		36,734	8
81,853		3,116,112		3,116,112	9
25		671		671	10
55,369		1,763,316		1,763,316	11
	230			230	12
3,200		112,550		112,550	13
6,600		247,350		247,350	14
0	0	0	0	0	
4,737,063	7,316,703	170,721,483	20,477,877	198,516,063	
4,737,063	**7,316,703**	**170,721,483**	**20,477,877**	**198,516,063**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2010	Year/Period of Report End of 2009/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	Clatskanie Peoples PUD	SF	WSPP-C			
2	Conoco Phillips	SF	WSPP-C			
3	Conoco Phillips	SF	Tariff 9			
4	Constellation Energy Commodities Group	SF	WSPP-C			
5	Credit Suisse Energy LLC	SF	WSPP-C			
6	Douglas County PUD No. 1	SF	WSPP-C			
7	Douglas County PUD No. 1	SF	290			
8	Eagle Energy Partners, LLP	SF	WSPP-C			
9	Endure Energy, LLC	SF	WSPP-C			
10	Eugene Water & Electric Board	SF	WSPP-C			
11	Fortis Energy Marketing & Trading GP	SF	WSPP-C			
12	Grant County PUD No. 2	SF	WSPP-C			
13	Grant County PUD No. 2	SF	Tariff 12			
14	Grant County PUD No. 2	SF	290			
	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) 04/16/2010	Year/Period of Report End of 2009/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.
2,399		54,448		54,448	1
26,208		915,195		915,195	2
	122,640			122,640	3
125,066		7,687,222		7,687,222	4
47,000		764,200		764,200	5
1,458		62,252		62,252	6
	5,000			5,000	7
9,600		178,100		178,100	8
6,684		249,609		249,609	9
13,036		394,772		394,772	10
50,575		1,771,800		1,771,800	11
15,715		508,230		508,230	12
16		535		535	13
	600			600	14
0	0	0	0	0	
4,737,063	7,316,703	170,721,483	20,477,877	198,516,063	
4,737,063	**7,316,703**	**170,721,483**	**20,477,877**	**198,516,063**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2010	Year/Period of Report End of 2009/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (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	Grant County PUD No. 2	SF	Tariff 10			
2	Hinson Power Company, LLC	SF	WSPP-C			
3	Iberdrola Renewables, Inc.	SF	WSPP-C			
4	Idaho Power Company	SF	WSPP-C			
5	Idaho Power Company	SF	Tariff 12			
6	Integry's Energy Service, Inc.	SF	WSPP-C			
7	Intercontinental ICE	SF	ISDA			
8	JP Morgan Ventures Energy	SF	Tariff 9			
9	JP Morgan Ventures Energy	SF	ISDA			
10	Macquarie Cook Power, Inc.	SF	WSPP-C			
11	Macquarie Cook Power, Inc.	SF	WSPP-C			
12	Modesto Irrigation District	SF	WSPP-C			
13	Morgan Stanley	SF	ISDA			
14	Morgan Stanley	SF	ISDA			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2010	Year/Period of Report End of 2009/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.
	4,835			4,835	1
2,880		69,200		69,200	2
434,552		16,458,261		16,458,261	3
20,413		685,627		685,627	4
54		1,922		1,922	5
4,000		157,100		157,100	6
			13,536	13,536	7
81,000		2,414,870		2,414,870	8
			84,168	84,168	9
67,147		2,329,272		2,329,272	10
	50			50	11
13,298		422,306		422,306	12
397,644		15,764,322		15,764,322	13
			-8,896	-8,896	14
0	0	0	0	0	
4,737,063	7,316,703	170,721,483	20,477,877	198,516,063	
4,737,063	**7,316,703**	**170,721,483**	**20,477,877**	**198,516,063**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2010	Year/Period of Report End of 2009/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 Glacier Wind Energy 1, LLC	SF	Tariff 9			
2	NaturEner Glacier Wind Energy 1, LLC	SF	Tariff 9			
3	NaturEner Glacier Wind Energy 1, LLC	SF	Tariff 9			
4	NaturEner Glacier Wind Energy 1, LLC	SF	Tariff 9			
5	NaturEner Power Watch, LLC	SF	Tariff 9			
6	NaturEner Power Watch, LLC	SF	Tariff 12			
7	NaturEner Power Watch, LLC	SF	Tariff 9			
8	NaturEner Power Watch, LLC	SF	Tariff 9			
9	NaturEner Power Watch, LLC	SF	Tariff 9			
10	NaturEner Power Watch, LLC	SF	Tariff 9			
11	Nexen Marketing U.S.A., Inc.	SF	WSPP-C			
12	NorthWestern Energy LLC	IF	Tariff 10			
13	NorthWestern Energy LLC	IF	Tariff 10			
14	NorthWestern Energy LLC	IF	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	04/16/2010	End of 2009/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.
2,736		96,588		96,588	1
			7,182	7,182	2
	412,404			412,404	3
			81,200	81,200	4
4,205		182,621		182,621	5
6		253		253	6
			1,560	1,560	7
	220,800			220,800	8
	312,500			312,500	9
			56,344	56,344	10
318		8,490		8,490	11
	3,256,935			3,256,935	12
			688,800	688,800	13
38,032		1,297,127		1,297,127	14
0	0	0	0	0	
4,737,063	7,316,703	170,721,483	20,477,877	198,516,063	
4,737,063	**7,316,703**	**170,721,483**	**20,477,877**	**198,516,063**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2010	Year/Period of Report End of 2009/Q4

SALES FOR RESALE (Account 447)

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2010	End of 2009/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.
151,013		5,431,652		5,431,652	1
55		1,804		1,804	2
7,734		240,851		240,851	3
	331,936			331,936	4
16,641		579,605		579,605	5
2,310		67,985		67,985	6
103,283		3,087,335		3,087,335	7
220		7,887		7,887	8
4,922		153,269		153,269	9
	500			500	10
	1,747,891			1,747,891	11
	390,166			390,166	12
6,577		223,131		223,131	13
39,778		1,616,942		1,616,942	14
0	0	0	0	0	
4,737,063	7,316,703	170,721,483	20,477,877	198,516,063	
4,737,063	**7,316,703**	**170,721,483**	**20,477,877**	**198,516,063**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2010	End of 2009/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	Pend Oreille Public Utility District	SF	Tariff10			
2	Portland General Electric Company	SF	WSPP-C			
3	Portland General Electric Company	SF	Tariff 12			
4	Portland General Electric Company	SF	290			
5	Portland General Electric Company	SF	Tariff 10			
6	Powerex	SF	WSPP-C			
7	Powerex	SF	Tariff 9			
8	Powerex	SF	Tariff 9			
9	PPL EnergyPlus, LLC	SF	Tariff 10			
10	PPL EnergyPlus, LLC	SF	WSPP-C			
11	PPL EnergyPlus, LLC	LF	Tariff 9			
12	Public Service of Colorado	SF	WSPP-C			
13	Puget Sound Energy	LF	Tariff 9			
14	Puget Sound Energy	SF	WSPP-C			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
	57,434			57,434	1
58,695		2,619,691		2,619,691	2
49		1,935		1,935	3
	525			525	4
	350			350	5
407,256		15,319,901		15,319,901	6
	78,930			78,930	7
			16,800	16,800	8
	271,095			271,095	9
30,091		958,923		958,923	10
17,577		547,390		547,390	11
1,200		55,000		55,000	12
22,499		700,659		700,659	13
143,111		5,149,085		5,149,085	14
0	0	0	0	0	
4,737,063	7,316,703	170,721,483	20,477,877	198,516,063	
4,737,063	**7,316,703**	**170,721,483**	**20,477,877**	**198,516,063**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2010	Year/Period of Report End of 2009/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Puget Sound Energy	SF	Tariff 12			
2	Rainbow Energy Marketing	SF	WSPP-C			
3	Redding, City of	SF	WSPP-C			
4	Sacramento Municipal Utility District	SF	WSPP-C			
5	Sacramento Municipal Utility District	SF	Tariff 12			
6	Sacramento Municipal Utility District	LF	WSPP-C			
7	San Diego Gas & Electric Company	SF	WSPP-C			
8	Seattle City Light	SF	WSPP-C			
9	Seattle City Light	SF	Tariff 12			
10	Sempra Energy Trading	SF	WSPP-C			
11	Sempra Energy Trading	SF	ISDA			
12	Shell Energy N.A.	SF	WSPP-C			
13	Shell Energy N.A.	SF	Tariff 9			
14	Sierra Pacific Power Company	SF	WSPP-C			
	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) 04/16/2010	Year/Period of Report End of 2009/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.
7		297		297	1
34,120		1,068,314		1,068,314	2
48		1,812		1,812	3
64,548		2,236,787		2,236,787	4
2		86		86	5
651,567		27,648,377		27,648,377	6
200		1,100		1,100	7
17,206		429,611		429,611	8
4		138		138	9
120,874		6,276,840		6,276,840	10
			28,012	28,012	11
403,194		13,920,196		13,920,196	12
	4,100			4,100	13
2,691		133,127		133,127	14
0	0	0	0	0	
4,737,063	7,316,703	170,721,483	20,477,877	198,516,063	
4,737,063	**7,316,703**	**170,721,483**	**20,477,877**	**198,516,063**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2010	Year/Period of Report End of 2009/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Sierra Pacific Power Company	SF	Tariff 12			
2	Snohomish County PUD	SF	WSPP-C			
3	Sovereign Power	LF	Tariff 10			
4	Sovereign Power	LF	Tariff 9			
5	Tacoma Power	SF	WSPP-C			
6	Tacoma Power	SF	Tariff 10			
7	The Energy Authority	SF	WSPP-C			
8	TransAlta Energy Marketing	SF	WSPP-C			
9	Turlock Irrigation District	SF	WSPP-C			
10	Vaagen Brothers	SF	Tariff 8			
11	IntraCompany Wheeling	LF				
12	IntraCompany Generation	LF				
13	Revenue Adjustment	AD				
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) 04/16/2010	Year/Period of Report End of 2009/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.
48		1,728		1,728	1
3,820		113,615		113,615	2
	97,382			97,382	3
11,973		413,788		413,788	4
3,266		61,906		61,906	5
	400			400	6
4,238		130,335		130,335	7
114,201		3,153,359		3,153,359	8
12,800		454,510		454,510	9
		5,179		5,179	10
		-17,881,243	17,881,243		11
			686,128	686,128	12
343			17,741	17,741	13
					14
0	0	0	0	0	
4,737,063	7,316,703	170,721,483	20,477,877	198,516,063	
4,737,063	**7,316,703**	**170,721,483**	**20,477,877**	**198,516,063**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2010	Year/Period of Report End of 2009/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	514,450	353,838
5	(501) Fuel	22,358,344	28,776,474
6	(502) Steam Expenses	2,614,109	1,880,633
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	699,318	814,258
10	(506) Miscellaneous Steam Power Expenses	2,783,706	3,455,151
11	(507) Rents	29,773	38,367
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	28,999,700	35,318,721
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	500,139	461,747
16	(511) Maintenance of Structures	546,526	526,317
17	(512) Maintenance of Boiler Plant	5,457,086	4,876,984
18	(513) Maintenance of Electric Plant	2,565,316	544,537
19	(514) Maintenance of Miscellaneous Steam Plant	937,372	637,092
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	10,006,439	7,046,677
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	39,006,139	42,365,398
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	2,278,227	1,642,209
45	(536) Water for Power	815,150	744,841
46	(537) Hydraulic Expenses	4,390,300	3,209,339
47	(538) Electric Expenses	5,604,151	4,724,140
48	(539) Miscellaneous Hydraulic Power Generation Expenses	630,038	984,206
49	(540) Rents	6,068,605	802,071
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	19,786,471	12,106,806
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	249,607	302,771
54	(542) Maintenance of Structures	343,445	312,861
55	(543) Maintenance of Reservoirs, Dams, and Waterways	646,541	662,450
56	(544) Maintenance of Electric Plant	1,937,827	2,164,716
57	(545) Maintenance of Miscellaneous Hydraulic Plant	1,835,745	294,574
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	5,013,165	3,737,372
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	24,799,636	15,844,178

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2010	Year/Period of Report End of 2009/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	846,899	1,650,998
63	(547) Fuel	68,656,659	107,175,030
64	(548) Generation Expenses	2,215,456	1,666,082
65	(549) Miscellaneous Other Power Generation Expenses	456,697	455,207
66	(550) Rents	-33,811	33,433
67	TOTAL Operation (Enter Total of lines 62 thru 66)	72,141,900	110,980,750
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	775,889	423,483
70	(552) Maintenance of Structures	1,850	4,186
71	(553) Maintenance of Generating and Electric Plant	1,893,421	4,920,956
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	100,412	114,800
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	2,771,572	5,463,425
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	74,913,472	116,444,175
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	303,784,778	276,853,230
77	(556) System Control and Load Dispatching	528,673	500,980
78	(557) Other Expenses	69,198,479	78,800,960
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	373,511,930	356,155,170
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	512,231,177	530,808,921
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,436,974	2,227,450
84	(561) Load Dispatching	2,224,918	1,981,275
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	190,291	252,115
94	(563) Overhead Lines Expenses	543,042	505,160
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	13,350,741	13,632,001
97	(566) Miscellaneous Transmission Expenses	1,387,100	1,312,796
98	(567) Rents	152,055	100,620
99	TOTAL Operation (Enter Total of lines 83 thru 98)	20,285,121	20,011,417
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	566,082	591,365
102	(569) Maintenance of Structures	330,766	279,425
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	1,127,999	1,237,393
108	(571) Maintenance of Overhead Lines	1,528,641	1,226,863
109	(572) Maintenance of Underground Lines	17,566	1,311
110	(573) Maintenance of Miscellaneous Transmission Plant	38,785	7,209
111	TOTAL Maintenance (Total of lines 101 thru 110)	3,609,839	3,343,566
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	23,894,960	23,354,983

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2010	End of 2009/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	1,367,048	1,391,231
135	(581) Load Dispatching		
136	(582) Station Expenses	546,953	621,675
137	(583) Overhead Line Expenses	1,577,717	1,975,815
138	(584) Underground Line Expenses	710,346	896,606
139	(585) Street Lighting and Signal System Expenses	218,441	194,939
140	(586) Meter Expenses	1,619,021	1,308,218
141	(587) Customer Installations Expenses	861,022	825,366
142	(588) Miscellaneous Expenses	5,871,255	5,097,414
143	(589) Rents	375,764	191,442
144	TOTAL Operation (Enter Total of lines 134 thru 143)	13,147,567	12,502,706
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	1,326,210	1,371,668
147	(591) Maintenance of Structures	280,729	294,513
148	(592) Maintenance of Station Equipment	1,030,655	750,947
149	(593) Maintenance of Overhead Lines	6,823,635	7,983,419
150	(594) Maintenance of Underground Lines	1,067,148	1,059,209
151	(595) Maintenance of Line Transformers	1,040,344	678,925
152	(596) Maintenance of Street Lighting and Signal Systems	638,654	610,966
153	(597) Maintenance of Meters	160,883	145,069
154	(598) Maintenance of Miscellaneous Distribution Plant	315,281	503,563
155	TOTAL Maintenance (Total of lines 146 thru 154)	12,683,539	13,398,279
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	25,831,106	25,900,985
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	567,832	490,861
160	(902) Meter Reading Expenses	2,624,185	2,313,137
161	(903) Customer Records and Collection Expenses	8,243,568	7,490,538
162	(904) Uncollectible Accounts	2,735,983	1,927,667
163	(905) Miscellaneous Customer Accounts Expenses	244,871	147,464
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	14,416,439	12,369,667

