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

Form 1 Approved
OMB No. 1902-0021
(Expires 2/29/2009)
Form 1-F Approved
OMB No. 1902-0029
(Expires 2/28/2009)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 2/28/2009)

AVU-E

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2009 MAY 12 AM 9:59
IDAHO PUBLIC UTILITIES COMMISSION

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

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

Exact Legal Name of Respondent (Company)	Year/Period of Report
Avista Corporation	End of 2008/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 2008/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, 99202	
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, 99202	

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(509) 495-8000	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

01 Name	03 Signature	04 Date Signed *(Mo, Da, Yr)*
Mark T. Thies	Mark T. Thies	4 /11 2009
02 Title Sr. VP and CFO		

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) 04/16/2009	Year/Period of Report End of 2008/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".

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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Substations	426-427	
68	Footnote Data	450	
	Stockholders' Reports Check appropriate box: [X] Four copies will be submitted [ ] No annual report to stockholders is prepared		

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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/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 and Controller
1411 E. Mission Avenue
Spokane, WA 99202

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	04/16/2009	End of 2008/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	75.11	Subsidiary of
5		processing, payment and		Avista Capital
6		information services to multi		
7		site customers in North Amer.		
8				
9	Avista Communications, Inc.	Inactive	100	Subsidiary of
10				Avista Capital
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				

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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		

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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	AVA Capital Trust III	An affiliated business trust	100	Affiliate of
3		formed by the Company.		Avista Corp.
4		Issued Pref. Trust Securities		
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
11				
12	AVA Formation Corp.	Holding Company	100	Formed in 2006 for
13				the purpose of
14				completing proposed
15				statutory share
16				exchange and
17				holding company
18				structure. Currently
19				a subsidiary of
20				Avista Corp.
21				
22	Coyote Springs 2, LLC	Owned an interest in a	100	inactive
23		generation plant.		
24				
25				
26				
27				

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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	04/16/2009	End of 2008/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 (Effective 01/01/08)		
3			
4	Executive Vice President	M. K. Malquist	
5			
6	Senior Vice President and Chief Financial Officer	M. T. Thies	
7	(Effective September 29, 2008)		
8			
9	Senior Vice President, General Counsel	M. M. Durkin	
10	and Chief Compliance Officer		
11			
12	Senior Vice President and Corporate Secretary	K. S. Feltes	
13	with responsibility for Human Resources		
14			
15	Vice President, Controller and	C. M. Burmeister - Smith	
16	Principal Accounting Officer		
17			
18	Vice President and Chief Information Officer	J.M. Kensok	
19			
20	Vice President with responsibility for Transmission	D. F. Kopczynski	
21	and Distribution Operations		
22			
23	Vice President and Chief Counsel for Regulatory and	D. J. Meyer	
24	Governmental Affairs		
25			
26	Vice President, with responsibility for State and	K. O. Norwood	
27	Federal Regulation		
28			
29	Vice President and Environmental Compliance Officer	D. P. Vermillion	
30	(Title change effective 08/15/2008)		
31			
32	Vice President of Finance and Treasurer	A. M. Wilson	
33			
34	Vice President, with responsibility for	R. D. Woodworth	
35	Sustainable Energy Solutions		
36			
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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/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, as of 01/01/08)	
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 (Effective 03/01/2008)	5721 SE Columbia Way, Suite 200, Vancouver, WA 986661
9		
10	Roy Lewis Eiguren	702 W. Idaho St., Suite 1000, 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	111 N. Wall St., Spokane, WA 99201
19		
20	R. John Taylor***	111 Main Street, Lewiston ID 83501
21		
22	Lura J. Powell (Resigned 05/08/2008)	1009 Country Ct., Richland, WA 99352
23		
24		
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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	04/16/2009	End of 2008/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. On March 14, 2008, Avista Corp., ARC and a third-party financial institution amended a Receivables Purchase Agreement. The most significant amendment extended the termination date to March 13, 2009. Under the Receivables Purchase Agreement, ARC can sell without recourse, 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 $320.0 million committed line of credit. As of December 31, 2008, ARC had the ability to sell up to $85.0 million of receivables and there was $17.0 million in accounts receivable sold under this revolving agreement, a decrease from the $85.0 million available and sold as of December 31, 2007.

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 request the issuance of up to $320.0 million in letters of credit. The Company had $250.0 million of borrowings outstanding as of December 31, 2008 and no borrowings outstanding as of December 31, 2007. Total letters of credit outstanding were $24.3 million as of December 31, 2008 and $34.8 million as of December 31, 2007. 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.

On November 26, 2008, the Company entered into a 364-day committed line of credit agreement with various banks in the total amount of $200.0 million with an expiration date of November 24, 2009. The Company had no borrowings outstanding as of December 31, 2008. The committed line of credit is secured by $200.0 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 facility was approved by the respective regulatory commissions as follows: WUTC (Docket No. UE-081842); IPUC (AVU-U-08-02); and OPUC (N/A).

On April 3, 2008, the Company issued $250.0 million of 5.95 percent First Mortgage Bonds due in 2018. The net proceeds from the issuance of $249.2 million (net of issuance discount and before Avista Corp.'s expenses), together with other available funds, were used to pay the $272.9 million of 9.75 percent Unsecured Senior Notes that matured on June 1, 2008. This debt issuance was approved by the respective regulatory commissions as follows: WUTC (Docket No. U-080182 Order No. 1); IPUC (Case No. AVU-U-08-01 Order No. 30509); and OPUC (Docket UF 4246 Order No. 08-143).

On December 16, 2008, the Company issued $30.0 million of 7.25 percent First Mortgage Bonds due in 2013. The net proceeds from the issuance of $29.9 million (net of placement agent fees and before Avista Corp.'s expenses) were used to repay $25.0 million of medium term notes that matured on December 10, 2008 and repay a portion of the borrowings outstanding under the Company's $320.0 million committed line of credit. This debt issuance was approved by the respective regulatory commissions as follows: WUTC (Docket No. UE-080182); IPUC (AVU-U-08-03); and OPUC (UF 4246).

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 2034 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 Consolidated Balance Sheet. This debt transaction was approved by the respective regulatory commissions as follows: WUTC (Docket No. UE-081859); IPUC (AVU-U-08-03); and OPUC (UF 4253).

On December 30, 2008, the City of Forsyth, Montana issued $17.0 million of its Pollution Control Revenue Refunding Bonds, Series 2008 (Avista Corporation Colstrip Project) due 2034 on behalf of Avista Corp. The proceeds of these bonds were used to refund $17.0 million of Pollution Control Revenue Refunding Bonds, Series 1999B (Avista Corporation Colstrip Project) issued by the City of Forsyth, Montana on behalf of Avista Corp. These bonds are included in the current portion of long-term debt because they are subject to purchase at any time at the option of the bond holder. This debt transaction was approved by the respective regulatory commissions as follows: WUTC (Docket No. UE-081859); IPUC (AVU-U-08-03); and OPUC (UF 4253).

7. At the May 8, 2008 Annual Meeting, the shareholders of Avista Corporation approved a proposal for an amendment of the Restated Articles of Incorporation to change from a plurality voting standard to a majority voting standard in uncontested elections of directors and to eliminate cumulative voting. For further details, see Avista Corporation's Definitive Proxy Statement filed with the Securities and Exchange Commission on March 31, 2008.

As a result of the amendment to the Restated Articles of Incorporation, a conforming amendment was made to the bylaws of Avista Corporation on May 9, 2008. Specifically, section 5 of Article II and Section 11 of Article III of the Bylaws of Avista Corporation was changed to eliminate references to cumulative voting.

8. Average annual wage increases were 3.4% for non-exempt employees effective March 1, 2008. Average annual wage increases were 3.9% for exempt employees effective March 1, 2008. Average annual wage increases were 7.4% for officers effective March 1, 2008. Certain bargaining unit employees received increases ranging from 3.0% to 3.5% effective in March and April 2008.

9. Reference is made to Note 25 of the Notes to Financial Statements, page 123 of this Report.

10. None

11. Reserved

12. See page 123 of this Report.

13. Gary G. Ely, Chairman of the Board and Chief Executive Officer of Avista Corp., retired from the Company and the board, effective December 31, 2007. The Company's board of directors elected Scott L. Morris to the positions of Chairman of the Board, President and Chief Executive Officer of Avista Corp., effective January 1, 2008.

On February 15, 2008, Ann Wilson was appointed Vice President of Finance and Treasurer.

On February 15, 2008, the Board of Directors appointed Brian W. Dunham to serve as a director on the board effective March 1, 2008. Mr. Dunham is the president and chief executive officer of Northwest Pipe Company, which manufactures welded steel water transmission lines.

On February 15, 2008, Lura J. Powell provided notification to Avista Corp. that she will not stand for re-election to the board when her term expires in May 2008 to focus on her professional commitments in technology and healthcare.

Mark Thies joined the Company as Senior Vice President and Chief Financial Officer in September 2008. The Chief Financial Officer position was previously held by Malyn Malquist. Malyn Malquist stayed on with the Company as Executive Vice President and then retired from the Company effective March 31, 2009.

On December 8, 2008, Dennis Vermillion was appointed President of Avista Utilities effective January 1, 2009. He will remain Vice President of Avista Corp.

On December 8, 2008, Richard Storro was appointed Vice President of Energy Resources.

14. Proprietary capital is not less than 30 percent.

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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/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	3,340,068,198	3,131,916,272
3	Construction Work in Progress (107)	200-201	75,568,224	75,679,838
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		3,415,636,422	3,207,596,110
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	1,142,578,137	1,090,037,407
6	Net Utility Plant (Enter Total of line 4 less 5)		2,273,058,285	2,117,558,703
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)		2,273,058,285	2,117,558,703
15	Utility Plant Adjustments (116)	122	0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		4,991,551	4,670,595
19	(Less) Accum. Prov. for Depr. and Amort. (122)		890,639	897,192
20	Investments in Associated Companies (123)		13,903,000	13,903,000
21	Investment in Subsidiary Companies (123.1)	224-225	77,487,962	71,371,272
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)		26,240,546	28,691,550
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		10,234,544	15,878,558
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		49,312,596	55,312,881
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		181,279,560	188,930,664
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		1,674,372	5,264,119
36	Special Deposits (132-134)		1,600,000	5,668,267
37	Working Fund (135)		619,853	679,537
38	Temporary Cash Investments (136)		2,684,444	2,608,103
39	Notes Receivable (141)		63,451	0
40	Customer Accounts Receivable (142)		207,867,900	87,238,080
41	Other Accounts Receivable (143)		6,188,617	9,920,307
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		5,844,603	2,965,676
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		120,021	502,535
45	Fuel Stock (151)	227	3,673,039	2,213,923
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	17,455,835	17,365,306
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	0	0
55	Gas Stored Underground - Current (164.1)		30,720,371	13,414,238
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		8,415,670	6,438,702
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		10,934	0
60	Rents Receivable (172)		646,271	509,924
61	Accrued Utility Revenues (173)		0	0
62	Miscellaneous Current and Accrued Assets (174)		194,919	6,153,636
63	Derivative Instrument Assets (175)		60,546,323	67,390,448
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		49,312,596	55,312,881
65	Derivative Instrument Assets - Hedges (176)		874,944	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		288,199,765	167,088,568
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		15,852,599	11,576,174
70	Extraordinary Property Losses (182.1)	230	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230	0	0
72	Other Regulatory Assets (182.3)	232	455,580,547	281,620,776
73	Prelim. Survey and Investigation Charges (Electric) (183)		3,088,816	234,518
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	32,008,980	40,642,265
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)		17,151,844	20,965,705
82	Accumulated Deferred Income Taxes (190)	234	131,055,525	90,823,103
83	Unrecovered Purchased Gas Costs (191)		-18,646,016	2,374,110
84	Total Deferred Debits (lines 69 through 83)		636,092,295	448,236,651
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		3,378,629,905	2,921,814,586

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Avista Corporation	(1) [x] An Original (2) [ ] A Rresubmission	04/16/2009	end of 2008/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	755,903,119	727,945,794
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)	252	0	0
5	Stock Liability for Conversion (203, 206)	252	0	0
6	Premium on Capital Stock (207)	252	0	0
7	Other Paid-In Capital (208-211)	253	19,170,532	2,281,868
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)	254	87,394	3,294,916
11	Retained Earnings (215, 215.1, 216)	118-119	253,478,332	221,313,566
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-25,488,897	-14,672,673
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-6,092,318	-19,607,486
16	Total Proprietary Capital (lines 2 through 15)		996,883,374	913,966,153
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	824,970,979	671,733,175
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	114,603,000	114,603,000
21	Other Long-Term Debt (224)	256-257	0	273,010,231
22	Unamortized Premium on Long-Term Debt (225)		239,850	248,733
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		1,752,256	1,328,472
24	Total Long-Term Debt (lines 18 through 23)		938,061,573	1,058,266,667
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	75,206
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		1,579,821	344,000
29	Accumulated Provision for Pensions and Benefits (228.3)		184,587,850	90,554,881
30	Accumulated Miscellaneous Operating Provisions (228.4)		2,936,173	1,826,000
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		7,140,857	1,899,098
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	10,501,880
34	Asset Retirement Obligations (230)		4,208,327	3,990,011
35	Total Other Noncurrent Liabilities (lines 26 through 34)		200,453,028	109,191,076
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		250,000,000	0
38	Accounts Payable (232)		153,032,408	114,760,498
39	Notes Payable to Associated Companies (233)		2,854,178	2,182,637
40	Accounts Payable to Associated Companies (234)		737,710	600,647
41	Customer Deposits (235)		6,979,171	6,331,722
42	Taxes Accrued (236)	262-263	6,105,577	-4,717,808
43	Interest Accrued (237)		10,871,471	12,577,801
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 Rresubmission	04/16/2009	end of 2008/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)		0	252
48	Miscellaneous Current and Accrued Liabilities (242)		32,188,393	41,016,254
49	Obligations Under Capital Leases-Current (243)		75,206	295,029
50	Derivative Instrument Liabilities (244)		78,603,554	21,148,085
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		7,140,857	1,899,098
52	Derivative Instrument Liabilities - Hedges (245)		0	10,501,880
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	10,501,880
54	Total Current and Accrued Liabilities (lines 37 through 53)		534,306,811	192,296,019
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		1,263,086	1,265,933
57	Accumulated Deferred Investment Tax Credits (255)	266-267	373,728	423,036
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	24,985,882	18,072,332
60	Other Regulatory Liabilities (254)	278	55,429,522	65,481,339
61	Unamortized Gain on Reaquired Debt (257)		3,237,373	3,528,194
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		334,892,041	320,049,323
64	Accum. Deferred Income Taxes-Other (283)		288,743,487	239,274,514
65	Total Deferred Credits (lines 56 through 64)		708,925,119	648,094,671
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		3,378,629,905	2,921,814,586

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/Q4

STATEMENT OF INCOME

Quarterly
1. Enter in column (d) the balance for the reporting quarter and in column (e) the balance for the same three month period for the prior year.
2. Report in column (f) the quarter to date amounts for electric utility function; in column (h) the quarter to date amounts for gas utility, and in (j) the quarter to date amounts for other utility function for the current year quarter.
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 (k) the quarter to date amounts for other utility function for the prior year quarter.
4. 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.
8. Report data for lines 8, 10 and 11 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1 and 407.2.

Line No.	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	1,657,671,994	1,321,662,326		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,278,636,823	965,325,057		
5	Maintenance Expenses (402)	320-323	47,636,921	45,512,775		
6	Depreciation Expense (403)	336-337	82,388,834	81,802,514		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	7,905,829	6,738,444		
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)		382,274	2,979,998		
13	(Less) Regulatory Credits (407.4)		8,388,441	8,618,156		
14	Taxes Other Than Income Taxes (408.1)	262-263	72,057,352	72,443,295		
15	Income Taxes - Federal (409.1)	262-263	3,249,258	22,447,987		
16	- Other (409.1)	262-263	53,201	520,211		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	42,600,284	12,026,706		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	4,970,670	4,122,957		
19	Investment Tax Credit Adj. - Net (411.4)	266	-49,308	-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)		1,521,601,404	1,197,105,613		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		136,070,590	124,556,713		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/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
921,386,136	744,131,553	736,285,858	577,530,773			2
						3
624,698,493	467,293,942	653,938,330	498,031,115			4
40,308,817	37,501,902	7,328,104	8,010,873			5
67,721,188	64,517,110	14,667,646	17,285,404			6
						7
6,448,003	5,686,773	1,457,826	1,051,671			8
99,047	99,047					9
						10
						11
153,132	337,368	229,142	2,642,630			12
6,730,732	7,499,030	1,657,709	1,119,126			13
47,356,209	46,412,373	24,701,143	26,030,922			14
143,777	14,193,471	3,105,481	8,254,516			15
-192,188	378,906	245,389	141,305			16
36,623,690	13,472,601	5,976,594	-1,445,895			17
4,711,220	3,382,861	259,450	740,096			18
		-49,308	-49,308			19
						20
						21
						22
						23
						24
811,918,216	639,011,602	709,683,188	558,094,011			25
109,467,920	105,119,951	26,602,670	19,436,762			26

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2009	Year/Period of Report End of 2008/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)		136,070,590	124,556,713		
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)		3,869,058	4,477,623		
35	Nonoperating Rental Income (418)		7,726	-18,512		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	4,123,038	-4,595,749		
37	Interest and Dividend Income (419)		10,085,671	7,743,889		
38	Allowance for Other Funds Used During Construction (419.1)		5,692,491	4,736,330		
39	Miscellaneous Nonoperating Income (421)		16,000			
40	Gain on Disposition of Property (421.1)		810,694	257,380		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		16,866,562	3,645,715		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)			2,289,978		
44	Miscellaneous Amortization (425)	340	1,110,571	1,110,572		
45	Donations (426.1)	340	956,059	622,859		
46	Life Insurance (426.2)		2,100,235	2,557,490		
47	Penalties (426.3)		138,152	37,600		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,211,097	1,097,891		
49	Other Deductions (426.5)		-1,891,457	3,799,017		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		3,624,657	11,515,407		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	547,911	251,464		
53	Income Taxes-Federal (409.2)	262-263	2,415,034	149,939		
54	Income Taxes-Other (409.2)	262-263	-288,122	-404,584		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	1,523,886	-257,145		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	3,294,942	4,052,315		
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)		903,767	-4,312,641		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		12,338,138	-3,557,051		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		62,954,659	69,538,504		
63	Amort. of Debt Disc. and Expense (428)		922,381	1,063,487		
64	Amortization of Loss on Reaquired Debt (428.1)		3,759,437	5,290,891		
65	(Less) Amort. of Premium on Debt-Credit (429)		8,885	8,885		
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)	340	6,218,511	7,605,326		
68	Other Interest Expense (431)	340	5,554,756	2,899,617		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		4,611,851	3,864,363		
70	Net Interest Charges (Total of lines 62 thru 69)		74,789,008	82,524,577		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		73,619,720	38,475,085		
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)		73,619,720	38,475,085		

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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	04/16/2009	End of 2008/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		219,765,445	166,534,217
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5	Tax Benefit Received from 401k			(14,870)
6	Dividends received from Subsidiaries			48,260,105
7	Prior period adjustment for benefit plan restatement			(2,471,138)
8	Stock compensation dividend adjustment			15,913
9	TOTAL Credits to Retained Earnings (Acct. 439)			45,790,010
10				
11	Stock Options Exercised			
12	Preferred Series K Reclass			(1,334,004)
13	Debt Repurchase Adjustment			(4,392,647)
14	Subsidiary Federal Tax Credits (Avista Energy)		-796,180	
15	TOTAL Debits to Retained Earnings (Acct. 439)		-796,180	(5,726,651)
16	Balance Transferred from Income (Account 433 less Account 418.1)		69,496,682	43,070,834
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			-37,070,823	(31,450,517)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-37,070,823	(31,450,517)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		535,087	1,547,552
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		251,930,211	219,765,445

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/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)		253,478,332	221,313,566
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-14,672,673	51,109,032
50	Equity in Earnings for Year (Credit) (Account 418.1)		4,123,038	(4,595,749)
51	(Less) Dividends Received (Debit)			48,260,105
52	Subsidiary Expense & Misc Subs Equity Comp		-14,939,262	(12,925,851)
53	Balance-End of Year (Total lines 49 thru 52)		-25,488,897	(14,672,673)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/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)	73,619,720	38,475,085
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	90,390,864	88,540,958
5	Amortization of deferred power and natural gas costs	45,835,653	19,629,891
6	Amortization of debt expense	4,672,935	6,345,495
7	Amortization of investment in exchange power	2,450,031	2,450,030
8	Deferred Income Taxes (Net)	41,798,683	4,003,423
9	Investment Tax Credit Adjustment (Net)	-49,308	-49,308
10	Net (Increase) Decrease in Receivables	-116,961,581	1,881,714
11	Net (Increase) Decrease in Inventory	-18,855,778	-3,940,327
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	2,228,853	-28,529,359
14	Net (Increase) Decrease in Other Regulatory Assets	-20,468,183	-8,395,908
15	Net Increase (Decrease) in Other Regulatory Liabilities	2,372,800	1,888,830
16	(Less) Allowance for Other Funds Used During Construction	5,692,491	4,736,330
17	(Less) Undistributed Earnings from Subsidiary Companies	4,123,038	-4,595,749
18	Other (provide details in footnote):	601,532	696,571
19	Write-down of asset		2,289,978
20	Change in other current assets and liabilities	-10,063,226	-2,782,552
21	Net change in receivables allowance	2,878,927	235,324
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	90,636,393	122,599,264
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-219,796,264	-196,772,585
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)	-219,796,264	-196,772,585
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	7,998,322	
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies	1,191,118	170,364,287
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	04/16/2009	End of 2008/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	17,967
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	2,006,496	-2,942,625
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-208,594,315	-29,332,956
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	296,165,000	
62	Preferred Stock		
63	Common Stock	28,564,671	4,977,331
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			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	574,729,671	4,977,331
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-401,855,029	-26,156,580
74	Preferred Stock		-26,250,000
75	Common Stock		
76	Other (provide details in footnote):		
77	Long-term debt and short-term borrowing issuance costs	-5,023,987	-164,700
78	Net Decrease in Short-Term Debt (c)		-4,000,000
79	Cash paid for settlement of interest rate swap agreements	-16,395,000	
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-37,070,823	-31,450,517
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	114,384,832	-83,044,466
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-3,573,090	10,221,842
87			
88	Cash and Cash Equivalents at Beginning of Period	8,551,759	-1,670,083
89			
90	Cash and Cash Equivalents at End of period	4,978,669	8,551,759

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 western 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 in the non-utility businesses including Avista Energy, Inc. (Avista Energy) and Advantage IQ, Inc. (Advantage IQ). 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.

The Company's operations are exposed to risks including, but not limited to:

- global financial and economic conditions (including the availability of credit) and their effect on the Company's ability to obtain funding for working capital and long-term capital requirements on acceptable terms,
- economic conditions in the Company's service areas, including the effect on the demand for, and customers' ability to pay for, the Company's utility services,
- streamflow and weather conditions that impact hydroelectric generation, utility operations and customer demand,
- market prices and supply of wholesale energy, which the Company purchases and sells, including power, fuel and natural gas,
- regulatory disallowance of the recovery of power and natural gas costs, operating costs and capital investments and the allowance of a reasonable rate of return on investment,
- the effects of changes in legislative and governmental regulations, including restrictions on emissions from generating plants and requirements for the acquisition of new resources,
- changes in regulatory requirements,
- availability of generation facilities,
- rate increases may change customer demand for electricity and natural gas, and
- competition.

Also, like other utilities, the Company's facilities and operations are exposed to natural disasters and terrorism risks or other malicious acts. In addition, the energy business exposes the Company to the financial, liquidity, credit and price risks associated with wholesale purchases and sales of energy commodities.

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 as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America. As required by the Federal Energy Regulatory Commission (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 accounting principles generally accepted in the United States of America. 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 accounting principles generally accepted in the United States of America in the presentation of (1) current portion of long-term debt (2) assets and liabilities for cost of removal of assets, (3) assets held for sale, (4) regulatory assets and liabilities, (5) deferred income taxes, and (6) comprehensive income.

Use of Estimates

The preparation of the financial statements in conformity with accounting principles generally accepted in the United States of America 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
Operating 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 $84.3 million (net of $11.4 million of unbilled receivables sold) as of December 31, 2008 and $16.1 million (net of $57.2 million of unbilled receivables sold) as of December 31, 2007. See Note 6 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 2008, 2007 and 2006.

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 $53.9 million in 2008, $51.0 million in 2007 and $48.3 million in 2006.

Income Taxes
The Company accounts for income taxes under Statement of Financial Accounting Standards (SFAS) No. 109, "Accounting for Income Taxes." Under SFAS No. 109, a deferred 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 income tax returns. The deferred tax expense for the period is equal to the net change in the deferred tax asset and liability accounts from the beginning to the end of the period. The effect on deferred taxes of a change in tax rates is recognized in income in the period that includes the enactment date. Deferred tax liabilities and regulatory assets are established for tax benefits flowed through to customers as prescribed by the respective regulatory commissions.

Stock-Based Compensation
On January 1, 2006, the Company adopted SFAS No. 123R, which supersedes APB No. 25 and SFAS No. 123 and their related implementation guidance. The statement requires that the compensation cost relating to share-based payment transactions be recognized in financial statements based on the fair value of the equity or liability instruments issued. The Company adopted SFAS No. 123R using the modified prospective method and, accordingly, financial statement amounts for prior periods presented were not restated to reflect the fair value method of recognizing compensation expense relating to share-based payments. See Note 24 for further information.

Earnings Per Common Share
Basic earnings per common share is computed by dividing income available for common stock by the weighted average number of common shares outstanding for the period. Diluted earnings per common share is calculated by dividing income available for common

stock 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 23 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. See Note 8 for further information related to 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):

	2008	2007	2006
Allowance as of the beginning of the year	$2,966	$2,730	$3,228
Additions expensed during the year	6,336	3,078	2,888
Net deductions	(3,457)	(2,842)	(3,386)
Allowance as of the end of the year	$5,845	$2,966	$2,730

Materials and Supplies, Fuel Stock and Natural Gas Stored

Inventories of materials and supplies, fuel stock and natural gas stored are recorded at the lower of cost or market, primarily using the average cost method.

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.

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 8.2 percent in 2008, and 9.11 percent in 2007 and 2006. The Company's AFUDC rates do not exceed the maximum allowable rates as determined in accordance with the requirements of regulatory authorities.

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 2.77 percent in 2008, 2.89 percent in 2007 and 2.89 percent in 2006.

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

- electric thermal production - 32 years,
- hydroelectric production - 77 years,
- electric transmission - 49 years,
- electric distribution - 39 years, and
- natural gas distribution property - 51 years.

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." The Company prepares its financial statements in accordance with SFAS No. 71 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.

SFAS No. 71 requires the Company to reflect the impact of regulatory decisions in its financial statements. SFAS No. 71 requires that certain costs and/or obligations (such as incurred power and natural gas costs not currently recovered through rates, but expected to be recovered in the future) are reflected as deferred charges or credits on the Balance Sheets. These costs and/or obligations are not reflected in the statement 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 SFAS No. 71 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 and natural gas deferrals,
- investment in exchange power,
- regulatory asset for deferred income taxes,
- unamortized debt expense,
- assets offsetting net utility energy commodity derivative liabilities (see Note 7 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
- unfunded pensions and other postretirement benefits.

Regulatory liabilities include:

- natural gas deferrals, and
- liabilities offsetting net utility energy commodity derivative assets (see Note 7 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, as well as premiums paid to repurchase 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.

Power Cost Deferrals and Recovery Mechanisms
Deferred power supply costs are recorded as a deferred charge on the Balance Sheets for future review and recovery through retail

rates. The power supply costs deferred include certain differences between actual net power supply costs incurred by Avista Corp. and the costs included in base retail rates. This difference in net power supply costs primarily results from changes in:

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

In Washington, the Energy Recovery Mechanism (ERM) allows Avista Corp. to periodically increase or decrease electric rates periodically 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. Avista Corp. accrues interest on deferred power costs in the Washington jurisdiction at a rate, which is adjusted semi-annually, of 6.7 percent as of December 31, 2008.

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. Through December 31, 2008, 50 percent of the annual power supply cost variance in this range was deferred for future surcharge or rebate to customers and the Company incurs the cost of, or receives the benefit from, the remaining 50 percent. 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 incurs the cost of, or receives the benefit from, 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 (through December 31, 2008):

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%
+/- excess over $10 million	90%	10%

Effective January 1, 2009, the ERM was adjusted for the sharing level for the annual power supply cost variance in the $4.0 million to $10.0 million band. The adjustment resulted in 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. The 50 percent customers/50 percent Company sharing was maintained when actual power supply expenses are higher (surcharge to customers) than the amount included in base retail rates within this band. The following is a summary of the revised ERM:

Annual Power Supply Cost Variability	Deferred for Future Surcharge or Rebate to Customers	Expense or Benefit to the Company
+/- $0 - $4 million	0%	100%
+ between $4 million - $10 million	50%	50%
- between $4 million - $10 million	75%	25%
+/- excess over $10 million	90%	10%

Avista Corp. has a power cost adjustment (PCA) mechanism in Idaho that allows it to modify electric rates on October 1 of each year with Idaho Public Utilities Commission (IPUC) approval. Under the PCA mechanism, Avista Corp. defers 90 percent of the difference between certain actual net power supply expenses and the amount included in base retail rates for its Idaho customers. 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. Avista Corp. accrues interest on deferred power costs in the Idaho jurisdiction at a rate, which is adjusted annually, of 5.0 percent as of December 31, 2008.

The following table shows activity in deferred power costs for Washington and Idaho during 2006, 2007 and 2008 (dollars in thousands):

	Washington	Idaho	Total

Deferred power costs as of December 31, 2005	$96,191	$7,987	$104,178
Activity from January 1 – December 31, 2006:			
Power costs deferred	-	5,718	5,718
Interest and other net additions	4,291	300	4,591
Recovery of deferred power costs through retail rates	(30,323)	(4,648)	(34,971)
Deferred power costs as of December 31, 2006	$70,159	$9,357	$79,516
Activity from January 1 – December 31, 2007:			
Power costs deferred	$16,344	$16,750	$33,094
Interest and other net additions	3,023	788	3,811
Recovery of deferred power costs through retail rates	(31,002)	(5,732)	(36,734)
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

Unrecovered Purchased Gas Costs 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.

NOTE 2. NEW ACCOUNTING STANDARDS

Effective January 1, 2008, the Company adopted the provisions of SFAS No. 157, "Fair Value Measurements" 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 No. 157-2, which deferred the effective date for certain portions of SFAS No. 157 related to nonrecurring measurements of nonfinancial assets and liabilities. The Company will be required to adopt those provisions of SFAS No. 157 in 2009. The adoption of the provisions of SFAS No. 157 that became effective on January 1, 2008, did not have a material impact on the Company's financial condition and results of operations. However, the Company expanded disclosures with respect to fair value measurements. See Note 21 for the expanded disclosures.

Effective January 1, 2008, the Company adopted SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities." This statement permits entities to choose to measure many financial assets and financial liabilities at fair value. Unrealized gains and losses on items for which the fair value option is elected would be reported in net income. The Company did not elect to use the fair value option under SFAS No. 159 for any financial assets and liabilities at implementation and as such the adoption of SFAS No. 159 did not have any material impact on its financial condition and results of operations.

Effective December 31, 2006, SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans – an amendment of FASB Statements No. 87, 88, 106, and 132 (R)" required the Company to recognize the overfunded or underfunded status of defined benefit postretirement plans in the Company's Balance Sheet measured as the difference between the fair value of plan assets and the benefit obligation. For a pension plan, the benefit obligation is the projected benefit obligation; for any other postretirement benefit plans, the benefit obligation is the accumulated postretirement benefit obligation. Previously, the Company only recognized the underfunded status of defined benefit pension plans as the difference between the fair value of plan assets and the accumulated benefit obligation. As the Company has historically recovered and currently recovers its pension and other postretirement benefit costs related to its regulated operations in retail rates, the Company records a regulatory asset for that portion of its pension and other postretirement benefit funding deficiency. As such, the underfunded status of the Company's pension and other postretirement benefit plans under SFAS No. 158 resulted in the recognition as of December 31, 2006 of:

- a liability of $60.1 million (associated deferred taxes of $21.0 million) for pensions and other postretirement benefits,
- a regulatory asset of $54.2 million (associated deferred taxes of $19.0 million) for pensions and other postretirement benefits,
- an increase to accumulated other comprehensive loss of $3.7 million (net of taxes of $2.1 million), and
- the removal of the intangible pension asset of $3.7 million (was included in other deferred charges).

As such, the total effect on the deferred income tax liability for the adoption of SFAS No. 158 was a net decrease of $2.1 million. The adoption of this statement did not have any effect on the Company's net income.