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2010	End of 2009/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	25,449,316	16,553,310
169	(909) Informational and Instructional Expenses	67,743	112,666
170	(910) Miscellaneous Customer Service and Informational Expenses	146,608	145,297
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	25,663,667	16,811,273
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	506,252	424,827
176	(913) Advertising Expenses	114,294	128,150
177	(916) Miscellaneous Sales Expenses	307,957	213,550
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	928,503	766,527
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	22,474,374	19,181,918
182	(921) Office Supplies and Expenses	3,928,835	3,782,093
183	(Less) (922) Administrative Expenses Transferred-Credit	49,301	38,836
184	(923) Outside Services Employed	11,313,636	10,997,229
185	(924) Property Insurance	1,283,269	1,015,509
186	(925) Injuries and Damages	3,543,277	2,968,505
187	(926) Employee Pensions and Benefits	1,053,264	1,186,191
188	(927) Franchise Requirements	6,704	5,950
189	(928) Regulatory Commission Expenses	4,999,707	4,783,704
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	264,628	4,017
192	(930.2) Miscellaneous General Expenses	3,129,106	3,198,612
193	(931) Rents	393,144	590,566
194	TOTAL Operation (Enter Total of lines 181 thru 193)	52,340,643	47,675,458
195	Maintenance		
196	(935) Maintenance of General Plant	7,960,364	7,319,496
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	60,301,007	54,994,954
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	663,266,859	665,007,310

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2010	End of 2009/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	BP Energy Comp	SF	ISDA			
5	Barclays Bank PLC	SF	WSPP			
6	Barclays Bank PLC	SF	ISDA			
7	Black Creek Hydro	LU	FERC #1			
8	Black Hills Power	SF	WSPP			
9	Bonneville Power Administration	LF	WNP#3 Agr.			
10	Bonneville Power Administration	SF	WSPP			
11	Bonneville Power Administration	EX	PNCA			
12	Bonneville Power Administration	SF	Tariff #8			
13	Bonneville Power Administration	OS	BPA OATT			
14	Bonneville Power Administration	SF	BPA OATT			
	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	04/16/2010	End of 2009/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.
					13,997,921	13,997,921	1
219,000				7,555,500		7,555,500	2
249,034				13,327,656		13,327,656	3
							4
524,360				32,302,596		32,302,596	5
					1,589,532	1,589,532	6
4,172				138,789		138,789	7
2,200				61,750		61,750	8
393,717				14,078,030		14,078,030	9
106,820				3,364,834		3,364,834	10
	3,050	2,550		14,429	24,660	39,089	11
33,673				1,100,827		1,100,827	12
					2,190	2,190	13
7,998				316,257	-24,109	292,148	14
7,373,956	688,110	689,010	11,824,462	273,902,860	18,057,458	303,784,780	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2010	End of 2009/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)	Average Monthly CP Demand (f)
1	Cargill Power Markets, LLC	SF	WSPP			
2	Chelan County PUD No. 1	LU	Rocky Reach			
3	Chelan County PUD No. 1	SF	WSPP			
4	City of Spokane	LU	PURPA			
5	Clatskanie Peoples PUD	SF	WSPP			
6	Constellation Energy Commodities Group	SF	WSPP			
7	Douglas County PUD No. 1	LU	Wells			
8	Douglas County PUD No. 1	LU	Wells Settlement			
9	Douglas County PUD No. 1	IF	Wells			
10	Douglas County PUD No. 1	SF	WSPP			
11	Douglas County PUD No. 1	EX	305			
12	Eagle Energy Partners	SF	WSPP			
13	Endure Energy	SF	WSPP			
14	Eugene Water & Electric Board	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	04/16/2010	End of 2009/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
13,868				454,918		454,918	1
150,363				1,657,777		1,657,777	2
3,607				478,318		478,318	3
45,267				1,792,493		1,792,493	4
8,971				227,238		227,238	5
96,656				4,477,827		4,477,827	6
249,723				1,411,526		1,411,526	7
19,308				364,527		364,527	8
			11,202,012			11,202,012	9
19,158				654,897		654,897	10
	109,860	110,011		1,511,393	-6,708	1,504,685	11
800				30,900		30,900	12
9,355				303,003		303,003	13
11,784				303,966		303,966	14
7,373,956	688,110	689,010	11,824,462	273,902,860	18,057,458	303,784,780	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2010	Year/Period of Report End of 2009/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	Fortis Energy Mkt	SF	WSPP			
2	Ford Hydro Limited Partnership	LU	PURPA			
3	Grant County PUD No. 2	LU	Wanapum			
4	Grant County PUD No. 2	LU	Priest Rapids			
5	Grant County PUD No. 2	LU	PR Displacement			
6	Grant County PUD No. 2	SF	WSPP			
7	Grant County PUD No. 2	SF	WSPP			
8	Hydro Technology Systems	LU	PURPA			
9	Idaho Power Company	SF	WSPP			
10	Inland Power & Light Company	RQ	208			
11	Integrys Energy Services	SF	WSPP			
12	Intercontinental Exchange LLC	SF	ISDA			
13	J P Morgan Ventures Energy	SF	WSPP			
14	Jim White	LU	PURPA			
	Total					

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2010	Year/Period of Report End of 2009/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.
4,000				140,940		140,940	1
2,355				114,259		114,259	2
268,849				4,988,908		4,988,908	3
151,094				4,998,816		4,998,816	4
193,981				5,332,754		5,332,754	5
25,137				733,658		733,658	6
			250			250	7
7,656				364,881		364,881	8
11,070				275,773		275,773	9
110				6,693		6,693	10
400				17,200		17,200	11
					-71,834	-71,834	12
16,064				497,139		497,139	13
980				90,084		90,084	14
7,373,956	688,110	689,010	11,824,462	273,902,860	18,057,458	303,784,780	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2010	Year/Period of Report End of 2009/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	John Day Hydro	LU	PURPA			
2	Kalich, Clint	LU	PURPA			
3	Macquarie Cook Power	SF	WSPP			
4	Mirant Energy Trading	LU	WSPP			
5	Morgan Stanley Capital Group	IF	WSPP			
6	Morgan Stanley Capital Group	SF	WSPP			
7	Morgan Stanley Capital Group	SF	ISDA			
8	NaturEner Power Watch	SF	WSPP			
9	Northpoint Energy Solutions	SF	WSPP			
10	NorthWestern Energy LLC	SF	WSPP			
11	Okanogan County PUD No. 1	SF	WSPP			
12	PPL Energy Plus	SF	WSPP			
13	PPM Energy	LU	PPM Energy			
14	PPM Energy	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)	
2,145				90,025		90,025	1
1							2
10,484				357,237		357,237	3
400				18,300		18,300	4
657,000				20,191,040		20,191,040	5
187,661				10,156,573		10,156,573	6
					1,500,540	1,500,540	7
					136,560	136,560	8
10,400				355,160		355,160	9
47,709				1,660,864		1,660,864	10
39,593				1,240,523		1,240,523	11
1,485,716				47,352,158		47,352,158	12
70,559				2,845,927		2,845,927	13
441,775				16,622,656		16,622,656	14
7,373,956	688,110	689,010	11,824,462	273,902,860	18,057,458	303,784,780	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2010	End of 2009/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)	Average Monthly CP Demand (f)
1	PacifiCorp	SF	WSPP			
2	Pacific NW Gen Corp	SF	WSPP			
3	Pend Oreille County PUD No. 1	SF	Pend O'			
4	Pend Oreille County PUD No. 1	SF	Pend O'			
5	Phillips Ranch	LU	PURPA			
6	Portland General Electric Company	EX	304			
7	Portland General Electric Company	EX	178			
8	Portland General Electric Company	SF	WSPP			
9	Potlatch Corporation	LU	PURPA			
10	Powerex Corp	SF	WSPP			
11	Powerex Corp	SF	WSPP			
12	Puget Sound Energy	SF	WSPP			
13	Rainbow Energy Marketing Corp	SF	WSPP			
14	Sacramento Municipal Utility District	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	04/16/2010	End of 2009/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)	
74,368				2,355,169		2,355,169	1
2,702				59,921		59,921	2
6,941				91,303		91,303	3
102,049	17,037	16,975		2,952,098	220	2,952,318	4
44				2,856		2,856	5
	9,843	9,841					6
	438,720	439,290			-19,170	-19,170	7
69,306				2,548,127		2,548,127	8
452,317				19,413,446		19,413,446	9
81,107				4,202,156		4,202,156	10
			622,200			622,200	11
39,571				1,350,950		1,350,950	12
85,071				2,818,359		2,818,359	13
8,925				250,588		250,588	14
7,373,956	688,110	689,010	11,824,462	273,902,860	18,057,458	303,784,780	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2010	Year/Period of Report End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	San Diego Gas & Electric	SF	WSPP			
2	Seattle City Light	SF	WSPP			
3	Seattle City Light	EX	WSPP			
4	Sempra Energy Trading	SF	WSPP			
5	Sheep Creek Hydro	LU	PURPA			
6	Shell Energy	SF	WSPP			
7	Shell Energy	SF	ISDA			
8	Sierra Pacific Power Company	SF	WSPP			
9	Snohomish County PUD No. 1	SF	WSPP			
10	Sovereign Power	IF	Sovereign			
11	Stimson Lumber	IU	PURPA			
12	Tacoma Power	SF	WSPP			
13	Tacoma Power	SF	WSPP			
14	The Energy Authority	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	04/16/2010	End of 2009/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)	
4				75		75	1
32,278				857,126		857,126	2
	109,600	109,600		1,535,040		1,535,040	3
134,161				7,461,057		7,461,057	4
5,829				241,514		241,514	5
204,048				8,101,271		8,101,271	6
					1,044,168	1,044,168	7
1,020				40,700		40,700	8
9,175				310,385		310,385	9
3,329				60,960		60,960	10
36,972				1,865,408		1,865,408	11
27,930				670,380		670,380	12
				75		75	13
13,312				419,328		419,328	14
7,373,956	688,110	689,010	11,824,462	273,902,860	18,057,458	303,784,780	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2010	End of 2009/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	TransAlta Energy Marketing	SF	WSPP			
2	IntraCompany Generation Services	OS	OATT			
3	Other - Inadvertent Interchange	EX				
4	Other - Inadvertent Interchange	EX				
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) 04/16/2010	Year/Period of Report End of 2009/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)	
178,524				11,227,421		11,227,421	1
				686,128		686,128	2
					-116,512	-116,512	3
		743					4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
7,373,956	688,110	689,010	11,824,462	273,902,860	18,057,458	303,784,780	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2010	Year/Period of Report End of 2009/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	Vaagen Brothers	Vaagen Brothers	Idaho Power Company	LFP
2	PacifiCorp	PacifiCorp	PacifiCorp	LFP
3	Seattle City Light	Seattle City Light	Bonneville Power Administration	LFP
4	Tacoma City Light	Tacoma City Light	Bonneville Power Administration	LFP
5	Grant County Public Utility Dist	Grant County Public Utility Dist	Grant County Public Utility Dist	LFP
6	Spokane Indian Tribes	Bonneville Power Administration	Spokane Indian Tribes	LFP
7	USBR	Bonneville Power Administration	East Greenacres	LFP
8	Consolidated Irrigation District	Bonneville Power Administration	Consolidated Irrigation District	LFP
9	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	FNO
10	City of Spokane	City of Spokane	Puget Sound Energy	LFP
11	Grant County Public Utility Dist	Bonneville Power Administration	NorthWestern Montana	LFP
12	Bonneville Power Administration	Bonneville Power Administration	Idaho Power Company	NF
13	Bonneville Power Administration	Bonneville Power Administration	Idaho Power Company	SFP
14	Idaho Power Company	Grant County Public Utility Dist	Idaho Power Company	NF
15	Idaho Power Company	Puget Sound Energy	Idaho Power Company	NF
16	Idaho Power Company	Avista Corporation	Bonneville Power Administration	NF
17	Idaho Power Company	Idaho Power Company	Bonneville Power Administration	NF
18	Idaho Power Company	Bonneville Power Administration	Idaho Power Company	NF
19	Idaho Power Company	Idaho Power Company	Chelan Public Utility District	NF
20	Idaho Power Company	Idaho Power Company	Puget Sound Energy	NF
21	Idaho Power Company	Idaho Power Company	Grant County Public Utility Dist	NF
22	Idaho Power Company	Chelan Public Utility District	Idaho Power Company	NF
23	Idaho Power Company	Bonneville Power Administration	Idaho Power Company	SFP
24	Idaho Power Company	NorthWestern Montana	Bonneville Power Administration	SFP
25	Idaho Power Company	Idaho Power Company	Puget Sound Energy	SFP
26	Idaho Power Company	Idaho Power Company	Bonneville Power Administration	SFP
27	Idaho Power Company	Chelan Public Utility District	Idaho Power Company	SFP
28	Idaho Power Company	Grant County Public Utility Dist	Idaho Power Company	SFP
29	NorthWestern Energy	NorthWestern Montana	Bonneville Power Administration	NF
30	NorthWestern Energy	NorthWestern Montana	Idaho Power Company	SFP
31	PacifiCorp	PacifiCorp	Bonneville Power Administration	NF
32	PacifiCorp	NorthWestern Montana	PacifiCorp	NF
33	PacifiCorp	Idaho Power Company	PacifiCorp	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	04/16/2010	End of 2009/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. 228	Colville Substation	Lolo-Oxbow 230 kv	4	15,885	15,885	1
FERC No. 182	Lolo-Oxbow 230 kv	Dry Gulch	20	53,857	53,857	2
FERC Trf No. 8	Chelan-Stratford 115	Stratford 115kV SS		192,178	192,178	3
FERC Trf No. 8	Chelan-Stratford 115	Stratford 115kV SS		192,178	192,178	4
FERC No. 104	Larson Substation	Round Lake/Coulee Cy	25	101,397	101,397	5
FERC Trf No. 8	Sunset	Westside	2	3,141	3,141	6
FERC Trf No. 8	Bell Substation	East Greenacres	3	3,129	3,129	7
FERC Trf No. 8	Bell Substation	Consolidated	4	6,299	6,299	8
FERC Trf No. 8				1,852,995	1,852,995	9
FERC No. 155	Sunset-Westside 115k	Westside	23	133,987	133,987	10
FERC Trf No. 8				41,078	41,078	11
FERC Trf No. 8				65,556	65,556	12
FERC Trf No. 8				17,488	17,488	13
FERC Trf No. 8				2,400	2,400	14
FERC Trf No. 8				415	415	15
FERC Trf No. 8				800	800	16
FERC Trf No. 8				62,046	62,046	17
FERC Trf No. 8				21,126	21,126	18
FERC Trf No. 8				775	775	19
FERC Trf No. 8				1,450	1,450	20
FERC Trf No. 8				400	400	21
FERC Trf No. 8				79	79	22
FERC Trf No. 8				223,209	223,209	23
FERC Trf No. 8				3,680	3,680	24
FERC Trf No. 8				3,994	3,994	25
FERC Trf No. 8				75,535	75,535	26
FERC Trf No. 8				400	400	27
FERC Trf No. 8				520	520	28
FERC Trf No. 8				91	91	29
FERC Trf No. 8						30
FERC Trf No. 8				292	292	31
FERC Trf No. 8				1,972	1,972	32
FERC Trf No. 8				50	50	33
						34
			81	**3,225,567**	**3,225,567**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2010	End of 2009/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.
61,864	15,885	19,481	97,230	1
206,460			206,460	2
133,527			133,527	3
133,527			133,527	4
27,381			27,381	5
14,583			14,583	6
16,533			16,533	7
35,448			35,448	8
5,333,884			5,333,884	9
127,506		32,088	159,594	10
167,900			167,900	11
	227,652		227,652	12
79,846			79,846	13
	9,600		9,600	14
	1,702		1,702	15
	3,200		3,200	16
	263,834		263,834	17
	85,332		85,332	18
	3,385		3,385	19
	6,332		6,332	20
	1,747		1,747	21
	316		316	22
1,033,899			1,033,899	23
15,714			15,714	24
14,479			14,479	25
201,382			201,382	26
1,450			1,450	27
1,885			1,885	28
	564		564	29
36,456			36,456	30
	4,562		4,562	31
	30,005		30,005	32
	781		781	33
				34
8,122,208	**1,002,697**	**51,569**	**9,176,474**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2010	End of 2009/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	PacifiCorp	PacifiCorp	Idaho Power Company	NF
2	PacifiCorp	PacifiCorp	Bonneville Power Administration	SFP
3	Iberdrola Renewables, Inc.	PacifiCorp	Bonneville Power Administration	NF
4	Iberdrola Renewables, Inc.	Idaho Power Company	Bonneville Power Administration	NF
5	Powerex	NorthWestern Montana	Bonneville Power Administration	NF
6	Powerex	Idaho Power Company	Bonneville Power Administration	NF
7	Powerex	Bonneville Power Administration	Idaho Power Company	NF
8	Puget Sound Energy	NorthWestern Montana	Bonneville Power Administration	NF
9	Puget Sound Energy	Bonneville Power Administration	Idaho Power Company	NF
10	Puget Sound Energy	NorthWestern Montana	Bonneville Power Administration	SFP
11	Portland General Electric	NorthWestern Montana	Portland General Electric	NF
12	Portland General Electric	NorthWestern Montana	Portland General Electric	SFP
13	Morgan Stanley Capital Group	Idaho Power Company	Avista Corporation	NF
14	Morgan Stanley Capital Group	Idaho Power Company	Bonneville Power Administration	NF
15	Morgan Stanley Capital Group	NorthWestern Montana	Bonneville Power Administration	NF
16	Sierra Pacific Power Company	Bonneville Power Administration	Idaho Power Company	NF
17	Sierra Pacific Power Company	Puget Sound Energy	Idaho Power Company	NF
18	Cargill Power Markets	NorthWestern Montana	Bonneville Power Administration	NF
19	Cargill Power Markets	NorthWestern Montana	Avista Corporation	NF
20	Cargill Power Markets	Idaho Power Company	Avista Corporation	NF
21	Cargill Power Markets	Idaho Power Company	Bonneville Power Administration	NF
22	Cargill Power Markets	Idaho Power Company	Grant County Public Utility Dist	NF
23	Cargill Power Markets	Bonneville Power Administration	Idaho Power Company	NF
24	Cargill Power Markets	Bonneville Power Administration	NorthWestern Montana	NF
25	Cargill Power Markets	Idaho Power Company	Chelan Public Utility District	NF
26	Cargill Power Markets	Bonneville Power Administration	Idaho Power Company	SFP
27	Cargill Power Markets	Idaho Power Company	Bonneville Power Administration	SFP
28	Cargill Power Markets	NorthWestern Montana	Avista Corporation	SFP
29	Cargill Power Markets	NorthWestern Montana	Grant County Public Utility Dist	SFP
30	Rainbow Energy Marketing Corp	Idaho Power Company	Bonneville Power Administration	NF
31	Rainbow Energy Marketing Corp	Idaho Power Company	Bonneville Power Administration	SFP
32	Coral Power	NorthWestern Montana	Chelan Public Utility District	NF
33	Coral Power	Bonneville Power Administration	Idaho Power Company	NF
34				
	TOTAL			

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2010	Year/Period of Report End of 2009/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				3,039	3,039	1
FERC Trf No. 8						2
FERC Trf No. 8				449	449	3
FERC Trf No. 8				400	400	4
FERC Trf No. 8				1,820	1,820	5
FERC Trf No. 8				6,154	6,154	6
FERC Trf No. 8				2,615	2,615	7
FERC Trf No. 8				8,214	8,214	8
FERC Trf No. 8				15	15	9
FERC Trf No. 8				2,512	2,512	10
FERC Trf No. 8				5,281	5,281	11
FERC Trf No. 8				1,076	1,076	12
FERC Trf No. 8				151	151	13
FERC Trf No. 8				1,106	1,106	14
FERC Trf No. 8				125	125	15
FERC Trf No. 8				5,384	5,384	16
FERC Trf No. 8				14	14	17
FERC Trf No. 8				1,868	1,868	18
FERC Trf No. 8				402	402	19
FERC Trf No. 8				400	400	20
FERC Trf No. 8				602	602	21
FERC Trf No. 8				192	192	22
FERC Trf No. 8				914	914	23
FERC Trf No. 8				529	529	24
FERC Trf No. 8				198	198	25
FERC Trf No. 8				400	400	26
FERC Trf No. 8				600	600	27
FERC Trf No. 8				1,198	1,198	28
FERC Trf No. 8				432	432	29
FERC Trf No. 8				2,400	2,400	30
FERC Trf No. 8				4,650	4,650	31
FERC Trf No. 8				4,968	4,968	32
FERC Trf No. 8				760	760	33
						34
			81	**3,225,567**	**3,225,567**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2010	Year/Period of Report End of 2009/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.
	47,476		47,476	1
14,858			14,858	2
	8,568		8,568	3
	1,600		1,600	4
	8,996		8,996	5
	26,658		26,658	6
	11,026		11,026	7
	32,920		32,920	8
	60		60	9
3,600			3,600	10
	23,516		23,516	11
4,450			4,450	12
	634		634	13
	4,646		4,646	14
	500		500	15
	23,015		23,015	16
	53		53	17
	7,052		7,052	18
	1,608		1,608	19
	1,634		1,634	20
	2,458		2,458	21
	784		784	22
	3,687		3,687	23
	2,189		2,189	24
	792		792	25
1,615			1,615	26
1,615			1,615	27
3,230			3,230	28
1,551			1,551	29
	9,600		9,600	30
12,460			12,460	31
	20,493		20,493	32
	3,293		3,293	33
				34
8,122,208	**1,002,697**	**51,569**	**9,176,474**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2010	End of 2009/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	NorthWestern Montana	Bonneville Power Administration	NF
2	Coral Power	NorthWestern Montana	Grant County Public Utility Dist	NF
3	Coral Power	Idaho Power Company	Chelan Public Utility District	NF
4	Coral Power	Idaho Power Company	Bonneville Power Administration	NF
5	PPL Energy Plus	Bonneville Power Administration	NorthWestern Montana	NF
6	PPL Energy Plus	Avista Corporation	NorthWestern Montana	NF
7	PPL Energy Plus	NorthWestern Montana	Bonneville Power Administration	NF
8	PPL Energy Plus	NorthWestern Montana	Idaho Power Company	NF
9	PPL Energy Plus	NorthWestern Montana	PacifiCorp	SFP
10	TransAlta Energy Marketing US	NorthWestern Montana	Bonneville Power Administration	NF
11	NaturEner USA	NorthWestern Montana	Bonneville Power Administration	NF
12	NaturEner USA	Bonneville Power Administration	NorthWestern Montana	SFP
13	NaturEner USA	NorthWestern Montana	Bonneville Power Administration	SFP
14	The Energy Authority	Bonneville Power Administration	NorthWestern Montana	NF
15	The Energy Authority	NorthWestern Montana	Bonneville Power Administration	NF
16	Grant County Public Utility Dist	NorthWestern Montana	Bonneville Power Administration	NF
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2010	Year/Period of Report End of 2009/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				252	252	1
FERC Trf No. 8				35	35	2
FERC Trf No. 8				203	203	3
FERC Trf No. 8				335	335	4
FERC Trf No. 8				71	71	5
FERC Trf No. 8						6
FERC Trf No. 8				160	160	7
FERC Trf No. 8				390	390	8
FERC Trf No. 8				600	600	9
FERC Trf No. 8				103	103	10
FERC Trf No. 8				2,364	2,364	11
FERC Trf No. 8				7,791	7,791	12
FERC Trf No. 8				31,780	31,780	13
FERC Trf No. 8				881	881	14
FERC Trf No. 8				8	8	15
FERC Trf No. 8				43,324	43,324	16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			81	**3,225,567**	**3,225,567**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2010	End of 2009/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.
	861		861	1
	187		187	2
	1,084		1,084	3
	1,438		1,438	4
	284		284	5
	200		200	6
	640		640	7
	1,560		1,560	8
1,615			1,615	9
	412		412	10
	6,216		6,216	11
92,465			92,465	12
341,025			341,025	13
	3,524		3,524	14
	32		32	15
	88,104		88,104	16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
8,122,208	**1,002,697**	**51,569**	**9,176,474**	

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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) 04/16/2010	Year/Period of Report End of 2009/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Bonneville Power Admin	LFP			1,173,079			1,173,079
2	Bonneville Power Admin	LFP			7,289,568		1,142,002	8,431,570
3	Bonneville Power Admin	LFP			788,931			788,931
4	Bonneville Power Admin	FNS			1,177,855		327,687	1,505,542
5	Bonneville Power Admin	OS					24,360	24,360
6	Bonneville Power Admin	SFP						
7	Bonneville Power Admin	NF	39,526	39,526		170,201	-1,305	168,896
8	Grant PUD	LFP			45,222		12,661	57,883
9	Kootenai Electric Coop	LFP						
10	Northern Lights	LFP			140,006			140,006
11	NorthWestern Energy	NF	27,643	27,643		226,163		226,163
12	Northwestern Energy	SFP						
13	Portland General Elec	LFP			646,608	25,032		671,640
14	Portland General Elec	NF						
15	Puget Sound Energy	NF						
16	Rainbow Energy Mkt	NF						
	TOTAL		119,737	119,737	11,261,269	584,067	1,505,405	13,350,741

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2010	End of 2009/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Seattle City Light	NF	18,843	18,843		28,265		28,265
2	Snohomish PUD	NF						
3	Tacoma Power	NF	33,725	33,725		134,406		134,406
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		119,737	119,737	11,261,269	584,067	1,505,405	13,350,741

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2010	End of 2009/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	519,077
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	124,584
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Miscellaneous General Expenses	1,167,539
7	Community Relations	634,630
8	Education and Informational	29,020
9	Other Miscellaneous General Expenses	132,361
10	Directors Fees and Expenses	521,895
11		
12		
13		
14		
15		
16		
17		
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44		
45		
46	TOTAL	3,129,106

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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) 04/16/2010	Year/Period of Report End of 2009/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			3,986,275		3,986,275
2	Steam Production Plant	10,392,947				10,392,947
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	7,905,265				7,905,265
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	8,764,880			2,450,031	11,214,911
7	Transmission Plant	9,428,800				9,428,800
8	Distribution Plant	26,627,445				26,627,445
9	Regional Transmission and Market Operation					
10	General Plant	2,737,339				2,737,339
11	Common Plant-Electric	5,252,346		1,031,569		6,283,915
12	TOTAL	71,109,022		5,017,844	2,450,031	78,576,897

B. Basis for Amortization Charges

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2010	Year/Period of Report End of 2009/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	50,467	65.00	-5.00	2.28	S1.5	17.88
15	312	76,183	60.00	-10.00	2.70	R1	18.57
16	314	18,647	50.00	-10.00	3.39	O1	28.07
17	315	9,386	55.00	-5.00	2.49	S1.5	20.78
18	316	8,838	50.00		2.26	R2	15.88
19	Subtotal	163,521					
20							
21	Colstrip No. 4						
22	311	49,618	65.00	-5.00	2.35	S1.5	21.32
23	312	49,311	60.00	-10.00	2.83	R1	23.84
24	314	16,284	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	4,212	50.00		2.46	R3	19.98
27	Subtotal	126,131					
28							
29	Kettle Falls						
30	310	148	35.00		2.19	SQ	
31	311	24,819	65.00	-5.00	2.34	S1.5	20.59
32	312	40,801	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	2,600	50.00		2.68	R2	21.44
36	Subtotal	92,514					
37							
38	HYDRO PLANT						
39	Cabinet Gorge						
40	330	7,725	75.00		2.75	R3	67.57
41	331	10,168	110.00	-5.00	1.62	R0.5	56.19
42	332	31,081	100.00		1.79	R1.5	77.96
43	333	37,441	60.00	-5.00	2.59	R1.5	52.14
44	334	5,458	45.00		1.43	R2.5	16.54
45	335	2,615	65.00		0.13	R1	1.20
46	336	1,099	60.00		2.05	S2.5	17.49
47	Subtotal	95,587					
48							
49	Noxon Rapids						
50	330	29,974	75.00		2.83	R3	69.37