In December 2007, the FASB issued SFAS No. 141(R), "Business Combinations." This statement replaces SFAS No. 141 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. The Company will be required to begin applying this statement to any business combinations in 2009.

In December 2007, the FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements." This statement amends Accounting Research Bulletin No. 51, "Consolidated Financial Statements," to establish accounting and reporting standards for 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 Company will be required to adopt SFAS No. 160 in 2009. The Company does not expect the adoption of SFAS No. 160 to have any material impact on its financial condition and results of operations. The Company is still in the process of evaluating the full impact SFAS No. 160 will have on its financial statements.

In March 2008, the FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities." This statement will require disclosure of the fair value of derivative instruments and their gains and losses in a tabular format. The statement will also require disclosure of derivative features that are related to credit risk. The Company will be required to adopt SFAS No. 161 in 2009. The Company will have expanded disclosures with respect to derivatives and hedging activities.

In December 2008, the FASB issued FSP FAS 132(R)-1, "Employers' Disclosures about Postretirement Benefit Plan Assets". This FSP amends FASB statement No. 132(R) "Employer's Disclosures about Pensions and Other Postretirement Benefits." This statement provides guidance on an employer's disclosures about plan assets of a defined benefit pension or other postretirement plan. The Company will be required to adopt FSP FAS 132(R)-1 at the end of 2009. The Company will have expanded disclosures with respect to its pension and other postretirement benefit plan assets.

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. Proceeds from the transaction included cash consideration for the net assets acquired by Shell Energy and the liquidation of the remaining net current assets of Avista Energy not sold to Shell Energy (primarily receivables, restricted cash and deposits with counterparties).

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 tax assets. The Company expects that the natural gas storage will ultimately be transferred to Avista Corp., subject to future regulatory approval. Avista Energy also has 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 Energy through 2026. The majority of the rights and obligations of the power purchase agreement were assigned to Shell Energy through the end of 2009. The Company expects that the power purchase agreement for the period 2010 through 2026 will be transferred to Avista Corp., subject to future regulatory approval.

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 25), existing litigation, tax liabilities, matters with respect to natural gas storage rights, and any potential issues associated with the power purchase agreement for the Lancaster Plant. 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 with respect to claims made prior to termination.

As of February 27, 2009, neither party has made any claims under the Indemnification Agreement or Guaranty.

NOTE 4. IMPAIRMENT OF ASSETS

During the third quarter of 2007, the Company recorded an impairment charge of $2.3 million for a turbine and related equipment. The Company originally planned to use the turbine in a regulated utility generation project. At the end of the third quarter of 2007, the Company reached a conclusion to sell the turbine and related equipment, which were classified as assets held for sale as of December 31, 2007, and included in other current assets on the Balance Sheet. The impairment charge reduced the carrying value of the assets to the estimated fair value. The turbine was sold in 2008.

Pursuant to a settlement agreement in its Washington general rate case entered into in October 2007 and approved by the WUTC in December 2007, Avista Corp. agreed to write off $3.8 million of unamortized debt repurchase costs. These costs were for premiums paid to repurchase debt prior to its scheduled maturity. In accordance with regulatory accounting practices, these premiums were recorded as a regulatory asset in unamortized loss on reacquired debt on the Balance Sheet and were being amortized over the average remaining maturity of outstanding debt.

NOTE 5. ADVANTAGE IQ ACQUISITION

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 redeem their shares of Advantage IQ common stock 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.

NOTE 6. 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. On March 14, 2008, Avista Corp., ARC and a third-party financial institution amended a Receivables Purchase Agreement. The most significant amendment extended the termination date to March 13, 2009. Under the Receivables Purchase Agreement, ARC can sell without recourse, 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 14). At each of December 31, 2008 and 2007, ARC had the ability to sell up to $85.0 million of receivables under this revolving agreement. There was $17.0 million in accounts receivable sold as of December 31, 2008 and $85.0 million in accounts receivable sold as of December 31, 2007 under this revolving agreement.

NOTE 7. ENERGY COMMODITY DERIVATIVES AND RISK MANAGEMENT

Avista Corp. is exposed to risks relating to changes in certain commodity prices. 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, both qualitative and quantitative. 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.

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 using 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 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 factors such as customer usage and weather, as well as 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 energy 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 economic, selling fuel and substituting wholesale purchases for the operation of Avista Corp.'s resources, 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 optimization process described above, Avista Corp. manages the impact of fluctuations in electric energy prices by measuring and controlling the volume of energy imbalance between projected loads and resources and through the use of derivative commodity instruments for hedging purposes. Load/resource imbalances within a planning horizon up to 36 months ahead are compared against established volumetric guidelines. Management determines the timing and actions to manage these energy imbalances. Management also assesses available resource decisions and actions that are appropriate for longer-term planning periods.

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 years into the future with the highest volumes hedged for the current and most immediately upcoming gas operating year (November through October). Avista Corp. also purchases a significant portion of its gas supply requirements 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 under utilized pipeline capacity, and
- sales of excess natural gas storage capacity.

Avista Corp. enters into forward contracts to purchase or sell electricity and natural gas. Under these forward contracts, Avista Corp. commits to purchase or sell a specified amount of energy at a specified time, or during a specified period, in the future. Certain of these forward contracts are considered derivative instruments. Avista Corp. also records derivative commodity assets and liabilities for over-the-counter and exchange-traded derivative instruments as well as certain long-term contracts.

SFAS No. 133, as amended, establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. It requires the recording of all derivatives as either assets or liabilities on the balance sheet measured at estimated fair value and the recognition of the unrealized gains and losses. 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.

In conjunction with the provisions of SFAS No. 133, the WUTC and the IPUC issued accounting orders authorizing Avista Corp. to offset any 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 annual adjustments to retail rates through purchased gas cost adjustments, the ERM and the PCA mechanism.

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 SFAS No. 133 are generally accounted for at cost 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.

Market Risk

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 to the extent that nonperformance by market participants of their contractual obligations and commitments affects the supply of, or demand for, the commodity.

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 they may not be able to collect amounts owed to them. 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, and
- 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.

Credit risk also involves the exposure that counterparties perceive related to the ability of the Company to perform deliveries and settlement under physical and financial energy contracts. These counterparties may seek assurances of performance in the form of letters of credit, prepayment, or cash deposits.

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.

Other Operational and Event Risks

In addition to market and credit risk, the Company is subject to operational and event risks including, among others:

- blackouts or disruptions to distribution, transmission or transportation systems,
- forced outages at generating plants,
- fuel quality and availability,
- disruptions to information systems and other administrative resources required for normal operations, and
- weather conditions and natural disasters that can cause physical damage to property, requiring repairs to restore utility service.

Terrorism and other malicious threats are a risk to the entire utility industry. Potential disruptions to operations or destruction of facilities from terrorism or other malicious acts are not readily determinable. The Company has taken various steps to mitigate terrorism risks and prepare contingency plans in the event that its facilities are targeted.

NOTE 8. CASH DEPOSITS FROM COUNTERPARTIES

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. From time to time, margin calls are 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 $0.2 million as of December 31, 2008 and $12.5 million as of December 31, 2007. 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 9. 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 $330.9 million and accumulated depreciation was $204.0 million as of December 31, 2008.

NOTE 10. ASSET RETIREMENT OBLIGATIONS

The Company follows SFAS No. 143, "Accounting for Asset Retirement Obligations," and 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):

	2008	2007	2006
Asset retirement obligation at beginning of year	$3,990	$4,810	$4,529
New liability recognized	-	-	-
Liability adjustment due to revision in estimated cash flows	-	(1,063)	-
Liability settled	(29)	(71)	(51)
Accretion expense	247	314	332
Asset retirement obligation at end of year	$4,208	$3,990	$4,810

NOTE 11. PENSION PLANS AND OTHER POSTRETIREMENT BENEFIT PLANS

The Company has a defined benefit pension plan covering substantially all regular full-time employees at Avista Corp. Individual benefits under this plan are based upon the employee's years of service 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 $28 million in cash to the pension plan in 2008 and $15 million each of 2007 and 2006. The Company expects to contribute $48 million to the pension plan in 2009.

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 $17.5 million in 2009, $18.1 million in 2010, $19.0 million in 2011, $20.0 million in 2012 and $21.2 million in 2013. For the ensuing five years (2014 through 2018), the Company expects that benefit payments under the pension plan and the SERP will total $127.0 million.

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
- reviews and approves changes to the investment and funding policies.

The Company has contracted with an investment consultant who is 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 investment allocation percentages by asset classes as indicated in the table in this Note.

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. The market-related value of pension plan assets invested in debt and equity securities was based primarily on fair value (market prices).

The market-related value of pension plan assets invested in real estate was determined 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 plan assets was determined as of December 31, 2008 and 2007.

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 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 change will also increase future years' pension costs.

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. Effective December 31, 2007, this plan was amended to eliminate a provision that allowed an executive officer to elect for their beneficiaries to receive one quarter of such payment each year over a ten-year period commencing within 30 days of the executive officer's death. The plan was also amended to provide that those who become executive officers after December 31, 2007 will no longer be eligible to receive benefits after retirement. The amendments to the plan reduced the benefit obligation by $1.6 million as of December 31, 2007.

The Company expects that benefit payments under other postretirement benefit plans will be $4.0 million in 2009, $3.8 million in 2010, $3.7 million in 2011, $3.6 million in 2012 and $3.6 million in 2013. For the ensuing five years (2014 through 2018), the Company expects that benefit payments under other postretirement benefit plans will total $16.6 million. The Company expects to contribute $4.0 million to other postretirement benefit plans in 2009, representing expected benefit payments to be paid during the year.

The Company uses a December 31 measurement date for its pension and other postretirement plans. The following table sets forth the pension and other postretirement plan disclosures as of December 31, 2008 and 2007 and the components of net periodic benefit costs for the years ended December 31, 2008, 2007 and 2006 (dollars in thousands):

	Pension Benefits		Other Post-retirement Benefits	
	2008	2007	2008	2007
Change in benefit obligation:				
Benefit obligation as of beginning of year	$323,090	$315,691	$34,352	$33,632
Service cost	10,209	10,694	772	672
Interest cost	20,812	19,161	2,371	2,159
Plan amendment	-	-	-	(1,601)
Actuarial loss (gain)	17,041	(5,245)	5,611	2,612
Transfer of accrued vacation	-	-	365	585
Benefits paid	(17,580)	(16,912)	(4,518)	(3,707)
Expenses paid	-	(299)	-	-
Benefit obligation as of end of year	$353,572	$323,090	$38,953	$34,352
Change in plan assets:				
Fair value of plan assets as of beginning of year	$242,561	$225,079	$22,718	$20,878
Actual return on plan assets	(63,575)	18,799	(6,670)	1,840
Employer contributions	28,000	15,000	-	-
Benefits paid	(16,349)	(16,018)	-	-
Expenses paid	-	(299)	-	-
Fair value of plan assets as of end of year	$190,637	$242,561	$16,048	$22,718
Funded status	$(162,935)	$(80,529)	$(22,905)	$(11,634)
Unrecognized net actuarial loss	160,280	62,174	18,357	4,472
Unrecognized prior service cost	2,444	3,098	(1,452)	(1,600)

Unrecognized net transition obligation	-	-	2,021	2,526
Accrued benefit cost	(211)	(15,257)	(3,979)	(6,236)
Additional liability	(162,724)	(65,272)	(18,926)	(5,398)
Accrued benefit liability	$(162,935)	$(80,529)	$(22,905)	$(11,634)
Accumulated pension benefit obligation	$307,413	$275,159	-	-
Accumulated postretirement benefit obligation:				
For retirees			$18,821	$18,572
For fully eligible employees			$8,903	$9,675
For other participants			$11,229	$6,105
Included in accumulated comprehensive loss (income) (net of tax):				
Unrecognized net transition obligation	$ -	$ -	$1,313	$1,642
Unrecognized prior service cost	1,589	2,013	(943)	(1,040)
Unrecognized net actuarial loss	104,182	40,414	11,932	2,907
Total	105,771	42,427	12,302	3,509
Less regulatory asset	(98,850)	(28,560)	(13,131)	(4,594)
Accumulated other comprehensive loss (income)	$6,921	$13,867	$(829)	$(1,085)
Weighted-average asset allocations as of December 31:				
Equity securities	48%	49%	51%	62%
Debt securities	32%	31%	49%	38%
Real estate	6%	6%	-	-
Absolute return	11%	11%	-	-
Other	3%	3%	-	-
Target asset allocations as of December 31:				
Equity securities	39-61%	39-61%	52-72%	52-72%
Debt securities	27-33%	27-33%	28-48%	28-48%
Real estate	3-7%	3-7%	-	-
Absolute return	10-14%	10-14%	-	-
Other	0-8%	0-8%	-	-
Weighted average assumptions as of December 31:				
Discount rate for benefit obligation	6.25%	6.34%	6.25%	6.20%
Discount rate for annual expense	6.34%	6.15%	6.20%	6.15%
Expected long-term return on plan assets	8.50%	8.50%	8.50%	8.50%
Rate of compensation increase	4.72%	4.66%		
Medical cost trend pre-age 65 – initial			9.00%	9.00%
Medical cost trend pre-age 65 – ultimate			5.00%	5.00%
Ultimate medical cost trend year pre-age 65			2017	2012
Medical cost trend post-age 65 – initial			9.00%	9.00%
Medical cost trend post-age 65 – ultimate			6.00%	6.00%
Ultimate medical cost trend year post-age 65			2015	2011

	2008	2007	2006	2008	2007	2006
Components of net periodic benefit cost:						
Service cost	$10,209	$10,694	$ 9,963	$ 772	$ 672	$ 639
Interest cost	20,812	19,161	17,158	2,371	2,159	1,956
Expected return on plan assets	(21,138)	(19,217)	(16,997)	(1,931)	(1,775)	(1,562)
Transition obligation recognition	-	-	-	505	505	505
Amortization of prior service cost	654	653	653	(149)	-	-
Net loss recognition	3,345	2,978	3,772	575	193	90
Net periodic benefit cost	$13,882	$14,269	$14,549	$2,143	$1,754	$1,628

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, 2008 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, 2008 by $1.8 million and the service and interest cost by $0.2 million.

The Company and its most significant subsidiaries have salary deferral 401(k) plans that are defined contribution plans and cover substantially all employees. Employees can make contributions to their respective accounts in the plans on a pre-tax basis up to the maximum amount permitted by law. The respective company matches a portion of the salary deferred by each participant according to the schedule in the respective plan. Employer matching contributions were $4.3 million in 2008, $4.6 million in 2007 and $4.4 million in 2006.

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, 2008 and 2007, there were deferred compensation assets of $8.8 million and $12.1 million included in other special funds and corresponding deferred compensation liabilities of $8.8 million and $12.1 million included in other deferred credits on the Balance Sheets.

NOTE 12. 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. The realization of deferred 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 tax assets and determined it is more likely than not that deferred 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, Montana and California. 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 the 2004 and 2005 tax years and all issues were resolved related to these years. The IRS is currently conducting an examination of the Company's 2006 and 2007 federal income tax returns. 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 with respect to 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 in accordance with the provisions of SFAS No. 109 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 $115.0 million at December 31, 2008 and $117.5 million at December 31, 2007 related to the probable recovery of certain deferred tax liabilities from customers through future rates.

NOTE 13. 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 $951.4 million in 2008, $733.5 million in 2007 and $682.5 million in 2006. 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):

	2009	2010	2011	2012	2013	Thereafter	Total
Power resources	$246,114	$127,118	$95,029	$ 82,093	$68,928	$390,303	$1,009,585
Natural gas resources	164,323	94,612	68,038	50,663	44,175	474,329	896,140
Total	$410,437	$221,730	$163,067	$132,756	$113,103	$864,632	$1,905,725

All of the 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):

	2009	2010	2011	2012	2013	Thereafter	Total
Contractual obligations	$24,546	$27,805	$26,353	$29,116	$29,987	$247,381	$385,188

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 $14.9 million in 2008, $18.0 million in 2007 and $13.1 million in 2006. Information as of December 31, 2008 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	$ 2,116	$1,026	$ 1,320	2011
Douglas County PUD:						
Wells Project	3.5%	30,000	1,791	793	4,411	2018
Grant County PUD:						
Priest Rapids Project	3.3%	28,000	5,253	727	8,485	2055
Wanapum Project (2)	8.2%	78,000	5,715	2,663	15,143	2055
Totals		173,000	$14,875	$5,209	$29,359	

(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 2008. Debt service costs are included in annual costs.

(2) The current contract expires October 31, 2009. A new contract was completed in 2001 with an expiration date of 2055. Beginning in November 2009, our rights to the output will be reduced to 3.3 percent. Under the new contract we will have the rights to the output but not the obligation to take the output. In September of each year we will be required to determine if we 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):

	2009	2010	2011	2012	2013	Thereafter	Total

Minimum payments	$4,527	$2,967	$2,910	$2,491	$2,427	$33,698	$49,020

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

Avista Energy's contractual commitments to purchase energy commodities as well as commitments related to transmission, transportation and other energy-related contracts in future periods are as follows (dollars in thousands):

	2009	2010	2011	2012	2013	Thereafter	Total
Energy purchase contracts	$21,700	$26,728	$26,728	$26,530	$25,543	$290,482	$417,711

These contractual commitments of Avista Energy are primarily related to the power purchase agreement for the Lancaster Plant. The majority of the rights and obligations of this agreement were assigned to Shell Energy through the end of 2009. Beginning in 2010 through 2026, the rights and obligations of the power purchase agreement for the Lancaster Plant are contracted to Avista Energy. The Company expects that these rights and obligations will be transferred to Avista Corp., subject to future regulatory approval.

NOTE 14. COMMITTED LINE OF CREDIT AGREEMENTS

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 request the issuance of up to $320.0 million in letters of credit. Total letters of credit outstanding were $24.3 million as of December 31, 2008 and $34.8 million as of December 31, 2007. 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 $200.0 million with an expiration date of November 24, 2009. The committed line of credit is secured by $200.0 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, 2008, the Company was in compliance with this covenant with a ratio of 3.27 to 1. The committed line of credit agreements also have a covenant which does not permit the ratio of " total debt" to " total capitalization" of Avista Corp. to be greater than 70 percent at any time. As of December 31, 2008, the Company was in compliance with this covenant with a ratio of 54.5 percent. If the proposed change in organization becomes effective, the committed line of credit agreements will remain at Avista Corp. The committed line of credit agreements also have a covenant which requires the Company to maintain a minimum funded ratio of the pension plan assets to liabilities. The Pension Protection Act of 2006 (that was implemented in 2008) modified the liability calculation utilized to calculate the funded ratio. Avista Corp. amended the covenant related to the pension funded ratio, under its $320.0 million committed line of credit agreement, to conform with the calculations under the Pension Protection Act of 2006.

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):

	2008	2007	2006
Balance outstanding at end of period	$ 250,000	$ -	$ 4,000
Maximum balance outstanding during the period	$ 250,000	$48,000	$77,000
Average balance outstanding during the period	$ 48,426	$ 6,833	$16,740
Average interest rate during the period	3.04%	7.91%	6.07%
Average interest rate at end of period	0.81%	- %	8.25%

NOTE 15. BONDS AND OTHER LONG-TERM DEBT

The following details the interest rate and maturity dates of bonds and other long-term debt outstanding as of December 31 (dollars in thousands):

Maturity Interest

Year	Description	Rate	2008	2007
2008	Secured Medium-Term Notes	6.06%-6.95%	$ -	$45,000
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 (1)	7.25%	30,000	-
2018	First Mortgage Bonds (2)	5.95%	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
2023	Secured Medium-Term Notes	7.18%-7.54%	13,500	13,500
2028	Secured Medium-Term Notes	6.37%	25,000	25,000
2032	Secured Pollution Control Bonds (3)	5.00%	-	66,700
2034	Secured Pollution Control Bonds (4)	1.20%	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 and other long-term debt		835,000	666,700
2008	Unsecured Senior Notes	9.75%	-	272,860
2023	Unsecured Pollution Control Bonds	6.00%	4,100	4,100
	Total unsecured bonds and other long-term debt		4,100	276,960
	Interest rate swaps		(14,129)	1,083
	Total long-term debt		$824,971	$944,743

(1) On December 16, 2008, the Company issued $30.0 million of 7.25 percent First Mortgage Bonds due in 2013. The net proceeds from the issuance of $29.9 million (net of placement agent fees and before Avista Corp.'s expenses) were used to repay $25.0 million of medium term notes that matured on December 10, 2008 and repay a portion of the borrowings outstanding under the Company's $320.0 million committed line of credit.

On April 3, 2008, the Company issued $250.0 million of 5.95 percent First Mortgage Bonds due in 2018. The net proceeds from the issuance of $249.2 million (net of issuance discount and before Avista Corp.'s expenses), together with other available funds, were used to pay the $272.9 million of 9.75 percent Unsecured Senior Notes that matured on June 1, 2008.

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 2034 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.

On December 30, 2008, the City of Forsyth, Montana issued $17.0 million of its Pollution Control Revenue Refunding Bonds, Series 2008 (Avista Corporation Colstrip Project) due 2034 on behalf of Avista Corp. The proceeds of these bonds were used to refund $17.0 million of Pollution Control Revenue Refunding Bonds, Series 1999B (Avista Corporation Colstrip Project) issued by the City of Forsyth, Montana on behalf of Avista Corp.

The following table details future long-term debt maturities including long-term debt to affiliated trusts (see Note 16) (dollars in thousands):

	2009	2010	2011	2012	2013	Thereafter	Total
Debt maturities	$17,000	$35,000	$ -	$7,000	$75,000	$818,503	$952,503

Substantially all utility properties owned by the Company are subject to the lien of the Company's various mortgage indentures. 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, 2008, property additions and retired bonds would have entitled the Company to issue $688.9 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, 2008, the net earnings test would limit the principal amount of additional bonds the Company could issue to $545.9 million.

See Note 14 for information regarding First Mortgage Bonds issued to secure the Company's obligations under its $320.0 million and $200.0 million committed line of credit agreements.

NOTE 16. 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. All of these securities have a fixed interest rate of 6.50 percent for five years (through March 31, 2009). Subsequent to the initial five-year fixed rate period, the securities will either have a new fixed rate or an adjustable rate. These debt securities may be redeemed by the Company on or after March 31, 2009 and will mature on April 1, 2034.

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 2008 ranged from 3.06 percent to 6.00 percent. As of December 31, 2008, the annual distribution rate was 3.06 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 with respect to, the Preferred Trust Securities to the extent that AVA Capital Trust III and Avista Capital II have 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 17. 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 the anticipated issuances of debt. These interest rate swap agreements are considered economic hedges against fluctuations in future cash flows associated with changes in interest rates.

In December 2006, Avista Corp. cash settled an interest rate swap agreement and paid $3.7 million. In March 2008, the Company cash settled two interest rate swap agreements and paid a total of $16.4 million. These settlements were deferred as regulatory items (part of long-term debt) and will be amortized as a component of interest expense over the remaining ten year terms of the interest rate swap agreements (forecasted interest payments) in accordance with regulatory accounting practices.

In December 2008, the Company entered into two interest rate swaps totaling $50.0 million. Under the terms of the outstanding interest rate swap agreements as of December 31, 2008, the value of the interest rate swaps is determined based upon Avista Corp. paying a fixed rate and receiving a variable rate based on LIBOR for a term of ten years beginning in 2009. As of December 31, 2008, Avista Corp. had a current derivative asset of $0.9 million and offsetting regulatory liability on the Balance Sheets in accordance with regulatory accounting practices. Upon settlement of the interest rate swaps, the regulatory asset or liability (included as part of long-term debt) will be amortized as a component of interest expense over the life of the forecasted interest payments. The interest rate swap agreements provide for mandatory cash settlement of these contracts in 2009.

In January 2009, the Company entered into two interest rate swaps totaling $50.0 million. Under the terms of the outstanding interest rate swap agreements, the value of the interest rate swaps is determined based upon Avista Corp. paying a fixed rate and receiving a variable rate based on LIBOR for a term of ten years beginning in 2009. Upon settlement of the interest rate swaps, the regulatory asset or liability (included as part of long-term debt) will be amortized as a component of interest expense over the life of the forecasted interest payments. The interest rate swap agreements provide for mandatory cash settlement of these contracts in 2009.

NOTE 18. 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 $4.8 million in 2008, $4.8 million in 2007 and $5.4 million in 2006. Future minimum lease payments required under operating leases having initial or remaining noncancelable lease terms in excess of one year as of December 31, 2008 were as follows (dollars in thousands):

	2009	2010	2011	2012	2013	Thereafter	Total
Minimum payments required	$1,395	$425	$209	$125	$118	$2,119	$4,391

NOTE 19. GUARANTEES

The Company has guaranteed the payment of distributions on, and redemption price and liquidation amount with respect to, the Preferred Trust Securities issued by its affiliates, AVA Capital Trust III and Avista Capital II, to the extent that these entities have funds available for such payments from the respective debt securities.

The output from the Lancaster Plant is contracted to Avista Energy through 2026 under a power purchase agreement. Avista Corp. has guaranteed the power purchase agreement for the performance of Avista Energy. The majority of the rights and obligations of this agreement were assigned to Shell Energy through the end of 2009. Beginning in 2010, the Company expects that these rights and obligations will be transferred to Avista Corp., subject to future regulatory approval.

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 25), existing litigation, tax liabilities, matters with respect to storage rights at Jackson Prairie, and any potential issues associated with the power purchase agreement for the Lancaster Plant. 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 with respect to claims made prior to termination.

NOTE 20. 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, 2008 and 2007. In September 2007, the Company redeemed the 262,500 remaining outstanding shares of preferred stock for $26.25 million. In September 2006, the Company made a mandatory redemption of 17,500 shares of preferred stock for $1.75 million.

NOTE 21. FAIR VALUE

The carrying values of cash and cash equivalents, restricted cash, accounts and notes receivable, accounts payable and the committed lines of credit are reasonable estimates of their fair values. Long-term debt and long-term debt to affiliated trusts 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, 2008 and 2007 (dollars in thousands):

	2008		2007	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Long-term debt	$839,100	$875,451	$943,660	$969,899
Long-term debt to affiliated trusts	113,403	102,027	113,403	109,109

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, are reported at estimated fair value on the Balance Sheets. As disclosed in Note 2, on January 1, 2008, the Company adopted the provisions of SFAS No. 157 related to its financial assets and liabilities and nonfinancial assets and liabilities measured at fair value on a recurring basis. SFAS No. 157 establishes 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 defined by SFAS No. 157 are 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.

As required by SFAS No. 157, 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 following table discloses by level within the fair value hierarchy the Company's assets and liabilities measured and reported on the Balance Sheet as of December 31, 2008 at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Counterparty Netting	Total
Assets:					
Energy commodity derivatives	$ -	$40,104	$68,047	$(47,604)	$60,547
Deferred compensation assets	6,990	-	-	-	6,990
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

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 our 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 and at Note 7 is due to netting arrangements with certain counterparties. The Company uses quoted market prices and forward price curves to estimate the fair value of our 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, which are also quoted under NYMEX. 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 7 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 excludes cash and cash equivalents of $1.8 million.

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

	2008
Balance as of January 1, 2008	$98,943
Total gains or losses (realized/unrealized)	
Included in net income	-
Included in other comprehensive income	-
Included in regulatory assets/liabilities (1)	(22,586)
Purchases, issuances, and settlements, net	(8,310)
Transfers to other categories	-
Balance as of December 31, 2008	$68,047

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

	2008
Balance as of January 1, 2008	$36,506
Total gains or losses (realized/unrealized)	
Included in net income	-
Included in other comprehensive income	-
Included in regulatory assets/liabilities (1)	(18,715)
Purchases, issuances, and settlements, net	(1,706)
Transfers to other categories	-
Balance as of December 31, 2008	$16,085

(1) In conjunction with the provisions of SFAS No. 133, the WUTC and the IPUC issued accounting orders authorizing Avista Corp. to offset any 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. As such, the Company does not recognize unrealized gains or losses on utility energy commodity derivative instruments in the Statements of Income. The Company recognizes realized gains or losses in the period of contract settlement, subject to regulatory 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 and the PCA mechanism.

NOTE 22. COMMON STOCK

In November 1999, the Company adopted a shareholder rights plan pursuant to which holders of common stock outstanding on February 15, 1999, or issued thereafter, were granted one preferred share purchase right (Right) on each outstanding share of common stock. Each Right, initially evidenced by and traded with the shares of common stock, entitles the registered holder to purchase one one-hundredth of a share of preferred stock of the Company, without par value, at a purchase price of $70, subject to certain adjustments, regulatory approval and other specified conditions. The Rights will be exercisable only if a person or group acquires 10 percent or more of the outstanding shares of common stock or commences a tender or exchange offer, the consummation of which would result in the beneficial ownership by a person or group of 10 percent or more of the outstanding shares of common stock. Upon any such acquisition, each Right will entitle its holder to purchase, at the purchase price, that number of shares of common stock or preferred stock of the Company (or, in the case of a merger of the Company into another person or group, common stock of the acquiring person or group) that has a market value at that time equal to twice the purchase price. In no event will the Rights be exercisable by a person that has acquired 10 percent or more of the Company's common stock. The Rights may be redeemed, at a redemption price of $0.01 per Right, by the Board of Directors of the Company at any time until any person or group has acquired 10 percent or more of the common stock. In connection with the proposed statutory share exchange (see Note 27), the shareholder rights plan was amended to provide that the Rights will expire upon the earlier of the effective time of the statutory share exchange or March 31, 2009 (the originally scheduled expiration date).

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 2006, the Company entered into a sales agency agreement with a sales agent, to issue up to 2 million shares of its common stock from time to time. In 2008, the Company issued 750,000 shares (total net proceeds of $16.6 million) under the sales agency agreement.

NOTE 23. EARNINGS PER COMMON SHARE

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

	2008	2007	2006
Numerator:			
Net income	$73,620	$38,475	$72,941
Subsidiary earnings adjustment for dilutive securities	(249)	(349)	-
Adjusted net income for computation of diluted earnings per common share	$73,371	$38,126	$72,941
Denominator:			
Weighted-average number of common shares outstanding-basic	53,637	52,796	49,162
Effect of dilutive securities:			
Contingent stock awards	213	168	371
Stock options	178	299	364
Weighted-average number of common shares outstanding-diluted	54,028	53,263	49,897
Total earnings per common share, basic	$1.37	$0.73	$1.48
Total earnings per common share, diluted	$1.36	$0.72	$1.46

Total stock options outstanding that were not included in the calculation of diluted earnings per common share were 250,950 for 2008, 303,950 for 2007 and 26,200 for 2006. 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 24. 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, 2008, 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, 2008, 1.7 million shares were remaining for grant under this plan.

Stock Compensation

On January 1, 2006, the Company adopted SFAS No. 123R, which supersedes APB No. 25 and SFAS No. 123 and their related implementation guidance. The statement requires that compensation cost relating to share-based payment transactions be recognized in the financial statements based on the fair value of the equity or liability instruments issued. The Company adopted SFAS No. 123R using the modified prospective method and, accordingly, financial statement amounts for prior periods presented were not restated to reflect the fair value method of recognizing compensation expense relating to share-based payments. The Company recorded stock-based compensation expense of $3.0 million for 2008, $2.7 million for 2007 and $4.0 million for 2006. The total income tax benefit recognized in the Statements of Income was $1.1 million for 2008, $1.0 million for 2007 and $1.5 million for 2006.