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2010	Year/Period of Report End of 2009/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	331	13,151	110.00	-5.00	1.77	R0.5	81.53
13	332	31,974	100.00		1.79	R1.5	75.35
14	333	66,931	60.00	-5.00	2.89	R1.5	56.01
15	334	14,202	45.00		2.53	R2.5	43.88
16	335	3,370	65.00		0.97	R1	19.90
17	336	225	60.00		2.12	R2.5	39.60
18	Subtotal	159,827					
19							
20	Post Falls						
21	330	2,732	75.00		3.79	R3	56.46
22	331	1,297	110.00	-5.00	0.36	R0.5	56.29
23	332	6,044	100.00		2.72	R1.5	92.62
24	333	2,234	60.00	-5.00	0.16	R1.5	
25	334	677	45.00		0.14	R2.5	0.01
26	335	223	65.00		2.68	R1	53.83
27	Subtotal	13,207					
28							
29	Long Lake						
30	330	418	75.00		5.68	R3	45.63
31	331	1,847	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	31,079					
37							
38	Little Falls						
39	330	4,217	75.00		7.03	R3	56.31
40	331	1,247	110.00	-5.00	0.12	R0.5	2.00
41	332	5,025	100.00		1.51	R1.5	51.95
42	333	3,964	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	16,624					
46							
47	Upper Falls						
48	330	64	75.00		2.48	R4	37.64
49	331	582	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 Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2010	Year/Period of Report End of 2009/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	1,136	60.00	-5.00	0.90	R1.5	6.67
13	334	4,593	45.00		1.85	R2.5	37.00
14	335	107	65.00		2.30	R1	51.46
15	Subtotal	13,608					
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	11,862	100.00		2.16	R1.5	72.53
21	333	9,611	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	28,986					
26							
27	Monroe Street						
28	331	8,420	110.00	-5.00	1.82	R0.5	109.02
29	332	8,045	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	29,259					
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	428	40.00		8.54	S1.5	11.83
43	346	300			1.24	SQ	
44	Subtotal	12,820					
45							
46	Rathdrum Turbine						
47	341	3,256			3.95	SQ	
48	342	1,700	55.00		4.10	R2.5	44.14
49	343	3,659	50.00		3.61	S2.5	33.50
50	344	48,858	45.00		3.37	R3	35.49

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	2,552	40.00		3.56	S1.5	
13	Subtotal	60,025					
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	782			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	30,093	45.00		2.84	R3	32.97
27	345	313	40.00		2.97	S1.5	31.24
28	346	7			2.69	SQ	
29	Subtotal	31,368					
30							
31	Coyote Springs 2						
32	341	11,340			2.76	SQ	
33	342	19,128	55.00		2.85	R3	44.23
34	344	117,158	45.00		2.92	R3	41.58
35	345	12,696	40.00		3.10	S1.5	32.07
36	346	1,082			2.76	SQ	
37	Subtotal	161,404					
38							
39	Solar Power	64					
40	Subtotal	64					
41	TRANSMISSION PLANT						
42	350	16,092	75.00		1.28	R4	53.27
43	352	16,041	60.00	-5.00	1.61	R4	44.73
44	353	177,679	47.00	-15.00	2.39	R3	31.13
45	354	17,113	70.00	-20.00	1.87	S3	43.89
46	355	131,721	60.00	-30.00	1.84	R3	37.27
47	356	106,233	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

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	471,686					
13							
14	DISTRIBUTION PLANT						
15	361	14,030	55.00	-10.00	1.80	R3	35.51
16	362	93,198	42.00	-10.00	2.60	R1.5	28.26
17	364	214,303	50.00	-25.00	2.66	R2.5	34.66
18	365	139,009	50.00	-15.00	2.46	R2.5	35.35
19	366	74,816	45.00	-10.00	2.71	R3	36.09
20	367	123,156	28.00	-15.00	6.38	L4	23.05
21	368	169,575	44.00	-5.00	2.00	R2	27.21
22	369	115,182	60.00	-15.00	1.63	R3	38.01
23	370	45,007	38.00		2.39	S1	33.72
24	373	14,931	32.00	-15.00	1.08	R2.5	8.68
25	373.4	14,411	32.00	-5.00	2.82	R2.5	18.79
26	Subtotal	1,017,618					
27							
28	GENERAL PLANT						
29	390.1	3,432	55.00	-5.00	1.85	S2	20.91
30	391.1	1,164	5.00		17.67	SQ	3.80
31	393	383	25.00		2.25	SQ	22.97
32	394	3,455	20.00		4.22	SQ	10.35
33	395	1,468	15.00		7.72	SQ	7.82
34	397	39,100	15.00		5.40	SQ	5.17
35	398	9	10.00		2.37	SQ	7.80
36	Subtotal	49,011					
37							
38	MISC POWER						
39	392	2,589	11.00	10.00	3.70	S3	
40	396	2,236	15.00	10.00	5.40	L2	
41	Subtotal	4,825					
42							
43	TOTAL COMPANY	2,588,333					
44							
45							
46							
47							
48							
49							
50							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2010	End of 2009/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.	2,174,407	200,306	2,374,713	
5					
6					
7					
8					
9	Washington Utilities and Transportation				
10	Commission: includes annual fee and various				
11	other electric dockets	849,719	398,791	1,248,510	
12					
13	Includes annual fee and various other natural				
14	gas dockets	437,753	250,746	688,499	
15					
16	Idaho Public Utilities Commission				
17	Includes annual fee and various other electric				
18	dockets	366,389	221,758	588,147	
19					
20	Includes annual fee and various other natural				
21	gas dockets	153,853	121,621	275,474	
22					
23	Public Utility Commission of Oregon				
24	Includes annual fees and various other natural				
25	gas dockets	496,247	365,904	862,151	
26					
27	Not directly assigned electric		788,336	788,336	
28	Not directly assigned natural gas		305,338	305,338	
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	4,478,368	2,652,800	7,131,168	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2010	Year/Period of Report End of 2009/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	2,374,713					4
							5
							6
							7
							8
							9
							10
Electric	928	1,248,510					11
							12
							13
Gas	928	688,499					14
							15
							16
							17
Electric	928	588,147					18
							19
							20
Gas	928	275,474					21
							22
							23
							24
Gas	928	862,151					25
							26
Electric	928	788,336					27
Gas	928	305,338					28
							29
							30
							31
							32
							33
							34
							35
							36
							37
							38
							39
							40
							41
							42
							43
							44
							45
		7,131,168					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	04/16/2010	End of 2009/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	9,261,834		
4	Transmission	2,458,774		
5	Regional Market			
6	Distribution	4,278,181		
7	Customer Accounts	6,087,189		
8	Customer Service and Informational	302,412		
9	Sales	450,051		
10	Administrative and General	12,850,633		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	35,689,074		
12	Maintenance			
13	Production	2,168,038		
14	Transmission	828,302		
15	Regional Market			
16	Distribution	4,167,758		
17	Administrative and General			
18	TOTAL Maintenance (Total of lines 13 thru 17)	7,164,098		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	11,429,872		
21	Transmission (Enter Total of lines 4 and 14)	3,287,076		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	8,445,939		
24	Customer Accounts (Transcribe from line 7)	6,087,189		
25	Customer Service and Informational (Transcribe from line 8)	302,412		
26	Sales (Transcribe from line 9)	450,051		
27	Administrative and General (Enter Total of lines 10 and 17)	12,850,633		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	42,853,172	8,697,729	51,550,901
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing	814,850		
35	Transmission			
36	Distribution	4,140,801		
37	Customer Accounts	2,657,558		
38	Customer Service and Informational	158,315		
39	Sales	173,349		
40	Administrative and General	4,618,054		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	12,562,927		
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	488,882		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2010	End of 2009/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	673	MW	136,563			
2	Reactive Supply and Voltage						
3	Regulation and Frequency Response	231,202	MWh	56,386	73,849	MW	660,210
4	Energy Imbalance				937	MW	3,868,578
5	Operating Reserve - Spinning	36,705	MWh	623,620	83,136	MWh	985,803
6	Operating Reserve - Supplement	65	MWh	1,095	42,975	MWh	578,840
7	Other	1,353,848	MW	12,103,405	1,353,848	MW	12,103,405
8	Total (Lines 1 thru 7)	1,622,493		12,921,069	1,554,745		18,196,836

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) ☐ An Original (2) ☒ A Resubmission	05/12/2010	End of 2009/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

	expenses				
911	Sales expense sprvsn	0	0	0	#of cust @ yr end
912	Demo and selling expenses	818,688	506,252	312,436	#of cust @ yr end
913	Advertising expenses	184,831	114,294	70,537	#of cust @ yr end
916	Misc sales expenses	498,015	307,957	190,057	#of cust @ yr end
920	Admin & gen salaries	29,027,895	20,977,197	8,050,697	four factor
921	Office supplies & expenses	5,245,288	3,781,351	1,463,937	four factor
922	Admin expenses tranf-cred	0	0	0	four factor
923	Outside srvcs employed	15,344,558	11,054,834	4,289,725	four factor
924	Property insurance	1,498,076	1,079,274	418,802	four factor
925	Injuries and damages	6,252,245	4,670,156	1,582,089	four factor
926	Employee pensions & benefits	51,299,245	37,077,330	14,221,916	four factor
927	Franchise requirement	0	0	0	four factor
928	Regulatory commission expenses	1,094,243	788,336	305,906	four factor
929	Duplicate charges-credit	0	0	0	four factor
930.1	General advertising expenses	341,451	246,582	94,868	four factor
930.2	Misc general expenses	3,791,176	2,776,920	1,014,256	four factor
931	Rents	442,673	311,267	131,406	four factor
935	Maint of general plant	8,145,748	5,942,208	2,203,540	four factor
403	Depreciation	7,173,935	5,252,346	1,921,588	four factor
404	Amort of LTD term plant	5,532,175	3,986,275	1,545,900	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) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/12/2010	Year/Period of Report End of 2009/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	33,379,076
389	Land and Land Rights	5,253,922
390	Structures and Improvements	50,729,510
391	Office Furniture and Equipment	33,342,183
392	Transportation Equipment	2,555,865
393	Stores Equipment	1,260,275
394	Tools, Shop & Garage Equipment	3,091,076
395	Laboratory Equipment	671,326
396	Power Operated Equipment	2,395,936
397	Communications Equipment	20,126,391
398	Miscellaneous Equipment	501,002
399	Asset Retirement Cost	351,680
	Total Common Plant	153,658,240
	Const. Work in Progress	10,459,887
	Total Utility Plant	164,118,127
	Acc. Prov. for Dep. & Amort.	43,861,499
	Net Utility Plant	120,256,628

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	1,070,856	567,832	503,024	#of cust @ yr end
902	Meter reading expenses	4,000,093	2,473,536	1,526,557	#of cust @ yr end
903	Cust rec & collection expenses	13,649,902	7,462,353	6,187,550	#of cust @ yr end
903.90-99	A/R misc fees	553,481	440,687	112,794	net direct plant
904	Uncollectible accounts	5,159,701	2,735,983	2,423,718	#of cust @ yr end
905	Misc cust acct expenses	461,795	244,870	216,925	#of cust @ yr end
907	Cust srvc & Info exp supervision	0	0	0	#of cust @ yr end
908	Cust assistance exp	862,408	533,287	329,121	#of cust @ yr end
909	Info & instruct advert expenses	5,532	2,954	2,578	#of cust @ yr end
910	Misc cust srvc & info	237,087	146,608	90,480	#of cust @ yr end

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	2,393,283		
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	2,882,165		
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)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru	814,850		
56	Transmission (Lines 35 and 47)	488,882		
57	Distribution (Lines 36 and 48)	6,534,084		
58	Customer Accounts (Line 37)	2,657,558		
59	Customer Service and Informational (Line 38)	158,315		
60	Sales (Line 39)	173,349		
61	Administrative and General (Lines 40 and 49)	4,618,054		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	15,445,092	3,129,724	18,574,816
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	58,298,264	11,827,453	70,125,717
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	26,760,626	5,428,240	32,188,866
69	Gas Plant	5,951,789	1,207,286	7,159,075
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	32,712,415	6,635,526	39,347,941
72	Plant Removal (By Utility Departments)			
73	Electric Plant	1,145,306	228,122	1,373,428
74	Gas Plant	72,891	14,518	87,409
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	1,218,197	242,640	1,460,837
77	Other Accounts (Specify, provide details in footnote):			
78	Stores Expense (163)	1,672,921	-1,672,921	
79	Regulatory Assets (182)	7,431		7,431
80	Preliminary Survey (183)	29,584		29,584
81	Small Tools Expense (184)	2,630,995	-2,630,995	
82	Miscellaneous Deferred Debits (186)	625,023		625,023
83	Non-Operating Expenses (417)	373,256		373,256
84	Expenditures or Certain Civic, Political and Realted Activiti	287,734		287,734
85	Employee Incentive Plane (232380)	4,049,397	-4,049,397	
86	DSM Tarrif Rider and Payroll Equialization (242600,242700)	15,863,599	-14,320,765	1,542,834
87	Incentive / Stock Compensation (238000)	305,123		305,123
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	25,845,063	-22,674,078	3,170,985
96	TOTAL SALARIES AND WAGES	118,073,939	-3,968,459	114,105,480

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2010	Year/Period of Report End of 2009/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	2,024	26	800	1,641	340	151	101	69	5
2	February	1,738	10	800	1,394	309	151	110	44	5
3	March	1,954	11	800	1,549	353	151	35	39	194
4	Total for Quarter 1	5,716			4,584	1,002	453	246	152	204
5	April	1,533	1	1100	1,267	233	154	28	30	79
6	May	1,516	29	1600	1,233	228	155	46	75	259
7	June	1,560	4	1800	1,261	244	157	44	150	
8	Total for Quarter 2	4,609			3,761	705	466	118	255	338
9	July	1,787	27	1700	1,466	258	157	53	245	10
10	August	1,825	3	1700	1,488	273	156	36	213	155
11	September	1,721	2	1700	1,419	253	156	49	138	112
12	Total for Quarter 3	5,333			4,373	784	469	138	596	277
13	October	1,631	12	800	1,298	289	155	41	221	8
14	November	1,655	30	1800	1,365	258	154	135	171	30
15	December	2,107	8	1900	1,714	362	154	16	205	168
16	Total for Quarter 4	5,393			4,377	909	463	192	597	206
17	Total Year to Date/Year	21,051			17,095	3,400	1,851	694	1,600	1,025

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2010	End of 2009/Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY	
2	Generation (Excluding Station Use):	
3	Steam	1,460,783
4	Nuclear	
5	Hydro-Conventional	3,765,761
6	Hydro-Pumped Storage	
7	Other	1,636,707
8	Less Energy for Pumping	
9	Net Generation (Enter Total of lines 3 through 8)	6,863,251
10	Purchases	7,373,956
11	Power Exchanges:	
12	Received	688,110
13	Delivered	689,010
14	Net Exchanges (Line 12 minus line 13)	-900
15	Transmission For Other (Wheeling)	
16	Received	3,225,567
17	Delivered	3,225,567
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)	14,236,307

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	8,954,984
23	Requirements Sales for Resale (See instruction 4, page 311.)	
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	4,737,063
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	11,925
27	Total Energy Losses	532,335
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	14,236,307