Stock Options

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

	2008	2007	2006
Number of shares under stock options:			
Options outstanding at beginning of year	1,411,911	1,541,045	2,095,211
Options granted	-	-	-
Options exercised	(582,238)	(123,134)	(504,452)
Options canceled	(81,000)	(6,000)	(49,714)
Options outstanding at end of year	748,673	1,411,911	1,541,045
Options exercisable at end of year	748,673	1,411,911	1,541,045
Weighted average exercise price:			
Options granted	$ -	$ -	$ -
Options exercised	$13.91	$15.14	$16.12
Options canceled	$21.70	$26.59	$20.77
Options outstanding at end of year	$15.85	$15.38	$15.41
Options exercisable at end of year	$15.85	$15.38	$15.41
Intrinsic value of options exercised (in thousands)	$4,248	$1,022	$3,520
Intrinsic value of options outstanding (in thousands)	$2,643	$8,697	$15,256

Information for options outstanding and exercisable as of December 31, 2008 was as follows:

Range of Exercise Prices	Number of Shares	Weighted Average Exercise Price	Weighted Average Remaining Life (in years)
$10.17-$12.41	393,323	$11.04	3.4
$15.88-$17.31	104,400	17.19	1.1
$19.34-$23.00	230,750	22.41	1.9
$26.59-$28.47	20,200	27.63	1.2
Total	748,673	$15.85	2.6

Total cash received from the exercise of stock options was $8.1 million for 2008, $1.9 million for 2007 and $9.9 million for 2006. As of December 31, 2008 and 2007, 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, 2008 was one year. The following table summarizes restricted stock activity for the years ended December 31:

	2008	2007	2006
Unvested shares at beginning of year	28,137	36,180	-
Shares granted	43,400	31,860	36,260
Shares cancelled	(1,230)	(19,936)	(80)
Shares vested	(14,368)	(19,967)	-
Unvested shares at end of year	55,939	28,137	36,180
Weighted average fair value at grant date	$20.05	$25.60	$21.32
Unrecognized compensation expense at end of year (in thousands)	$691	$517	$439
Intrinsic value, unvested shares at end of year (in thousands)	$1,084	$606	$916
Intrinsic value, shares vested during the year (in thousands)	$293	$461	$ -

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 (TSR) performance over a three-year period as compared against other utilities; under SFAS 123R 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. Under Statement SFAS 123R, 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 in accordance with the provisions of SFAS No. 123R. 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 costs as well as the resulting estimated fair value of performance shares granted:

	2008	2007	2006
Risk-free interest rate	2.2%	4.8%	4.6%
Expected life, in years	3	3	3
Expected volatility	20.2%	19.4%	21.9%
Dividend yield	2.8%	2.5%	2.9%
Weighted average grant date fair value (per share)	$16.96	$18.71	$18.08

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

The following summarizes performance share activity:

	2008	2007	2006
Opening balance of unvested performance shares	207,841	300,406	318,331
Performance shares granted	170,100	114,640	138,710
Performance shares canceled	(5,239)	(45,632)	(1,404)
Performance shares vested	(119,779)	(161,573)	(155,231)
Ending balance of unvested performance shares	252,923	207,841	300,406
Intrinsic value of unvested performance shares (in thousands)	$4,902	$4,477	$7,603

Unrecognized compensation expense (in thousands)	$2,227	$2,058	$2,400

The weighted average remaining vesting period for the Company's performance shares outstanding as of December 31, 2008 was 1.7 years. Unrecognized compensation expense as of December 31, 2008 will be recognized during 2009 and 2010. The following summarizes the impact of the market condition on the vested performance shares:

	2008	2007	2006
Performance shares vested	119,779	161,573	155,231
Impact of market condition on shares vested	21,560	(56,551)	34,151
Shares of common stock earned	141,339	105,022	189,382
Intrinsic value of common stock earned (in thousands)	$2,739	$2,262	$4,793

In 2008, 2007 and 2006, the number of performance shares vested was adjusted by 18 percent, (35) percent and 22 percent due to 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 under the guidance of SFAS No. 123R. 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, 2008 and 2007, the Company had recognized compensation expense and a liability of $0.5 million and $0.4 million related to the dividend component of performance share grants.

NOTE 25. 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. With respect to 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. With respect to matters that affect Avista Corp.'s operations, the Company intends to seek, to the extent appropriate, recovery of incurred costs through the rate making process. With respect to matters discussed in this Note that affect Avista Energy (particularly the California Refund Proceeding), any potential liabilities or refunds remain at Avista Corp. and/or its subsidiaries and were not assumed by Shell Energy and/or its affiliates.

Federal Energy Regulatory Commission Inquiry

On April 19, 2004, the FERC issued an order approving the contested Agreement in Resolution of Section 206 Proceeding (Agreement in Resolution) reached by Avista Corp. Avista Energy and the FERC's Trial Staff with respect to an investigation into the activities of Avista Corp. and Avista Energy in western energy markets during 2000 and 2001. In the Agreement in Resolution, the FERC Trial Staff stated that its investigation found: (1) no evidence that any executives or employees of Avista Corp. or Avista Energy knowingly engaged in or facilitated any improper trading strategy; (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) that Avista Corp. and Avista Energy did not withhold relevant information from the FERC's inquiry into the western energy markets for 2000 and 2001. In April 2005 and June 2005, the California Parties and the City of Tacoma, respectively, filed petitions for review of the FERC's decisions approving the Agreement in Resolution with the United States Court of Appeals for the Ninth Circuit (Ninth Circuit). 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.

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 California Independent System Operator (CalISO) and the California Power Exchange (CalPX) during the period from October 2, 2000 to June 20, 2001 (Refund Period). The findings of the FERC administrative law judge were largely adopted in March 2003 by the FERC. The refunds ordered are based on the development of a mitigated market clearing price (MMCP) methodology. If the refunds required by the formula would cause a seller to recover less than its actual costs for the Refund Period, the FERC has held that the seller would be allowed to document these costs and limit its refund liability commensurately. In September 2005, Avista Energy submitted its cost filing claim pursuant to the FERC's August 2005 order and demonstrated an overall revenue shortfall for sales into the California spot markets during the Refund Period after the MMCP methodology is applied to its transactions. That filing was accepted in orders issued by the FERC in January 2006 and November

2006. In its February 2007 status report, the CalISO stated that it intends to process Avista Energy's cost offset filing (see further discussion regarding the California refund rerun below).

In 2001, Pacific Gas & Electric (PG&E) and Southern California Edison (SCE) defaulted on payment obligations to the CalPX and the CalISO. As a result, the CalPX and the CalISO failed to pay various energy sellers, including Avista Energy. Both PG&E and the CalPX declared bankruptcy in 2001. In March 2002, SCE paid its defaulted obligations to the CalPX. In April 2004, PG&E paid its defaulted obligations into an escrow fund in accordance with its bankruptcy reorganization. Funds held by the CalPX and in the PG&E escrow fund are not subject to release until the FERC issues an order directing such release in the California refund proceeding. As of December 31, 2008, 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.

In addition, in June 2003, the FERC issued an order to review bids above $250 per MW made by participants in the short-term energy markets operated by the CalISO and the CalPX from May 1, 2000 to October 2, 2000. In May 2004, the FERC provided notice that Avista Energy was no longer subject to this investigation. In March and April 2005, the California Parties and PG&E, respectively, petitioned for review of the FERC's decision by the Ninth Circuit. In addition, many of the other orders that the FERC has issued in the California refund proceedings are now on appeal before the Ninth Circuit. Some of those issues were consolidated as a result of a case management conference conducted in September 2004. In October 2004, the Ninth Circuit ordered that briefing proceed in two rounds. The first round is 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. 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 Case. In its Order on Remand, issued in October 2007, the FERC ordered the CalISO and the CalPX to complete their refund calculations, including all entities that participated in the CalISO/CalPX markets (including those amounts that would have been paid by municipal utility entities for their sales into the CalISO and the CalPX spot markets during the refund period). The FERC then directed the CalISO to reduce refunds owed to refund recipients by the amounts attributable to municipal sales to the California markets.

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 a FPA section 309 remedy for tariff violations prior to October 2, 2000. The Ninth Circuit also granted California's petition for review challenging the FERC's exclusion of the energy exchange transactions as well as the FERC's exclusion of forward market transactions from the California refund proceedings. Petitions for rehearing were filed on November 16, 2007. It is unclear at this time what impact, if any, the Court's remand might have on Avista Energy. The second round of issues and their corresponding briefing schedules have not yet been set by the Ninth Circuit.

The CalISO continues to work on its compliance filing for the Refund Period, which will show "who owes what to whom." On September 3, 2008, the CalISO filed its 42nd 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). The CalISO states that there are eleven (11) open issues that the FERC must rule on before any distribution can be made. Once these issues are ruled on, the CalISO states that it then 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.

Any potential liabilities or refunds owed by or to Avista Energy in the California Refund Proceeding were retained by Avista Corp. and/or its subsidiaries and have not been transferred to Shell Energy and/or its affiliates.
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 to the Company's management, the Company does not expect that the California refund proceeding will have a material adverse effect on its financial condition, results of operations or cash flows. This is primarily due to the fact that FERC orders have stated that any refunds will be netted against unpaid amounts owed to the respective parties and the Company does not believe that refunds would exceed unpaid amounts owed to the Company.

Pacific Northwest Refund Proceeding

In July 2001, the FERC initiated a preliminary evidentiary hearing to develop a factual record as to whether prices for spot market sales of wholesale energy in the Pacific Northwest between December 25, 2000, and June 20, 2001, were just and reasonable. During the hearing, Avista Corp. and Avista Energy vigorously opposed claims that rates for spot market sales were unjust and unreasonable and that the imposition of refunds would be appropriate. In June 2003, the FERC terminated the Pacific Northwest refund proceedings, after finding that the equities do not justify the imposition of refunds. These equitable factors included the fact that the participants in the Pacific Northwest market include not only utilities and other entities that are subject to FERC jurisdiction, but also a very substantial number of governmental entities that are not subject to FERC jurisdiction with respect to wholesale sales and thus could not be ordered by the FERC to make refunds based on existing law. Seven petitions for review were filed with the Ninth Circuit challenging the merits of the FERC's decision not to order refunds and raising procedural issues.

On August 24, 2007, the Ninth Circuit issued its opinion on the consolidated petitions for review of the Pacific Northwest refund proceeding. 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 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 filed on December 17, 2007.

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.

California Attorney General Complaint

In May 2002, the FERC conditionally dismissed a complaint filed in March 2002 by the Attorney General of the State of California (California AG) that alleged violations of the Federal Power Act 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 July 2002, the California AG requested a rehearing on the FERC order, which request was denied in September 2002. Subsequently, the California AG filed a Petition for Review of the FERC's decision with the Ninth Circuit. 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. Nonetheless, the California AG has interpreted the decision as providing authority to the FERC to order refunds in the California refund proceeding for an expanded refund period.

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

State of Montana Proceedings

The Attorney General of the State of Montana (Montana AG) petitioned the Montana Public Service Commission (MPSC) to fine public utilities $1,000 a day for each day it finds they engaged in alleged "deceptive, fraudulent, anticompetitive or abusive practices" and order refunds when consumers were forced to pay more than just and reasonable rates. In February 2004, the MPSC issued an order initiating investigation of the Montana retail electricity market for the purpose of determining whether there is evidence of unlawful manipulation of that market. The Montana AG requested specific information from Avista Energy and Avista Corp. regarding their transactions within the state of Montana during the period from January 1, 2000 through December 31, 2001. In December 2008, the MPSC closed the Docket and terminated the investigation, subject to the receipt of a final report from the Montana AG.

Colstrip Generating Project Complaints

In May 2003, various parties (all of which are residents or businesses of Colstrip, Montana) filed complaints against the owners of the Colstrip Generating Project (Colstrip) in Montana District Court. Avista Corp. owns a 15 percent interest in Units 3 & 4 of Colstrip. The plaintiffs alleged damages to buildings as a result of foundation settlement caused by seepage from Colstrip's freshwater surge pond. Avista Corp.'s ownership interest in the freshwater surge pond is approximately 11 percent. The plaintiffs also alleged contamination and trespass damages resulting from leakage from several of Colstrip's process ponds, most of which are for Units 1 & 2 ponds of which Avista Corp. has no ownership interest. In April 2008, the owners of Colstrip reached a settlement with the plaintiffs. Under the settlement, Avista Corp.'s portion of the payment to the plaintiffs was $2.1 million. Avista Corp. may be able to recover a portion of this payment through insurance. The Company filed petitions with the WUTC and the IPUC to defer any payments as a regulatory asset, in order to allow for potential future recovery through future rates. On September 12, 2008, the IPUC issued its order approving the Company's petition. The WUTC petition was subsequently withdrawn and the portion related to the Washington jurisdiction of $1.3 million was expensed in 2008.

In March 2007, two families that own property near the holding ponds from Units 3 & 4 of Colstrip filed a complaint against the owners of Colstrip and Hydrometrics, Inc. in Montana District Court. 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 and other relief similar to that asserted in the litigation described above. No trial date has been set. 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.

Colstrip Royalty Claim

Western Energy Company (WECO) supplies coal to the owners of Colstrip Units 3 & 4 under a Coal Supply Agreement and a Transportation Agreement. Avista Corp. owns a 15 percent interest in Colstrip Units 3 & 4. The Minerals Management Service (MMS) of the United States Department of the Interior has issued orders, going back to 1991, to WECO to pay additional royalties concerning coal delivered to Colstrip Units 3 & 4 via the conveyor belt. The owners of Colstrip Units 3 & 4 take delivery of the coal at the beginning of the conveyor belt.

The orders assert that additional royalties are owed to MMS as a result of WECO not paying royalties in connection with revenue received by WECO from the owners of Colstrip Units 3 & 4 under the Transportation Agreement during the period October 1, 1991 through December 31, 2007.

The state of Montana also filed claims assessing additional coal production taxes on Coal Transportation Agreement revenues collected by WECO from the owners of Colstrip Units 3 & 4. Settlement of production tax claims has recently occurred between WECO and the Montana Department of Revenue.

WECO and the owners of Colstrip Units 3 & 4 have agreed to a cost sharing agreement for the payment of the settlements owed to the Montana Department of Revenue for coal production taxes and for the MMS royalty claims as they are determined through litigation or settlement. Avista Corp. estimates that its share of the royalties, taxes and interest alleged would be $2.1 million including payment for the calendar year 2008.

Based on information currently known to the Company's management, the Company does not expect that this issue will have a material adverse effect on its financial condition, results of operations or cash flows. However, the Company would most likely seek recovery, through the ratemaking process, of any amounts paid.

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 $1.2 million and will take approximately 2 1/2 years to complete. 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 de minimus 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. As such, it is not possible to make an estimate of any liability at this time.

Lake Coeur d'Alene

In July 1998, the United States District Court for the District of Idaho issued its finding that 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. This action had been brought by the United States on behalf of the Tribe against the state of Idaho. Avista Corp. was not a party to this action. The United States District Court decision was affirmed by the United States Court of Appeals for the Ninth Circuit. The United States Supreme Court affirmed this decision 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 Section 10(e) payments.

The Company's Post Falls Hydroelectric Generating Station (Post Falls), a facility constructed in 1906 with annual generation of 10 average megawatts controls the water level in the Lake for portions of the year (including portions of the lakebed owned by the Tribe). The Company has other hydroelectric generating facilities on the Spokane River downstream of Post Falls.

In December 2008, Avista Corp., the Tribe and the United States 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 the use of the Tribe's reservation lands under Section 10(e) of the Federal Power Act (Section 10(e) payments) and issues related to licensing of the Company's hydroelectric generating facilities located on the Spokane River (see Spokane River Relicensing 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 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 a 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 a 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 resource protection trust fund (the Trust Fund). Annual payments from the Company to the Trust Fund for protection, mitigation and enhancement measurements would commence with the issuance of a new FERC license and are expected to total approximately $100 million over an assumed 50-year license term.

In September 2008, as part of the settlement of the Company's general rate case the IPUC approved deferral of the Idaho jurisdictional allocation of amounts paid to the Tribe, the Trust Fund or related to the licensing of its hydroelectric generating facilities for later recovery through rates in a subsequent general rate filing. Avista Corp. included these items in its general rate case filed in January 2009. In December 2008, the WUTC approved a settlement of the Company's general rate case filing which provides similar treatment of the Washington jurisdictional allocation of amounts paid to the Tribe, the Trust Fund or related to the licensing of its hydroelectric generating facilities.

On January 27, 2009, the Public Counsel Section of the Washington Attorney General's Office (Public Counsel) filed a Petition for Judicial Review of the WUTC's recent order approving the settlement of the Company's general rate case. Public Counsel raised a number of issues that were previously argued before the WUTC. These include whether settlement costs associated with resolving the dispute with the Tribe were prudent and whether recovery of such costs would constitute illegal "retroactive ratemaking." The appeals process may take several months and a decision is not expected until later in 2009. The court will either affirm the decision of the WUTC in its entirety or reverse the decision, in whole or in part, and remand the matter back to the WUTC for further consideration, which could possibly result in refunds.

Spokane River Relicensing

The Company owns and operates six hydroelectric plants on the Spokane River, and 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. Since the FERC was unable to issue new license orders prior to the August 1, 2007 (and subsequent August 1, 2008) expiration of the current license, an annual license was issued for all five plants, in effect extending the current license and its conditions until August 1, 2009. The Company has no reason to believe that Spokane River Project operations will be interrupted in any manner relative to the timing of the FERC's actions.

The Company filed a Notice of Intent to Relicense in July 2002. The formal consultation process involving planning and information gathering with stakeholder groups lasted through July 2005, when the Company filed its new license applications with the FERC. The Company initially requested the FERC to consider a license for Post Falls, which has a present capability of 18 MW, separately from the other four hydroelectric plants due to the complexity of issues related to the Post Falls development. In the license applications, the Company proposed a number of measures intended to address the impact of the Spokane River Project and enhance resources associated with the Spokane River. FERC licenses are granted for terms of 30 to 50 years.

Since the Company's July 2005 filing of applications to relicense the Spokane River Project, the FERC has continued various stages of processing the applications. In May 2006, the FERC issued a notice requesting other parties to provide terms and conditions regarding the two license applications. In response to that notice, a number of parties including the Tribe, the state of Idaho, Washington state agencies, and the United States DOI filed either recommended terms and conditions, pursuant to Sections 10(a) and 10(j) of the Federal Power Act (FPA), or mandatory conditions related to the Post Falls application, pursuant to Section 4(e) of the FPA. In January 2007, the FERC issued a draft Environmental Impact Statement (EIS). After review of comments, the FERC issued a final EIS in July 2007. This was the last administrative step for the FERC before the issuance of license orders; however, the FERC was unable to move forward prior to Federal Clean Water Act 401 Water Quality Certifications (Certifications) being issued by the states of Idaho and Washington.

The states of Idaho and Washington issued Certifications for the Project on June 5, 2008 and June 10, 2008, respectively. The Idaho Certification was based on a Settlement Agreement between Avista Corp., Idaho Department of Environmental Quality and the Idaho Department of Fish and Game, and is final. The Washington Certification, which was issued by the Washington Department of Ecology (Ecology); however, was appealed by Avista Corp., Inland Empire Paper and the Sierra Club/Center for Environmental Law and Policy. All issues, with the exception of one appealed by the Sierra Club/Center for Environmental Law and Policy (aesthetic spills at the Upper Falls plant) were resolved through a four-party Settlement Agreement. Avista Corp. is continuing negotiations on the remaining issue. A hearing is scheduled before the Washington Pollution Control Hearing Board in August 2009 to address the remaining issue under appeal.

On December 16, 2008 Avista, the United States DOI, and the Tribe reached agreement resolving Federal Power Act Section 4(e) conditions, as well as the payment of annual charges under Section 10(e) of the FPA regarding Post Falls, which stores water on a portion of the Coeur d'Alene Indian Reservation. The three parties submitted a request to the FERC on January 29, 2009 to incorporate the agreed-upon terms and conditions in a new single 50-year license for all five Spokane River hydroelectric plants.

The United States Department of Fish and Wildlife concurred, via a letter to FERC on July 31, 2008, that the Spokane River Project is not likely to adversely affect any listed or threatened endangered species.

Avista Corp. can not determine exactly when the FERC will complete action on the applications. Once granted, a new license will describe the final conditions Avista Corp. will be responsible to implement, and the term for a new license.

The Company's estimate of the potential cost of the conditions proposed for the Spokane River Project, based on estimates of what it would cost to implement the recommendations and conditions included in the FERC's FEIS and the numerous Settlement Agreements, total approximately $305 million over a 50-year period.

In addition, the December 16, 2008 settlement agreement between the Company and the Tribe resolved FPA Section 10(e), or storage payments related to the Post Falls hydroelectric facility. Under the Agreement, Avista Corp. will pay the Tribe $0.4 million annually for the first 20 years of a new FERC license and $0.7 million annually for the remainder of the license term for section 10(e) charges.

The WUTC approved, for future recovery, costs incurred in relicensing the Spokane River project, as well as the costs related to settlement with the Tribe. The WUTC approved deferred accounting treatment, with a carrying cost, until these costs are reflected in future retail rates. The IPUC approved similar deferred accounting treatment. Our general rate cases, filed in January 2009, reflect recovery of both the direct and deferred costs. The Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to the relicensing of the Spokane river plants.

Clark Fork Settlement Agreement
Dissolved atmospheric gas levels exceed state of Idaho and federal water quality standards downstream of the Cabinet Gorge Hydroelectric Generating Project (Cabinet Gorge) during periods when excess river flows must be diverted over the spillway. Under the terms of the Clark Fork Settlement Agreement, the Company developed an abatement and mitigation strategy with the other signatories to the agreement and developed the Gas Supersaturation Control Program (GSCP). The Idaho Department of Environmental Quality and the USFWS approved the GSCP in February 2004 and the FERC issued an order approving the GSCP in January 2005.

The GSCP provides for the opening and modification of one and, potentially, both of the two existing diversion tunnels built when Cabinet Gorge was originally constructed. When river flows exceed the capacity of the powerhouse turbines, the excess flows would be diverted to the tunnels rather than released over the spillway. The Company has undertaken physical and computer modeling studies to confirm the feasibility and likely effectiveness of the tunnel solution. Analysis of the predicted total dissolved gas performance indicates that the tunnels will not meet the performance criteria anticipated in the GSCP. In August 2007, the Gas Supersaturation Subcommittee concluded that the tunnel project does not meet the expectations of the GSCP and is not an acceptable project. As a result, the Company has met and will continue meeting with key stakeholders to review and amend the GSCP which includes developing alternatives to the construction of the tunnels. The Company has expended $5.0 million on the tunnel project. The WUTC and IPUC have accepted the recovery of these costs through rates.

The USFWS has 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.

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 will result 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 were encouraged by preliminary results and believe that we will be able to comply with the Montana law without utilizing the temporary alternate emission limit provision. Preliminary estimates indicate that the Company's share of installation capital costs will be $1.5 million and annual operating costs will increase by $2.9 million (beginning in late-2009). The Company will continue to seek recovery, through the ratemaking process, of the costs to comply with various air quality requirements.

Residential Exchange Program
The residential exchange program is intended to provide access to the benefits of low-cost federal hydroelectricity to residential and small-farm customers of the region's private (investor owned) and public (governmental or customer owned) utilities. The Bonneville Power Administration (BPA) administers the residential exchange program under the Northwest Power Act. Previously, Avista Corp. and other private utilities in the Pacific Northwest executed settlement agreements with BPA to resolve each party's rights and obligations under the residential exchange program. These settlements covered payment of benefits for the period October 1, 2001, through September 30, 2011. On May 3, 2007, the Ninth Circuit ruled that the BPA exceeded its authority when it entered into the settlement agreements with private utilities (including Avista Corp.) for the period from 2001 through 2011.

In February 2008, the BPA initiated its WP-07 Supplemental rate case (WP-07S) to, among other things, determine the level of benefits for customers served by private utilities (including Avista Corp.) for its fiscal year 2009. In addition to resolving residential exchange issues for the long-term, the BPA also proposed an interim payout to private utilities for its fiscal year 2008, which included $9.6 million for customers of Avista Corp. Rate adjustments to pass through the interim payment to Avista Corp.'s customers were approved by the WUTC and IPUC in April 2008. In September 2008, the BPA issued its final Record of Decision in WP-07S. Avista Corp. is evaluating the BPA's final Record of Decision, and may take steps to challenge the BPA's final Record of Decision. Avista Corp. has executed new Residential Exchange contracts with the BPA, for customer benefits in 2009. Rate adjustments to pass through the payments in the amount of $2.4 million for the period November 1, 2008 through October 31, 2009 have been approved by the WUTC and IPUC.

Since the residential exchange settlement payments are passed through to Avista Corp.'s customers as adjustments to electric bills, there is no effect on Avista Corp.'s net income or cash flows.

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 Federal 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 Company is participating in this extensive adjudication process, which is unlikely to be concluded in the foreseeable future.

As of December 31, 2008, the Company's collective bargaining agreement with the International Brotherhood of Electrical Workers represented approximately 50 percent of all of Avista Corp.'s employees. The agreement with the local union in Washington and Idaho representing the majority (approximately 90 percent) of the bargaining unit employees expires in March 2010. Two local agreements in Oregon, which cover approximately 50 employees, expire in April 2010.

NOTE 26. REGULATORY MATTERS

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 2009	8.22%	10.2%	46%
Idaho electric and natural gas	October 2008	8.45%	10.2%	48%
Oregon natural gas	April 2008	8.21%	10.0%	50%

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, the Company entered into a settlement stipulation with respect to its general rate case that was filed with the WUTC in March 2008. Other parties to the settlement stipulation are the staff of the WUTC, Northwest Industrial Gas Users, and the Energy Project. The Industrial Customers of Northwest Utilities (ICNU) joined in portions of the settlement and the Public Counsel Section of the Washington Attorney General's Office (Public Counsel) did not join in the settlement stipulation. 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 is 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 is designed to increase annual revenues by $4.8 million.

On January 27, 2009, Public Counsel filed a Petition for Judicial Review of the WUTC's recent order approving the Company's multiparty settlement. Public Counsel raised a number of issues that were previously argued before the WUTC. These include whether settlement costs associated with resolving the dispute with the Coeur d'Alene Tribe were prudent and whether recovery of such costs would constitute illegal "retroactive ratemaking." 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 does not prevent the new rates from going into effect. The appeals process may take several months and a decision is not expected until later in 2009. The court will either affirm the decision of the WUTC in its entirety or reverse the decision, in whole or in part, and remand the matter back to the WUTC for further consideration, which could possibly result in refunds.

In January 2009, the Company filed a general rate case with the WUTC requesting to increase base electric rates for the Company's Washington customers. In the general rate case filing, the Company requested a net electric rate increase of 8.6 percent. The net electric rate increase is based on a requested 16.0 percent increase in billed rates with an offsetting 7.4 percent reduction in the current ERM surcharge. The Company also requested a 2.4 percent increase in natural gas rates. The filing is designed to increase annual base electric service revenues by $69.8 million ($37.5 million net after considering the reduction in the current ERM surcharge) and increase annual natural gas service revenues by $4.9 million. The Company's request is based on a proposed rate of return on rate base of 8.68 percent, with a common equity ratio of 47.5 percent and an 11.0 percent return on equity. The WUTC generally has up to 11 months to review a general rate case filing.

As part of the general rate case settlement agreement that was modified and approved by the WUTC in December 2005, the Company agreed to increase the utility equity component to 35 percent by the end of 2007 and 38 percent by the end of 2008. The utility equity component met this target as it was approximately 47.6 percent as of December 31, 2008.

Idaho General Rate Cases

In August 2008, the Company entered into an all-party settlement stipulation with respect to 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 is 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 is designed to increase annual revenues by $3.9 million.

In January 2009, the Company filed a general rate case with the IPUC requesting to increase base electric rates for its Idaho customers. In the general rate case filing, the Company requested a net electric rate increase of 7.8 percent. The net electric rate increase is based on a requested 12.8 percent increase in billed rates with an offsetting 5.0 percent reduction in the current PCA surcharge. The Company also requested a 3.0 percent increase in natural gas rates. The filing is designed to increase annual base electric service revenues by $31.2 million ($18.9 million net after considering the reduction in the current PCA surcharge) and increase annual natural gas service revenues by $2.7 million. The Company's request is based on a proposed rate of return on rate base of 8.8 percent, with a common equity ratio of 50 percent and an 11.0 percent return on equity. The IPUC generally has up to seven months to review a general rate case filing.

Oregon General Rate Case

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).

NOTE 27. POTENTIAL HOLDING COMPANY FORMATION

At the Annual Meeting of Shareholders in May 2006, the shareholders of Avista Corp. approved a proposal to proceed with a statutory share exchange, which would change the Company's organization to a holding company structure. The holding company, currently named AVA Formation Corp. (AVA), would become the parent of Avista Corp. After the contemplated dividend to AVA of the capital stock of Avista Capital (Avista Capital Dividend) now held by Avista Corp., AVA would then also be the parent of Avista Capital. The Avista Capital Dividend would effect the structural separation of Avista Corp.'s non-utility businesses from its regulated utility business.

Avista Corp. received approval from the FERC in April 2006 (conditioned on approval by the state regulatory agencies), the IPUC in June 2006 and the WUTC in February 2007. Avista Corp. also filed for approval from the utility regulators in Oregon and Montana and proceedings are pending in each of these jurisdictions. The statutory share exchange is subject to the receipt of the remaining regulatory approvals and the satisfaction of other conditions. The Company cannot predict when the remaining regulatory approvals will be obtained or if they will be on terms acceptable to the Company.

The IPUC accepted a stipulation entered into between Avista Corp. and the IPUC Staff that sets forth a variety of conditions, which would serve to segregate the Company's utility operations from the other businesses conducted by the holding company. The stipulation among other things would require Avista Corp. to maintain certain common equity levels as part of its capital structure. Avista Corp. committed to increase its actual utility common equity component to 35 percent by the end of 2007 and 38 percent by the end of 2008, which is consistent with provisions of the Company's Washington general rate case implemented on January 1, 2006. The calculation of the utility equity component is essentially the ratio of Avista Corp.'s total common equity to total capitalization excluding, in each case, Avista Corp.'s investment in Avista Capital. The utility equity component was approximately 47.6 percent as of December 31, 2008. In addition, IPUC approval would be required for any dividend from Avista Corp. to the holding company that would reduce utility common equity below 25 percent of total capitalization which, for this purpose, includes long and short-term debt, capitalized lease obligations and preferred and common equity.

The WUTC accepted a similar stipulation entered into between Avista Corp. and the WUTC staff. WUTC approval would be required for any dividend from Avista Corp. to the holding company that would reduce utility common equity below 30 percent of total capitalization.

Pursuant to the Plan of Share Exchange, a statutory share exchange would be effected whereby each outstanding share of Avista Corp. common stock would be exchanged for one share of AVA common stock, no par value, so that holders of Avista Corp. common stock would become holders of AVA common stock and Avista Corp. would become a subsidiary of AVA. The other outstanding securities of Avista Corp. would not be affected by the statutory share exchange, with limited exceptions for stock options and other securities outstanding under equity compensation and employee benefit plans.

NOTE 28. INFORMATION SERVICES CONTRACTS

The Company has information services contracts that expire at various times through 2013. Total payments under these contracts were $15.4 million in 2008, $15.4 million in 2007 and $12.5 million in 2006. 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 $15.1 million in 2009, $15.4 million in 2010, $14.5 million in 2011, $14.5 million in 2012 and $14.9 million in 2013. 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 29. SUPPLEMENTAL CASH FLOW INFORMATION

(dollars in thousands)

	2007	2007
Cash paid for interest	$76,434	$78,705
Cash paid for income taxes	$8,116	$28,947
Other Cash Flows from Operating Activities:		
Power and natural gas deferrals	$(2,736)	$(3,899)

Change in special deposits	$4,068	$(1,626)
Change in other current assets	$(2,149)	$(141)
Non-cash stock compensation	$2,541	$2,512
ESOP dividends	$-	$1
Gain on sale of assets	$(1,123)	$-
Regulatory disallowance of debt repurchase costs	$-	$3,850

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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	04/16/2009	End of 2008/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.