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2010	Year/Period of Report End of 2009/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	1,337,102	389,676	1,678	26	0800
30	February	1,209,567	410,926	1,429	10	0800
31	March	1,261,417	426,800	1,585	11	0800
32	April	1,073,235	364,901	1,295	1	1100
33	May	1,176,173	466,079	1,258	29	1600
34	June	1,139,301	433,851	1,296	4	1800
35	July	1,300,754	513,784	1,502	27	1700
36	August	1,144,958	375,374	1,522	3	1700
37	September	1,050,008	350,481	1,451	2	1700
38	October	1,037,430	279,674	1,332	12	0800
39	November	1,192,235	484,229	1,400	30	1800
40	December	1,314,127	241,288	1,763	8	1900
41	TOTAL	14,236,307	4,737,063			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2010	End of 2009/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			56.00		
6	Net Peak Demand on Plant - MW (60 minutes)	307			40		
7	Plant Hours Connected to Load	5950			1		
8	Net Continuous Plant Capability (Megawatts)	278			56		
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	1559368000			43000		
13	Cost of Plant: Land and Land Rights	0			129664		
14	Structures and Improvements	11340586			365280		
15	Equipment Costs	150063153			12463105		
16	Asset Retirement Costs	351682			0		
17	Total Cost	161755421			12958049		
18	Cost per KW of Installed Capacity (line 17/5) Including	563.6077			231.3937		
19	Production Expenses: Oper, Supv, & Engr	746337			10097		
20	Fuel	64261305			3493		
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	1729124			2503		
26	Misc Steam (or Nuclear) Power Expenses	21027			2581		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	640772			160		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	1451442			26842		
33	Maintenance of Misc Steam (or Nuclear) Plant	7453			2418		
34	Total Production Expenses	68857460			48094		
35	Expenses per Net KWh	0.0442			1.1185		
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	10696851	0	0	593	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	6.007	0.000	0.000	5.891	0.000	0.000
41	Average Cost of Fuel per Unit Burned	6.007	0.000	0.000	5.891	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	5.890	0.000	0.000	5.776	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.041	0.000	0.000	0.081	0.000	0.000
44	Average BTU per KWh Net Generation	6997.000	0.000	0.000	14607.000	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	04/16/2010	End of 2009/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	226	176	6
5198	8528	483	7
50	222	149	8
50	222	0	9
49	222	0	10
30	210	2	11
183407000	1277376000	44308000	12
941300	1289445	621682	13
24818704	100084999	3255691	14
67547018	189567744	56768863	15
450687	134589	0	16
93757709	291076777	60646236	17
1849.2645	1247.1156	364.2417	18
329066	185385	32915	19
8584021	13774324	2627749	20
0	0	0	21
548822	2065287	0	22
0	0	0	23
0	0	0	24
664432	33208	110412	25
385325	2322513	190033	26
0	29773	0	27
0	0	0	28
105236	392967	165	29
40719	505807	1169	30
1502918	3954168	0	31
1112126	1453190	118078	32
200033	737339	38978	33
13472698	25453961	3119499	34
0.0735	0.0199	0.0704	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
Wood	Gas		Coal	Oil		Gas			36
Tons	MCF		Tons	Bbls		MCF			37
274833	9161	0	803467	1499	0	539630	0	0	38
8500000	1020000	0	17025333	140000	0	1020000	0	0	39
31.064	5.088	0.000	17.003	75.527	0.000	4.870	0.000	0.000	40
31.064	5.088	0.000	17.003	75.527	0.000	4.870	0.000	0.000	41
3.650	4.988	0.000	1.000	12.750	0.000	4.774	0.000	0.000	42
0.047	0.059	0.000	0.011	0.000	0.000	0.059	0.000	0.000	43
12792.000	0.000	0.000	10705.000	0.000	0.000	12423.000	0.000	0.000	44

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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2010	End of 2009/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)	24.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	25			0		
7	Plant Hours Connected to Load	1385			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	27763000			0		
13	Cost of Plant: Land and Land Rights	144733			0		
14	Structures and Improvements	781685			0		
15	Equipment Costs	30586720			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	31513138			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	1313.0474			0.0000		
19	Production Expenses: Oper, Supv, & Engr	29039			0		
20	Fuel	1460673			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	158577			0		
26	Misc Steam (or Nuclear) Power Expenses	13103			0		
27	Rents	104			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	293			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	243917			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	42379			0		
34	Total Production Expenses	1948085			0		
35	Expenses per Net KWh	0.0702			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	259882	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	5.621	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	5.621	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	5.510	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.053	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	9548.000	0.000	0.000	0.000	0.000	0.000

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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2010	End of 2009/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) 04/16/2010	Year/Period of Report End of 2009/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 2545 Plant Name: Monroe Street (b)	FERC Licensed Project No. 2545 Plant Name: Upper Falls (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Run-of-River
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1890	1922
4	Year Last Unit was Installed	1992	1922
5	Total installed cap (Gen name plate Rating in MW)	14.80	10.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	16	11
7	Plant Hours Connect to Load	8,674	5,840
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	15	10
10	(b) Under the Most Adverse Oper Conditions	13	10
11	Average Number of Employees	1	1
12	Net Generation, Exclusive of Plant Use - Kwh	103,900,000	51,612,000
13	Cost of Plant		
14	Land and Land Rights	0	1,081,854
15	Structures and Improvements	8,420,172	582,599
16	Reservoirs, Dams, and Waterways	8,045,079	7,126,169
17	Equipment Costs	12,743,784	5,835,837
18	Roads, Railroads, and Bridges	50,448	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	29,259,483	14,626,459
21	Cost per KW of Installed Capacity (line 20 / 5)	1,976.9921	1,462.6459
22	Production Expenses		
23	Operation Supervision and Engineering	2,771	2,769
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	461,085	484,390
27	Misc Hydraulic Power Generation Expenses	29,151	64,563
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	4,600
30	Maintenance of Structures	2,931	3,746
31	Maintenance of Reservoirs, Dams, and Waterways	24,254	25,608
32	Maintenance of Electric Plant	33,707	48,031
33	Maintenance of Misc Hydraulic Plant	2,599	1,142
34	Total Production Expenses (total 23 thru 33)	556,498	634,849
35	Expenses per net KWh	0.0054	0.0123

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2010	Year/Period of Report End of 2009/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	550	90	6
8,748	6,833	6,900	7
			8
255	557	83	9
116	142	80	10
12	13	5	11
1,060,429,000	1,673,251,000	487,090,000	12
			13
10,572,310	35,831,527	1,597,959	14
10,168,310	13,150,391	1,847,066	15
31,080,974	31,973,870	16,637,951	16
45,514,034	84,502,791	12,176,179	17
1,098,564	225,369	0	18
0	0	0	19
98,434,192	165,683,948	32,259,155	20
371.4498	344.7440	460.8451	21
			22
110,703	89,853	964	23
43,208	0	0	24
0	10,924	19,631	25
1,048,741	1,208,611	650,985	26
46,621	130,016	76,985	27
0	0	0	28
23,844	27,782	2,062	29
103,585	105,765	55,474	30
15,447	22,631	85,175	31
567,474	375,493	206,601	32
32,353	1,661,857	2,119	33
1,991,976	3,632,932	1,099,996	34
0.0019	0.0022	0.0023	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	04/16/2010	End of 2009/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 2545 Plant Name: NIne Mile Falls (b)	FERC Licensed Project No. 2545 Plant Name: Post Falls (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Storage
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1908	1906
4	Year Last Unit was Installed	1994	1980
5	Total installed cap (Gen name plate Rating in MW)	26.40	14.80
6	Net Peak Demand on Plant-Megawatts (60 minutes)	21	18
7	Plant Hours Connect to Load	87,334	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	14	10
11	Average Number of Employees	1	2
12	Net Generation, Exclusive of Plant Use - Kwh	105,851,000	84,350,000
13	Cost of Plant		
14	Land and Land Rights	33,429	3,076,554
15	Structures and Improvements	3,943,110	1,297,912
16	Reservoirs, Dams, and Waterways	11,862,323	6,044,594
17	Equipment Costs	12,544,583	3,133,029
18	Roads, Railroads, and Bridges	625,181	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	29,008,626	13,552,089
21	Cost per KW of Installed Capacity (line 20 / 5)	1,098.8116	915.6817
22	Production Expenses		
23	Operation Supervision and Engineering	2,937	7,062
24	Water for Power	0	0
25	Hydraulic Expenses	12,084	223
26	Electric Expenses	501,116	549,431
27	Misc Hydraulic Power Generation Expenses	51,124	43,688
28	Rents	0	0
29	Maintenance Supervision and Engineering	10,249	664
30	Maintenance of Structures	15,150	91
31	Maintenance of Reservoirs, Dams, and Waterways	153,035	237,537
32	Maintenance of Electric Plant	117,931	206,982
33	Maintenance of Misc Hydraulic Plant	9,086	750
34	Total Production Expenses (total 23 thru 33)	872,712	1,046,428
35	Expenses per net KWh	0.0082	0.0124

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2010	End of 2009/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
6,881	0	0	7
			8
35	0	0	9
34	0	0	10
5	0	0	11
199,278,000	0	0	12
			13
4,325,371	0	0	14
1,246,514	0	0	15
5,025,359	0	0	16
6,135,097	0	0	17
0	0	0	18
0	0	0	19
16,732,341	0	0	20
522.8857	0.0000	0.0000	21
			22
344	0	0	23
0	0	0	24
8,948	0	0	25
565,419	0	0	26
48,265	0	0	27
711,664	0	0	28
1,870	0	0	29
56,565	0	0	30
39,972	0	0	31
168,807	0	0	32
5,000	0	0	33
1,606,854	0	0	34
0.0081	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	04/16/2010	End of 2009/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)		
2	Plant Construction type (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total installed cap (Gen name plate Rating in MW)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	0
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	0	0
35	Expenses per net KWh	0.0000	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2010	End of 2009/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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2010	End of 2009/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Kettle Falls CT	2002	7.20	8.0	5,225,000	9,169,338
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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) 04/16/2010	Year/Period of Report End of 2009/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	237,420	303,438	69,559	Nat Gas	502	1
						2
						3
						4
						5
						6
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2010	End of 2009/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		1,549.00		
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	108.00		1
14	Benewah	Shawnee	230.00	230.00	Steel Pole	60.00		1
15	Noxon Plant	Pine Creek Sub	230.00	230.00	H Type	43.00		1
16	Cabinet Gorge Plant	Noxon	230.00	230.00	H Type	19.00		1
17	Benewah Sw. Station	Pine Creek Sub	230.00	230.00	Steel Tower			1
18	Benewah Sw. Station	Pine Creek Sub	230.00	230.00	H Type	43.00		1
19	Divide Creek	Lolo Sub	230.00	230.00	Steel Tower			1
20	Divide Creek	Lolo Sub	230.00	230.00	H Type	43.00		1
21	N. Lewiston	Walla Walla	230.00	230.00	Steel Tower	4.00		1
22	N. Lewiston	Walla Walla	230.00	230.00	H Type	43.00		1
23	N. Lewiston	Shawnee	230.00	230.00	Steel Tower	7.00		1
24	N. Lewiston	Shawnee	230.00	230.00	H Type	27.00		1
25	Walla Walla	Wanapum	230.00	230.00	Alum.			1
26	Walla Walla	Wanapum	230.00	230.00	H Type	78.00		1
27	BPA (Libby)	Noxon Plant	230.00	230.00	Steel Tower	1.00		1
28	BPA/Hot Springs #1	Noxon Plant	230.00	230.00	Steel Tower	1.00		1
29	BPA/Hot Springs #2	Noxon Plant (dead)	230.00	230.00	Steel Tower		2.00	1
30	BPA/Hot Springs #2	Noxon Plant	230.00	230.00	H Type	68.00		1
31	BPA Line	West Side Sub	230.00	230.00	Steel Pole	2.00		2
32	Hatwai	N. Lewiston Sub	230.00	230.00	H Type	7.00		1
33	Divide Creek	Imnaha	230.00	230.00	H Type	20.00		1
34	Colstrip Plant	Broadview	500.00	500.00				
35								
36					TOTAL	2,216.00	3.00	31

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2010	End of 2009/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
	136,038	70,092	206,130					1
								2
	8,930,844	92,755,469	101,686,313	441,475	726,272		1,167,747	3
								4
795 McMACSR	17,913	1,334,573	1,352,486		327		327	5
1272 McMACSR								6
1272 ACSS								7
1272 ACSS	30,323	3,273,923	3,304,246		1,408		1,408	8
795 McMACSR								9
1590 ACSS								10
795 McMACSR	324,327	36,029,040	36,353,367		104,827		104,827	11
795 McMACSR								12
1272 McMAL	456,162	6,761,817	7,217,979	1,202	59,226		60,428	13
1590 ACSS	570,207	47,541,250	48,111,457	187	97		284	14
954 McMAL	105,647	18,015,979	18,121,626	1,508	59,576		61,084	15
954 McMAL	49,049	1,076,579	1,125,628	19,149	36,160		55,309	16
954 McMAL								17
954 McMAL	157,193	2,600,653	2,757,846	3,582	324,270		327,852	18
1272 McMAL								19
1272 McMAL	86,228	3,692,730	3,778,958	4,038	177,005		181,043	20
1272 McMAL								21
1272 McMAL	623,984	6,265,206	6,889,190	1,416	9,876		11,292	22
1272 McMAL								23
1272 McMAL	872,151	8,067,073	8,939,224					24
1272 McMAL								25
1272 McMAL	70,781	2,573,418	2,644,199	4,444	4,474		8,918	26
1272 McMAL								27
1272 McMAL		19,521	19,521	597	7,220		7,817	28
1272 McMAL								29
1272 McMAL	144,638	3,304,585	3,449,223	156	55,197		55,353	30
1272 McMAL	36,461	594,543	631,004		122		122	31
1272 McMACSR	106,581	2,533,547	2,640,128	285	2,818		3,103	32
1272 McMAL	60,302	1,297,751	1,358,053					33
	595,789	28,967,914	29,563,703	236,495	178,667	75,735	490,897	34
								35
	13,374,618	266,775,663	280,150,281	714,534	1,747,542	75,735	2,537,811	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	04/16/2010	End of 2009/Q4

TRANSMISSION LINES ADDED DURING YEAR

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

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)	(c)	Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1	None added in 2009						
2							
3							
4							
5							
6							
7							
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43							
44	TOTAL						