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		(15,981,101)		1,368,559
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				(2,379,000)
3	Preceding Quarter/Year to Date Changes in Fair Value		3,199,837		1,010,441
4	Total (lines 2 and 3)		3,199,837		(1,368,559)
5	Balance of Account 219 at End of Preceding Quarter/Year		(12,781,264)		
6	Balance of Account 219 at Beginning of Current Year		(12,781,264)		
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value		6,688,946		
9	Total (lines 7 and 8)		6,688,946		
10	Balance of Account 219 at End of Current Quarter/Year		(6,092,318)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/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	(3,346,361)	(6,682)	(17,965,585)		
2		609,000	(1,770,000)		
3	(3,479,861)	(602,318)	128,099		
4	(3,479,861)	6,682	(1,641,901)	38,475,085	36,833,184
5	(6,826,222)		(19,607,486)		
6	(6,826,222)		(19,607,486)		
7	10,656,750		10,656,750		
8	(3,830,528)		2,858,418		
9	6,826,222		13,515,168	73,619,720	87,134,888
10			(6,092,318)		

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 (f) 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)	3,313,806,232	2,534,598,235
4	Property Under Capital Leases	2,419,182	
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	3,316,225,414	2,534,598,235
9	Leased to Others		
10	Held for Future Use	1,631,351	1,457,302
11	Construction Work in Progress	75,568,224	61,824,355
12	Acquisition Adjustments	22,211,433	
13	Total Utility Plant (8 thru 12)	3,415,636,422	2,597,879,892
14	Accum Prov for Depr, Amort, & Depl	1,142,578,137	862,999,350
15	Net Utility Plant (13 less 14)	2,273,058,285	1,734,880,542
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	1,105,346,502	856,572,707
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	17,851,932	6,426,642
22	Total In Service (18 thru 21)	1,123,198,434	862,999,349
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	19,379,703	
33	Total Accum Prov (equals 14) (22,26,30,31,32)	1,142,578,137	862,999,349

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
656,008,542				123,199,455	3
1,619,845				799,337	4
					5
					6
					7
657,628,387				123,998,792	8
					9
174,049					10
6,080,717				7,663,152	11
22,211,433					12
686,094,586				131,661,944	13
248,348,881				31,229,906	14
437,745,705				100,432,038	15
					16
					17
228,174,179				20,599,616	18
					19
					20
794,999				10,630,291	21
228,969,178				31,229,907	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
19,379,703					32
248,348,881				31,229,907	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	04/16/2009	End of 2008/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	15,259,132	370,850
4	(303) Miscellaneous Intangible Plant	3,604,851	218,231
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	18,863,983	589,081
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	2,232,907	-437
9	(311) Structures and Improvements	124,569,652	475,590
10	(312) Boiler Plant Equipment	161,631,319	1,639,795
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	48,079,386	1,487,123
13	(315) Accessory Electric Equipment	26,333,355	97,866
14	(316) Misc. Power Plant Equipment	15,275,332	199,604
15	(317) Asset Retirement Costs for Steam Production	585,276	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	378,707,227	3,899,541
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	56,000,957	216,470
28	(331) Structures and Improvements	39,391,080	542,283
29	(332) Reservoirs, Dams, and Waterways	112,156,592	5,333,709
30	(333) Water Wheels, Turbines, and Generators	114,547,842	9,327,906
31	(334) Accessory Electric Equipment	28,948,787	2,736,614
32	(335) Misc. Power PLant Equipment	6,211,072	80,242
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)	359,255,892	18,237,224
36	D. Other Production Plant		
37	(340) Land and Land Rights	903,118	
38	(341) Structures and Improvements	15,507,422	109,994
39	(342) Fuel Holders, Products, and Accessories	21,064,431	250
40	(343) Prime Movers	21,876,780	
41	(344) Generators	196,883,690	10,249,213
42	(345) Accessory Electric Equipment	15,105,891	1,181,420
43	(346) Misc. Power Plant Equipment	1,341,166	25,976
44	(347) Asset Retirement Costs for Other Production	351,682	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	273,034,180	11,566,853
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,010,997,299	33,703,618

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
			15,629,982		3
349,073			3,474,009		4
349,073			19,103,991		5
					6
					7
782			2,231,688		8
228,917			124,816,325		9
378,583			162,892,531		10
					11
1,881,953			47,684,556		12
59,602			26,371,619		13
			15,474,936		14
			585,276		15
2,549,837			380,056,931		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
356,930			55,860,497		27
25,363			39,908,000		28
59			117,490,242		29
406			123,875,342		30
197,416			31,487,985		31
2,819			6,288,495		32
			1,999,562		33
					34
582,993			376,910,123		35
					36
			903,118		37
			15,617,416		38
			21,064,681		39
			21,876,780		40
9,162,288			197,970,615		41
457,745			15,829,566		42
23,037			1,344,105		43
			351,682		44
9,643,070			274,957,963		45
12,775,900			1,031,925,017		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	04/16/2009	End of 2008/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	13,747,883	1,849,069
49	(352) Structures and Improvements	15,223,954	526,839
50	(353) Station Equipment	167,230,771	6,571,468
51	(354) Towers and Fixtures	17,079,954	18,360
52	(355) Poles and Fixtures	126,246,914	2,596,987
53	(356) Overhead Conductors and Devices	100,597,053	3,879,113
54	(357) Underground Conduit	561,148	2,044,340
55	(358) Underground Conductors and Devices	1,317,910	1,120,161
56	(359) Roads and Trails	1,826,844	45,402
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	443,832,431	18,651,739
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	3,947,661	120,528
61	(361) Structures and Improvements	10,858,010	1,437,997
62	(362) Station Equipment	81,402,697	5,260,411
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	185,545,007	11,526,026
65	(365) Overhead Conductors and Devices	121,489,836	8,072,027
66	(366) Underground Conduit	65,856,250	5,529,402
67	(367) Underground Conductors and Devices	106,836,636	9,318,281
68	(368) Line Transformers	151,061,288	9,880,149
69	(369) Services	105,185,266	5,025,520
70	(370) Meters	23,347,930	21,414,178
71	(371) Installations on Customer Premises		
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	26,262,991	1,587,887
74	(374) Asset Retirement Costs for Distribution Plant	129,707	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	881,923,279	79,172,406
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	2,151,329	35,168
88	(391) Office Furniture and Equipment	513,876	333,758
89	(392) Transportation Equipment	8,589,953	1,304,915
90	(393) Stores Equipment	300,788	77,674
91	(394) Tools, Shop and Garage Equipment	3,293,560	106,855
92	(395) Laboratory Equipment	3,068,562	14,532
93	(396) Power Operated Equipment	20,056,431	2,851,928
94	(397) Communication Equipment	32,238,944	4,414,354
95	(398) Miscellaneous Equipment	3,888	
96	SUBTOTAL (Enter Total of lines 86 thru 95)	70,342,012	9,139,184
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)	70,342,012	9,139,184
100	TOTAL (Accounts 101 and 106)	2,425,959,004	141,256,028
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)	2,425,959,004	141,256,028

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2009	Year/Period of Report End of 2008/Q4

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
1,452			15,595,500		48
424			15,750,369		49
872,748			172,929,491		50
			17,098,314		51
558,008			128,285,893		52
545,662			103,930,504		53
			2,605,488		54
108,000			2,330,071		55
			1,872,246		56
					57
2,086,294			460,397,876		58
					59
			4,068,189		60
33,925			12,262,082		61
459,093			86,204,015		62
					63
294,588			196,776,445		64
293,841			129,268,022		65
36,218			71,349,434		66
589,161			115,565,756		67
1,395,473			159,545,964		68
101,423			110,109,363		69
489,066			44,273,042		70
					71
					72
89,849			27,761,029		73
			129,707		74
3,782,637			957,313,048		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			124,681		86
11,753			2,174,744		87
128,981			718,653		88
413,030			9,481,838		89
50,668			327,794		90
47,307			3,353,108		91
1,693,720			1,389,374		92
1,175,820			21,732,539		93
189,272			36,464,026		94
1,107			2,781		95
3,711,658			75,769,538		96
					97
					98
3,711,658			75,769,538		99
22,705,562			2,544,509,470		100
					101
					102
					103
22,705,562			2,544,509,470		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	04/16/2009	End of 2008/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 $100,000, 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	Electric Revenue	699,924
3	Wood Pole Management	953,560
4	Spokane-CDA 115kv line Relay Upgrades	345,674
5	Metro-Post St Reconductor Phase 1	157,872
6	Terre View 115-sub construct (WSU)	983,627
7	System-Replace Obsolete Reclosers	141,705
8	NE Sub-Increase Capacity	381,808
9	Indian Trail 115-13kv sub-construct new sub	213,198
10	SE 12F2 Improve Tower Mtn Reliability	163,775
11	F&C 12F2 Strong Reconductor	121,725
12	Transportation Equipment	1,569,595
13	WSDOT Highway Franchise Consolidation	342,721
14	Minor Projects (73) Under $100,000	654,931
15		
16	State of Idaho	
17	Electric Revenue Blanket	170,418
18	Wood Pole Management	231,892
19	Holbrook-Upgrade Feeder	241,869
20	Appleway-Purchase Property	188,986
21	Tribal Permits and Settlements	134,593
22	Plummer-Increase Capacity/Rebuild	417,619
23	Idaho Road Sub	353,360
24	NezPerce 115 sub-insta Capacitor Bank	158,536
25	Transportation Equipment	626,049
26	Productivity Initiative	246,891
27	Minor Projects (22) Under $100,000	289,067
28		
29		
30	Common-WA & ID	
31	Noxon-Pinecreek 230kv: Ready Fiber Optic	184,559
32	System Rplc High Voltage OCBs	132,506
33	Spokane-CDA 115kv Line Relay upgrades	642,916
34	Terre View 115-sub Construct WSU	484,065
35	Beacon St yd-Oil Containment	204,495
36	Nez Perce 115sub-inst capacitor bank	371,220
37	Lolo 230-rebuild 230kv yard	469,993
38	Rathdrum 233- Construct Feeder	153,504
39	Cabinet Gorge Capital Projects	141,026
40	Kettle Falls Capital Projects	369,908
41	Noxon Capital Projects	560,068
42	CS2 Capital Projects	429,913
43	TOTAL	61,824,355

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2009	Year/Period of Report End of 2008/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 $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Noxon Rapids Unit 1 Turbine	12,112,639
2	Noxon Rapids Unit 2 Turbine	451,700
3	Noxon Rapids Unit 3 Turbine	390,982
4	Nine Mile Redevelopment	317,777
5	Telephone/Video Systems	227,405
6	Clark Fork Implement PME Agreement	3,497,641
7	Hydro Relicensing	27,209,920
8	Transportation Equipment	490,620
9	Productivity Initiative	611,186
10	Minor Projects (188) Under $100,000	2,580,917
11		
12	Common -WA/ID/OR	
13	Minot Projects (0) Under $100,000	
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
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41		
42		
43	TOTAL	61,824,355

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/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	816,649,875	816,649,875		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	62,831,976	62,831,976		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	1,019,938	1,019,938		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	-269,532	-269,532		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	63,582,382	63,582,382		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	21,997,326	21,997,326		
13	Cost of Removal	3,045,574	3,045,574		
14	Salvage (Credit)	1,286,613	1,286,613		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	23,756,287	23,756,287		
16	Other Debit or Cr. Items (Describe, details in footnote):	96,737	96,737		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	856,572,707	856,572,707		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	237,857,615	237,857,615		
21	Nuclear Production				
22	Hydraulic Production-Conventional	90,948,956	90,948,956		
23	Hydraulic Production-Pumped Storage				
24	Other Production	45,632,205	45,632,205		
25	Transmission	151,579,025	151,579,025		
26	Distribution	287,538,257	287,538,257		
27	Regional Transmission and Market Operation				
28	General	43,016,649	43,016,649		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/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)	856,572,707	856,572,707		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/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			-103,783,905
4	OCI Investment in Subs			
5	Avista Capital - Other Changes in Net Investment			-11,378,300
6	Avista Capital - Other Changes in Net Investment			2,281,868
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42	Total Cost of Account 123.1 $ 0		TOTAL	71,371,272

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/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
		184,251,609		2
4,123,038		-99,660,867		3
				4
	3,629,762	-7,748,538		5
	-1,636,110	645,758		6
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4,123,038	1,993,652	77,487,962		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	04/16/2009	End of 2008/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)	2,213,923	3,673,039	(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)	10,710,048	10,461,384	(1)
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	1,892,177	2,106,403	(1)
8	Transmission Plant (Estimated)		27,135	(1)
9	Distribution Plant (Estimated)	192,257	227,359	(1)
10	Regional Transmission and Market Operation Plant (Estimated)			(1),(2)
11	Assigned to - Other (provide details in footnote)	4,570,824	4,633,554	(1),(2)
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	17,365,306	17,455,835	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)			
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	19,579,229	21,128,874	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/Q4

Transmission Service and Generation Interconnection Study Costs

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

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	PPL Energy Plus, LLC	10,309	186200	10,309	186210
3	PPL Energy Plus, LLC	10,309	186200	10,309	186210
4					
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21	**Generation Studies**				
22	RES America Developments Inc.	20,481	186200	20,481	186210
23	PPL Montana LLC	6,770	186200	6,770	186210
24	UPC Wind Prospects LLC (Palouse)	21,115	186200	7,826	186210
25	UPC Wind Prospects LLC (Latah)	23,084	186200		
26	Wilkins Wind Project	8,133	186200		
27	Horizon Wind Project	21,432	186200		
28	Avista - Reardan Project	7,154	186200		
29	Avista - Gambee Grangeville Projec	7,408	186200		
30	Avista - Garfield County Project	6,270	186200		
31	BP Wind Interconnect	4,749	186200		
32	PPM Energy Wind	93	186200		
33	Avista - Grangeville Wind	4,578	186200		
34	Martinsdale Wind Intr	825	186200		
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $50,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Regulatory Asset FAS 106	2,363,760		926/107	472,752	1,891,008
2	Guaranteed Residual Value-Airplane	1,826,000	1,110,173			2,936,173
3	Reg Asset Post Ret Liab	51,006,123	121,271,624			172,277,747
4	Regulatory Asset FAS109 Utility Plant	102,061,458		283	2,596,433	99,465,025
5	Regulatory Asset FAS109 DSIT Non Plant	3,050,796	256,092			3,306,888
6	Regulatory Asset FAS109 DFIT State Tax Cr	3,972,764	595,466			4,568,230
7	Regulatory Asset FAS109 WNP3	8,603,769		283	737,482	7,866,287
8	Reg Assets- Decouplings Surcharge	225,167	254,426			479,593
9						
10	Regulatory Asset AMR	23,387,754		Various	23,640,523	-252,769
11	Regulatory Asset RTO Deposits- ID	283,223		Various	70,806	212,417
12	Regulatory Asset BPA Residential Exchange	3,836,996		Various	3,587,767	249,229
13	Regulatory Asset BPA Residential Exch Interest	161,862		Various	161,862	
14	Regulatory Asset ERM Approved for Recovery	41,958,848		Various	12,230,664	29,728,184
15						
16	ID Wind Gen AFUDC		35,194			35,194
17						
18	Regulatory Asset Wartsila Units	3,343,865		Vaious	1,018,612	2,325,253
19	MTM St Regulatory Asset	7,171,420	53,057,550			60,228,970
20	MTM LT Regulatory Asset					
21	Regulatory Asset FAS143 Asset Retirement Obligation	3,085,123	250,156			3,335,279
22						
23	Reg Asset AN- CDA Lake Settlement		41,733,385			41,733,385
24						
25	Regulatory Asset Workers Comp	2,851,024	246,144			3,097,168
26	CS2 Lev Ret	1,267,775	174,560			1,442,335
27	Regulatory Asset ID PCA Deferral 1	7,516,287		Various	7,516,287	
28	Regulatory Asset ID PCA Deferral 2	13,646,762	3,434,232			17,080,994
29	Regulatory Asset ID PCA Deferral 3		3,573,957			3,573,957
30						
31						
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33						
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44	TOTAL	281,620,776	225,992,959		52,033,188	455,580,547

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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) 04/16/2009	Year/Period of Report End of 2008/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 $50,000, 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	594,442			4,505	589,937
4	WA Deferred Power Costs	16,564,895			9,341,072	7,223,823
5	WA ERM YTD Company Band	8,482,641			4,482,641	4,000,000
6	WA ERM YTD Contra Account	-8,482,641	4,482,641			-4,000,000
7	Regulatory Asset ROT Deposit	553,747			158,213	395,534
8	Regulatory Asset-Mt lease pymt	1,366,800	1,428,501			2,795,301
9	Regulatory Asset-Mt lease pymt	2,633,200	2,779,808			5,413,008
10	Colstrip Common Fac.	2,355,642				2,355,642
11	Regulatory Asset- COLS		738,101			738,101
12						
13						
14						
15	Payroll Accrual	14,022			14,022	
16						
17	Plant Allocation of clearing jr	1,038,165	1,133,859			2,172,024
18						
19	Misc Error Suspense	-1,038	13,495			12,457
20						
21						
22	Misc susp acct-non w/o	200,000			171,673	28,327
23	Unamortized A/R sale	8,103	17,664			25,767
24						
25	Intangible Pension Asset					
26						
27	Nez Perce Settlement	186,809			5,212	181,597
28	Misc Deferred Debit Centralia	656,829	19,161			675,990
29						
30						
31						
32	ID Panhandle Forest Use Permit	207,424	16,913			224,337
33	Metro-Sunset 115KV TE	351,506			351,506	
34						
35	UPRR Permit Conv	333,585	16,578			350,163
36	Insurance Recvy CDA Lake	161,991			161,991	
37	Corp reorg stk iss. costs	118,086				118,086
38						
39						
40						
41	Nez Perce Permit Conversion	-964	964			
42						
43	PG & E Canada to N Cal trans	44,051	449,556			493,607
44	Misc Work Orders <$50,000	83,795	31,935			115,730
45	Subsidiary Billings	2,125,708			57,883	2,067,825
46	"Null" Projects directly to 186	4,458			350,163	-345,705
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	40,642,265				32,008,980

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/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 $50,000, 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	2,564,057			1,280,292	1,283,765
3	Oregon Gas Comm Consvt	40,060			24,096	15,964
4						
5	Oregon Common Gas Eff	414,778			272,477	142,301
6	WPNG HE Wtr Htrs-Oregon	260,525			258,779	1,746
7	WPNG HE Furnaces	2,121,880			2,081,157	40,723
8						
9	WPNG OR Res Low 1	342,978			191,262	151,716
10						
11	Oregon DSM Gen admin		9,073			9,073
12	Tankless Water Heater Rebate		7,194			7,194
13	Chimney Damper Rebate		594			594
14	Programmable Thermostat Rebate		8,843			8,843
15	High eff Space Heater Rebate		675			675
16						
17	Oregon DSM Program Amort		2,536,269			2,536,269
18						
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28						
29						
30						
31						
32	Energy Star Homes	275,659			275,563	96
33	Energy Star Manufactored Homes	16,225			16,205	20
34	HE Washing Machines	95,701			95,617	84
35	Regulatory Assets Consv	354,695			101,144	253,551
36	Regulatory Assets Consv	784,023			336,413	447,610
37						
38						
39	Regulatory Assets Conservation	154,919			154,919	
40						
41	Dry Creek Transport	364,432	1,774			366,206
42	Glendale Cust Premises Equip	183,654			183,654	
43	Lake CDA Issues	1,950,624			1,950,624	
44	Shareholder Lawsuit 2002	5,800			5,800	
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	40,642,265				32,008,980

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/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		13,791,783	15,824,253
3			
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	13,791,783	15,824,253
9	Gas		
10		3,123,264	2,255,652
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15	3,123,264	2,255,652
17	Other	73,908,056	112,975,620
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	90,823,103	131,055,525

Notes

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/Q4

CAPITAL STOCKS (Account 201 and 204)

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

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Account 201 - Common Stock Issued			
2	No Par Value	200,000,000		
3	Restricted shares			
4	TOTAL_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 Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2009	Year/Period of Report End of 2008/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
54,487,574	755,903,119					2
				55,939	1,121,577	3
54,487,574	755,903,119			55,939	1,121,577	4
						5
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/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	87,394
2		
3		
4		
5		
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21		
22	TOTAL	87,394

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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	04/16/2009	End of 2008/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	Acct. 221 - Bonds:		
2			
3			
4	Secured Medium Term Notes A	250,000,000	787,692
5	Discount		50,200
6	Secured Medium Term Notes B	161,000,000	788,947
7	Secured Medium Term Notes C	109,000,000	969,770
8	FMB's 6.125%	45,000,000	825,301
9	Discount		204,750
10	FMB's 5.45%	90,000,000	1,054,153
11	Discount		239,400
12	FMB's 6.25%	150,000,000	1,812,935
13	(Premium)		-266,500
14	Discount		634,000
15	FMB's 5.70%	150,000,000	4,702,304
16	Discount		222,000
17	FMB's 5.95%	250,000,000	2,246,419
18			835,000
19	FMB's 7.25%	30,000,000	420,306
20	Pollution Control Revenue Bonds		
21	6% Series due 2023	4,100,000	115,355
22	Colstrip 1999A due 2032	66,700,000	2,700,582
23	Discount		20,500
24	Colstrip 1999B due 2034	17,000,000	954,386
25			
26	Acct. 222		
27	Acct. 223 Advances from associated companies	1,200,000	
28	LTD - AVA Trust III	61,856,000	1,658,634
29	LTD - AVA Trust II	51,547,000	3,633,783
30	Acct. 224 Other		
31	Senior Notes	400,000,000	9,128,000
32	Discount		2,716,000
33	TOTAL	1,837,403,000	36,453,917

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/Q4

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
						3
Var.	Var.	Var.	Var.	48,000,000	4,099,869	4
						5
6-9-1995	7-1-2010	6-9-1995	7-1-2010	5,000,000	345,000	6
Var.	Var.	Var.	Var.	50,000,000	5,024,125	7
9-8-2003	9-1-2013	9-8-2003	9-1-2013	45,000,000	2,756,250	8
						9
11-18-2004	12-1-2019	11-18-2004	12-1-2019	90,000,000	4,905,000	10
						11
11-17-2005	12-1-2035	11-17-2005	12-1-2035	153,989,418	9,375,000	12
						13
						14
12-15-2006	7-1-2037	12-15-2006	7-1-2037	147,067,094	8,550,000	15
						16
4-3-2008	6-1-2018	4-3-2008	6-1-2018	234,814,467	11,073,611	17
						18
12-16-2008	12-16-2013	12-16-2008	12-16-2013	30,000,000	90,625	19
						20
12-18-1984	12-1-2023	12-18-1984	12-1-2032	4,100,000	246,000	21
9-1-1999	10-1-2032	9-1-1999	10-1-2032	66,700,000	3,345,934	22
						23
9-1-1999	3-1-2034	9-1-1999	3-1-2034	17,000,000	872,388	24
						25
						26
				1,200,000		27
4-5-2004	4-1-2034	4-30-2004	3-31-2034	61,856,000	4,020,640	28
6-3-1997	6-1-2037	6-30-1997	5-31-2037	51,547,000	2,120,149	29
						30
4-3-2001	6-1-2008	5-1-2001	6-1-2008		11,084,938	31
						32
				1,006,273,979	67,909,529	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	04/16/2009	End of 2008/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)	73,619,720
2		
3		
4	Taxable Income Not Reported on Books	
5		9,501,848
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		91,483,730
11	Federal Income Tax	5,376,170
12	Deferred Income Tax	35,858,558
13	Investment Tax Credit & State Income Tax	3,893
14	Income Recorded on Books Not Included in Return	
15		59,774,306
16	Equity in Sub Earnings (Income)/Loss	-4,123,038
17	Corporate Overhead Unallocated Subs	823,208
18		
19	Deductions on Return Not Charged Against Book Income	
20		-262,942,348
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	9,376,046
28	Show Computation of Tax:	
29		
30	Federal Tax Net Income	9,376,046
31	State Tax	171,437
32	Federal Tax Net Income including State Tax	9,547,483
33		
34	Federal Tax @ 35%	3,341,619
35		
36		
37	Prior Years Tax Return, Revenue Agent Report & Misc True Ups	3,865,437
38	Kettle Falls & Cabinet Gorge Tax Credits	-1,830,887
39		
40	Total Federal Tax Expense (agrees to line 11)	5,376,169
41		
42		
43		
44		

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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	04/16/2009	End of 2008/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			19,767,521	-6,011,211	
3	Income Tax	-23,161,363		5,020,161		
4	Income Tax	1,535,388		-3,835,702		
5	Income Tax (Current)			3,195,302	14,227,203	
6	Retained Earnings					
7	Prior Retained Earnings	-5,013,521				
8	Prior Retained Earnings	-2,127,838				
9	Current Retained Earnings			-2,374,114	-938,493	
10	Total Federal	-28,767,334		21,773,168	7,277,499	
11						
12	STATE OF WASHINGTON:					
13	Property Tax (2006)	-556				556
14	Property Tax (2007)	10,692,000		-3,157,737	7,533,707	-556
15	Property Tax (2008)			7,771,834	660	
16	Excise Tax (2005)	91,452				
17	Excise Tax (2006)	-464				
18	Excise Tax (2007)	2,614,792		353,169	2,567,961	
19	Excise Tax (2008)			24,034,759	21,549,461	
20	Natural Gas Use Tax	34,707		93,266	94,758	
21	Municipal Occupation Tax	2,695,522		21,642,563	21,723,299	
22	Sales & Use Tax (2005)	-57,409				57,409
23	Sales & Use Tax (2006)	49,466				-57,409
24	Sales & Use Tax (2007)	60,189			46,546	
25	Sales & Use Tax (2008)			763,350	713,084	-1
26	Motor Vehicle Tax (2008)			11,090	11,090	
27	Total Washington	16,179,699		51,512,294	54,240,566	-1
28						
29	STATE OF IDAHO:					
30	Income Tax (2006)	487,826				
31	Income Tax (2007)	-180,121		-100,628	-176,233	
32	Income Tax (2008)			41,224	485,000	
33	Property Tax (2007)	2,121,077		-8,245	2,112,832	
34	Property Tax (2008)			3,737,222	1,225,086	-1
35	Motor Vehicle Tax (2008)			10,098	10,098	
36	Sales & Use Tax (2005)	436				
37	Sales & Use Tax (2007)	5,173			5,186	
38	Sales & Use Tax (2008)			75,499	52,263	
39	Irrigation Credits (2007)			-470	-470	
40	KWH Tax (2007)	34,357		-9,496	24,862	1
41	TOTAL	-4,717,808		94,915,994	84,092,608	-1

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2009	Year/Period of Report End of 2008/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
25,778,732		3,742,962			16,024,559	2
-18,141,202					5,020,161	3
-2,300,314		213,585			-4,049,287	4
-11,031,901		-2,617,399			5,812,701	5
						6
-5,013,521						7
-2,127,838						8
-1,435,621					-2,374,114	9
-14,271,665		1,339,148			20,434,020	10
						11
						12
						13
		-2,392,149			-765,588	14
7,771,174		6,258,500			1,513,334	15
91,452						16
-464						17
400,000		-48,417			401,586	18
2,485,298		15,767,570			8,267,189	19
33,215					93,266	20
2,614,786		13,959,888			7,682,675	21
						22
-7,943						23
13,643						24
50,265					763,350	25
					11,090	26
13,451,426		33,545,392			17,966,902	27
						28
						29
487,826						30
-104,516		-54,969			-45,659	31
-443,776		-49,822			91,046	32
		10			-8,255	33
2,512,135		3,043,418			693,804	34
					10,098	35
436						36
-13						37
23,236					75,499	38
					-470	39
		-9,495			-1	40
6,105,577		48,503,169			46,412,825	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	04/16/2009	End of 2008/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	KWH Tax (2008)			338,468	317,213	
2	Franchise Tax (2006)	-2,346				2,346
3	Franchise Tax (2007)	1,619,792		6	1,617,452	-2,346
4	Franchise Tax (2008)			4,107,494	2,433,731	
5	Total Idaho	4,086,194		8,191,172	8,107,020	
6						
7	STATE OF MONTANA:					
8	Income Tax (2005)					
9	Income Tax (2006)	516,192			-4,053	
10	Income Tax (2007)	-9,721		-181,898	-132,184	
11	Income Tax (2008)			27,219	375,000	
12	Property Tax (2006)	5,672		-5,672		
13	Property Tax (2007)	3,084,105		-2,990	3,081,115	
14	Property Tax (2008)			6,676,978	3,340,662	
15	Colstrip Generation Tax			4,228	4,228	
16	KWH Tax (2007)	240,285			240,285	
17	KWH Tax (2008)			1,183,035	915,808	
18	Motor Vehicle Tax (2008)			3,287	3,287	
19	Consumer Council Tax	4,865		46,489	26,904	
20	Public Commission Tax	8		24	26	
21	Total Montana	3,841,406		7,750,700	7,851,078	
22						
23	STATE OF OREGON:					
24	Income Tax (2006)	266,087				
25	Income Tax (2007)	-528,274		151,254	-377,015	
26	Income Tax (2008)			-214,586	335,000	
27	Property Tax (2005)	288,681		-1,467		-287,214
28	Property Tax (2006)	-285,790		-1,424		287,214
29	Property Tax (2007)	-759,157		759,157		
30	Property Tax (2008)			900,406	1,910,406	
31	Motor Vehicle Tax (2008)			1,807	1,807	
32	BETC Credit (2000)	-387,653				387,653
33	BETC Credit (2001)	163,940				-163,940
34	BETC Credit (2002)	-46,118				46,118
35	BETC Credit (2003)	25,292				-25,292
36	BETC Credit (2004)	37,086				-37,086
37	BETC Credit (2005)	-82,896				82,896
38	BETC Credit (2006 & Prior)	-208,108				-290,349
39	BETC Credit (2007)	17,786		191,873		
40	BETC Credit (2008)			-46,847		
41	TOTAL	-4,717,808		94,915,994	84,092,608	-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	04/16/2009	End of 2008/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
(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)	No.
21,255		338,468				1
						2
		6				3
1,673,763		2,544,119			1,563,375	4
4,170,346		5,811,735			2,379,437	5
						6
						7
						8
520,245						9
-59,435		-181,898				10
-347,781		27,219				11
		-5,672				12
		-2,990				13
3,336,316		6,676,978				14
		4,228				15
						16
267,227		1,183,035				17
					3,287	18
24,450		46,489				19
6		24				20
3,741,028		7,747,413			3,287	21
						22
						23
266,087						24
-5		-70,944			222,198	25
-549,586		-53,647			-160,939	26
		-1,467				27
		-1,424				28
		-76,843			836,000	29
-1,010,000		71,933			828,473	30
					1,807	31
						32
						33
						34
						35
						36
						37
-498,457						38
209,659		191,873				39
-46,847					-46,847	40
6,105,577		48,503,169			46,412,825	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	04/16/2009	End of 2008/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	Glendale Regulatory Tax Cr.			-351,469		
2	Franchise Tax (2004)	-62,168				62,168
3	Franchise Tax (2005)	60,185				-60,185
4	Franchise Tax (2006)	37,494				-4,616
5	Franchise Tax (2007)	1,413,741			1,416,374	2,633
6	Franchise Tax (2008)			4,293,223	3,328,956	
7	Total Oregon	-49,872		5,681,927	6,615,528	
8						
9	STATE OF CALIFORNIA:					
10	Income Tax (2005)	-10,400			-8,531	
11	Income Tax (2006)	-800			-486	
12	Income Tax (2007)			-1,838	1,362	
13	Total California	-11,200		-1,838	-7,655	
14						
15	MISCELLANEOUS STATES:					
16	Income Tax (2007)					
17	Income Tax (2008)			-1,125	-1,124	
18	Total Misc States			-1,125	-1,124	
19						
20	COUNTY & MUNICIPAL					
21	WA Renewable Energy			-9,614	-9,614	
22	Misc.	3,299		19,310	19,310	
23	Total County	3,299		9,696	9,696	
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	-4,717,808		94,915,994	84,092,608	-1

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2009	Year/Period of Report End of 2008/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)	
-351,469					-351,469	1
						2
						3
755						4
						5
996,390					4,293,223	6
-983,473		59,481			5,622,446	7
						8
						9
-1,869						10
-314						11
-3,200					-1,838	12
-5,383					-1,838	13
						14
						15
						16
-1					-1,125	17
-1					-1,125	18
						19
						20
					-9,614	21
3,299					19,310	22
3,299					9,696	23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
6,105,577		48,503,169			46,412,825	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	04/16/2009	End of 2008/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							
7							
8	TOTAL						
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Gas Propertry (100%	423,036			411400	49,308	
11							
12	TOTAL PROPERTY	423,036				49,308	
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
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47							
48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/Q4

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

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
			5
			6
			7
			8
			9
373,728			10
			11
373,728			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
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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) 04/16/2009	Year/Period of Report End of 2008/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 $10,000, 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	CCS Install (253000)	164	419000	164		
2	Pacificorp Capacitor (253080)	14,058	456100	9,372		4,686
3						
4	Centralia Environmental (253110)	965,260	232650	1,374		963,886
5	Rathdrum Refund (253120)	408,686	550000	33,822		374,864
6	NE Tank Spil (253130)	135,540	186200	36,933		98,607
7	Bills Pole Rentals (253140)	202,867			8,753	211,620
8	CR-CS2 GE LTSA (253150)				4,739,221	4,739,221
9	IR Swaps (254170)				568,713	568,713
10	Sale/Leaseback on Bldg (253850)	1,045,824	931000	261,456		784,368
11	Clark Fork Relicensing (253890)	-949,317	184999	274,403		-1,223,720
12	Defer Comp Retired Execs (253900)	236,392	431100	55,944		180,448
13	Defer Comp Active Execs (253910)	12,114,655	128250	3,306,934		8,807,721
14	Executive Incent Plan (253920)	140,000				140,000
15	Unbilled Revenue (253990)	3,758,203			1,577,265	5,335,468
16	Regulatory Accruals (253650)				4,000,000	4,000,000
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
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30						
31						
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33						
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37						
38						
39						
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41						
42						
43						
44						
45						
46						
47	TOTAL	18,072,332		3,980,402	10,893,952	24,985,882

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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	04/16/2009	End of 2008/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account	Balance at Beginning of Year	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1	Amounts Credited to Account 411.1
	(a)	(b)	(c)	(d)
1	Account 282			
2	Electric	243,603,622	20,991,257	
3	Gas	65,325,660	9,585,595	
4	Other	11,120,041	1,257,180	
5	TOTAL (Enter Total of lines 2 thru 4)	320,049,323	31,834,032	
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	320,049,323	31,834,032	
10	Classification of TOTAL			
11	Federal Income Tax	309,404,482	31,412,550	
12	State Income Tax	10,644,841	421,482	
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
		236000	12,489,079			252,105,800	2
264,791		236/409	4,931,847			70,244,199	3
164,821						12,542,042	4
429,612			17,420,926			334,892,041	5
							6
							7
							8
429,612			17,420,926			334,892,041	9
							10
429,612			17,420,926			323,825,718	11
						11,066,323	12
							13

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Electric	47,772,530	842,539	1,068,560
4				
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	47,772,530	842,539	1,068,560
10	Gas			
11	Gas	3,246,029	-9,824,248	-285,262
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	3,246,029	-9,824,248	-285,262
18	Other	188,255,955	4,301,642	-3,620
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	239,274,514	-4,680,067	779,678
20	Classification of TOTAL			
21	Federal Income Tax	236,223,718	-4,680,067	779,678
22	State Income Tax	3,050,796		
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

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

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	(k)	
							1
							2
480,536		182	737,483	190	729,555	48,019,117	3
		407	46,569	191	78,414	31,845	4
				236	402,332	402,332	5
							6
							7
							8
480,536			784,052		1,210,301	48,453,294	9
							10
-60,649	16,366	182	69,457			-6,439,429	11
							12
							13
							14
							15
							16
-60,649	16,366		69,457			-6,439,429	17
	3,357,882	182	1,745,275	190/283	59,271,562	246,729,622	18
419,887	3,374,248		2,598,784		60,481,863	288,743,487	19
							20
419,887	3,374,248		2,598,784		53,868,087	279,078,915	21
					6,613,776	9,664,572	22
							23

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/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 $50,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Idaho Investment Tax Credit (254005)	7,120,008			1,234,857	8,354,865
2	Oregon BETC Credit (254010)	257,984	190005	128,992		128,992
3	Deffered Gas Exchange (254028)		495028	494,565		-494,565
4	FAS 109 Invest Tax Credit (254180)	227,796	190180	6,639		221,157
5	Nez Perce (254220)	792,404	various	5,502		786,902
6	Oregon Senate Bill (254250)	3,638,488	407431	1,118,862		2,519,626
7	Reg liability CCX CR ID (254300)				754,484	754,484
8	BPA Res Exch Regulatory Liab (254345)		407450	1,629,929		-1,629,929
9	Unrealized Currency Exchange (254399)	30,876			49,757	80,633
10	Mark to Market FAS133 (254750)	53,413,783		8,706,426		44,707,357
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
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25						
26						
27						
28						
29						
30						
31						
32						
33						
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36						
37						
38						
39						
40						
41	TOTAL	65,481,339		12,090,915	2,039,098	55,429,522

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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.

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	279,640,876	251,356,668
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	247,713,799	224,179,531
5	Large (or Ind.) (See Instr. 4)	101,785,110	95,206,943
6	(444) Public Street and Highway Lighting	5,961,756	5,516,824
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales	980,339	856,061
10	TOTAL Sales to Ultimate Consumers	636,081,880	577,116,027
11	(447) Sales for Resale	224,672,881	138,609,644
12	TOTAL Sales of Electricity	860,754,761	715,725,671
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	860,754,761	715,725,671
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	570,818	558,237
18	(453) Sales of Water and Water Power	306,684	309,017
19	(454) Rent from Electric Property	2,774,767	2,792,411
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	47,550,273	14,275,491
22	(456.1) Revenues from Transmission of Electricity of Others	9,428,833	10,470,726
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	60,631,375	28,405,882
27	TOTAL Electric Operating Revenues	921,386,136	744,131,553

ELECTRIC OPERATING REVENUES (Account 400)

5. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
6. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
7. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
8. 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
3,743,696	3,670,026	311,381	306,737	2
				3
3,187,832	3,132,068	39,075	38,488	4
2,058,527	2,084,372	1,388	1,377	5
25,757	25,418	434	426	6
				7
				8
13,507	12,842	74	69	9
9,029,319	8,924,726	352,352	347,097	10
3,566,073	2,536,103			11
12,595,392	11,460,829	352,352	347,097	12
				13
12,595,392	11,460,829	352,352	347,097	14

Line 12, column (b) includes $ 10,497,151 of unbilled revenues.

Line 12, column (d) includes 90,630 MWH relating to unbilled revenues

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	RESIDENTIAL SALES (440)					
2	1 Residential Service	3,551,307	253,762,316	297,608	11,933	0.0715
3	2 Residential Service					
4	3 Residential Service					
5	12 Res. & Farm Gen. Service	65,311	6,748,600	12,017	5,435	0.1033
6	15 MOPS II Residential					
7	22 Res. & Farm Lg. Gen. Service	49,946	3,490,509	97	514,907	0.0699
8	30 Pumping-Special					
9	32 Res. & Farm Pumping Service	14,027	1,042,119	1,659	8,455	0.0743
10	48 Res. & Farm Area Lighting	4,847	994,119			0.2051
11	49 Area Lighting-High-Press.	295	67,180			0.2277
12	56 Centralia Refund					
13	95 Wind Power		172,291			
14	72 Residential Service					
15	73 Residential Service					
16	74 Residential Service					
17	76 Residential Service					
18	77 Residential Service					
19	58A Tax Adjustment		-43,258			
20	58 Tax Adjustment		7,253,316			
21	SubTotal	3,685,733	273,487,192	311,381	11,837	0.0742
22	Residential-Unbilled	57,963	6,153,684			0.1062
23	Total Residential Sales	3,743,696	279,640,876	311,381	12,023	0.0747
24						
25	COMMERCIAL SALES (442)					
26	2 General Service					
27	3 General Service					
28	11 General Service	665,829	61,687,997	33,594	19,820	0.0926
29	12 Res. & Farm Gen. Service					
30	16 MOPS II Commercial					
31	19 Contract-General Service					
32	21 Large General Service	2,032,057	147,948,358	4,460	455,618	0.0728
33	25 Extra Lg. Gen. Service	353,026	17,764,630	13	27,155,846	0.0503
34	28 Contract-Extra Large Serv					
35	31 Pumping Service	92,007	6,132,197	1,008	91,277	0.0666
36	47 Area Lighting-Sod. Vap	6,897	1,251,174			0.1814
37	49 Area Lighting-High-Press.	2,346	424,214			0.1808
38	56 Centralia Refune					
39	95 Wind Power		63,679			
40	74 Large General Service					
41	TOTAL Billed	12,504,762	850,257,610	352,352	35,489	0.0680
42	Total Unbilled Rev.(See Instr. 6)	90,630	10,497,151	0	0	0.1158
43	TOTAL	12,595,392	860,754,761	352,352	35,747	0.0683

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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	75 Large General Service					
2	76 Large General Service					
3	77 General Service					
4	58A Tax Adjustment		-44,210			
5	58 Tax Adjustment		8,513,743			
6	SubTotal	3,152,162	243,741,782	39,075	80,670	0.0773
7	Commercial-Unbilled	35,670	3,972,017			0.1114
8	Total Commercial	3,187,832	247,713,799	39,075	81,582	0.0777
9						
10	INDUSTRIAL SALES (442)					
11	2 General Service					
12	3 General Service					
13	8 Lg Gen Time of Use					
14	11 General Service	6,833	645,180	234	29,201	0.0944
15	12 Res. & Farm Gen. Service					
16	21 Large General Service	183,873	12,684,216	190	967,753	0.0690
17	25 Extra Lg. Gen. Service	1,783,289	81,528,110	22	81,058,591	0.0457
18	28 Contract - Extra Large Service	862	309,781	1	862,000	0.3594
19	29 Contract Lg. Gen. Service					
20	30 Pumping Service - Special	26,900	1,589,966	38	707,895	0.0591
21	31 Pumping Service	54,910	3,766,164	750	73,213	0.0686
22	32 Pumping Svc Res & Firm	4,596	292,863	153	30,039	0.0637
23	47 Area Lighting-Sod. Vap.	218	35,037			0.1607
24	49 Area Lighting - High-Press	49	8,095			0.1652
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		-872			
33	58 Tax Adjustment		553,392			
34	SubTotal	2,061,530	101,413,660	1,388	1,485,252	0.0492
35	Industrial-Unbilled	-3,003	371,450			-0.1237
36	Total Industrial	2,058,527	101,785,110	1,388	1,483,089	0.0494
37						
38	STREET AND HWY LIGHTING (444)					
39	6 Mercury Vapor St. Ltg.					
40	7 HP Sodium Vap. St. Ltg					
41	TOTAL Billed	12,504,762	850,257,610	352,352	35,489	0.0680
42	Total Unbilled Rev.(See Instr. 6)	90,630	10,497,151	0	0	0.1158
43	TOTAL	12,595,392	860,754,761	352,352	35,747	0.0683

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2009	Year/Period of Report End of 2008/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	11 General Service					
2	41 Co-Owned St. Lt. Service	221	35,295	16	13,813	0.1597
3	42 Co-Owned St. Lt. Service	20,037	5,261,801	353	56,762	0.2626
4	High-Press. Sod. Vap.					
5	43 Cust-Owned St. Lt. Energy	25	2,039	1	25,000	0.0816
6	and Maint. Service					
7	44 Cust-Owned St. Lt. Energy	843	101,925	29	29,069	0.1209
8	and Maint. Svce - High-Pres					
9	Sodium Vapor					
10	45 Cust. Owned St. Lt. Energy Svc	1,340	81,650	6	223,333	0.0609
11	46 Cust. Owned St. Lt. Energy Svc	3,291	265,891	29	113,483	0.0808
12	58A Tax Adjustment		-970			
13	58 Tax Adjustment		214,125			
14	SubTotal	25,757	5,961,756	434	59,348	0.2315
15	Street & Hwy Lighting-Unbilled					
16	Total Street & Hwy Lighting	25,757	5,961,756	434	59,348	0.2315
17						
18	OTHER SALES TO PUBLIC					
19	(445)					
20	None					
21						
22	INTERDEPARTMENTAL SALES	13,507	980,006	74	182,527	0.0726
23	58 Tax Adjustment		333			
24	Total Interdepartmental	13,507	980,339	74	182,527	0.0726
25						
26	SALES FOR RESALE (447)					
27	61 Sales to Other Utilities (NDA)	3,566,073	224,672,881			0.0630
28						
29						
30	Total Sales for Resale	3,566,073	224,672,881			0.0630
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	12,504,762	850,257,610	352,352	35,489	0.0680
42	Total Unbilled Rev.(See Instr. 6)	90,630	10,497,151	0	0	0.1158
43	TOTAL	12,595,392	860,754,761	352,352	35,747	0.0683

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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) 04/16/2009	Year/Period of Report End of 2008/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	Arizona Public Service	SF	WSPP-C			
2	BC Transmission Corp.	SF	Tariff 12			
3	Barclays Bank PLC	SF	WSPP-C			
4	Barclays Bank PLC	SF	ISDA			
5	Bear Energy LP	SF	WSPP-C			
6	Benton County Public Utility District	SF	WSPP-C			
7	Black Hills Power, Inc.	SF	WSPP-C			
8	BP Energy Company	SF	WSPP-C			
9	Bonneville Power Administration	LF	Tariff 8			
10	Bonneville Power Administration	LF	BPA OATT			
11	Bonneville Power Administration	SF	WSPP-C			
12	Bonneville Power Administration	SF	Tariff 12			
13	Cargill Power Markets, LLC	SF	WSPP-C			
14	Chelan County PUD No. 1	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	04/16/2009	End of 2008/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		130		130	1
15		1,014		1,014	2
159,403		8,649,804		8,649,804	3
			359,686	359,686	4
141,963		9,217,990		9,217,990	5
210		13,970		13,970	6
400		7,600		7,600	7
172,395		9,306,920		9,306,920	8
32,854		2,067,677		2,067,677	9
2,142		128,816		128,816	10
45,991		3,047,875		3,047,875	11
23		647		647	12
59,442		2,643,254		2,643,254	13
2,000		104,300		104,300	14
0	0	0	0	0	
3,566,073	6,272,815	202,188,645	16,211,421	224,672,881	
3,566,073	**6,272,815**	**202,188,645**	**16,211,421**	**224,672,881**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	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	Coral Power, LLC	SF	WSPP-C			
6	Coral Power, LLC	SF	Tariff 9			
7	Credit Suisse Energy LLC	SF	WSPP-C			
8	Douglas County PUD No. 1	SF	WSPP-C			
9	EPCOR Merchant & Capital US	SF	WSPP-C			
10	Eugene Water & Electric Board	SF	WSPP-C			
11	Fortis Energy Marketing & Trading GP	SF	WSPP-C			
12	Franklin County PUD No. 1	SF	WSPP-C			
13	Grant County PUD No. 2	SF	WSPP-C			
14	Grant County PUD No. 2	SF	Tariff 12			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
1,238		71,930		71,930	1
25		1,943		1,943	2
	122,976			122,976	3
276,615		17,766,319		17,766,319	4
103,172		6,060,874		6,060,874	5
	1,350			1,350	6
3,600		200,100		200,100	7
6					8
600		43,200		43,200	9
2,602		136,520		136,520	10
53,099		2,571,208		2,571,208	11
65		4,375		4,375	12
25,669		1,468,375		1,468,375	13
6		469		469	14
0	0	0	0	0	
3,566,073	6,272,815	202,188,645	16,211,421	224,672,881	
3,566,073	**6,272,815**	**202,188,645**	**16,211,421**	**224,672,881**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/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:
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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.
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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	Grant County PUD No. 2	SF	Tariff 10			
2	Grays Harbor County PUD No. 1	SF	WSPP-C			
3	Highland Energy	SF	WSPP-C			
4	Highland Energy	SF	Tariff 9			
5	Hinson Power Company, LLC	SF	WSPP-C			
6	Iberdrola Renewables, Inc.	SF	WSPP-C			
7	Idaho Power Company	SF	WSPP-C			
8	Idaho Power Company	SF	Tariff 10			
9	Idaho Power Company	SF	Tariff 12			
10	Integry's Energy Service, Inc.	SF	WSPP-C			
11	J. Aron & Company	SF	WSPP-C			
12	JP Morgan Ventures Energy	SF	WSPP-C			
13	Lehman Brothers Commodity Services, Inc	SF	WSPP-C			
14	Modesto Irrigation District	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	04/16/2009	End of 2008/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.
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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.
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10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
	3,105			3,105	1
115		7,620		7,620	2
10,001		546,938		546,938	3
	889			889	4
512		16,912		16,912	5
121,654		6,432,100		6,432,100	6
71,054		3,839,428		3,839,428	7
	100			100	8
58		3,006		3,006	9
3,400		168,700		168,700	10
23,758		831,530		831,530	11
21,630		1,094,890		1,094,890	12
54,000		4,899,200		4,899,200	13
10,484		552,579		552,579	14
0	0	0	0	0	
3,566,073	6,272,815	202,188,645	16,211,421	224,672,881	
3,566,073	**6,272,815**	**202,188,645**	**16,211,421**	**224,672,881**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/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.
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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	Morgan Stanley	SF	WSPP-C			
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	NorthWestern Energy LLC	SF	WSPP-C			
6	NorthWestern Energy LLC	SF	Tariff 10			
7	NorthWestern Energy LLC	LF	Tariff 9			
8	NorthWestern Energy LLC	IF	Tariff 10			
9	NorthWestern Energy LLC	IF	Tariff 10			
10	NorthWestern Energy LLC	IF	Tariff 9			
11	NorthWestern Energy LLC	SF	Tariff 12			
12	Okanogan County PUD	SF	WSPP-C			
13	PNGC Power	SF	WSPP-C			
14	PacifiCorp	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	04/16/2009	End of 2008/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.
207,399		13,074,311		13,074,311	1
844		46,370		46,370	2
	50,400			50,400	3
			12,203	12,203	4
44,921		3,137,828		3,137,828	5
	559,299			559,299	6
8,250		481,749		481,749	7
	2,716,645			2,716,645	8
			310,152	310,152	9
38,837		2,476,831		2,476,831	10
90		5,949		5,949	11
9,895		541,390		541,390	12
5,290		340,610		340,610	13
33,783		1,520,386		1,520,386	14
0	0	0	0	0	
3,566,073	6,272,815	202,188,645	16,211,421	224,672,881	
3,566,073	**6,272,815**	**202,188,645**	**16,211,421**	**224,672,881**	

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	PacifiCorp	SF	Tariff 12			
2	PacifiCorp	SF	Tariff 10			
3	PacifiCorp	LF	Tariff 9			
4	Peaker LLC	LF	Tariff 9			
5	Pend Oreille Public Utility District	IF	Tariff 10			
6	Pend Oreille Public Utility District	IF	Tariff 9			
7	Pend Oreille Public Utility District	SF	Tariff 10			
8	Pend Oreille Public Utility District	SF	Tariff 9			
9	Portland General Electric Company	SF	WSPP-C			
10	Portland General Electric Company	SF	Tariff 12			
11	Portland General Electric Company	SF	Tariff 10			
12	Powerex	SF	WSPP-C			
13	Powerex	SF	Tariff 9			
14	Powerex	SF	Tariff 9			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,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.
265		15,569		15,569	1
	875			875	2
5,250		306,568		306,568	3
	1,749,091			1,749,091	4
	407,233			407,233	5
2,352		37,056		37,056	6
	68,906			68,906	7
36,603		1,961,139		1,961,139	8
68,104		3,561,873		3,561,873	9
81		5,092		5,092	10
	6,420			6,420	11
269,594		13,998,960		13,998,960	12
	103,521			103,521	13
			13,092	13,092	14
0	0	0	0	0	
3,566,073	6,272,815	202,188,645	16,211,421	224,672,881	
3,566,073	**6,272,815**	**202,188,645**	**16,211,421**	**224,672,881**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/Q4

SALES FOR RESALE (Account 447)

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/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.
	366,683			366,683	1
18,851		1,054,865		1,054,865	2
18,748		1,094,885		1,094,885	3
8,000		415,660		415,660	4
204,849		13,924,578		13,924,578	5
37		2,447		2,447	6
23,997		1,401,453		1,401,453	7
	250			250	8
102,645		5,692,068		5,692,068	9
3,645		195,254		195,254	10
55,098		3,647,642		3,647,642	11
643,459		47,832,272		47,832,272	12
13,517		807,729		807,729	13
1		64		64	14
0	0	0	0	0	
3,566,073	6,272,815	202,188,645	16,211,421	224,672,881	
3,566,073	**6,272,815**	**202,188,645**	**16,211,421**	**224,672,881**	

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	Sempra Energy Trading	SF	WSPP-C			
2	Shell Energy N.A.	SF	WSPP-C			
3	Sierra Pacific Power Company	SF	WSPP-C			
4	Sierra Pacific Power Company	SF	Tariff 12			
5	Snohomish County PUD	SF	WSPP-C			
6	Sovereign Power	LF	Tariff 9			
7	Sovereign Power	LF	Tariff 10			
8	Suez Energy Marketing NA, Inc	SF	WSPP-C			
9	Tacoma Power	SF	WSPP-C			
10	Tacoma Power	SF	Tariff 10			
11	The Energy Authority	SF	WSPP-C			
12	TransAlta Energy Marketing	SF	WSPP-C			
13	Turlock Irrigation District	SF	WSPP-C			
14	IntraCompany Wheeling	LF				
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
165,641		8,970,735		8,970,735	1
48,354		2,556,744		2,556,744	2
4,908		348,808		348,808	3
103		5,990		5,990	4
2,370		134,150		134,150	5
7,750		445,357		445,357	6
	114,622			114,622	7
2,000		165,200		165,200	8
8,287		538,566		538,566	9
	450			450	10
3,280		162,301		162,301	11
94,905		3,925,770		3,925,770	12
3,558		264,110		264,110	13
		-14,817,897	14,817,897		14
0	0	0	0	0	
3,566,073	6,272,815	202,188,645	16,211,421	224,672,881	
3,566,073	**6,272,815**	**202,188,645**	**16,211,421**	**224,672,881**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2009	Year/Period of Report End of 2008/Q4

SALES FOR RESALE (Account 447)

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

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

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,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.
			679,786	679,786	1
309			18,605	18,605	2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
0	0	0	0	0	
3,566,073	6,272,815	202,188,645	16,211,421	224,672,881	
3,566,073	**6,272,815**	**202,188,645**	**16,211,421**	**224,672,881**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/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	353,838	271,720
5	(501) Fuel	28,776,474	26,719,429
6	(502) Steam Expenses	1,880,633	1,840,213
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	814,258	835,130
10	(506) Miscellaneous Steam Power Expenses	3,455,151	2,068,116
11	(507) Rents	38,367	29,922
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	35,318,721	31,764,530
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	461,747	514,698
16	(511) Maintenance of Structures	526,317	496,664
17	(512) Maintenance of Boiler Plant	4,876,984	5,724,096
18	(513) Maintenance of Electric Plant	544,537	1,031,164
19	(514) Maintenance of Miscellaneous Steam Plant	637,092	723,773
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	7,046,677	8,490,395
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	42,365,398	40,254,925
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	1,642,209	1,657,569
45	(536) Water for Power	744,841	735,341
46	(537) Hydraulic Expenses	3,209,339	2,744,019
47	(538) Electric Expenses	4,724,140	4,515,089
48	(539) Miscellaneous Hydraulic Power Generation Expenses	984,206	718,330
49	(540) Rents	802,071	755,035
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	12,106,806	11,125,383
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	302,771	309,538
54	(542) Maintenance of Structures	312,861	336,239
55	(543) Maintenance of Reservoirs, Dams, and Waterways	662,450	1,368,818
56	(544) Maintenance of Electric Plant	2,164,716	2,114,811
57	(545) Maintenance of Miscellaneous Hydraulic Plant	294,574	150,450
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	3,737,372	4,279,856
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	15,844,178	15,405,239

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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	1,650,998	1,202,574
63	(547) Fuel	107,175,030	99,775,888
64	(548) Generation Expenses	1,666,082	1,331,508
65	(549) Miscellaneous Other Power Generation Expenses	455,207	444,348
66	(550) Rents	33,433	21,779
67	TOTAL Operation (Enter Total of lines 62 thru 66)	110,980,750	102,776,097
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	423,483	942,204
70	(552) Maintenance of Structures	4,186	4,998
71	(553) Maintenance of Generating and Electric Plant	4,920,956	1,749,571
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	114,800	160,317
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	5,463,425	2,857,090
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	116,444,175	105,633,187
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	276,853,230	191,126,248
77	(556) System Control and Load Dispatching	500,980	480,570
78	(557) Other Expenses	78,800,960	26,956,543
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	356,155,170	218,563,361
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	530,808,921	379,856,712
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,227,450	2,406,849
84	(561) Load Dispatching	1,981,275	-26,009
85	(561.1) Load Dispatch-Reliability		16,212
86	(561.2) Load Dispatch-Monitor and Operate Transmission System		1,165,928
87	(561.3) Load Dispatch-Transmission Service and Scheduling		770,853
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	252,115	166,599
94	(563) Overhead Lines Expenses	505,160	160,177
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	13,632,001	13,853,279
97	(566) Miscellaneous Transmission Expenses	1,312,796	878,319
98	(567) Rents	100,620	77,306
99	TOTAL Operation (Enter Total of lines 83 thru 98)	20,011,417	19,469,513
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	591,365	480,094
102	(569) Maintenance of Structures	279,425	324,247
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	1,237,393	990,440
108	(571) Maintenance of Overhead Lines	1,226,863	940,925
109	(572) Maintenance of Underground Lines	1,311	11,075
110	(573) Maintenance of Miscellaneous Transmission Plant	7,209	99,918
111	TOTAL Maintenance (Total of lines 101 thru 110)	3,343,566	2,846,699
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	23,354,983	22,316,212

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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/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	1,391,231	1,086,493
135	(581) Load Dispatching		
136	(582) Station Expenses	621,675	456,006
137	(583) Overhead Line Expenses	1,975,815	872,105
138	(584) Underground Line Expenses	896,606	1,400,038
139	(585) Street Lighting and Signal System Expenses	194,939	209,843
140	(586) Meter Expenses	1,308,218	908,418
141	(587) Customer Installations Expenses	825,366	886,924
142	(588) Miscellaneous Expenses	5,097,414	4,614,263
143	(589) Rents	191,442	152,361
144	TOTAL Operation (Enter Total of lines 134 thru 143)	12,502,706	10,586,451
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	1,371,668	1,334,695
147	(591) Maintenance of Structures	294,513	269,664
148	(592) Maintenance of Station Equipment	750,947	872,990
149	(593) Maintenance of Overhead Lines	7,983,419	6,718,499
150	(594) Maintenance of Underground Lines	1,059,209	1,064,426
151	(595) Maintenance of Line Transformers	678,925	550,762
152	(596) Maintenance of Street Lighting and Signal Systems	610,966	559,751
153	(597) Maintenance of Meters	145,069	176,847
154	(598) Maintenance of Miscellaneous Distribution Plant	503,563	352,619
155	TOTAL Maintenance (Total of lines 146 thru 154)	13,398,279	11,900,253
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	25,900,985	22,486,704
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	490,861	533,668
160	(902) Meter Reading Expenses	2,313,137	2,138,197
161	(903) Customer Records and Collection Expenses	7,490,538	7,992,442
162	(904) Uncollectible Accounts	1,927,667	1,635,521
163	(905) Miscellaneous Customer Accounts Expenses	147,464	190,078
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	12,369,667	12,489,906

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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/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	16,553,310	11,181,123
169	(909) Informational and Instructional Expenses	112,666	65,646
170	(910) Miscellaneous Customer Service and Informational Expenses	145,297	117,124
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	16,811,273	11,363,893
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	424,827	501,591
176	(913) Advertising Expenses	128,150	258,828
177	(916) Miscellaneous Sales Expenses	213,550	189,311
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	766,527	949,730
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	19,181,918	19,387,201
182	(921) Office Supplies and Expenses	3,782,093	3,633,500
183	(Less) (922) Administrative Expenses Transferred-Credit	38,836	34,969
184	(923) Outside Services Employed	10,997,229	11,687,401
185	(924) Property Insurance	1,015,509	1,128,497
186	(925) Injuries and Damages	2,968,505	3,289,641
187	(926) Employee Pensions and Benefits	1,186,191	991,605
188	(927) Franchise Requirements	5,950	6,327
189	(928) Regulatory Commission Expenses	4,783,704	4,315,148
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	4,017	9,097
192	(930.2) Miscellaneous General Expenses	3,198,612	3,092,795
193	(931) Rents	590,566	698,836
194	TOTAL Operation (Enter Total of lines 181 thru 193)	47,675,458	48,205,079
195	Maintenance		
196	(935) Maintenance of General Plant	7,319,496	7,127,608
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	54,994,954	55,332,687
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	665,007,310	504,795,844