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2010	Year/Period of Report End of 2009/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)	
			115						1
									2
									3
									4
									5
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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) 04/16/2010	Year/Period of Report End of 2009/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	Dry Creek	Transm. Unattended	230.00	115.00	13.80
14	Dry Gulch	Distr. Unattended	115.00	13.80	
15	East Colfax	Distr. Unattended	115.00	13.80	
16	East Farms	Distr. Unattended	115.00	13.80	
17	Fort Wright	Distr. Unattended	115.00	13.80	
18	Francis and Cedar	Distr. Unattended	115.00	13.80	
19	Gifford	Distr. Unattended	115.00	34.00	
20	Glenrose	Distr. Unattended	115.00	13.80	
21	Greenwood	Distr. Unattended	115.00	13.80	
22	Hallett & White	Distr. Unattended	115.00	13.80	
23	Indian Trail	Dist. Unattended	115.00	13.80	
24	Industrial Park	Dist. Unattended	115.00	13.80	
25	Kettle Falls	Distr. Unattended	115.00	13.80	
26	Lee & Reynolds	Distr. Unattended	115.00	13.80	
27	Liberty Lake	Distr. Unattended	115.00	13.80	
28	Little Falls 115/34Kv	Distr. Unattended	115.00	34.00	
29	Lyons & Standard	Distr. Unattended	115.00	13.80	
30	Mead	Distr. Unattended	115.00	13.80	
31	Metro	Distr. Unattended	115.00	13.80	
32	Milan	Distr. Unattended	115.00	13.80	
33	Millwood	Dist. Unattended	115.00	13.80	
34	Ninth & Central	Distr. Unattended	115.00	13.80	
35	Northeast	Distr. Unattended	115.00	13.80	
36	Northwest	Distr. Unattended	115.00	13.80	
37	Opportunity	Dist. Unattended	115.00	13.80	
38	Othello	Distr. Unattended	115.00	13.80	
39	Post Street	Distr. Unattended	115.00	13.80	
40	Pound Lane	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) 04/16/2010	Year/Period of Report End of 2009/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	2	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
15	3					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
150	1		Two Stage Fan & Caps	223	250	13
24	2		Frcd Oil & Air Fan	2	40	14
12	1		FrOil/Air Fan	1	20	15
12	1		Two Stage Fan	1	20	16
24	2		Fr Oil/Air/2StgFan	2	40	17
36	2		Two Stage Fan	2	60	18
12	1					19
12	1		Frcd Oil & Air Fan	1	20	20
12	1		Two Stage Fan	1	20	21
12	1		Two Stg Fan	1	20	22
12	1		Two Stage Fan	1	20	23
28	3		Two Stg/Pt/Frcd Oil	15	45	24
12	1		Frcd Oil & Air Fan	1	20	25
12	1		Two Stage Fan	1	20	26
24	2		Two Stage Fan	2	40	27
12	1					28
36	2		Two Stage Fan	2	60	29
18	1		Two Stage Fan	1	30	30
24	2		Two Stage Fan	2	40	31
24	2		Frcd Oil & Air Fan	2	40	32
24	2		FrcAir/FrcOil/AirFan	2	36	33
24	2	1	Frcd & Two Stage Fan	2	40	34
24	2		Two Stage Fan	2	40	35
24	2		Two Stage Fan	2	40	36
12	1		Two Stage Fan	1	20	37
24	2		FrOil/AirFan	2	40	38
36	2		Frcd Oil & Wt Fan	2	60	39
24	2		Two Stage Fan	2	40	40

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2010	Year/Period of Report End of 2009/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	Pullman	Dist Unattended	115.00	13.80	
2	Ross Park	Distr. Unattended	115.00	13.80	
3	Roxboro	Distr. Unattended	115.00	24.00	
4	Shawnee	Trans. Unattended	230.00	115.00	13.80
5	Silver Lake	Distr. Unattended	115.00	13.80	
6	Southeast	Distr. Unattended	115.00	13.80	
7	South Othello	Distr. Unattended	115.00	13.80	
8	South Pullman	Distr. Unattended	115.00	13.80	
9	Sunset	Distr. Unattended	115.00	13.80	
10	Terre View	Dist. Unattended	115.00	13.80	
11	Third & Hatch	Distr. Unattended	115.00	13.80	
12	Waikiki	Distr. Unattended	115.00	13.80	
13	West Side	Trans. Unattended	230.00	115.00	13.80
14	Other: 72substa less than 10MVA	Distr. Unattended			
15					
16	STATE OF IDAHO				
17	Appleway	Dist. Unattended	115.00	13.80	
18	Avondale	Dist. Unattended	115.00	13.80	
19	Benewah	Trans. Unattended	230.00	115.00	13.80
20	Big Creek	Distr. Unattended	115.00	13.80	
21	Blue Creek	Distr. Unattended	115.00	13.80	
22	Bunker Hill Limited	Distr. Unattended	115.00	13.80	
23	Cabinet Gorge (Switchyard)	Trans. Unattended	230.00	115.00	13.80
24	Clark Fork	Distr. Unattended	115.00	21.80	
25	Coeur d'Alene 15th Ave	Distr. Unattended	115.00	13.80	
26	Cottonwood	Distr. Unattended	115.00	24.90	
27	Dalton	Distr. Unattended	115.00	13.80	
28	Grangeville	Distr. Unattended	115.00	13.80	
29	Holbrook	Distr. Unattended	115.00	13.80	
30	Huetter	Distr. Unattended	115.00	13.80	
31	Idaho Road	Distr Unattended	115.00	13.80	
32	Juliaetta	Distr. Unattended	115.00	13.80	
33	Kamiah	Dist. Unattended	115.00	13.80	
34	Kooskia	Distr. Unattended	115.00	13.80	
35	Lolo	Tran & Dist Unattnd	230.00	115.00	13.80
36	Moscow	Distr. Unattended	115.00	13.80	
37	Moscow 230Kv	Tran & Dist Unattnd	230.00	115.00	13.80
38	North Moscow	Distr. Unattended	115.00	13.80	
39	North Lewiston 230kV	Trans Unattended	230.00	115.00	13.80
40	North Lewiston	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) 04/16/2010	Year/Period of Report End of 2009/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		Frcd Oil & Air Fan	2	40	1
30	2		Two Stage Fan	2	60	2
24	2		Two Stage Fan	2	40	3
150	1		Two Stage Fan		250	4
12	1		Frcd Oil & Air Fan	1	20	5
30	2		Two Stage Fan	2	50	6
12	1		Two Stage Fan	1	20	7
30	2		Two Stage Fan	2	50	8
35	4	1	Pt. & Two Stage Fan	52	50	9
12	1		Two Stage Fan	1	20	10
54	3		Two Stg Fan & Cap	103	90	11
24	2		Two Stage Fan	2	40	12
250	2					13
189	136					14
						15
						16
30	2		Two Stage Fan	2	50	17
12	1		Frcd Oil & Air Fan	1	20	18
75	1		Two Stage Fan & Caps	223	125	19
17	2		Portable Fan	2	22	20
20	3	1				21
12	1		Frcd Air Fan	1	26	22
75	1		Two Stage Fan	1	125	23
10	1		Frcd Air Fan	1	13	24
36	2		Two Stage Fan	2	60	25
12	1		Two Stage Fan	1	20	26
24	2		FrcOil/Air2StgFan	2	40	27
25	4		FrcdOil/Air/Pt Fan	2	34	28
12	1		Two Stage Fan	1	20	29
12	1		Two Stage Fan	1	20	30
12	1		Two Stage Fan	1	20	31
12	1		Frcd Oil & Air Fan	1	20	32
12	1		Two Stage Fan	1	20	33
15	3		Frcd Air Fan	2	20	34
262	3		Frcd Oil/Air/Two Stg	1	270	35
24	2		FrOil/Air/2Stg Fan	2	40	36
137	2	1	Capacitors	48		37
12	1		Two Stage Fan	1	20	38
250	1	1	Capacitors	48		39
10	3					40

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2010	Year/Period of Report End of 2009/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	Oden	Distr. Unattended	115.00	21.80	
2	Oldtown	Distr. Unattended	115.00	21.80	
3	Orofino	Distr. Unattended	115.00	13.80	
4	Osburn	Distr. Unattended	115.00	13.80	
5	Pine Creek	Tran & Dist Unattnd	230.00	115.00	13.80
6	Pleasant View	Distr. Unattended	115.00	13.80	
7	Plummer	Dist Unattended	115.00	13.80	
8	Post Falls	Distr. Unattended	115.00	13.80	
9	Potlatch	Distr. Unattended	115.00	13.80	
10	Prarie	Distr. Unattended	115.00	13.80	
11	Priest River	Distr. Unattended	115.00	20.80	
12	Rathdrum	Trans & Distr Unattd	230.00	115.00	13.80
13	Sagle	Dist. Unattended	115.00	20.80	
14	Sandpoint	Distr. Unattended	115.00	20.80	
15	South Lewiston	Distr. Unattended	115.00	13.80	
16	Sweetwater	Distr. Unattended	115.00	24.90	
17	St. Maries	Distr. Unattended	115.00	23.90	
18	Tenth & Stewart	Distr. Unattended	115.00	13.80	
19	Wallace	Distr. Unattended	115.00	13.80	
20	Other: 28 substa less than 10 MVA	Distr. Unattended			
21					
22	STATE OF MONTANA				
23	1 substation less than 10 MVA	Distr. Unattended			
24					
25	SUBSTA. @ GENERATING PLANTS				
26	STATE OF WASHINGTON				
27	Boulder Park	Trans. Attended	115.00	13.80	
28	Kettle Falls	Trans. Attended	115.00	13.80	
29	Long Lake	Trans. Attended	115.00	4.00	4.00
30	Nine Mile	Trans. Attended	115.00	13.80	2.30
31	Little Falls	Trans. Attended	115.00	4.00	
32	Northeast	Trans. Attended	115.00	13.80	
33	Post Street	Trans. Attended	13.80	4.00	35.00
34					
35	STATE OF IDAHO				
36	Cabinet Gorge (HED)	Trans. Attended	230.00	13.80	
37	Post Falls	Trans. Attended	115.00	2.30	
38	Rathdrum	Trans. Attended	115.00	13.80	
39	STATE OF MONTANA				
40	Noxon	Trans. Attended	230.00	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	04/16/2010	End of 2009/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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
10	1		Frcd Air Fan		13	1
18	2		Frcd Air Fan	2	22	2
20	2		Frcd Oil & Air Fan	1	28	3
12	1		Portable Fan	1	15	4
262	3		Capacitors	48		5
12	1		Two Stage Fan	1	20	6
12	1		Two Stage Fan	1	20	7
18	1		Two Stage Fan	1	30	8
15	2		Portable Fan	2	19	9
12	1		Frcd Oil & Air Fan	1	20	10
10	1	1	Frcd Air Fan	1	13	11
462	3		Frcd Oil & Air Fan	49	470	12
12	1		Two Stage Fan	1	20	13
30	3		Frcd Air Fan	3	38	14
27	4		Port Fan/FrcdOil/Air	4	39	15
12	1		Frcd Oil & Air Fan	1	20	16
24	2		Two Stage Fan	2	40	17
30	2		Frcd Oil/Air/Two Stg	2	50	18
10	3					19
74	45	1				20
						21
						22
5	1					23
						24
						25
						26
36	1		Two Stage Fan	1	60	27
34	1	1	Two Stage Fan	1	62	28
80	4	1				29
24	2		Frcd Oil & Air Fan	1	40	30
24	2		Frcd Oil & Air Fan	2	40	31
36	1		Two Stage Fan	1	60	32
2						33
						34
						35
300	6	1	Frcd Oil and Air Fan	2	30	36
16	2		Frcd Air/Oil/Air Fan	2	21	37
114	2	3	Two Stage Fan	2	190	38
						39
555	9	1				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	04/16/2010	End of 2009/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					
2	STATE OF OREGON				
3	Coyote Springs II	Trans. Attended	500.00	13.80	18.00
4					
5	SUMMARY:				
6	Washington:				
7	4 subs	Trans. Unattended			
8	118subs	Distr. Unattended			
9	1 subs	Tran & Dist Unattnd			
10	7 subs	Trans. Attended			
11	Idaho:				
12	3 subs	Trans. Unattended			
13	63 subs	Distr. Unattended			
14	4 subs	Tran & Dist Unattnd			
15	3 subs	Trans. Attended			
16	Montana: 1 sub	Trans. Attended			
17	1 sub	Distr. Unattended			
18	Oregon: 1 sub	Trans. Unattended			
19	System: 206 subs				
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
						2
213	1	1	Two Stage fan	1	355	3
						4
						5
						6
850						7
1192						8
536						9
269						10
						11
400						12
666						13
1123						14
430						15
555						16
5						17
213						18
6239						19
						20
						21
						22
						23
						24
						25
						26
						27
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						31
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						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	04/16/2010	2009/Q4

FOOTNOTE DATA

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

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

Includes: Change in Removal Work in Progress - $179,908

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:

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.: 24 Column: b
Total Charges Incurred Life to Date.

Schedule Page: 231 Line No.: 25 Column: b
Total Charges Incurred Life to Date.

Schedule Page: 231 Line No.: 25 Column: d
Total Reimbursements Received Life to Date.

Schedule Page: 231 Line No.: 26 Column: b
Total Charges Incurred Life to Date.

Schedule Page: 231 Line No.: 27 Column: b
Total Charges Incurred Life to Date.

Schedule Page: 231 Line No.: 27 Column: d
Total Reimbursements Received 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.

Schedule Page: 231 Line No.: 33 Column: b
Total Charges Incurred Life to Date.

Schedule Page: 231 Line No.: 34 Column: b
Total Charges Incurred Life to Date.

Schedule Page: 310 Line No.: 3 Column: b
SWAP
Schedule Page: 310 Line No.: 5 Column: b
SWAP
Schedule Page: 310 Line No.: 7 Column: b
BPA Contract Terminates September 30, 2011.
Schedule Page: 310 Line No.: 8 Column: b
BPA Contract Terminates January 1, 2036.
Schedule Page: 310.1 Line No.: 7 Column: c
Pondage
Schedule Page: 310.1 Line No.: 14 Column: c
Pondage
Schedule Page: 310.2 Line No.: 7 Column: b
SWAP
Schedule Page: 310.2 Line No.: 9 Column: b
SWAP
Schedule Page: 310.2 Line No.: 14 Column: b
SWAP
Schedule Page: 310.3 Line No.: 2 Column: b
Loss Return
Schedule Page: 310.3 Line No.: 4 Column: b
Bundled Transmission
Schedule Page: 310.3 Line No.: 7 Column: b
Loss Return
Schedule Page: 310.3 Line No.: 9 Column: b
Capacity Contract expires June 30, 2010
Schedule Page: 310.3 Line No.: 10 Column: b
Bundled Transmission
Schedule Page: 310.3 Line No.: 12 Column: b
Capacity Sale expires January 6, 2011.
Schedule Page: 310.3 Line No.: 13 Column: b
Bundled Transmission
Schedule Page: 310.3 Line No.: 14 Column: b
Contract terminates January 6, 2011.
Schedule Page: 310.4 Line No.: 3 Column: b
NorthWestern Energy LLC sale expires October 31, 2013.
Schedule Page: 310.4 Line No.: 9 Column: b
PacifiCorp sale terminates October 31, 2013.
Schedule Page: 310.4 Line No.: 10 Column: c
Pondage
Schedule Page: 310.4 Line No.: 11 Column: b
Peaker, LLC capacity contract terminates December 31, 2016.
Schedule Page: 310.4 Line No.: 12 Column: b
Contract expires 9/30/2014.
Schedule Page: 310.4 Line No.: 13 Column: b
Contract expires 9/30/2014.
Schedule Page: 310.5 Line No.: 4 Column: c
Pondage
Schedule Page: 310.5 Line No.: 8 Column: b
Bundled Transmission
Schedule Page: 310.5 Line No.: 11 Column: b
PPL sale terminates October 31, 2013.
Schedule Page: 310.5 Line No.: 13 Column: b
Puget Sound Energy sale terminates October 31, 2013.