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/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 Energy Comp	IF	WSPP			
2	BP Energy Comp	SF	WSPP			
3	BP Energy Comp	SF	ISDA			
4	Barclays Bank PLC	SF	WSPP			
5	Barclays Bank PLC	SF	ISDA			
6	Bear Energy	SF	WSPP			
7	Benton County PUD No. 1	SF	WSPP			
8	Black Creek Hydro	LU	FERC #1			
9	Black Hills Power	SF	WSPP			
10	Bonneville Power Administration	LF	WNP#3 Agr.			
11	Bonneville Power Administration	SF	WSPP			
12	Bonneville Power Administration	EX	PNCA			
13	Bonneville Power Administration	SF	Tariff #8			
14	Bonneville Power Administration	OS	BPA OATT			
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
219,597				7,576,200		7,576,200	1
23,768				1,448,158		1,448,158	2
					1,706,752	1,706,752	3
212,237				16,063,992		16,063,992	4
					1,065,876	1,065,876	5
101,023				7,782,744		7,782,744	6
2,300				177,185		177,185	7
311				12,997		12,997	8
400				35,600		35,600	9
374,999				13,283,097		13,283,097	10
128,007				6,201,358		6,201,358	11
	16,965	17,250		87,788	-12,435	75,353	12
33,507				1,916,667		1,916,667	13
					13,528	13,528	14
5,686,485	718,926	720,744	4,292,113	269,923,183	2,637,934	276,853,230	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/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	Bonneville Power Administration	SF	BPA OATT			
2	Cargill Power Markets, LLC	SF	WSPP			
3	Chelan County PUD No. 1	LU	Rocky Reach			
4	Chelan County PUD No. 1	SF	WSPP			
5	City of Spokane	LU	PURPA			
6	Clatskanie Peoples PUD	SF	WSPP			
7	Constellation Energy Commodities Group	SF	WSPP			
8	Douglas County PUD No. 1	LU	Wells			
9	Douglas County PUD No. 1	LU	Wells Settlement			
10	Douglas County PUD No. 1	IF	Wells			
11	Douglas County PUD No. 1	SF	WSPP			
12	Douglas County PUD No. 1	EX	305			
13	EPCOR Merchant & Capital US	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	04/16/2009	End of 2008/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
10,040				737,408	-167,821	569,587	1
55,188				3,414,336		3,414,336	2
165,000				2,115,518		2,115,518	3
2,005				76,765		76,765	4
45,914				1,776,464		1,776,464	5
1,355				80,675		80,675	6
132,959				8,495,574		8,495,574	7
148,068				1,315,059		1,315,059	8
26,603				475,874		475,874	9
			2,800,503			2,800,503	10
61,304				4,138,637		4,138,637	11
	114,525	114,479		1,576,250	1,590	1,577,840	12
2,400				220,092		220,092	13
7,813				360,339		360,339	14
5,686,485	718,926	720,744	4,292,113	269,923,183	2,637,934	276,853,230	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/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	Franklin County PUD No. 1	SF	WSPP			
4	Grant County PUD No. 2	LU	Wanapum			
5	Grant County PUD No. 2	LU	Priest Rapids			
6	Grant County PUD No. 2	LU	PR Displacement			
7	Grant County PUD No. 2	SF	WSPP			
8	Grays Harbor County PUD No. 1	SF	WSPP			
9	Highland Energy	IU	WSPP			
10	Hydro Technology Systems	LU	PURPA			
11	Idaho Power Company	SF	WSPP			
12	Inland Power & Light Company	RQ	208			
13	J P Morgan Ventures Energy	SF	WSPP			
14	Jim White	LU	PURPA			
	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)	
36,183				2,715,516		2,715,516	1
3,654				188,388		188,388	2
667				47,669		47,669	3
326,280				5,715,404		5,715,404	4
138,345				5,253,030		5,253,030	5
194,571				4,625,161		4,625,161	6
25,320				1,341,646		1,341,646	7
655				44,445		44,445	8
36,581				2,231,742		2,231,742	9
8,507				396,361		396,361	10
14,524				834,078		834,078	11
134				7,054		7,054	12
35,124				2,417,842		2,417,842	13
958				85,217		85,217	14
5,686,485	718,926	720,744	4,292,113	269,923,183	2,637,934	276,853,230	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/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	Lehman Bothers	SF	WSPP			
4	Mirant Energy Trading	SF	WSPP			
5	Morgan Stanley Capital Group	IF	WSPP			
6	Morgan Stanley Capital Group	SF	WSPP			
7	Morgan Stanley Capital Group	SF	ISDA			
8	NorthWestern Energy LLC	SF	WSPP			
9	Okanogan County PUD No. 1	SF	WSPP			
10	PPL Energy Plus	SF	WSPP			
11	PPM Energy	LU	PPM Energy			
12	PPM Energy	SF	WSPP			
13	PacifiCorp	SF	WSPP			
14	Pacific NW Gen Corp	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	04/16/2009	End of 2008/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
2,095				90,186		90,186	1
1				171		171	2
12,925				954,036		954,036	3
6,800				564,008		564,008	4
658,745				20,245,978		20,245,978	5
149,127				8,906,317		8,906,317	6
					129,392	129,392	7
50,516				2,866,172		2,866,172	8
62,402				3,951,331		3,951,331	9
634,967				35,086,455		35,086,455	10
84,717				3,344,627		3,344,627	11
145,541				9,883,819		9,883,819	12
60,930				3,645,858		3,645,858	13
4,532				276,136		276,136	14
5,686,485	718,926	720,744	4,292,113	269,923,183	2,637,934	276,853,230	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/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	Pend Oreille County PUD No. 1	SF	Pend O'			
2	Pend Oreille County PUD No. 1	SF	Pend O'			
3	Phillips Ranch	LU	PURPA			
4	Portland General Electric Company	EX	304			
5	Portland General Electric Company	EX	178			
6	Portland General Electric Company	SF	WSPP			
7	Potlatch Corporation	LU	PURPA			
8	Powerex Corp	SF	WSPP			
9	Powerex Corp	SF	WSPP			
10	Puget Sound Energy	SF	WSPP			
11	Rainbow Energy Marketing Corp	SF	WSPP			
12	Seattle City Light	SF	WSPP			
13	Seattle City Light	EX	WSPP			
14	Sempra Energy Trading	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	04/16/2009	End of 2008/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
3,225				385,026		385,026	1
69,964	19,652	20,829		4,451,476	-86,974	4,364,502	2
37				2,274		2,274	3
	10,533	10,496					4
	447,067	447,690			-11,974	-11,974	5
11,829				871,015		871,015	6
418,233				17,950,560		17,950,560	7
47,396				3,735,903		3,735,903	8
			1,491,360			1,491,360	9
41,918				2,928,832		2,928,832	10
193,624				9,992,999		9,992,999	11
53,423				3,911,424		3,911,424	12
	110,000	110,000		1,705,000		1,705,000	13
126,081				10,094,421		10,094,421	14
5,686,485	718,926	720,744	4,292,113	269,923,183	2,637,934	276,853,230	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2009	Year/Period of Report End of 2008/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	Sheep Creek Hydro	LU	PURPA			
2	Shell Energy	SF	WSPP			
3	Shell Energy	SF	WSPP			
4	Sierra Pacific Power Company	SF	WSPP			
5	Silicon Valley Power	SF	WSPP			
6	Snohomish County PUD No. 1	SF	WSPP			
7	Sovereign Power	IF	Sovereign			
8	Stimson Lumber	IU	PURPA			
9	Suez Energy Mkt	SF	WSPP			
10	Tacoma Power	SF	WSPP			
11	The Energy Authority	SF	WSPP			
12	TransAlta Energy Marketing	SF	WSPP			
13	Tucson Electric	SF	WSPP			
14	IntraCompany Generation Services	OS	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	04/16/2009	End of 2008/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)	
5,433				323,254		323,254	1
159,025				12,595,471		12,595,471	2
			250			250	3
3,852				208,142		208,142	4
60				1,620		1,620	5
5,758				241,240		241,240	6
2,783				157,494		157,494	7
37,367				1,999,557		1,999,557	8
1,200				85,980		85,980	9
20,204				737,158		737,158	10
9,750				406,967		406,967	11
25,675				1,365,998		1,365,998	12
49				4,165		4,165	13
				679,783		679,783	14
5,686,485	718,926	720,744	4,292,113	269,923,183	2,637,934	276,853,230	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2009	Year/Period of Report End of 2008/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	Other - Inadvertent Interchange	EX				
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/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)	
	184						1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
5,686,485	718,926	720,744	4,292,113	269,923,183	2,637,934	276,853,230	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/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	Vaagen Bros Lumber	Vaagen Bros Lumber	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 PUD	Grant County PUD	Grant County PUD	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	Bonneville Power Administration	Bonneville Power Administration	Idaho Power Company	NF
12	Bonneville Power Administration	Bonneville Power Administration	Avista Corporation	NF
13	Bonneville Power Administration	NorthWestern Montana	Bonneville Power Administration	NF
14	Bonneville Power Administration	Bonneville Power Administration	Idaho Power Company	SFP
15	Idaho Power Company	Portland General Electric	Idaho Power Company	NF
16	Idaho Power Company	Avista Corporation	Idaho Power Company	NF
17	Idaho Power Company	Grant County Public Utility Dist	Idaho Power Company	NF
18	Idaho Power Company	PacifiCorp	Idaho Power Company	NF
19	Idaho Power Company	Douglas County PUD	Idaho Power Company	NF
20	Idaho Power Company	Puget Sound Energy	Idaho Power Company	NF
21	Idaho Power Company	Chelan Public Utility District	Idaho Power Company	NF
22	Idaho Power Company	Avista Corporation	Bonneville Power Administration	NF
23	Idaho Power Company	Idaho Power Company	Bonneville Power Administration	NF
24	Idaho Power Company	Idaho Power Company	Avista Corporation	NF
25	Idaho Power Company	Bonneville Power Administration	Idaho Power Company	NF
26	Idaho Power Company	Idaho Power Company	PacifiCorp	NF
27	Idaho Power Company	Idaho Power Company	Puget Sound Energy	NF
28	Idaho Power Company	NorthWestern Montana	Idaho Power Company	NF
29	Idaho Power Company	Idaho Power Company	Grant County Public Utility Dist	NF
30	Idaho Power Company	Chelan Public Utility District	Idaho Power Company	NF
31	Idaho Power Company	Bonneville Power Administration	Idaho Power Company	SFP
32	Idaho Power Company	Bonneville Power Administration	NorthWestern Montana	SFP
33	Idaho Power Company	Avista Corporation	Bonneville Power Administration	SFP
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	04/16/2009	End of 2008/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	24,334	24,334	1
FERC No. 182	Lolo-Oxbow 230 kv	Dry Gulch	20	58,790	58,790	2
FERC Trf No. 8	Chelan-Stratford 115	Stratford 115kV SS		191,707	191,707	3
FERC Trf No. 8	Chelan-Stratford 115	Stratford 115kV SS		191,706	191,706	4
FERC No. 104	Larson Substation	Round Lake/Coulee Cy	25	83,375	83,375	5
FERC Trf No. 8	Sunset	Westside	2	3,233	3,233	6
FERC No. 80.2	Bell Substation	East Greenacres	3	3,162	3,162	7
FERC Trf No. 8	Bell Substation	Consolidated	4	5,706	5,706	8
FERC Trf No. 8				1,845,468	1,845,468	9
No 155	Sunset-Westside 115k	Westside	23	128,135	128,135	10
FERC Trf No. 8				23,248	23,248	11
FERC Trf No. 8						12
FERC Trf No. 8				100	100	13
FERC Trf No. 8				20,393	20,393	14
FERC Trf No. 8				200	200	15
FERC Trf No. 8				2,400	2,400	16
FERC Trf No. 8				1,448	1,448	17
FERC Trf No. 8				650	650	18
FERC Trf No. 8				1,064	1,064	19
FERC Trf No. 8				200	200	20
FERC Trf No. 8				1,420	1,420	21
FERC Trf No. 8				1,600	1,600	22
FERC Trf No. 8				21,054	21,054	23
FERC Trf No. 8				2,168	2,168	24
FERC Trf No. 8				74,222	74,222	25
FERC Trf No. 8				600	600	26
FERC Trf No. 8				1,998	1,998	27
FERC Trf No. 8				214	214	28
FERC Trf No. 8				400	400	29
FERC Trf No. 8				4,914	4,914	30
FERC Trf No. 8				233,762	233,762	31
FERC Trf No. 8				1,477	1,477	32
FERC Trf No. 8				7,800	7,800	33
						34
			81	**3,293,560**	**3,293,560**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/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.
67,488	24,334	28,281	120,103	1
261,516			261,516	2
120,524			120,524	3
120,524			120,524	4
27,711			27,711	5
14,582			14,582	6
16,588			16,588	7
35,448			35,448	8
5,431,948			5,431,948	9
127,506		32,088	159,594	10
	87,236		87,236	11
	11,468		11,468	12
	204		204	13
71,771			71,771	14
	800		800	15
	9,019		9,019	16
	5,634		5,634	17
	2,600		2,600	18
	3,551		3,551	19
	747		747	20
	5,284		5,284	21
	4,654		4,654	22
	98,081		98,081	23
	8,672		8,672	24
	302,222		302,222	25
	2,400		2,400	26
	7,992		7,992	27
	719		719	28
	1,600		1,600	29
	18,713		18,713	30
853,617			853,617	31
5,654			5,654	32
30,744			30,744	33
				34
7,914,641	**1,453,822**	**60,369**	**9,428,832**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2009	Year/Period of Report End of 2008/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Idaho Power Company	Grant County Public Utility Dist	Idaho Power Company	SFP
2	Idaho Power Company	Idaho Power Company	Bonneville Power Administration	SFP
3	NorthWestern Energy	NorthWestern Montana	Bonneville Power Administration	NF
4	NorthWestern Energy	NorthWestern Montana	Puget Sound Energy	NF
5	NorthWestern Energy	NorthWestern Montana	Chelan Public Utility District	NF
6	NorthWestern Energy	NorthWestern Montana	Portland General Electric	NF
7	NorthWestern Energy	NorthWestern Montana	Idaho Power Company	SFP
8	PacifiCorp	PacifiCorp	Bonneville Power Administration	NF
9	PacifiCorp	NorthWestern Montana	PacifiCorp	NF
10	PacifiCorp	PacifiCorp	NorthWestern Montana	NF
11	PacifiCorp	PacifiCorp	Idaho Power Company	NF
12	PacifiCorp	PacifiCorp	Bonneville Power Administration	SFP
13	PacifiCorp	Avista Corporation	Bonneville Power Administration	NF
14	PacifiCorp	PacifiCorp	Bonneville Power Administration	NF
15	Powerex	NorthWestern Montana	Bonneville Power Administration	NF
16	Powerex	Idaho Power Company	Bonneville Power Administration	NF
17	Powerex	Bonneville Power Administration	Idaho Power Company	NF
18	Powerex	Avista Corporation	Bonneville Power Administration	NF
19	Powerex	Bonneville Power Administration	Idaho Power Company	SFP
20	Powerex	NorthWestern Montana	Bonneville Power Administration	SFP
21	Puget Sound Energy	Puget Sound Energy	Idaho Power Company	NF
22	Puget Sound Energy	NorthWestern Montana	Puget Sound Energy	NF
23	Puget Sound Energy	NorthWestern Montana	Bonneville Power Administration	NF
24	Puget Sound Energy	Idaho Power Company	Puget Sound Energy	NF
25	Constellation Energy Commodities Group	Avista Corporation	NorthWestern Montana	NF
26	Portland General Electric	NorthWestern Montana	Portland General Electric	NF
27	Portland General Electric	Idaho Power Company	Portland General Electric	NF
28	Portland General Electric	NorthWestern Montana	Bonneville Power Administration	NF
29	Portland General Electric	NorthWestern Montana	Bonneville Power Administration	SFP
30	Morgan Stanley Capital Group	Bonneville Power Administration	NorthWestern Montana	NF
31	Morgan Stanley Capital Group	Bonneville Power Administration	Idaho Power Company	NF
32	Morgan Stanley Capital Group	NorthWestern Montana	Bonneville Power Administration	NF
33	Morgan Stanley Capital Group	Bonneville Power Administration	NorthWestern Montana	SFP
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	04/16/2009	End of 2008/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				400	400	1
FERC Trf No. 8				7,811	7,811	2
FERC Trf No. 8				4,794	4,794	3
FERC Trf No. 8				626	626	4
FERC Trf No. 8				309	309	5
FERC Trf No. 8				539	539	6
FERC Trf No. 8						7
FERC Trf No. 8				1,430	1,430	8
FERC Trf No. 8				6,376	6,376	9
FERC Trf No. 8				264	264	10
FERC Trf No. 8				961	961	11
FERC Trf No. 8				1,139	1,139	12
FERC Trf No. 8						13
FERC Trf No. 8				1,247	1,247	14
FERC Trf No. 8				22,835	22,835	15
FERC Trf No. 8				4,578	4,578	16
FERC Trf No. 8				21,055	21,055	17
FERC Trf No. 8				1,523	1,523	18
FERC Trf No. 8				8,390	8,390	19
FERC Trf No. 8				9,901	9,901	20
FERC Trf No. 8				67	67	21
FERC Trf No. 8				97	97	22
FERC Trf No. 8				725	725	23
FERC Trf No. 8				710	710	24
FERC Trf No. 8				56	56	25
FERC Trf No. 8				16,763	16,763	26
FERC Trf No. 8				125	125	27
FERC Trf No. 8				1,876	1,876	28
FERC Trf No. 8				688	688	29
FERC Trf No. 8				400	400	30
FERC Trf No. 8				434	434	31
FERC Trf No. 8				2,201	2,201	32
FERC Trf No. 8				11,047	11,047	33
						34
			81	**3,293,560**	**3,293,560**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/Q4

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
1,102			1,102	1
23,254			23,254	2
	20,408		20,408	3
	3,111		3,111	4
	1,589		1,589	5
	2,860		2,860	6
29,400			29,400	7
	43,171		43,171	8
	37,720		37,720	9
	1,168		1,168	10
	9,245		9,245	11
11,499			11,499	12
	400		400	13
	7,616		7,616	14
	100,696		100,696	15
	19,484		19,484	16
	76,197		76,197	17
	5,211		5,211	18
75,130			75,130	19
33,980			33,980	20
	298		298	21
	776		776	22
	4,688		4,688	23
	4,591		4,591	24
	224		224	25
	72,362		72,362	26
	552		552	27
	8,702		8,702	28
2,778			2,778	29
	1,600		1,600	30
	2,960		2,960	31
	9,524		9,524	32
57,624			57,624	33
				34
7,914,641	**1,453,822**	**60,369**	**9,428,832**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/Q4

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

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

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

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2009	Year/Period of Report End of 2008/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		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
FERC Trf No. 8				51,417	51,417	1
FERC Trf No. 8				400	400	2
FERC Trf No. 8				1,800	1,800	3
FERC Trf No. 8				33,541	33,541	4
FERC Trf No. 8				309	309	5
FERC Trf No. 8				520	520	6
FERC Trf No. 8				342	342	7
FERC Trf No. 8				24	24	8
FERC Trf No. 8				4,704	4,704	9
FERC Trf No. 8				12,781	12,781	10
FERC Trf No. 8				16	16	11
FERC Trf No. 8				350	350	12
FERC Trf No. 8				680	680	13
FERC Trf No. 8				8,413	8,413	14
FERC Trf No. 8				26,721	26,721	15
FERC Trf No. 8				42	42	16
FERC Trf No. 8				1,041	1,041	17
FERC Trf No. 8				210	210	18
FERC Trf No. 8				20,095	20,095	19
FERC Trf No. 8				21,523	21,523	20
FERC Trf No. 8				125	125	21
FERC Trf No. 8				95	95	22
FERC Trf No. 8				158	158	23
FERC Trf No. 8				43	43	24
FERC Trf No. 8				532	532	25
FERC Trf No. 8				390	390	26
FERC Trf No. 8				50	50	27
FERC Trf No. 8				40	40	28
FERC Trf No. 8				675	675	29
FERC Trf No. 8				8,164	8,164	30
FERC Trf No. 8				3,822	3,822	31
FERC Trf No. 8				595	595	32
FERC Trf No. 8				609	609	33
						34
			81	**3,293,560**	**3,293,560**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/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.
	175,036		175,036	1
	1,665		1,665	2
	6,487		6,487	3
106,395			106,395	4
	1,272		1,272	5
	2,161		2,161	6
	1,439		1,439	7
	96		96	8
	15,508		15,508	9
	38,544		38,544	10
	66		66	11
	1,529		1,529	12
	3,340		3,340	13
44,600			44,600	14
100,621			100,621	15
1,615			1,615	16
	3,416		3,416	17
	552		552	18
49,000			49,000	19
	92,103		92,103	20
	530		530	21
	526		526	22
	672		672	23
	177		177	24
	2,370		2,370	25
	1,655		1,655	26
	211		211	27
	194		194	28
	2,890		2,890	29
	34,005		34,005	30
	16,250		16,250	31
	2,594		2,594	32
	2,551		2,551	33
				34
7,914,641	**1,453,822**	**60,369**	**9,428,832**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/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	PPL Energy Plus	NorthWestern Montana	Puget Sound Energy	NF
2	Highland Energy	NorthWestern Montana	Grant County PUD	NF
3	Highland Energy	NorthWestern Montana	Bonneville Power Administration	NF
4	TransAlta Energy Marketing US	Bonneville Power Administration	NorthWestern Montana	NF
5	TransAlta Energy Marketing US	NorthWestern Montana	Bonneville Power Administration	NF
6	TransAlta Energy Marketing US	Bonneville Power Administration	Idaho Power Company	NF
7	TransAlta Energy Marketing US	Bonneville Power Administration	NorthWestern Montana	SFP
8	NaturEner USA	Bonneville Power Administration	NorthWestern Montana	SFP
9	NaturEner USA	NorthWestern Montana	Bonneville Power Administration	SFP
10	The Energy Authority	NorthWestern Montana	MID C	NF
11				
12				
13				
14				
15				
16				
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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) 04/16/2009	Year/Period of Report End of 2008/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				512	512	1
FERC Trf No. 8				120	120	2
FERC Trf No. 8				239	239	3
FERC Trf No. 8				85	85	4
FERC Trf No. 8				2,225	2,225	5
FERC Trf No. 8				150	150	6
FERC Trf No. 8				11,127	11,127	7
FERC Trf No. 8				2,975	2,975	8
FERC Trf No. 8				9,585	9,585	9
FERC Trf No. 8						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			81	3,293,560	3,293,560	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/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.
	2,100		2,100	1
	480		480	2
	956		956	3
	340		340	4
	10,118		10,118	5
	682		682	6
33,166			33,166	7
56,892			56,892	8
101,964			101,964	9
	224		224	10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
7,914,641	**1,453,822**	**60,369**	**9,428,832**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/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			1,172,808			1,172,808
2	Bonneville Power Admin	LFP			7,846,008		583,608	8,429,616
3	Bonneville Power Admin	LFP			788,745			788,745
4	Bonneville Power Admin	FNS			1,075,396		318,413	1,393,809
5	Bonneville Power Admin	OS					24,360	24,360
6	Bonneville Power Admin	SFP			3,404			3,404
7	Bonneville Power Admin	NF	28,815	28,815		125,015		125,015
8	Grant PUD	LFP			20,257			20,257
9	Kootenai Electric Coop	LFP			41,944			41,944
10	Northern Lights	LFP			135,820			135,820
11	NorthWestern Energy	NF	37,389	37,389		243,772	-61,549	182,223
12	Northwestern Energy	SFP			278,670			278,670
13	Portland General Elec	LFP			642,588			642,588
14	Portland General Elec	NF	616	616		924		924
15	Puget Sound Energy	NF	456	456		2,316		2,316
16	Rainbow Energy Mkt	NF	6,996	6,996		24,486		24,486
	TOTAL		211,202	211,202	12,005,640	761,528	864,832	13,632,000

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	04/16/2009	End of 2008/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Seattle City Light	NF	74,179	74,179		238,528		238,528
2	Snohomish PUD	NF	59,846	59,846		116,347		116,347
3	Tacoma Power	NF	2,905	2,905		10,140		10,140
4	TOTAL		211,202	211,202	12,005,640	761,528	864,832	13,632,000
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		211,202	211,202	12,005,640	761,528	864,832	13,632,000

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	04/16/2009	End of 2008/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	433,447
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	102,459
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	1,433,583
6	Community Relations	453,236
7	Education and Informational	19,691
8	Other Miscellaneous General Expenses	272,917
9	Directors Fees and Expense	469,967
10	Consulting Fees	13,312
11		
12		
13		
14		
15		
16		
17		
18		
19		
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21		
22		
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46	TOTAL	3,198,612

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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	04/16/2009	End of 2008/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			3,276,481		3,276,481
2	Steam Production Plant	10,309,774				10,309,774
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	7,341,157				7,341,157
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	8,772,317		2,450,031		11,222,348
7	Transmission Plant	9,266,249				9,266,249
8	Distribution Plant	24,527,250				24,527,250
9	Regional Transmission and Market Operation					
10	General Plant	2,615,229				2,615,229
11	Common Plant-Electric	4,889,212		721,491		5,610,703
12	TOTAL	67,721,188		6,448,003		74,169,191

B. Basis for Amortization Charges

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/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	50,447	65.00	-5.00	2.28	S1.5	17.88
15	312	75,399	60.00	-10.00	2.70	R1	18.57
16	314	19,854	50.00	-10.00	3.39	O1	28.07
17	315	9,381	55.00	-5.00	2.49	S1.5	20.78
18	316	8,819	50.00		2.26	R2	15.88
19	Subtotal	163,900					
20							
21	Colstrip No. 4						
22	311	49,599	65.00	-5.00	2.35	S1.5	21.32
23	312	47,069	60.00	-10.00	2.83	R1	23.84
24	314	14,550	50.00	-10.00	3.50	O1	28.31
25	315	6,685	55.00	-5.00	2.59	S1.5	25.11
26	316	4,193	50.00		2.46	R3	19.98
27	Subtotal	122,096					
28							
29	Kettle Falls						
30	310	148	35.00		2.19	SQ	
31	311	24,771	65.00	-5.00	2.34	S1.5	20.59
32	312	40,425	60.00	-10.00	3.31	R1	22.43
33	314	13,279	50.00	-10.00	3.18	O1	16.35
34	315	10,306	55.00	-5.00	2.74	S1.5	17.61
35	316	2,463	50.00		2.68	R2	21.44
36	Subtotal	91,392					
37							
38	HYDRO PLANT						
39	Cabinet Gorge						
40	330	7,725	75.00		2.75	R3	67.57
41	331	10,090	110.00	-5.00	1.62	R0.5	56.19
42	332	30,911	100.00		1.79	R1.5	77.96
43	333	37,427	60.00	-5.00	2.59	R1.5	52.14
44	334	5,471	45.00		1.43	R2.5	16.54
45	335	2,386	65.00		0.13	R1	1.20
46	336	1,099	60.00		2.05	S2.5	17.49
47	Subtotal	95,109					
48							
49	Noxon Rapids						
50	330	29,974	75.00		2.83	R3	69.37

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	331	12,884	110.00	-5.00	1.77	R0.5	81.53
13	332	31,871	100.00		1.79	R1.5	75.35
14	333	49,803	60.00	-5.00	2.89	R1.5	56.01
15	334	14,150	45.00		2.53	R2.5	43.88
16	335	2,672	65.00		0.97	R1	19.90
17	336	225	60.00		2.12	R2.5	39.60
18	Subtotal	141,579					
19							
20	Post Falls						
21	330	2,732	75.00		3.79	R3	56.46
22	331	1,274	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	685	45.00		0.14	R2.5	0.01
26	335	223	65.00		2.68	R1	53.83
27	Subtotal	13,192					
28							
29	Long Lake						
30	330	418	75.00		5.68	R3	45.63
31	331	1,845	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	2,822	45.00		0.82	R2.5	30.46
35	335	433	65.00		1.58	R1	30.46
36	Subtotal	30,980					
37							
38	Little Falls						
39	330	4,217	75.00		7.03	R3	56.31
40	331	928	110.00	-5.00	0.12	R0.5	2.00
41	332	5,025	100.00		1.51	R1.5	51.95
42	333	3,969	60.00	-5.00	0.51	R1.5	
43	334	1,975	45.00		0.93	R2.5	12.81
44	335	145	65.00		1.18	R1	19.46
45	Subtotal	16,259					
46							
47	Upper Falls						
48	330	64	75.00		2.48	R4	37.64
49	331	538	110.00	-5.00	0.12	R0.5	9.42
50	332	7,126	100.00		1.20	R1.5	76.61

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	333	1,136	60.00	-5.00	0.90	R1.5	6.67
13	334	2,094	45.00		1.85	R2.5	37.00
14	335	107	65.00		2.30	R1	51.46
15	Subtotal	11,065					
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	11,840	100.00		2.16	R1.5	72.53
21	333	9,465	60.00	-5.00	3.03	R1.5	56.34
22	334	2,637	45.00		2.57	R2.5	31.52
23	335	290	65.00		2.31	R1	45.87
24	336	625	60.00		2.64	S2.5	56.50
25	Subtotal	28,811					
26							
27	Monroe Street						
28	331	8,405	110.00	-5.00	1.82	R0.5	109.02
29	332	8,045	100.00		1.72	R1.5	99.22
30	333	11,018	60.00	-5.00	2.28	R1.5	60.23
31	334	1,653	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	29,205					
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	424	40.00		8.54	S1.5	11.83
43	346	300			1.24	SQ	
44	Subtotal	12,816					
45							
46	Rathdrum Turbine						
47	341	3,187			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

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	345	2,540	40.00		3.56	S1.5	
13	Subtotal	59,944					
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	725			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	30,094	45.00		2.84	R3	32.97
27	345	271	40.00		2.97	S1.5	31.24
28	346	7			2.69	SQ	
29	Subtotal	31,270					
30							
31	Coyote Springs 2						
32	341	11,341			2.76	SQ	
33	342	19,128	55.00		2.85	R3	44.23
34	344	116,410	45.00		2.92	R3	41.58
35	345	12,589	40.00		3.10	S1.5	32.07
36	346	1,037			2.76	SQ	
37	Subtotal	160,505					
38							
39	TRANSMISSION PLANT						
40	350	11,362	75.00		1.28	R4	53.27
41	352	15,750	60.00	-5.00	1.61	R4	44.73
42	353	172,930	47.00	-15.00	2.39	R3	31.13
43	354	17,098	70.00	-20.00	1.87	S3	43.89
44	355	128,395	60.00	-30.00	1.84	R3	37.27
45	356	103,821	60.00	-10.00	1.93	R3	43.30
46	357	2,606	60.00		1.58	R4	52.84
47	358	2,330	55.00		1.73	S3	41.27
48	359	1,872	65.00		1.65	R4	45.05
49	Subtotal	456,164					
50							

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	DISTRIBUTION PLANT						
13	361	12,262	55.00	-10.00	1.80	R3	35.51
14	362	86,204	42.00	-10.00	2.60	R1.5	28.26
15	364	196,777	50.00	-25.00	2.66	R2.5	34.66
16	365	129,268	50.00	-15.00	2.46	R2.5	35.35
17	366	71,349	45.00	-10.00	2.71	R3	36.09
18	367	115,566	28.00	-15.00	6.38	L4	23.05
19	368	159,546	44.00	-5.00	2.00	R2	27.21
20	369	110,109	60.00	-15.00	1.63	R3	38.01
21	370	44,273	38.00		2.39	S1	33.72
22	373	14,446	32.00	-15.00	1.08	R2.5	8.68
23	373.4	13,315	32.00	-5.00	2.82	R2.5	18.79
24	Subtotal	953,115					
25							
26	GENERAL PLANT						
27	390.1	2,175	55.00	-5.00	1.85	S2	20.91
28	391.1	718	5.00		17.67	SQ	3.80
29	393	328	25.00		2.25	SQ	22.97
30	394	3,353	20.00		4.22	SQ	10.35
31	395	1,389	15.00		7.72	SQ	7.82
32	397	36,464	15.00		5.40	SQ	5.17
33	398	3	10.00		2.37	SQ	7.80
34	Subtotal	44,430					
35							
36	MISC POWER						
37	392	1,518	11.00	10.00	3.70	S3	
38	396	2,506	15.00	10.00	5.40	L2	
39	Subtotal	4,024					
40							
41	TOTAL COMPANY	2,475,025					
42							
43							
44							
45							
46							
47							
48							
49							
50							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/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.	1,886,187	344,169	2,230,356	
5					
6					
7					
8					
9	Washington Utilities and Transportation				
10	Commission: includes annual fee and various				
11	other electric dockets	746,339	333,218	1,079,557	
12					
13	Includes annual fee and various other natural				
14	gas dockets	438,327	226,012	664,339	
15					
16	Idaho Public Utilities Commission				
17	Includes annual fee and various other electric				
18	dockets	509,718	240,302	750,020	
19					
20	Includes annual fee and various other natural				
21	gas dockets	218,450	114,501	332,951	
22					
23	Public Utility Commission of Oregon				
24	Includes annual fees and various other natural				
25	gas dockets	544,741	180,056	724,797	
26					
27	Not directly assigned electric		723,772	723,772	
28	Not directly assigned natural gas		282,026	282,026	
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
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40					
41					
42					
43					
44					
45					
46	TOTAL	4,343,762	2,444,056	6,787,818	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/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			Deferred to Account 182.3	Contra Account	Amount	Deferred in Account 182.3 End of Year	Line No.
Department (f)	Account No. (g)	Amount (h)	(i)	(j)	(k)	(l)	
							1
							2
							3
Electric	928	2,230,356					4
							5
							6
							7
							8
							9
							10
Electric	928	1,079,557					11
							12
							13
Gas	928	664,339					14
							15
							16
							17
Electric	928	750,020					18
							19
							20
Gas	928	332,951					21
							22
							23
							24
Gas		724,797					25
							26
Electric	928	723,772					27
Gas	928	282,026					28
							29
							30
							31
							32
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							44
							45
		6,787,818					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	04/16/2009	End of 2008/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	8,977,551		
4	Transmission	2,490,980		
5	Regional Market			
6	Distribution	4,626,264		
7	Customer Accounts	5,449,349		
8	Customer Service and Informational	339,599		
9	Sales	389,128		
10	Administrative and General	12,012,969		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	34,285,840		
12	Maintenance			
13	Production	2,380,308		
14	Transmission	833,610		
15	Regional Market			
16	Distribution	4,241,139		
17	Administrative and General			
18	TOTAL Maintenance (Total of lines 13 thru 17)	7,455,057		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	11,357,859		
21	Transmission (Enter Total of lines 4 and 14)	3,324,590		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	8,867,403		
24	Customer Accounts (Transcribe from line 7)	5,449,349		
25	Customer Service and Informational (Transcribe from line 8)	339,599		
26	Sales (Transcribe from line 9)	389,128		
27	Administrative and General (Enter Total of lines 10 and 17)	12,012,969		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	41,740,897	8,035,812	49,776,709
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply	752,515		
34	Storage, LNG Terminaling and Processing	8,397		
35	Transmission			
36	Distribution	3,864,070		
37	Customer Accounts	2,411,740		
38	Customer Service and Informational	162,043		
39	Sales	151,966		
40	Administrative and General	4,649,383		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	12,000,114		
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	499,826		

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DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution	2,068,178		
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	2,568,004		
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)	752,515		
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru	8,397		
56	Transmission (Lines 35 and 47)	499,826		
57	Distribution (Lines 36 and 48)	5,932,248		
58	Customer Accounts (Line 37)	2,411,740		
59	Customer Service and Informational (Line 38)	162,043		
60	Sales (Line 39)	151,966		
61	Administrative and General (Lines 40 and 49)	4,649,383		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	14,568,118	2,804,833	17,372,951
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	56,309,015	10,840,645	67,149,660
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	24,609,596	4,726,535	29,336,131
69	Gas Plant	6,599,555	1,267,514	7,867,069
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	31,209,151	5,994,049	37,203,200
72	Plant Removal (By Utility Departments)			
73	Electric Plant	908,961	171,862	1,080,823
74	Gas Plant	83,692	15,824	99,516
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	992,653	187,686	1,180,339
77	Other Accounts (Specify, provide details in footnote):			
78	Stores Expense	1,594,474	-1,594,474	
79	Regulatory Assets	214,454		214,454
80	Preliminary Survey and Investigation	-3,566		-3,566
81	Small Tool Expense	2,424,013	-2,424,013	
82	Miscellaneous Deferred Debits	23,023,863		23,023,863
83	Non-operating Expenses	396,265		396,265
84				
85	Expenditures of Certain Civic, Political and Related	238,729		238,729
86	Employee Incentive	3,015,100	-3,015,100	
87	DSM Tarrif Rider and Payroll Equilization Liability	15,086,274	-13,720,024	1,366,250
88	Incentive/ Stock Compensations	42,804		42,804
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	46,032,410	-20,753,611	25,278,799
96	TOTAL SALARIES AND WAGES	134,543,229	-3,731,231	130,811,998

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/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	25,135,774
389	Land and Land Rights	3,568,315
390	Structures and Improvements	42,073,255
391	Office Furniture and Equipment	25,951,182
392	Transportation Equipment	2,061,676
393	Stores Equipment	930,305
394	Tools, Shop & Garage Equipment	1,995,656
395	Laboratory Equipment	600,828
396	Power Operated Equipment	1,926,054
397	Communications Equipment	18,903,065
398	Miscellaneous Equipment	501,002
399	Asset Retirement Cost	351,680
	Total Common Plant	123,998,792
	Const. Work in Progress	7,663,152
	Total Utility Plant	131,661,944
	Acc. Prov. for Dep. & Amort.	31,229,906
	Net Utility Plant	100,432,038

3. Common Expense 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	924,600	490,861	433,739	# cust @ yr. end
902	Meter reading expenses	3,519,743	2,182,840	1,336,903	# cust @ yr. end
903	Cust rec & collection expenses	11,474,317	6,265,758	5,208,559	# cust @ yr. end
903.90-99	A/R Misc. fees	1,112,596	904,674	207,922	net direct plant
904	Uncollectible accounts	3,631,011	1,927,667	1,703,343	# cust @ yr. end
905	Misc cust acct expenses	277,767	147,464	130,303	# cust @ yr. end
907	Cust srvc & info exp supervision	0	0	0	# cust @ yr. end
908	Cust assistance exp	819,933	508,495	311,438	# cust @ yr. end
909	Info & instruct advert expenses	88,132	47,299	40,833	# cust @ yr. end
910	Misc cust srvc & info	234,286	145,297	88,989	# cust @ yr. end

COMMON UTILITY PLANT AND EXPENSES

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

	expenses				
911	Sales expense sprvsn	0	0	0	# cust @ yr. end
912	Demo and selling exp	685,017	424,827	260,190	# cust @ yr. end
913	Advertising expenses	206,637	128,150	78,487	# cust @ yr. end
916	Misc sales expense	344,340	213,550	130,791	# cust @ yr. end
920	Admin & gen salaries	25,038,044	18,072,846	6,965,197	four factor
921	Office supplies & expenses	0	0	0	four factor
922	Admin expenses tranf-cred	5,089,802	3,664,899	1,424,903	four factor
923	Outside srvcs employed	15,007,852	10,799,795	4,208,058	four factor
924	Property insurance	1,138,330	819,142	319,188	four factor
925	Injuries & damages	5,750,714	4,281,058	1,469,656	four factor
926	Employee pensions & benefits	35,981,195	25,983,616	9,997,579	four factor
927	Franchise requirement	0	0	0	four factor
928	Regulatory commission expenses	1,005,797	723,772	282,026	four factor
929	Duplicate charges - credit	0	0	0	four factor
930.1	General advertising exp	5,077	4,017	1,060	four factor
930.2	Misc general expenses	4,202,376	3,078,544	1,123,832	four factor
931	Rents	787,601	557,706	229,894	four factor
935	Maint of general plant	7,752,899	5,649,014	2,103,885	four factor
403	Depreciation	6,704,799	4,889,213	1,815,587	four factor
404	Amort of LTD term plant	4,552,272	3,276,482	1,275,790	four factor

Note 1: The four factor allocator is made up of 25 percent each of customer counts, direct labor, direct O&M, and net direct plant.

4. Letters of approval received from staffs of State Regulatory Commissions in 1993

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2009	Year/Period of Report End of 2008/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	333	MW	134,770			
2	Reactive Supply and Voltage	333	MW	408			
3	Regulation and Frequency Response	141,561	MWh	80,785	72,155	MW	645,068
4	Energy Imbalance				840	MW	3,006,328
5	Operating Reserve - Spinning	77,358	MWh	1,498,374	46,190	MWh	608,723
6	Operating Reserve - Supplement	853	MWh	6,764	58,179	MWh	710,031
7	Other	1,357,884	MW	12,139,479	1,357,884	MW	12,139,479
8	Total (Lines 1 thru 7)	1,578,322		13,860,580	1,535,248		17,109,629

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2009	Year/Period of Report End of 2008/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	2,039	23	800	1,646	369	168	35	94	332
2	February	1,782	5	1900	1,460	297	168	13	8	13
3	March	1,652	25	800	1,353	267	168	35	12	
4	Total for Quarter 1	5,473			4,459	933	504	83	114	345
5	April	1,589	1	900	1,301	262	168	35	77	
6	May	1,495	19	1400	1,232	218	169	40	276	375
7	June	1,862	30	1600	1,533	275	171	54	525	49
8	Total for Quarter 2	4,946			4,066	755	508	129	878	424
9	July	1,797	3	1600	1,462	267	171	53	383	75
10	August	1,903	18	1600	1,567	284	170	43	165	
11	September	1,457	19	1700	1,202	211	170	41	66	128
12	Total for Quarter 3	5,157			4,231	762	511	137	614	203
13	October	1,544	29	800	1,271	246	169	20	38	
14	November	1,626	24	1800	1,339	253	166	60	43	
15	December	2,191	16	1900	1,770	384	166	39	77	
16	Total for Quarter 4	5,361			4,380	883	501	119	158	
17	Total Year to Date/Year	20,937			17,136	3,333	2,024	468	1,764	972

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ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY	
2	Generation (Excluding Station Use):	
3	Steam	1,958,082
4	Nuclear	
5	Hydro-Conventional	3,851,251
6	Hydro-Pumped Storage	
7	Other	1,734,908
8	Less Energy for Pumping	
9	Net Generation (Enter Total of lines 3 through 8)	7,544,241
10	Purchases	5,686,485
11	Power Exchanges:	
12	Received	718,926
13	Delivered	720,744
14	Net Exchanges (Line 12 minus line 13)	-1,818
15	Transmission For Other (Wheeling)	
16	Received	3,293,560
17	Delivered	3,293,560
18	Net Transmission for Other (Line 16 minus line 17)	
19	Transmission By Others Losses	
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	13,228,908

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	9,029,319
23	Requirements Sales for Resale (See instruction 4, page 311.)	
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	3,566,073
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	9,705
27	Total Energy Losses	623,811
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	13,228,908

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2009	Year/Period of Report End of 2008/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 on line 2 by month the system's output in Megawatt hours for each month.
(3) Report on line 3 by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
(4) Report on line 4 by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
(5) Report on lines 5 and 6 the specified information for each monthly peak load reported on line 4.

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	1,105,963	134,731	1,705	23	800
30	February	1,000,743	163,745	1,509	5	1900
31	March	1,244,292	407,272	1,397	25	800
32	April	1,000,410	235,222	1,345	1	900
33	May	1,125,257	398,014	1,255	19	1400
34	June	1,122,422	410,743	1,568	30	1600
35	July	1,302,391	502,218	1,492	2	1600
36	August	1,012,735	230,104	1,602	18	1600
37	September	885,426	184,688	1,224	19	1700
38	October	1,009,099	248,685	1,303	29	800
39	November	1,101,927	316,093	1,373	24	1800
40	December	1,318,243	334,558	1,821	16	1900
41	TOTAL	13,228,908	3,566,073			

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Coyote Springs 2* (b)			Plant Name: *Spokane N.E.* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Not Applicable			Not Applicable		
3	Year Originally Constructed	2003			1978		
4	Year Last Unit was Installed	2003			1978		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	287.00			61.80		
6	Net Peak Demand on Plant - MW (60 minutes)	307			30		
7	Plant Hours Connected to Load	6675			82		
8	Net Continuous Plant Capability (Megawatts)	279			61		
9	When Not Limited by Condenser Water	279			0		
10	When Limited by Condenser Water	279			0		
11	Average Number of Employees	22			1		
12	Net Generation, Exclusive of Plant Use - KWh	1696319000			2154000		
13	Cost of Plant: Land and Land Rights	0			129664		
14	Structures and Improvements	11340586			365280		
15	Equipment Costs	149164262			13182384		
16	Asset Retirement Costs	351682			0		
17	Total Cost	160856530			13677328		
18	Cost per KW of Installed Capacity (line 17/5) Including	560.4757			221.3160		
19	Production Expenses: Oper, Supv, & Engr	1339059			9496		
20	Fuel	103444188			267937		
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	1257794			50469		
26	Misc Steam (or Nuclear) Power Expenses	8849			4288		
27	Rents	67255			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	263092			22359		
30	Maintenance of Structures	0			1673		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	4492709			82586		
33	Maintenance of Misc Steam (or Nuclear) Plant	200			14315		
34	Total Production Expenses	110873146			453123		
35	Expenses per Net KWh	0.0654			0.2104		
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	11609569	0	0	27740	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	8.910	0.000	0.000	9.659	0.000	0.000
41	Average Cost of Fuel per Unit Burned	8.910	0.000	0.000	9.659	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	8.736	0.000	0.000	9.469	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.061	0.000	0.000	0.124	0.000	0.000
44	Average BTU per KWh Net Generation	6981.000	0.000	0.000	13136.000	0.000	0.000

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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/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
5064	8780	126	7
50	222	149	8
50	222	0	9
49	222	0	10
30	210	2	11
200423000	1757659000	13067000	12
941300	1290825	621682	13
24770695	100045629	3186951	14
66472954	185950687	56756800	15
450687	134589	0	16
92635636	287421730	60565433	17
1827.1329	1231.4556	363.7564	18
176760	177078	134188	19
7522699	21253774	1332065	20
0	0	1332065	21
557765	1322868	0	22
0	0	0	23
0	0	0	24
769802	44456	143933	25
427189	2945137	86483	26
0	38367	0	27
0	0	0	28
108780	345391	37632	29
90985	435332	1492	30
1124664	3752319	0	31
222484	322054	139334	32
165897	471195	57891	33
11167025	31107971	3265083	34
0.0557	0.0177	0.2499	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
WOOD	GAS		Coal	Oil		GAS			36
TONS	MCF		Tons	Bbls		MCF			37
302536	2386	0	1124845	954	0	158815	0	0	38
8500000	1020000	0	16781000	140000	0	1020000	0	0	39
24.790	9.556	0.000	18.771	145.989	0.000	8.388	0.000	0.000	40
24.790	9.556	0.000	18.771	145.989	0.000	8.388	0.000	0.000	41
2.920	9.369	0.000	1.120	24.650	0.000	8.223	0.000	0.000	42
0.038	0.112	0.000	0.012	0.000	0.000	0.102	0.000	0.000	43
12844.000	0.000	0.000	10747.000	0.000	0.000	12397.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/Q4

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

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Boulder Park* (b)	Plant Name: (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Internal Comb	
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional	
3	Year Originally Constructed	2002	
4	Year Last Unit was Installed	2002	
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	24.60	0.00
6	Net Peak Demand on Plant - MW (60 minutes)	25	0
7	Plant Hours Connected to Load	1109	0
8	Net Continuous Plant Capability (Megawatts)	25	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	20606000	0
13	Cost of Plant: Land and Land Rights	144733	0
14	Structures and Improvements	724602	0
15	Equipment Costs	30545079	0
16	Asset Retirement Costs	0	0
17	Total Cost	31414414	0
18	Cost per KW of Installed Capacity (line 17/5) Including	1277.0087	0.0000
19	Production Expenses: Oper, Supv, & Engr	10669	0
20	Fuel	1838037	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	95084	0
26	Misc Steam (or Nuclear) Power Expenses	5437	0
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	45239	0
30	Maintenance of Structures	233	0
31	Maintenance of Boiler (or reactor) Plant	0	0
32	Maintenance of Electric Plant	193808	0
33	Maintenance of Misc Steam (or Nuclear) Plant	37338	0
34	Total Production Expenses	2225845	0
35	Expenses per Net KWh	0.1080	0.0000

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	GAS					
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF					
38	Quantity (Units) of Fuel Burned	194238	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	9.463	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	9.463	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	9.277	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.089	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	9615.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2009	Year/Period of Report End of 2008/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
									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

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	8,386	8,692
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	16	11
10	(b) Under the Most Adverse Oper Conditions	14	9
11	Average Number of Employees	1	1
12	Net Generation, Exclusive of Plant Use - Kwh	104,210,000	77,977,000
13	Cost of Plant		
14	Land and Land Rights	0	1,081,854
15	Structures and Improvements	8,405,476	538,257
16	Reservoirs, Dams, and Waterways	8,045,079	7,126,169
17	Equipment Costs	12,704,055	3,337,508
18	Roads, Railroads, and Bridges	50,448	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	29,205,058	12,083,788
21	Cost per KW of Installed Capacity (line 20 / 5)	1,973.3147	1,208.3788
22	Production Expenses		
23	Operation Supervision and Engineering	36,448	35,792
24	Water for Power	43	0
25	Hydraulic Expenses	2,278	14,602
26	Electric Expenses	403,049	396,978
27	Misc Hydraulic Power Generation Expenses	64,033	78,076
28	Rents	0	0
29	Maintenance Supervision and Engineering	2,228	279
30	Maintenance of Structures	7,190	-3,613
31	Maintenance of Reservoirs, Dams, and Waterways	169,958	28,089
32	Maintenance of Electric Plant	37,419	42,731
33	Maintenance of Misc Hydraulic Plant	2,472	367
34	Total Production Expenses (total 23 thru 33)	725,118	593,301
35	Expenses per net KWh	0.0070	0.0076

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/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	530	90	6
8,780	6,775	7,033	7
			8
261	530	90	9
189	277	81	10
12	13	5	11
1,080,836,000	1,696,459,000	496,845,000	12
			13
9,913,802	35,831,528	1,597,959	14
10,089,656	12,883,459	1,845,328	15
30,910,987	31,859,561	16,637,951	16
45,284,673	66,624,841	12,079,416	17
1,098,564	225,369	0	18
0	0	0	19
97,297,682	147,424,758	32,160,654	20
367.1611	306.7515	459.4379	21
			22
108,175	89,326	1,034	23
0	0	0	24
2,185	50,496	7,403	25
973,287	981,924	570,425	26
206,013	162,303	63,681	27
0	0	0	28
33,490	37,341	5,756	29
90,909	99,777	75,999	30
32,852	33,132	20,243	31
205,707	883,830	161,443	32
64,929	37,437	2,140	33
1,717,547	2,375,566	908,124	34
0.0016	0.0014	0.0018	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	04/16/2009	End of 2008/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)	20	18
7	Plant Hours Connect to Load	8,752	8,780
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	20	18
10	(b) Under the Most Adverse Oper Conditions	9	12
11	Average Number of Employees	1	2
12	Net Generation, Exclusive of Plant Use - Kwh	104,892,000	85,518,000
13	Cost of Plant		
14	Land and Land Rights	33,429	3,076,554
15	Structures and Improvements	3,943,110	1,274,575
16	Reservoirs, Dams, and Waterways	11,840,543	6,044,594
17	Equipment Costs	12,391,557	3,141,665
18	Roads, Railroads, and Bridges	625,181	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	28,833,820	13,537,388
21	Cost per KW of Installed Capacity (line 20 / 5)	1,092.1902	914.6884
22	Production Expenses		
23	Operation Supervision and Engineering	44,863	28,138
24	Water for Power	0	0
25	Hydraulic Expenses	1,018	103
26	Electric Expenses	427,685	386,919
27	Misc Hydraulic Power Generation Expenses	145,046	130,430
28	Rents	0	0
29	Maintenance Supervision and Engineering	52,891	458
30	Maintenance of Structures	10,156	1,000
31	Maintenance of Reservoirs, Dams, and Waterways	117,149	45,374
32	Maintenance of Electric Plant	314,998	123,702
33	Maintenance of Misc Hydraulic Plant	6,014	419
34	Total Production Expenses (total 23 thru 33)	1,119,820	716,543
35	Expenses per net KWh	0.0107	0.0084

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2009	Year/Period of Report End of 2008/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: Little Falls (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
Run-of-River			1
Conventional			2
1910			3
1911			4
32.00	0.00	0.00	5
37	0	0	6
7,032	0	0	7
			8
37	0	0	9
36	0	0	10
5	0	0	11
204,514,000	0	0	12
			13
4,325,371	0	0	14
928,141	0	0	15
5,025,360	0	0	16
6,088,106	0	0	17
0	0	0	18
0	0	0	19
16,366,978	0	0	20
511.4681	0.0000	0.0000	21
			22
401	0	0	23
0	0	0	24
13,388	0	0	25
523,079	0	0	26
37,311	0	0	27
640,574	0	0	28
57,640	0	0	29
28,700	0	0	30
106,845	0	0	31
132,014	0	0	32
4,688	0	0	33
1,544,640	0	0	34
0.0076	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	04/16/2009	End of 2008/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	04/16/2009	End of 2008/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	04/16/2009	End of 2008/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	2,762,000	9,169,338
2						
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7						
8						
9						
10						
11						
12						
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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	04/16/2009	End of 2008/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	132,955	292,805	21,896	Nat Gas	909	1
						2
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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	04/16/2009	End of 2008/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		1,548.00		
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	2,215.00	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	04/16/2009	End of 2008/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
	8,434,651	88,411,161	96,845,812	468,900	663,579	584	1,133,063	3
								4
795 McMACSR	17,913	1,334,573	1,352,486		6,276		6,276	5
1272 McMACSR								6
1272 ACSS								7
1272 ACSS	30,323	3,280,805	3,311,128	1,025	7,852		8,877	8
795 McMACSR								9
1590 ACSS								10
795 McMACSR	324,327	36,013,172	36,337,499		26,329		26,329	11
795 McMACSR								12
1272 McMAL	456,162	6,758,366	7,214,528	30,161	10,635		40,796	13
1590 ACSS	570,207	47,025,179	47,595,386	1,981	3,175		5,156	14
954 McMAL	105,647	17,385,076	17,490,723	9,502	57,278		66,780	15
954 McMAL	49,049	1,066,610	1,115,659		4,588		4,588	16
954 McMAL								17
954 McMAL	157,193	2,600,653	2,757,846	7,071	20,580		27,651	18
1272 McMAL								19
1272 McMAL	86,228	3,660,550	3,746,778	423	16,000		16,423	20
1272 McMAL								21
1272 McMAL	623,984	6,153,355	6,777,339	13,625	5,806		19,431	22
1272 McMAL								23
1272 McMAL	872,151	8,065,713	8,937,864	4,639			4,639	24
1272 McMAL								25
1272 McMAL	70,781	2,552,486	2,623,267	22,497	40,460		62,957	26
1272 McMAL								27
1272 McMAL		19,521	19,521		5,832		5,832	28
1272 McMAL								29
1272 McMAL	144,638	3,287,453	3,432,091	2,150	61,183		63,333	30
1272 McMAL	36,461	594,543	631,004		2,667		2,667	31
1272 McMACSR	106,581	2,517,780	2,624,361					32
1272 McMAL	60,302	1,297,448	1,357,750					33
	595,789	28,743,579	29,339,368	44,275	461,390	68,206	573,871	34
								35
	12,878,425	260,838,115	273,716,540	606,249	1,393,630	68,790	2,068,669	36

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2009	Year/Period of Report End of 2008/Q4

TRANSMISSION LINES ADDED DURING YEAR

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

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	Benewah	Shawnee	45.00	Steel Pole	8.00	1	1
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
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32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		45.00		8.00	1	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	04/16/2009	End of 2008/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	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
1590	ACSS	SDC-20.79	230	468	-1,592	409,732		408,608	1
									2
									3
									4
									5
									6
									7
									8
									9
									10
									11
									12
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									37
									38
									39
									40
									41
									42
									43
				468	-1,592	409,732		408,608	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	04/16/2009	End of 2008/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. Unattended	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 Gulch	Distr. Unattended	115.00	13.80	
14	East Colfax	Distr. Unattended	115.00	13.80	
15	East Farms	Distr. Unattended	115.00	13.80	
16	Fort Wright	Distr. Unattended	115.00	13.80	
17	Francis and Cedar	Distr. Unattended	115.00	13.80	
18	Gifford	Distr. Unattended	115.00	34.00	
19	Glenrose	Distr. Unattended	115.00	13.80	
20	Greenwood	Distr. Unattended	115.00	13.80	
21	Hallett & White 115-13kv	Distr. Unattended	115.00	13.80	
22	Indian Trail	Dist. Unattended	115.00	13.80	
23	Industrial Park	Distr. Unattended	115.00	13.80	
24	Kettle Falls	Distr. Unattended	115.00	13.80	
25	Lee & Reynolds	Distr. Unattended	115.00	13.80	
26	Liberty Lake	Distr. Unattended	115.00	13.80	
27	Little Falls 115/34Kv	Distr. Unattended	115.00	34.00	
28	Lyons & Standard	Distr. Unattended	115.00	13.80	
29	Mead	Distr. Unattended	115.00	13.80	
30	Metro	Distr. Unattended	115.00	13.80	
31	Milan	Distr. Unattended	115.00	13.80	
32	Millwood	Trnsm & Dist Unattd	115.00	60.00	13.80
33	Ninth & Central	Distr. Unattended	115.00	13.80	
34	Northeast	Distr. Unattended	115.00	13.80	
35	Northwest	Distr. Unattended	115.00	13.80	
36	Opportunity	Dist. Unattended	115.00	13.80	
37	Othello	Distr. Unattended	115.00	13.80	
38	Post Street	Distr. Unattended	115.00	13.80	
39	Pound Lane	Distr. Unattended	115.00	13.80	
40	Pullman	Dist Unattended	115.00	13.80	

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
						2
24	2		Frcd Oil & Air Fan	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		Frcd Air	3	15	8
12	1		Frcd Oil & Air Fan	1	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
24	2		Frcd Oil & Air Fan	2	40	13
12	1		FrOil/Air Fan	1	20	14
12	1		Two Stage Fan	1	20	15
24	2		Fr Oil/Air/2StgFan	2	40	16
60	2		Frcd Air Fan	2	36	17
12	1					18
12	1		Frcd Oil & Air Fan	1	20	19
13	4	1	FrOil/Air/Two Stage	4	22	20
12	1		Two Stg Fan	1	20	21
12	1		Two Stage Fan	1	20	22
28	3		Two Stg/Pt/Frcd Oil	40	40	23
12	1		Frcd Oil & Air Fan	1	20	24
12	1		Two Stage Fan	1	20	25
24	2		Two Stage Fan	2	40	26
12	1					27
36	2		Two Stage Fan	2	60	28
18	1		Two Stage Fan	1	30	29
24	2		Two Stage Fan	2	40	30
24	2		Frcd Oil & Air Fan	2	40	31
44	3	1	FrcAir/FrcOil/AirFan	3	61	32
24	2	1	Frcd & Two Stage Fan	2	40	33
24	2		Two Stage Fan	2	40	34
24	2		Two Stage Fan	2	40	35
12	1		Two Stage Fan	1	20	36
24	2		FrOil/AirFan	2	40	37
95	4		Frcd Oil & Wt Fan	4	95	38
24	2		Two Stage Fan	2	40	39
24	2		Frcd Oil & Air Fan	2	40	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	04/16/2009	End of 2008/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	Ross Park	Distr. Unattended	115.00	13.80	
2	Roxboro	Distr. Unattended	115.00	24.00	
3	Shawnee	Trans. Unattended	230.00	115.00	
4	Silver Lake	Distr. Unattended	115.00	13.80	
5	Southeast	Distr. Unattended	115.00	13.80	
6	South Othello	Distr. Unattended	115.00	13.80	
7	South Pullman	Distr. Unattended	115.00	13.80	
8	Sunset	Distr. Unattended	115.00	13.80	
9	Third & Hatch	Distr. Unattended	115.00	13.80	
10	Waikiki	Distr. Unattended	115.00	13.80	
11	Washington State University-East Campus	Distr. Unattended	13.80	4.16	
12	West Side	Trans. Unattended	230.00	115.00	13.80
13	Other: 72substa less than 10MVA	Distr. Unattended			
14					
15	STATE OF IDAHO				
16	Appleway	Dist & Trfr Unattnd	115.00	13.80	
17	Avondale	Dist. Unattended	115.00	13.80	
18	Benewah	Trans. Unattended	230.00	115.00	13.80
19	Big Creek	Distr. Unattended	115.00	13.80	
20	Blue Creek	Distr. Unattended	115.00	13.80	
21	Bunker Hill	Distr. Unattended	115.00	13.80	
22	Clark Fork	Distr. Unattended	115.00	21.80	
23	Coeur d'Alene 15th Ave	Distr. Unattended	115.00	13.80	
24	Cottonwood	Distr. Unattended	115.00	24.90	
25	Dalton	Distr. Unattended	115.00	13.80	
26	Grangeville	Dist & Trfr Unattnd	115.00	13.80	
27	Holbrook	Distr. Unattended	115.00	13.80	
28	Huetter	Distr. Unattended	115.00	13.80	
29	Juliaetta	Distr. Unattended	115.00	13.80	
30	Kamiah	Dist & Trfr Unattnd	115.00	13.80	
31	Kooskia	Distr. Unattended	115.00	13.80	
32	Lolo	Tran & Dist Unattnd	230.00	115.00	13.80
33	Moscow	Distr. Unattended	115.00	13.80	
34	Moscow 230Kv	Tran & Dist Unattnd	230.00	115.00	13.80
35	North Moscow	Distr. Unattended	115.00	13.80	
36	North Lewiston	Trans Unattended	230.00	115.00	13.80
37	North Lewiston	Distr. Unattended	115.00	13.80	
38	Oden	Distr. Unattended	115.00	21.80	
39	Oldtown	Distr. Unattended	115.00	21.80	
40	Orofino	Distr. Unattended	115.00	13.80	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/16/2009	End of 2008/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.
30	2		Two Stage Fan	2	60	1
24	2		Two Stage Fan	2	40	2
250	1					3
12	1		Frcd Oil & Air Fan	1	20	4
30	2		Two Stage Fan	2	50	5
12	1		Two Stage Fan	1	20	6
30	2		Two Stage Fan	240	50	7
35	4	1	Pt. & Two Stage Fan	4	50	8
54	3		Two Stg Fan & Cap	103	90	9
24	2		Two Stage Fan	2	40	10
15	2		Two Stage Fan	2	19	11
250	2					12
193	137					13
						14
						15
30	2		Two Stage Fan	2	50	16
12	1		Frcd Oil & Air Fan	1	20	17
75	1		Two Stage Fan	1	125	18
17	2		Portable Fan	2	22	19
20	3	1				20
12	1		Frcd Air Fan	1	26	21
10	1		Frcd Air Fan	1	13	22
36	2		Two Stage Fan	2	60	23
12	1		Two Stage Fan	1	20	24
24	2		FrcOil/Air2StgFan	2	40	25
25	4		FrcdOil/Air/Pt Fan	2	34	26
12	1		Two Stage Fan	1	20	27
12	1		Two Stage Fan	1	20	28
12	1		Frcd Oil & Air Fan	1	20	29
12	1		Two Stage Fan	1	20	30
15	3		Frcd Air Fan	2	20	31
270	3		Frcd Oil/Air/Two Stg	1	262	32
24	2		FrOil/Air/2Stg Fan	2	40	33
137	2	1	Capacitors	80	182	34
12	1		Two Stage Fan	1	20	35
250	1	1	Frcd Oil/Air&Cptrs	81	295	36
10	3					37
10	1		Frcd Air Fan		13	38
10	1		Frcd Air Fan	1	13	39
20	2		Frcd Oil & Air Fan	1	28	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	04/16/2009	End of 2008/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	Osburn	Distr. Unattended	115.00	13.80	
2	Pine Creek	Tran & Dist Unattnd	230.00	110.00	13.80
3	Pleasant View	Distr. Unattended	115.00	13.80	
4	Post Falls	Distr. Unattended	115.00	13.80	
5	Potlatch	Dist & Trfr Unattnd	115.00	13.80	
6	Prarie	Distr. Unattended	115.00	13.80	
7	Priest River	Distr. Unattended	115.00	20.80	
8	Sagle	Dist. Unattended	115.00	20.80	
9	Sandpoint	Distr. Unattended	115.00	20.80	
10	South Lewiston	Distr. Unattended	115.00	13.80	
11	Sweetwater	Distr. Unattended	115.00	24.00	
12	St. Maries	Distr. Unattended	115.00	24.00	
13	Tenth & Stewart	Distr. Unattended	115.00	13.80	
14	Wallace	Dist & Whse Unattnd	115.00	13.80	
15	Rathdrum	Tran & Dist Unattnd	230.00	115.00	13.80
16	Other: 29 substa less than 10 MVA	Distr. Unattended			
17					
18	STATE OF MONTANA				
19	1 substation less than 10 MVA	Distr. Unattended			
20					
21	SUBSTA. @ GENERATING PLANTS				
22	STATE OF WASHINGTON				
23	Boulder Park	Trans Step-Up	115.00	13.80	
24	Kettle Falls	Trans Step-Up	115.00	13.80	
25	Long Lake	Trans.	115.00	4.00	4.00
26	Nine Mile	Trns Step-Up & Dist	115.00	60.00	2.30
27	Little Falls	Trans.	115.00	4.00	
28	Northeast	Trans. Step-Up	115.00	13.80	
29					
30	STATE OF IDAHO				
31	Cabinet Gorge (Switchyard)		230.00	115.00	13.80
32	Cabinet Gorge (HED)	Trans. Step-Up	230.00	13.80	
33	Post Falls	Trans. Step-Up	115.00	2.30	
34	Rathdrum	Trans. Step-Up	115.00	13.80	
35	STATE OF MONTANA				
36	Noxon	Trans. Step-Up	230.00	13.80	
37					
38	STATE OF OREGON				
39	Coyote Springs II	Trans. Step -Up	500.00	13.80	18.00
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	04/16/2009	End of 2008/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.
12	1		Portable Fan	1	15	1
262	3		Capacitors	80	307	2
12	1		Two Stage Fan	1	20	3
18	1		Two Stage Fan	1	30	4
15	2		Portable Fan	2	19	5
12	1		Frcd Oil & Air Fan	1	20	6
10	1	1	Frcd Air Fan	1	13	7
12	1		Two Stage Fan	1	20	8
30	3		Frcd Air Fan	3	38	9
27	4		Port Fan/FrcdOil/Air	4	39	10
12	1		Frcd Oil & Air Fan	1	20	11
24	2		Two Stage Fan	2	40	12
30	2		Frcd Oil/Air/Two Stg	2	50	13
10	3					14
462	3		FrcdOil/AirFan/Cptrs	243	470	15
82	47	1				16
						17
						18
5	1					19
						20
						21
						22
36	1		Two Stage Fan	1	60	23
30	1	1	Two Stage Fan	1	62	24
80	4	1				25
18	2		Frcd Oil & Air Fan	1	40	26
24	2		Frcd Oil & Air Fan	2	40	27
36	1		Two Stage Fan	1	60	28
						29
						30
125	1		2 stage fan	1	13	31
30	6	1	Frcd Oil and Air Fan	2	30	32
16	2		Frcd Air/Oil/Air Fan	2	21	33
114	2	3	Two Stage Fan	2	190	34
						35
532	9	1	Frcd Oil Air	6	555	36
						37
						38
213	1	1	Two Stage fan	2	355	39
						40

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2009	Year/Period of Report End of 2008/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	SUMMARY:				
2	Washington:				
3	10 subs	Trans. Unattended			
4	116 subs	Distr. Unattended			
5	3 subs	Tran & Dist Unattnd			
6	Idaho:				
7	6 subs	Trans. Unattended			
8	58 subs	Distr. Unattended			
9	9 subs	Tran & Dist Unattnd			
10	Montana: 1 sub	Trans. Unattended			
11	1 sub	Distr. Unattended			
12	Oregon: 1 sub	Trans. Unattended			
13	System: 205 subs				
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
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36					
37					
38					
39					
40					

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2009	Year/Period of Report End of 2008/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
						2
1189						3
1221						4
604						5
						6
660						7
511						8
1222						9
533						10
5						11
213						12
6158						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
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						30
						31
						32
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						39
						40

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

Includes Accum Provision of non-recoverable plant of <$291,550> and FAS 143 depreciation of $22,019

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

Includes change in Removal Work in Process of $96,737

Schedule Page: 224 Line No.: 5 Column: f

Line 5 - Avista Capital - Other changes in Net Investment:
Represents the liability to non-controlling interest at Advantage IQ

Schedule Page: 224 Line No.: 6 Column: f

Line 6 - Avista Capital - Other changes in Net Investment:
Represents the change in controlling ownership of Advantage IQ

Name of Respondent Avista Corporation	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2009	Year/Period of Report 2008/Q4

FOOTNOTE DATA

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

Schedule Page: 231 Line No.: 2 Column: d
Total Reimbursements Received Life to Date.

Schedule Page: 231 Line No.: 3 Column: b
Total Charges Incurred Life to Date.

Schedule Page: 231 Line No.: 3 Column: d
Total Reimbursements Received Life to Date.

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

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

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

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

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

Schedule Page: 231 Line No.: 24 Column: d
Total Reimbursements Received Life to Date.

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

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

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

Schedule Page: 231 Line No.: 28 Column: b
Total Charges Incurred Life to Date.

Schedule Page: 231 Line No.: 29 Column: b
Total Charges Incurred Life to Date.

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

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

Schedule Page: 231 Line No.: 32 Column: b
Total Charges Incurred Life to Date.

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: 256 Line No.: 22 Column: h

Background

On December 31, 2008, the City of Forsyth, Montana Pollution Control Revenue Refunding Bonds, Series 1999A (Avista Corporation Colstrip Project) due 2034 were remarketed on behalf of Avista Corp. in the amount of $66.7 million. 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.

The trust Indenture indicates the following:

THE BONDS SHALL NOT BE DEEMED TO CONSTITUTE A DEBT, LIABILITY OR GENERAL OBLIGATION OF THE ISSUER, THE STATE OR OF ANY POLITICAL SUBDIVISION THEREOF, OR A PLEDGE OF THE FAITH AND CREDIT OF THE ISSUER, THE STATE OR OF ANY SUCH POLITICAL SUBDIVISION, BUT SHALL BE PAYABLE SOLELY FROM THE REVENUES AND PROCEEDS PROVIDED THEREFOR. THE ISSUER SHALL NOT BE OBLIGATED TO PAY THE SAME NOR INTEREST THEREON EXCEPT FROM THE REVENUES AND PROCEEDS PLEDGED THEREFOR, AND NEITHER THE FAITH AND CREDIT NOR THE TAXING POWER OF THE ISSUER, THE STATE OR OF ANY POLITICAL SUBDIVISION THEREOF IS PLEDGED TO THE PAYMENT OF THE PRINCIPAL OF OR THE INTEREST ON THE BONDS.

Accounting Guidance

SFAS 140 paragraph 16 indicates that there are specific criteria that must be met in order to remove a liability from the financial statements.