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

Contract expires 2014.

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

SWAP

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

Sovereign Power contract terminates 1-31-2010

Schedule Page: 310.7 Line No.: 4 Column: b

Sovereign Power Contract terminates 1-31-2010

Schedule Page: 310.7 Line No.: 11 Column: a

Intracompany Wheeling

Schedule Page: 310.7 Line No.: 11 Column: b

IntraCompany Wheeling terminates 09/30/2023.

Schedule Page: 310.7 Line No.: 12 Column: a

Intracompany Generation - Sale of Ancillary Services

Schedule Page: 310.7 Line No.: 12 Column: b

IntraCompany Generation - Sale of Ancillary Services.

Schedule Page: 310.7 Line No.: 13 Column: b

Estimated revenues - true up in later periods.

FOOTNOTE DATA

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

Fianncial Swap

Schedule Page: 326 Line No.: 6 Column: a

Financial Swap

Schedule Page: 326 Line No.: 11 Column: a

Non Monetary

Schedule Page: 326 Line No.: 13 Column: a

Ancillary Services - Spinning & Supplemental

Schedule Page: 326 Line No.: 14 Column: a

Non Monetary

Schedule Page: 326.1 Line No.: 11 Column: a

Non Monetary

Schedule Page: 326.2 Line No.: 12 Column: a

Financial Swap

Schedule Page: 326.3 Line No.: 7 Column: a

Financial Swap

Schedule Page: 326.3 Line No.: 8 Column: a

Non Monetary

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

Non Monetary

Schedule Page: 326.4 Line No.: 7 Column: a

Non Monetary

Schedule Page: 326.5 Line No.: 7 Column: a

Financial Swap

Schedule Page: 326.6 Line No.: 3 Column: a

Non Monetary

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) X An Original (2) _ A Resubmission	04/16/2010	2009/Q4

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.: 7 Column: a

Ancillary Services

Schedule Page: 335 Line No.: 6 Column: b

Schedule Page: 335 Line No.: 6

Vendor	Purpose	Amount
VENDORS LESS THAN $5,000		102,137
3D INTERNET	Miscellaneous	3,602
ADVENTURES IN ADVERTISING	Miscellaneous	13,408
AMEREN	Professional Services	11,747
AZAR'S FOOD SERVICES	Treasury Fee	11,984
BANK OF NY - PERSHING	Miscellaneous	38,896
BNY MELLON	Postage	5,709
BOARDVANTAGE INC	Professional Services	20,749
BROADRIDGE	General Services	54,372
CAREY INTERNATIONAL INC	Employee Car Rental	5,572
CITIBANK NA	Miscellaneous	36,685
CITY OF SPOKANE	Miscellaneous	14,286
COATES KOKES	Professional Services	21,604
CORP CREDIT CARD	Subscriptions	46,994
CORPORATE EXECUTIVE BOARD	Subscriptions	9,069
DAVID D HOLMES	Office Supplies	4,535
DAVIS WRIGHT TREMAINE LLP	Miscellaneous	3,660
DESAUTEL HEGE COMMUNICATIONS	Professional Services	14,357
DEWEY & LEBOEUF LLP	General Services	14,194
EDISON ELECTRIC INSTITUTE	Board Meeting	5,000
EDS CORPORATION	Miscellaneous	18,613
ENERGY INDUSTRY CBT ALLIANCE	Miscellaneous	5,043
FITCH RATINGS	Miscellaneous	30,619
GARD COMMUNICATIONS	Professional Services	29,230
J CRAIG SWEAT PHOTOGRAPHY	Miscellaneous	5,973
MARK T THIES	Employee Misc Expenses	22,624
MARKET DECISIONS CORPORATION	Professional Services	17,874
MELLON INVESTOR SERVICES LLC	Miscellaneous	100,766
MICHAEL G ANDREA	Employee Misc Expenses	6,940
MICHAEL G FOSTER SCHOOL OF BUSINESS	Miscellaneous	18,011
MOODYS INVESTORS SERVICE	Miscellaneous	71,324
NYSE MARKET INC	General Services	36,512
PAT NEWMANN	Professional Services	10,606
PATRICIA J SHEA	Employee Misc Expenses	4,171
R R DONNELLEY RECEIVABLES INC	Rating Agency Fees	6,057
ROGER D WOODWORTH	Materials & Equipment	6,448
SIMANTEL	Professional Services	6,974
SUMTOTAL SYSTEMS INC	Miscellaneous	4,562
THE BANK OF NEW YORK MELLON	Miscellaneous	11,837
THE COEUR D ALENE RESORT	Miscellaneous	20,527
THE DAVENPORT HOTEL	Miscellaneous	21,236
THE LAUREL HILL ADVISORY GROUP LLC	General Services	5,326
VERIFORCE	Miscellaneous	7,244
WASHINGTON STATE UNIVERSITY	Miscellaneous	8,105
WILMINGTON TRUST COMPANY	Miscellaneous	3,602

Schedule Page: 335 Line No.: 10

Directors	2009 Expenses
Vendor Name	
HEIDI B STANLEY	$69,644
BRIAN W DUNHAM	$34,167
MARK RACICOT	$9,441
ERIK J ANDERSON	$79,858
KRISTIANNE BLAKE	$64,528
JOHN F KELLY	$75,683
MICHAEL L NOEL	$50,942
R JOHN TAYLOR	$73,353
JACK W GUSTAVEL	-$22,544
ROY EIGUREN	$71,273
SCOTT MORRIS	$15,541

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.

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.

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

License period from August 1, 1972 to July 31, 2007. Extended one year 07-09.

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

License period from August 1, 1972 to July 31, 2007. Extended one year 07-09.

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 August 1, 1972 to July 31, 2007. Extended one year 07-09.

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

License period from August 1, 1972 to July 31, 2007. Extended one year 07-09.

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

Licensed period from August 1, 1972 to July 31, 2007. Extended one year 07-09.

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

Not a licensed project.

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Avista Corp.

2009
IDAHO Annual Report

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Avista Corp.

2009
IDAHO Electric Report

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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 16, 2010	December 31, 2009

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)	908,790,620	750,833,839
4	Property Under Capital Leases	499,578	78,643
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Investment in Kettle Falls		
8	TOTAL (Enter Total of lines 3 thru 7)	909,290,198	750,912,482
9	Leased to Others		
10	Held for Future Use	174,049	
11	Construction Work in Progress	3,606,293	3,225,486
12	Acquisition Adjustments	0	0
13	TOTAL Utility Plant (Enter Total of lines 8 thru 12)	913,070,540	754,137,968
14	Accum. Prov. for Depr., Amort., & Depl.	0	0
15	Net Utility Plant (Enter total of line 13 less 14)	913,070,540	754,137,968
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

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	April 16, 2010	December 31, 2009

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
147,715,332				10,241,449	3
420,935					4
					5
					6
					7
148,136,267				10,241,449	8
					9
174,049					10
341,280				39,527	11
					12
148,651,596				10,280,976	13
0					14
148,651,596				10,280,976	15
					16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
0				0	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
2 Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	April 16, 2010	December 31, 2009

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 Un-Classified; 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	9,036,684	1,572,741
4	(303) Miscellaneous Intangible Plant	-	781,818
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	9,036,684	2,354,559
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	5,953,536	658,508
28	(331) Structures and Improvements	10,889,395	61,428
29	(332) Reservoirs, Dams, and Waterways	35,635,193	169,989
30	(333) Water Wheels, Turbines, and Generators	39,660,795	17,634
31	(334) Accessory Electric Equipment	6,156,209	22,933
32	(335) Misc. Power Plant Equipment	2,588,223	228,299
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)	101,981,915	1,158,791
36	D. Other Production Plant		
37	(340) Land and Land Rights	621,682	-
38	(341) Structures and Improvements	3,186,951	68,740
39	(342) Fuel Holders, Products and Accessories	1,700,144	-
40	(343) Prime Movers	3,658,328	-
41	(344) Generators	48,858,107	-
42	(345) Accessory Electric Equipment	2,540,221	12,063

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 16, 2010	December 31, 2009

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
-		-	781,818	(303)	4
-	-	-	11,391,243		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
-	-	-	6,612,044	(330)	27
15,631	-	-	10,935,192	(331)	28
-	-	-	35,805,182	(332)	29
4,144	-	-	39,674,285	(333)	30
44,000	-	-	6,135,142	(334)	31
-	-	-	2,816,522	(335)	32
-	-	-	1,098,564	(336)	33
-	-	-	-	(337)	34
63,775	-	-	103,076,931		35
					36
-	-	-	621,682	(340)	37
-	-	-	3,255,691	(341)	38
-	-	-	1,700,144	(342)	39
-	-	-	3,658,328	(343)	40
-	-	-	48,858,107	(344)	41
-	-	-	2,552,284	(345)	42

Name of Respondent	This Report Is:	State of Idaho Date of Report	State of Idaho Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	April 16, 2010	December 31, 2009

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

Line No.	Account (a)	Balance at End of Year (g)	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)	60,565,433	80,803
46	TOTAL Production Plant (Enter Total of lines 16, 25, 35, and 45)	162,547,348	1,239,594
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	4,723,857	378,307
49	(352) Structures and Improvements	7,878,518	290,423
50	(353) Station Equipment	71,663,985	2,872,069
51	(354) Towers and Fixtures	556,655	-
52	(355) Poles and Fixtures	45,107,749	1,224,502
53	(356) Overhead Conductors and Devices	27,858,107	9,462,528
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)	159,162,873	14,227,829
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	964,029	-
61	(361) Structures and Improvements	3,220,616	1,238,614
62	(362) Station Equipment	29,360,249	3,347,187
63	(363) Storage Battery Equipment	-	-
64	(364) Poles, Towers, and Fixtures	77,399,457	6,950,855
65	(365) Overhead Conductors and Devices	52,931,763	3,707,020
66	(366) Underground Conduit	27,500,997	1,127,331
67	(367) Underground Conductors and Devices	41,847,168	2,683,411
68	(368) Line Transformers	57,285,996	2,101,139
69	(369) Services	42,274,170	1,620,579
70	(370) Meters	28,106,354	396,462
71	(371) Installations on Customer Premises	-	-
72	(372) Leased Property on Customer Premises	-	-
73	(373) Street Lighting and Signal Systems	12,393,941	549,237
74	(374) Asset Retirement Costs for Distribution Plant	-	-
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	373,284,740	23,721,835
76	5. GENERAL PLANT		
77	(389) Land and Land Rights	101,907	345,425
78	(390) Structures and Improvements	1,125,864	3,729,377
79	(391) Office Furniture and Equipment	-	-
80	(392) Transportation Equipment	1,345,131	1,158,612
81	(393) Stores Equipment	14,745	168,326
82	(394) Tools, Shop and Garage Equipment	432,865	7,522
83	(395) Laboratory Equipment	130,533	18,511
84	(396) Power Operated Equipment	5,753,129	1,419,875
85	(397) Communication Equipment	3,932,695	1,495,701
86	(398) Miscellaneous Equipment	2,299	2,436
87	SUBTOTAL (Enter Total of lines 77 thru 86)	12,839,168	8,345,785
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)	12,839,168	8,345,785
91	TOTAL (Accounts 101 and 106)	716,870,813	49,889,602
92	(102) Electric Plant Purchased	-	-
93	(Less) (102) Electric Plant Sold	-	
94	(103) Experimental Plant Unclassified	-	-
95	TOTAL Electric Plant in Service	716,870,813	49,889,602

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	40284	December 31, 2009

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
-	-	-	60,646,236		45
63,775	-	-	163,723,167		46
					47
-	-	-	5,102,164	(350)	48
-	-	-	8,168,941	(352)	49
1,281,957	-	-	73,254,097	(353)	50
-	-	-	556,655	(354)	51
58,826	-	-	46,273,425	(355)	52
1,055	-	-	37,319,580	(356)	53
-	-	-	-	(357)	54
-	-	-	-	(358)	55
-	-	-	1,374,002	(359)	56
-	-	-	-	(359.1)	57
1,341,838	-	-	172,048,864		58
					59
-	-	-	964,029	(360)	60
-	-	-	4,459,230	(361)	61
266,222	-	-	32,441,214	(362)	62
-	-	-	-	(363)	63
84,817	-	-	84,265,495	(364)	64
81,638	-	-	56,557,145	(365)	65
24,311	-	-	28,604,017	(366)	66
97,011	-	-	44,433,568	(367)	67
17,859	-	-	59,369,276	(368)	68
33,123	-	-	43,861,626	(369)	69
-	-	-	28,502,816	(370)	70
-	-	-	-	(371)	71
-	-	-	-	(372)	72
41,228	-	-	12,901,950	(373)	73
-	-	-	-	(374)	74
646,209	-	-	396,360,366		75
					76
-	-	-	447,332	(389)	77
1,290	-	-	4,853,951	(390)	78
-	-	-	-	(391)	79
726	-	-	2,503,017	(392)	80
-	-	-	183,071	(393)	81
-	-	-	440,387	(394)	82
-	-	-	149,044	(395)	83
-	-	-	7,173,004	(396)	84
9,604	-	-	5,418,792	(397)	85
-	-	-	4,735	(398)	86
11,620	-	-	21,173,333		87
-	-	-	-	(399)	88
-	-	-	-	(399.1)	89
11,620	-	-	21,173,333		90
2,063,442	-	-	764,696,973		91
-	-	-	-	(102)	92
			-		93
-	-	-	-	(103)	94
2,063,442	-	-	764,696,973		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 16, 2010	Dec. 31, 2009

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	101,397,475	88,806,974
3	(442) Commercial and Industrial Sales (3)		
4	Small (or Commercial)	81,073,948	71,994,661
5	Large (or Industrial)	62,109,598	56,575,008
6	(444) Public Street and Highway Lighting	2,126,115	1,821,535
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales	178,952	142,079
10	TOTAL Sales to Ultimate Consumers	246,886,088 (1)	219,340,257
11	(447) Sales for Resale	69,738,693	5,676,695
12	TOTAL Sales of Electricity	316,624,781	225,016,952
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Provision for Refunds	316,624,781	225,016,952
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	242,635	214,804
18	(453) Sales of Water and Water Power	133,929	
19	(454) Rent from Electric Property	897,391	845,345
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	12,080,448	392,497
22	(456.1) Revenues from Transmission of Electricty of Others	3,223,695	5,004,067
23			
24			
25			
26	TOTAL Other Operating Revenues	16,578,098	6,456,713
27	TOTAL Electric Operating Revenues	$333,202,879	$231,473,665

State of Idaho

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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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
1,224,836	1,229,004	104,609	103,795	2
				3
1,010,376	1,020,533	16,484	16,356	4
1,198,407	1,242,247	486	482	5
8,847	8,716	123	124	6
				7
				8
2,226	2,020	25	23	9
3,444,692 (2)	3,502,520	121,727	120,780	10
1,664,130	125,471			11
5,108,822	3,627,991	121,727	120,780	12
				13
5,108,822	3,627,991	121,727	120,780	14

(1) Includes $1,002,408 of unbilled revenues.

(2) Includes 8,765 MWH relating to unbilled revenues.

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Avista Corporation	[X] An Original [ ] A Resubmission	April 16, 2010	Dec. 31, 2009 State of Idaho

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	1,182,333	95,832,303	99,577	11,874	8.11
3	2 Residential Service					
4	3 Residential Service					
5	12 Res. & Farm Gen. Service	20,637	2,179,673	4,414	4,675	10.56
6	22 Res. & Farm Lg. Gen. Service	12,024	863,421	24	501,000	7.18
7	30 Pumping-Special					
8	32 Res. & Farm Pumping Service	3,685	326,713	594	6,204	8.87
9	48 Res. & Farm Area Lighting	1,222	248,995			20.38
10	49 Area Lighting-High-Press.	281	72,087			25.65
11	56 Centralia Credit					
12	95 Wind Power		49,400			
13	73 Residential					
14	74 Residential Service					
15	76 Residential Service					
16	77 Residential Service					
17	79 Residential Service					
18	58 Tax Adjustment		1,330,984			
19	Total	1,220,182	100,903,576	104,609	11,664	8.28
20	Residential-Unbilled	4,654	493,899			
21	**COMMERCIAL SALES (442)**					
22	2 General Service					
23	3 General Service					
24	11 General Service	297,718	27,487,095	14,685	20,274	9.23
25	19 Contract-General Service					
26	21 Large General Service	608,312	45,114,346	1,341	453,626	7.42
27	25 Extra Lg. Gen. Service	69,452	3,665,836	3	23,150,667	5.28
28	28 Contract-Extra Large Service					
29	31 Pumping Service	28,085	2,168,390	455	61,725	7.72
30	47 Area Lighting-Sod. Vap.	972	138,141			14.21
31	49 Area Lighting-High-Press.	2,383	491,797			20.64
32	56 Centralia Credit					
33	95 Wind Power		9,693			
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		1,534,147			
41	Total	1,006,922	80,609,445	16,484	61,085	8.02
42	Commercial-Unbilled	3,454	464,503			
43	Total Billed	2,227,104	181,513,021	121,093		8.15
44	Total Unbilled Rev. (See Instr. 6)	8,108	958,402	0		11.82
45	TOTAL	2,235,212	182,471,423	121,093		8.16

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year 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 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	**INDUSTRIAL SALES (442)**					
2	2 General Service					
3	3 General Service					
4	8 Lg Gen Time of Use					
5	11 General Service	3,716	366,199	131	28,366	9.85
6	21 Large General Service	77,924	5,601,890	84	927,667	7.19
7	25 Extra Lg. Gen. Service	1,088,882	53,953,567	8	136,110,250	4.95
8	28 Contract-Extra Large Service					
9	29 Contract Lg. Gen. Service					
10	30 Pumping Service -Special					
11	31 Pumping Service	23,665	1,803,906	219	108,059	7.62
12	32 Pumping Svc Res & Frm	3,452	255,831	44	78,455	7.41
13	47 Area Lighting-Sod. Vap.	60	7,599			12.67
14	49 Area Lighting-High-Press.	51	9,435			18.50
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		67,165			
24	Total	1,197,750	62,065,592	486	2,464,506	5.18
25	Industrial-Unbilled	657	44,006	0		
26						
27	**STREET AND HWY LIGHTING (444)**					
28	11 General Service					
29	41 Co.-Owned St. Lt. Service	115	17,286	5	23,000	15.03
30	42 Co.-Owned St. Lt. Service	6833	1,884,867	88	77,648	27.58
31	High-Press. Sod. Vap.					
32	43 Cust.-Owned St. Lt. Energy	9	847	1	9,000	9.41
33	and Maint. Service					
34	44 Cust.-Owned St. Lt. Energy	587	85,004	15	39,133	14.48
35	and Maint. Svce.-High-					
36	Press. Sod. Vap.					
37	45 Cust.Owned St. Lt. Energy Service	280	18,158	3	93,333	6.49
38	46 Cust.Owned St. Lt. Energy Service	1,023	86,503	11	93,000	8.46
39	High-Press. Sod. Vap.					
40	56 Centralia Credit					
41	58 Tax Adjustment		33,450			
42	Total	8,847	2,126,115	123	71,927	7.20
43	Street and Hwy Lighting-Unbilled					
44	Total Billed	3,433,701	245,704,728	121,702		7.16
45	Total Unbilled Rev. (See Instr. 6)	8,765	1,002,408	0		11.44
46	TOTAL	3,442,466	246,707,136	121,702		7.17

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year 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 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	**OTHER SALES TO PUBLIC**					
2	**AUTHORITIES (445)**					
3	None					
4						
5	**INTERDEPARTMENTAL**					
6	**SALES (448)**	2,226	178,952	25	89,040	8.04
7	58 Tax Adjustment					
8	Total	2,226	178,952	25	89,040	8.04
9						
10	**SALES FOR RESALE (447) (1)**					
11	61 Sales to Other Utilities - ID	1,664,130	69,738,693			
12						
13						
14						
14	Total	1,664,130	69,738,693			
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	5,100,057	315,622,373	121,727	41,898	6.19
40	Total Unbilled Rev.	8,765	1,002,408	0		11.44
41	TOTAL	5,108,822	316,624,781	121,727	41,970	6.20

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	April 16, 2010	December 31, 2009

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	-	-
5	(501) Fuel	-	-
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	26,653	29,469
11	(507) Rents	-	-
12	(509) Allowances	-	-
13	TOTAL Operation (Enter Total of Lines 4 thru 11)	27,242	29,469
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	680	2,695
16	(511) Maintenance of Structures	-	-
17	(512) Maintenance of Boiler Plant	-	-
18	(513) Maintenance of Electric Plant	-	-
19	(514) Maintenance of Miscellaneous Steam Plant	-	-
20	TOTAL Maintenance (Enter Total of Lines 14 thru 18)	680	2,695
21	TOTAL Power Production Expenses-Steam Plant (Enter Total of lines 12 and 19)	27,922	32,165
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	798,300	576,382
45	(536) Water for Power	286,362	264,999
46	(537) Hydraulic Expenses	1,867,708	966,417
47	(538) Electric Expenses	1,645,377	1,381,772
48	(539) Miscellaneous Hydraulic Power Generation Expenses	167,116	369,894
49	(540) Rents	2,145,975	115,560
50	TOTAL Operation (Enter Total of lines 43 thru 48)	6,910,838	3,675,024

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	87,034	59,208
53	(542) Maintenance of Structures	103,726	92,885
54	(543) Maintenance of Reservoirs, Dams, and Waterways	267,952	104,072
55	(544) Maintenance of Electric Plant	848,660	407,029
56	(545) Maintenance of Miscellaneous Hydraulic Plant	75,554	128,007
57	TOTAL Maintenance (Enter Total of lines 52 thru 56)	1,382,925	791,201
58	TOTAL Power Production Expenses-Hydraulic Power (Enter total of lines 49 and 57)	8,293,763	4,466,225
59	D. Other Power Generation		
60	Operation		
61	(546) Operation Supervision and Engineering	38,150	187,627
62	(547) Fuel	2,627,749	1,332,065
63	(548) Generation Expenses	110,412	143,951
64	(549) Miscellaneous Other Power Generation Expenses	267,663	208,643
65	(550) Rents	(11,914)	(12,034)
66	TOTAL Operation (Enter Total of lines 61 thru 65)	3,032,060	1,860,251
67	Maintenance		
68	(551) Maintenance Supervision and Engineering	41,886	54,201
69	(552) Maintenance of Structures	1,169	1,492
70	(553) Maintenance of Generating and Electric Plant	118,078	139,334
71	(554) Maintenance of Miscellaneous Other Power Generation Plant	42,205	59,690
72	TOTAL Maintenance (Enter Total of lines 68 thru 71)	203,338	254,717
73	TOTAL Power Production Expenses-Other Power (Enter Total of lines 66 and 72)	3,235,398	2,114,968
74	E. Other Power Supply Expenses		
75	(555) Purchased Power	106,719,593	98,504,379
76	(556) System Control and Load Dispatching	185,723	178,249
77	(557) Other Expenses	12,543,494	21,009,194
78	TOTAL Other Power Supply Expenses (Enter Total of lines 75 thru 77)	119,448,809	119,691,822
79	TOTAL Power Production Expenses (Enter Total of lines 20, 40, 58, 73 and 78)	131,005,893	126,305,180
80	2. TRANSMISSION EXPENSES		
81	Operation		
82	(560) Operation Supervision and Engineering	852,402	790,512
83	(561) Load Dispatching	769,280	694,403
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	69,316	80,512
93	(563) Overhead Line Expenses	79,442	201,791
94	(564) Underground Line Expenses	-	-
95	(565) Transmission of Electricity by Others	4,690,115	4,850,266
96	(566) Miscellaneous Transmission Expenses	484,611	466,456
97	(567) Rents	26,811	11,325
98	TOTAL Operation (Enter Total of lines 82 thru 89)	6,971,978	7,095,265
99	Maintenance		
100	(568) Maintenance Supervision and Engineering	166,195	155,286
101	(569) Maintenance of Structures	120,137	132,710
102	(570) Maintenance of Station Equipment	416,494	385,303
103	(571) Maintenance of Overhead Lines	1,005,428	483,364
104	(572) Maintenance of Underground Lines	3,892	-
105	(573) Maintenance of Miscellaneous Transmission Plant	16,288	4,893
106	TOTAL Maintenance (Enter Total of lines 92 thru 97)	1,728,436	1,161,555
107	TOTAL Transmission Expenses (Enter Total of lines 90 and 98)	8,700,413	8,256,821
108	3. DISTRIBUTION EXPENSES		
109	Operation		
110	(580) Operation Supervision and Engineering	484,527	454,876

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	218,337	244,290
106	(583) Overhead Line Expenses	548,930	657,028
107	(584) Underground Line Expenses	252,091	288,975
108	(585) Street Lighting and Signal System Expenses	172,955	153,838
109	(586) Meter Expenses	139,228	6,837
110	(587) Customer Installations Expenses	401,850	448,342
111	(588) Miscellaneous Distribution Expenses	1,780,724	1,542,106
112	(589) Rents	89,562	62,715
113	TOTAL Operation (Enter Total of lines 102 thru 112)	4,088,203	3,859,008
114	Maintenance		
115	(590) Maintenance Supervision and Engineering	461,079	447,419
116	(591) Maintenance of Structures	103,495	61,480
117	(592) Maintenance of Station Equipment	365,933	158,009
118	(593) Maintenance of Overhead Lines	2,618,661	3,123,891
119	(594) Maintenance of Underground Lines	286,540	311,460
120	(595) Maintenance of Line Transformers	261,020	108,403
121	(596) Maintenance of Street Lighting and Signal Systems	190,439	142,400
122	(597) Maintenance of Meters	38,336	45,544
123	(598) Maintenance of Miscellaneous Distribution Plant	79,238	210,123
124	TOTAL Maintenance (Enter Total of lines 115 thru 123)	4,404,741	4,608,726
125	TOTAL Distribution Expenses (Enter Total of lines 113 and 124)	8,492,944	8,467,734
126	4. CUSTOMER ACCOUNTS EXPENSES		
127	Operation		
128	(901) Supervision	194,693	168,326
129	(902) Meter Reading Expenses	362,283	292,217
130	(903) Customer Records and Collection Expenses	2,709,234	2,513,513
131	(904) Uncollectible Accounts	938,087	661,036
132	(905) Miscellaneous Customer Accounts Expenses	83,959	50,568
133	TOTAL Customer Accounts Expenses (Enter Total of lines 128 thru 132)	4,288,255	3,685,659
134	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
135	Operation		
136	(907) Supervision	-	-
137	(908) Customer Assistance Expenses	5,867,133	3,881,823
138	(909) Informational and Instructional Expenses	17,264	32,428
139	(910) Miscellaneous Customer Service and Informational Expenses	50,267	49,825
140	TOTAL Cust. Service and Informational Expenses (Enter Total of lines 136 thru 139)	5,934,664	3,964,076
141	6. SALES EXPENSES		
142	Operation		
143	(911) Supervision	-	-
144	(912) Demonstrating and Selling Expenses	173,500	155,244
145	(913) Advertising Expenses	39,188	40,564
146	(916) Miscellaneous Sales Expenses	38,600	21
147	TOTAL Sales Expenses (Enter Total of lines 143 thru 146)	251,288	195,829
148	7. ADMINISTRATIVE AND GENERAL EXPENSES		
149	Operation		
150	(920) Administrative and General Salaries	8,148,288	6,574,227
151	(921) Office Supplies and Expenses	1,379,591	1,297,351
152	(Less) (922) Administrative expenses Transferred-Credit	(17,312)	(13,322)

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	April 16, 2010	December 31, 2009

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	3,972,670	3,772,598
155	(924) Property Insurance	450,607	348,360
156	(925) Injuries and Damages	1,243,326	1,023,022
157	(926) Employee Pensions and Benefits	338,615	377,208
158	(927) Franchise Requirements	6,704	5,950
159	(928) Regulatory Commission Expenses	1,698,820	1,763,403
160	(Less) (929) Duplicate Charges-Cr.	-	-
161	(930.1) General Advertising Expenses	84,243	-
162	(930.2) Miscellaneous General Expenses	1,019,353	1,030,973
163	(931) Rents	100,527	174,907
164	TOTAL Operation (Enter Total of lines 150 thru 163)	18,425,432	16,354,678
165	Maintenance		
166	(935) Maintenance of General Plant	2,102,635	1,896,567
167	TOTAL Administrative and General Expenses (Enter Total of lines 164 and 166)	20,528,067	18,251,244
168	TOTAL Electric Operation and Maintenance Expenses (Enter Total of lines 79,99,125,133,140,147,and 167)	179,201,524	169,126,543

NUMBER OF ELECTRIC DEPARTMENT EMPLOYEES

1. The data on number of employees should be reported ɔr the payroll period ending nearest to October 31, or any ayroll period ending 60 days before or after October 31.
2. If the respondent's payroll for the reporting period in- ludes any special construction personnel, include such mployees 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 equiva- lents. Show the estimated number of equivalent employees attributed to the electric department from joint functions.

1 Payroll Period Ended (Date) December 31, 2009		
2 Total Regular Full-Time Employees	83	87
3 Total Part-Time and Temporary Employees	2	4
4 Allocation of General Employees	128	122
5 Total Employees (See Note 1)	213	213