Paragraph 16 - A debtor shall derecognize a liability if and only if it has been extinguished. A liability has been extinguished if either of the following conditions is met:

a. The debtor pays the creditor and is relieved of its obligation for the liability. Paying the creditor includes delivery of cash, other financial assets, goods, or services or reacquisition by the debtor of its outstanding debt securities whether the securities are canceled or held as so-called treasury bonds.

b. The debtor is legally released from being the primary obligor under the liability, either judicially or by the creditor.

Conclusion

The $66.7 million of pollution control bonds should be excluded from Avista Corp's balance sheet based upon the following:

Avista Corp. has effectively paid the creditors by purchasing the outstanding Bonds, which meets the requirements of paragraph 16a.

Although the Bonds are not in Avista Corp's name, the trust indenture indicates that the Bonds shall not be deemed to be an obligation of the issuer (the City of Forsyth). The bonds are effectively a "conduit bond" which indicates they are the obligation of Avista Corp. Therefore, the reacquisition of bonds that Avista Corp is the primary obligor would meet the requirements of paragraph 16a to extinguish the bonds.

Schedule Page: 256 Line No.: 31 Column: h

The $272,860,000 Senior Notes matured June 1, 2008.

Schedule Page: 261 Line No.: 8 Column: a

Schedule Page: 261 Line No: 5 Column: b

Taxable Income Not Reported on Books

Tax NOT Book Income	BPA C&RD Receipts	-
Tax NOT Book Income	Contributions in Aid of Construction - Electric	6,259,362
Tax NOT Book Income	CSS Temp Service Fees - ID	54,920
Tax NOT Book Income	CSS Temp Service Fees - WA	73,800
Tax NOT Book Income	Customer Uncollectibles - Sales for Resale - ED AN	2,705,100
Tax NOT Book Income	Contributions In Aid of Construction - Gas North	304,971
Tax NOT Book Income	BETC - Oregon Purchased Tax Credits (@ 87%)	(96,870)
Tax NOT Book Income	Contributions in Aid of Construction - OR	32,762
Tax NOT Book Income	Customer Uncollectibles (excluding ED AN)	125,086
Tax NOT Book Income	Customer Uncollectibles (excluding ED AN)	33,340
Tax NOT Book Income	Customer Uncollectibles (excluding ED AN)	15,401
Tax NOT Book Income	BETC Interest - Perm Diff	(6,023)
		9,501,848

Schedule Page: 261 Line No:10 Column: b

Deductions Recorded on Books Not deducted for Return

Book NOT Tax Expense	Book Depreciation - Electric	71,818,207
Book NOT Tax Expense	DSM - Old Electric Program Amort	1,280,293
Book NOT Tax Expense	FAS 106 - Deferred Amort Postretire Benefits - ED ID	88,782
Book NOT Tax Expense	FAS 106 - Deferred Amort Postretire Benefits - ED WA	250,574
Book NOT Tax Expense	Montana Settlement - ED ID	(1,428,501)
Book NOT Tax Expense	Montana Settlement - ED WA	(2,779,808)
Book NOT Tax Expense	Non-monetary Purchased Power	(277,615)
Book NOT Tax Expense	Rathdrum Turbine Sales Tax Refund	(33,828)
Book NOT Tax Expense	Redemption Expense Amort - PCBs	194,949
Book NOT Tax Expense	WNP3 - Investment Exchange Power	2,450,031
Book NOT Tax Expense	Book Depreciation - Gas North	11,614,556

FOOTNOTE DATA

Book NOT Tax Expense	DSM - Old Gas Program Amort	437,557
Book NOT Tax Expense	FAS 106 - Deferred Amort Postretire Benefits - GD WA	55,561
Book NOT Tax Expense	Book Depreciation - Gas South	4,510,915
Book NOT Tax Expense	Transportation Book Depreciation	113,228
Book NOT Tax Expense	Airplane Lease Payments	215,186
Book NOT Tax Expense	FAS 106 (68.6% O&M)	(955,212)
Book NOT Tax Expense	Meal Disallowances	272,755
Book NOT Tax Expense	Paid Time Off Equalization	427,699
Book NOT Tax Expense	Redemption Expense Amort	2,394,894
Book NOT Tax Expense	Transportation Book Depreciation	999,769
Book NOT Tax Expense	Airplane Lease Payments	57,355
Book NOT Tax Expense	FAS 106 (68.6% O&M)	(254,599)
Book NOT Tax Expense	Meal Disallowances	72,699
Book NOT Tax Expense	Paid Time Off Equalization	113,998
Book NOT Tax Expense	Redemption Expense Amort	638,328
Book NOT Tax Expense	Transportation Book Depreciation	263,810
Book NOT Tax Expense	Airplane Lease Payments	26,495
Book NOT Tax Expense	FAS 106 (68.6% O&M)	(117,609)
Book NOT Tax Expense	Meal Disallowances	33,583
Book NOT Tax Expense	Paid Time Off Equalization	52,660
Book NOT Tax Expense	Redemption Expense Amort	294,869
Book NOT Tax Expense	401(k) ESOP Dividend Deduction	(1,044,570)
Book NOT Tax Expense	AVA Holding Co - Corporate Restructure	7,921
Book NOT Tax Expense	Impairment on LM 2500	(2,289,978)
Book NOT Tax Expense	Political Contributions	1,211,098
Book NOT Tax Expense	Preferred Dividend Requirement	-
Book NOT Tax Expense	SERP - Supplemental Executive Retirement Plan	629,528

Book NOT Tax Expense	Penalties	138,152
		91,483,730

Schedule Page:261 Line No:15 Column b

Income Recorded on Books Not Included in Return

Book NOT Tax Income	AFUDC - Electric	(1,934,908)
Book NOT Tax Income	Boulder Park Disallow - IPUC Order 10/2004	(103,530)
Book NOT Tax Income	Clark Fork PMEs - ED ID	(274,403)
Book NOT Tax Income	CS2 Retention - ED ID	(174,560)
Book NOT Tax Income	Gain General Office Building - ED	(196,092)
Book NOT Tax Income	Grid West/RTO Funding - ED.ID	70,806
Book NOT Tax Income	Grid West/RTO Funding - ED.WA	158,213
Book NOT Tax Income	Idaho PCA	1,660,797
Book NOT Tax Income	Injury & Damages - Electric	135,500
Book NOT Tax Income	Kettle Falls Disallowance - ED WA	(134,954)
Book NOT Tax Income	NE Tank Spill	(36,933)
Book NOT Tax Income	Nez Perce Settlement - ED ID	5,212
Book NOT Tax Income	Nez Perce Settlement - ED WA	(22,008)
Book NOT Tax Income	Unbilled Revenue Add-ons - ED ID	598,226
Book NOT Tax Income	Unbilled Revenue Add-ons - ED WA	747,631
Book NOT Tax Income	WA Deferred Power Costs	23,802,834
Book NOT Tax Income	Wartsila Units	233,428
Book NOT Tax Income	Wartsila Units	785,184
Book NOT Tax Income	AFUDC - Gas North	(295,526)
Book NOT Tax Income	Decoupling Mechanism - WA Gas	(249,921)
Book NOT Tax Income	Deferred Gas - GD ID	3,217,554
Book NOT Tax Income	Deferred Gas - GD WA	8,749,580
Book NOT Tax Income	Deferred Gas - GD AN	1,597,806
Book NOT Tax Income	Gain General Office Building - GD	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) X An Original (2) __ A Resubmission	04/16/2009	2008/Q4

FOOTNOTE DATA

		(65,364)
Book NOT Tax Income	Injury & Damages - Gas North	1,100,321
Book NOT Tax Income	Unbilled Revenue Add-ons - GD ID	48,717
Book NOT Tax Income	Unbilled Revenue Add-ons - GD WA	182,690
Book NOT Tax Income	AFUDC - Gas South	
		(119,981)
Book NOT Tax Income	Deferred Gas - OR	8,148,345
Book NOT Tax Income	DSM OR - Additions - 186700 - GD OR	2,628,336
Book NOT Tax Income	DSM OR - Amortization - 495600	
		(38,608)
Book NOT Tax Income	DSM OR - Amortization - 908250	1,263,423
Book NOT Tax Income	DSM OR - Amortization Accrual - 908250 (DJ 235)	50,056
Book NOT Tax Income	Injury & Damages - Oregon	-
Book NOT Tax Income	Deferred Gas - ID - Interest	201,846
Book NOT Tax Income	Deferred Gas - WA - Interest	540,412
Book NOT Tax Income	DFIT on Equity Stock Comp	2,411,528
Book NOT Tax Income	DFIT on Liability Stock Comp	284,319
Book NOT Tax Income	Idaho PCA - Interest	
		(1,152,699)
Book NOT Tax Income	Kettle Falls Nonoperating - ED ID	
		(53,066)
Book NOT Tax Income	Officers Life Insurance (Cash Surrender)	
		(960,878)
Book NOT Tax Income	Officer Life Insurance Benefit Accrual	
		(11,007)
Book NOT Tax Income	PGE Monetization (Spokane Energy)	9,593,949
Book NOT Tax Income	WA Deferred Power Costs - Interest	
		(2,231,098)
Book NOT Tax Income	Tax-Exempt Interest Income	
		(317,272)
Book NOT Tax Income	OR Deferred Gas - Interest	162,390
Book NOT Tax Income	OR DSM Deferred - Interest	
		(213,177)
Book NOT Tax Income	Wind Generation AFUDC	
		(35,194)
Book NOT Tax Income	Colstrip Settlement - ED ID	
		(738,101)
Book NOT Tax Income	Colstrip Settlement - ED WA	-

Book NOT Tax Income	Chicago Climate Exchange - ED ID	754,484
Book NOT Tax Income	Chicago Climate Exchange - ED WA	-
		59,774,306

Schedule Page:261 Line No: 20 Column b

Deductions on Return Not Charged Against Book Income

Tax NOT Book Expense	BPA Residential Exchange - ED ID	609,223
Tax NOT Book Expense	BPA Residential Exchange - ED WA	3,140,406
Tax NOT Book Expense	Cost of Removal / Salvage - Electric	(1,760,187)
Tax NOT Book Expense	DSM Tariff Rider - ED ID	(1,768,539)
Tax NOT Book Expense	DSM Tariff Rider - ED WA	(1,587,898)
Tax NOT Book Expense	DSM Tariff Rider - ED AN	320,000
Tax NOT Book Expense	Tax Depreciation - Electric	(132,192,708)
Tax NOT Book Expense	Tax Depreciation - Rathdrum Turbine	(3,836,432)
Tax NOT Book Expense	Cost of Removal / Salvage - Gas North	(117,163)
Tax NOT Book Expense	DSM Tariff Rider - GD ID	(627,887)
Tax NOT Book Expense	DSM Tariff Rider - GD WA	(1,273,972)
Tax NOT Book Expense	DSM Tariff Rider - GD AN	0
Tax NOT Book Expense	Tax Depreciation - Gas North	(29,658,937)
Tax NOT Book Expense	Cost of Removal / Salvage - Oregon	(359,686)
Tax NOT Book Expense	Tax Depreciation - OR Gas	(15,594,413)
Tax NOT Book Expense	Tax Depreciation - Basic American Foods Non-Utility	(12,785)
Tax NOT Book Expense	Tax Depreciation - Sandpoint Acquisition Adjustment	(458,114)
Tax NOT Book Expense	WPNG Acquisition OR - Book	1,110,571
Tax NOT Book Expense	Tax Amortization WPNG Acquisition - OR	(631,039)
Tax NOT Book Expense	Section 199 Manufacturing Deduction	(2,830,350)
Tax NOT Book Expense	Oregon Senate Bill 408 (SB 408)	(1,186,711)
Tax NOT Book Expense	Deferred Compensation Accrual	(4,856,348)
Tax NOT Book Expense	FASB 87 & Retirement Pay Accrual (68.6% O&M)	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) X An Original (2) __ A Resubmission	04/16/2009	2008/Q4

FOOTNOTE DATA

		(17,760,785)
Tax NOT Book Expense	Interest Rate Swaps - Amortization	(10,838,756)
Tax NOT Book Expense	Deferred Compensation Accrual	(1,294,396)
Tax NOT Book Expense	FASB 87 & Retirement Pay Accrual (68.6% O&M)	(4,733,906)
Tax NOT Book Expense	Interest Rate Swaps - Amortization	(2,888,929)
Tax NOT Book Expense	Deferred Compensation Accrual	(597,933)
Tax NOT Book Expense	FASB 87 & Retirement Pay Accrual (68.6% O&M)	(2,186,778)
Tax NOT Book Expense	Interest Rate Swaps - Amortization	(1,334,511)
Tax NOT Book Expense	CDA Lake Settlement ED ID	-
Tax NOT Book Expense	CDA Lake Settlement ED WA	-
Tax NOT Book Expense	CDA Lake Settlement ED AN	(27,733,385)
		(262,942,348)

FOOTNOTE DATA

Schedule Page: 310 Line No.: 4 Column: b
SWAP

Schedule Page: 310 Line No.: 9 Column: b
BPA Contract Terminates September 30, 2011.

Schedule Page: 310 Line No.: 10 Column: b
BPA Contract Terminates January 1, 2036.

Schedule Page: 310.3 Line No.: 4 Column: b
Bundled Transmission

Schedule Page: 310.3 Line No.: 7 Column: b
NorthWestern Energy LLC sale expires October 31, 2013.

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

Schedule Page: 310.4 Line No.: 3 Column: b
PacifiCorp sale terminates October 31, 2013.

Schedule Page: 310.4 Line No.: 4 Column: b
Peaker, LLC capacity contract terminates December 31, 2016.

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

Schedule Page: 310.5 Line No.: 3 Column: b
PPL sale terminates October 31, 2013.

Schedule Page: 310.5 Line No.: 7 Column: b
Puget Sound Energy sale terminates October 31, 2013.

Schedule Page: 310.5 Line No.: 12 Column: b
Contract expires 2014.

Schedule Page: 310.6 Line No.: 6 Column: b
Sovereign Power contract terminates 1-31-2010

Schedule Page: 310.6 Line No.: 7 Column: b
Sovereign Contract terminates 1-31-2010

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

Schedule Page: 310.6 Line No.: 14 Column: b
IntraCompany Wheeling terminates 09/30/2023.

Schedule Page: 310.7 Line No.: 1 Column: a
Intracompany generation - sale of ancillary services

Schedule Page: 310.7 Line No.: 1 Column: b
IntraCompany Generation - Sale of Ancillary Services terminates 12/31/2009.

Schedule Page: 310.7 Line No.: 2 Column: b
Estimated revenues - true up in later periods.

FOOTNOTE DATA

Schedule Page: 326 Line No.: 3 Column: l

Financial Swap

Schedule Page: 326 Line No.: 10 Column: b

Terminates 2019

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

Non Monetary

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

Ancillary services - Spin & Supplemental

Schedule Page: 326.1 Line No.: 1 Column: l

Non Monetary

Schedule Page: 326.1 Line No.: 12 Column: l

Non Monetary

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

Footnote Linked. See note on 326, Row: 10, col/item:

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

Financial Swap

Schedule Page: 326.4 Line No.: 2 Column: l

Non Monetary

Schedule Page: 326.4 Line No.: 5 Column: l

Non Monetary

FOOTNOTE DATA

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

Ancilliary Services

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

Use of Facilities

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

Use of Facilities Charge

Schedule Page: 332 Line No.: 11 Column: g

OATT Rate Case Refund

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

Schedule Page: 335 Line No.: 9

Directors	**2008 Expenses**
Vendor Name	
HEIDI B STANLEY	$23,118
BRIAN W DUNHAM	$41,166
ERIK J ANDERSON	$70,247
KRISTIANNE BLAKE	$66,403
JOHN F KELLY	$77,051
MICHAEL L NOEL	$53,789
R JOHN TAYLOR	$26,105
JACK W GUSTAVEL	$22,850
LURA J POWELL	$22,267
ROY EIGUREN	$66,965

Schedule Page: 335 Line No.: 5

Vendor	**Purpose**	**Amount**
VENDORS LESS THAN $5,000		129,036
ADVENTURES IN ADVERTISING	Pay Stations	15383
AZAR'S FOOD SERVICES	Miscellaneous	7735
BOARDVANTAGE INC	Subscriptions	20661.46
BOWNE OF LOS ANGELES INC	Professional Services	19874.52
BROADRIDGE	Treasury Fee	36154
CITIBANK NA	Miscellaneous	35142.55
CITY OF SPOKANE	Miscellaneous	13748
COPYRIGHT CLEARANCE CENTER INC	Miscellaneous	5106.91
CORP CREDIT CARD	Subscriptions	60614.44
DEWEY & LEBOEUF LLP	General Services	31888
EDITH POOR	Professional Services	10479.25
EXECUTIVE MBA PROGRAM	Employee Misc Expenses	17990
FITCH RATINGS	Miscellaneous	30583
FOUNDATION FOR WATER & ENERGY EDUCATION	Donations	6190
KOLBE CORP	Professional Services	5971.14
KORN FERRY INTERNATIONAL	Miscellaneous	128210.41
MALYN K MALQUIST	Office Supplies	6615
MARIAN MCMAHON DURKIN	Employee Misc Expenses	5169.28
MELLON INVESTOR SERVICES LLC	Miscellaneous	103843.85
MICHAEL G ANDREA	Employee Misc Expenses	11503.43
MOODYS INVESTORS SERVICE	Miscellaneous	67642.4
NATIONAL HYDROPOWER ASSOCIATION	Donations	20520
NORTHWEST GAS ASSOCIATION	Professional Services	8995
NYSE MARKET INC	General Services	35423.03
PAT NEWMANN	Professional Services	26528

PATRICIA J SHEA	Materials & Equipment	5356
ROGER D WOODWORTH	Rating Agency Fees	6020
SKILLSOFT CORPORATION	Miscellaneous	6271
THE BANK OF NEW YORK	Miscellaneous	20525
THE BANK OF NEW YORK MELLON	Miscellaneous	7094
THE COEUR D ALENE	Miscellaneous	15201
THE COEUR D ALENE RESORT	Employee Lodging	27067
THE DAVENPORT HOTEL	Miscellaneous	11930
THE LAUREL HILL ADVISORY GROUP LLC	General Services	15907
THE TRUSTEES OF THE UNIVERSITY	Conference Fees	6620
UNION BANK OF CALIFORNIA	Miscellaneous	6203
WASHINGTON ROUNDTABLE	Miscellaneous	7196
WOLFF SERVICES	Employee Relocation	6699

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.

Name of Respondent Avista Corporation	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2009	Year/Period of Report 2008/Q4

FOOTNOTE DATA

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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RECEIVED
2009 MAY 13 AM 9: 16
IDAHO PUBLIC
UTILITIES COMMISSION

Avista Corp.

2008 Form 1
State Supplements

IDAHO

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 17, 2009	December 31, 2008

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)	796,823,282	670,684,893
4	Property Under Capital Leases	1,633,474	
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Investment in Kettle Falls		
8	TOTAL (Enter Total of lines 3 thru 7)	798,456,756	670,684,893
9	Leased to Others		
10	Held for Future Use	39,828	
11	Construction Work in Progress	3,583,492	3,037,585
12	Acquisition Adjustments	0	0
13	TOTAL Utility Plant (Enter Total of lines 8 thru 12)	802,080,076	673,722,478
14	Accum. Prov. for Depr., Amort., & Depl.	0	0
15	Net Utility Plant (Enter total of line 13 less 14)	802,080,076	673,722,478
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 17, 2009	December 31, 2008

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
120,785,323				5,353,066	3
403,189				1,230,285	4
					5
					6
					7
121,188,512				6,583,351	8
					9
39,828					10
495,965				49,942	11
					12
121,724,305				6,633,293	13
0					14
121,724,305				6,633,293	15
					16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
0				0	33

State of Idaho

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
2 Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	February 16, 2009	December 31, 2008

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

1. Report below the original cost of electric plant in service according to the prescribed accounts.

2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Accounts 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified - Electric.

3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.

4. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.

5. Classify Account106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) reversals of tentative distributions of prior year of unclassified retirements. Attach supplemental statement showing the account distributions of these tentative classifications in columns (c) and (d), including the

Line No.	Account (a)		Balance at Beginning of Year (b)	Additions (c)
1		1. INTANGIBLE PLANT		
2	(301)	Organization	0	
3	(302)	Franchises and Consents	9,036,684	
4	(303)	Miscellaneous Intangible Plant	0	
5		TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	9,036,684	-
6		2. PRODUCTION PLANT		
7		A. Steam Production Plant		
8	(310)	Land and Land Rights	0	
9	(311)	Structures and Improvements	0	
10	(312)	Boiler Plant Equipment	0	
11	(313)	Engines and Engine Driven Generators	0	
12	(314)	Turbogenerator Units	0	
13	(315)	Accessory Electric Equipment	0	
14	(316)	Misc. Power Plant Equipment	0	
15	(317)	Asset Retirement Costs for Steam Production	0	
16		TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	-	-
17		B. Nuclear Production Plant		
18	(320)	Land and Land Rights	0	
19	(321)	Structures and Improvements	0	
20	(322)	Reactor Plant Equipment	0	
21	(323)	Turbogenerator Units	0	
22	(324)	Accessory Electric Equipment	0	
23	(325)	Misc. Power Plant Equipment	0	
24	(326)	Asset Retirement Costs for Nuclear Production	0	
25		TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	-	-
26		C. Hydraulic Production Plant		
27	(330)	Land and Land Rights	6,310,260	206
28	(331)	Structures and Improvements	10,586,852	310,643
29	(332)	Reservoirs, Dams, and Waterways	30,301,484	5,333,709
30	(333)	Water Wheels, Turbines, and Generators	39,585,859	74,936
31	(334)	Accessory Electric Equipment	6,086,159	240,486
32	(335)	Misc. Power Plant Equipment	2,575,531	12,692
33	(336)	Roads, Railroads, and Bridges	1,098,564	
34	(337)	Asset Retirement Costs for Hydraulic Production	0	
35		TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	96,544,709	5,972,672
36		D. Other Production Plant		
37	(340)	Land and Land Rights	621,682	
38	(341)	Structures and Improvements	3,186,951	
39	(342)	Fuel Holders, Products and Accessories	1,700,144	
40	(343)	Prime Movers	3,658,328	
41	(344)	Generators	48,632,967	225,140
42	(345)	Accessory Electric Equipment	1,870,665	1,081,821

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	##	December 31, 2008

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
			0	(301)	2
			9,036,684	(302)	3
			0	(303)	4
0	0	0	9,036,684		5
					6
					7
			0	(310)	8
			0	(311)	9
			0	(312)	10
			0	(313)	11
			0	(314)	12
			0	(315)	13
			0	(316)	14
			0	(317)	15
0	0	0	0		16
					17
			0	(320)	18
			0	(321)	19
			0	(322)	20
			0	(323)	21
			0	(324)	22
			0	(325)	23
			0	(326)	24
0	0	0	0		25
					26
356,930			5,953,536	(330)	27
8,100			10,889,395	(331)	28
0			35,635,193	(332)	29
0			39,660,795	(333)	30
170,436			6,156,209	(334)	31
0			2,588,223	(335)	32
			1,098,564	(336)	33
			0	(337)	34
535,466	0	0	101,981,915		35
					36
			621,682	(340)	37
			3,186,951	(341)	38
			1,700,144	(342)	39
			3,658,328	(343)	40
			48,858,107	(344)	41
412,265			2,540,221	(345)	42

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	February 16, 2009	December 31, 2008

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

Line No.		Account (a)	Balance at Beginning of Year (b)	Additions (c)
43	(346)	Misc. Power Plant Equipment	0	
44	(347)	Asset Retirement Costs for Other Production	0	
45		TOTAL Other Production Plant (Enter Total of lines 37 thru 45)	59,670,737	1,306,961
46		TOTAL Production Plant (Enter Total of lines 16, 25, 35, and 45)	156,215,446	7,279,633
47		3. TRANSMISSION PLANT		
48	(350)	Land and Land Rights	4,493,755	231,554
49	(352)	Structures and Improvements	7,461,853	416,665
50	(353)	Station Equipment	69,716,294	2,608,460
51	(354)	Towers and Fixtures	556,655	0
52	(355)	Poles and Fixtures	44,422,551	742,633
53	(356)	Overhead Conductors and Devices	27,296,137	566,399
54	(357)	Underground Conduit	0	0
55	(358)	Underground Conductors and Devices	0	0
56	(359)	Roads and Trails	1,374,002	
57	(359.1)	Asset Retirement Costs for Transmission Plant	0	
58		TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	155,321,247	4,565,711
59		4. DISTRIBUTION PLANT		
60	(360)	Land and Land Rights	971,116	(7,087)
61	(361)	Structures and Improvements	3,191,163	36,828
62	(362)	Station Equipment	29,570,485	266,254
63	(363)	Storage Battery Equipment	0	-
64	(364)	Poles, Towers, and Fixtures	72,922,931	4,665,929
65	(365)	Overhead Conductors and Devices	49,814,264	3,207,439
66	(366)	Underground Conduit	26,382,155	1,137,368
67	(367)	Underground Conductors and Devices	39,311,479	2,705,947
68	(368)	Line Transformers	54,364,259	2,953,859
69	(369)	Services	40,614,375	1,704,658
70	(370)	Meters	8,375,595	19,730,759
71	(371)	Installations on Customer Premises	0	-
72	(372)	Leased Property on Customer Premises	0	-
73	(373)	Street Lighting and Signal Systems	11,757,917	671,328
74	(374)	Asset Retirement Costs for Distribution Plant	0	
75		TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	337,275,739	37,073,282
76		5. GENERAL PLANT		
77	(389)	Land and Land Rights	101,907	
78	(390)	Structures and Improvements	1,125,918	11,699
79	(391)	Office Furniture and Equipment	0	0
80	(392)	Transportation Equipment	1,396,703	77,156
81	(393)	Stores Equipment	30,140	0
82	(394)	Tools, Shop and Garage Equipment	433,560	6,351
83	(395)	Laboratory Equipment	314,087	0
84	(396)	Power Operated Equipment	5,373,039	640,808
85	(397)	Communication Equipment	3,793,581	139,114
86	(398)	Miscellaneous Equipment	2,785	0
87		SUBTOTAL (Enter Total of lines 77 thru 86)	12,571,720	875,128
88	(399)	Other Tangible Property	0	
89	(399.1)	Asset Retirement Costs for General Plant	0	
90		TOTAL General Plant (Enter Total of lines 87 and 90)	12,571,720	875,128
91		TOTAL (Accounts 101 and 106)	670,420,836	49,793,754
92	(102)	Electric Plant Purchased	0	
93	(Less)	(102) Electric Plant Sold	0	
94	(103)	Experimental Plant Unclassified	0	
95		TOTAL Electric Plant in Service	670,420,836	49,793,754

State of Idaho

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) ##	December 31, 2008

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.
			0	(346)	43
			0	(347)	44
412,265	-	-	60,565,433		45
947,731	-	-	162,547,348		46
					47
1,452			4,723,857	(350)	48
			7,878,518	(352)	49
660,769		0	71,663,985	(353)	50
			556,655	(354)	51
57,435		0	45,107,749	(355)	52
4,429		0	27,858,107	(356)	53
			0	(357)	54
			0	(358)	55
			1,374,002	(359)	56
			0	(359.1)	57
724,085	0	0	159,162,873		58
					59
			964,029	(360)	60
7,375			3,220,616	(361)	61
125,915		(350,575)	29,360,249	(362)	62
0			0	(363)	63
189,403			77,399,457	(364)	64
89,940		0	52,931,763	(365)	65
18,526		0	27,500,997	(366)	66
170,347		89	41,847,168	(367)	67
32,122			57,285,996	(368)	68
45,524		661	42,274,170	(369)	69
			28,106,354	(370)	70
			0	(371)	71
			0	(372)	72
35,304		0	12,393,941	(373)	73
			0	(374)	74
714,456	0	(349,825)	373,284,740		75
					76
			101,907	(389)	77
11,753			1,125,864	(390)	78
0			0	(391)	79
128,728			1,345,131	(392)	80
15,395			14,745	(393)	81
7,046			432,865	(394)	82
183,554			130,533	(395)	83
260,718			5,753,129	(396)	84
0		0	3,932,695	(397)	85
486			2,299	(398)	86
607,680	0	0	12,839,168		87
			0	(399)	88
			0	(399.1)	89
607,680	0	0	12,839,168		90
2,993,952	0	(349,825)	716,870,813		91
			0	(102)	92
			0		93
			0	(103)	94
2,993,952	0	(349,825)	716,870,813		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 18, 2009	Dec. 31, 2008

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)	OPERATING REVENUES Amount for Previous Year (c)
1	Sales of Electricity		
2	(440) Residential Sales	88,806,974	82,202,981
3	(442) Commercial and Industrial Sales (3)		
4	Small (or Commercial)	71,994,661	66,597,380
5	Large (or Industrial)	56,575,008	53,023,256
6	(444) Public Street and Highway Lighting	1,821,535	1,766,926
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales	142,079	109,758
10	TOTAL Sales to Ultimate Consumers	219,340,257 (1)	203,700,301
11	(447) Sales for Resale	5,676,695	665,530
12	TOTAL Sales of Electricity	225,016,952	204,365,831
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Provision for Refunds	225,016,952	204,365,831
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	214,804	195,158
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	845,345	766,116
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	392,497	265,133
22	(456.1) Revenues from Transmission of Electricty of Others	5,004,067	5,183,591
23			
24			
25			
26	TOTAL Other Operating Revenues	6,456,713	6,409,998
27	TOTAL Electric Operating Revenues	$231,473,665	$210,775,829

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
1,229,004	1,189,723	103,795	101,671	2
				3
1,020,533	996,001	16,356	16,027	4
1,242,247	1,249,326	482	477	5
8,716	8,600	124	126	6
				7
				8
2,020	1,631	23	19	9
3,502,520 (2)	3,445,281	120,780	118,320	10
125,471	20,002			11
3,627,991	3,465,283	120,780	118,320	12
				13
3,627,991	3,465,283	120,780	118,320	14

(1) Includes $3,943,917 of unbilled revenues.

(2) Includes 29,478 MWH relating to unbilled revenues.

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

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SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the mWh of electricity sold, revenue, average number of customers, average kWh per customer, and average revenue per kWh, excluding data for Sales for Resale which is reported on pages 310-311.

2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," page 301. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable revenue account subheading.

3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.

4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).

5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.

6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWH Sold (b)	Revenue (c)	Average Number of Customers (d)	KWH of Sales per Customer (e)	Revenue (cents) per KWH Sold (f)
1	**RESIDENTIAL SALES (440)**					
2	1 Residential Service	1,170,311	82,023,028	98,896	11,834	7.01
3	2 Residential Service					
4	3 Residential Service					
5	12 Res. & Farm Gen. Service	19,789	1,836,640	4,290	4,613	9.28
6	22 Res. & Farm Lg. Gen. Service	11,701	714,503	23	508,739	6.11
7	30 Pumping-Special					
8	32 Res. & Farm Pumping Service	3,596	271,463	586	6,137	7.55
9	48 Res. & Farm Area Lighting	1,246	219,860			17.65
10	49 Area Lighting-High-Press.	295	67,180			22.77
11	56 Centralia Credit					
12	95 Wind Power		48,646			
13	73 Residential					
14	74 Residential Service					
15	76 Residential Service					
16	77 Residential Service					
17	79 Residential Service					
18	58 Tax Adjustment		1,128,167			
19	Total	1,206,938	86,309,487	103,795	11,628	7.23
20	Residential-Unbilled	22,066	2,497,487			
21	**COMMERCIAL SALES (442)**					
22	2 General Service					
23	3 General Service					
24	11 General Service	298,591	24,473,912	14,568	20,496	8.20
25	19 Contract-General Service					
26	21 Large General Service	605,808	39,020,399	1,336	453,449	6.44
27	25 Extra Lg. Gen. Service	72,432	3,285,500	3	24,144,000	4.54
28	28 Contract-Extra Large Service					
29	31 Pumping Service	29,209	1,931,767	449	65,053	6.61
30	47 Area Lighting-Sod. Vap.	1,071	132,983			12.42
31	49 Area Lighting-High-Press.	2,346	424,214			18.08
32	56 Centralia Credit					
33	95 Wind Power		10,292			
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		1,322,219			
41	Total	1,009,457	70,601,286	16,356	61,718	7.05
42	Commercial-Unbilled	11,076	1,393,375			
43	Total Billed	2,216,395	156,910,773	120,151		7.08
44	Total Unbilled Rev. (See Instr. 6)	33,142	3,890,862	0		11.74
45	TOTAL	2,249,537	160,801,635	120,151		7.15

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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	3,767	329,715	129	29,202	8.75
6	21 Large General Service	82,753	5,156,773	83	997,024	6.23
7	25 Extra Lg. Gen. Service	1,133,551	49,275,926	10	113,355,100	4.35
8	28 Contract-Extra Large Service					
9	29 Contract Lg. Gen. Service					
10	30 Pumping Service -Special					
11	31 Pumping Service	22,799	1,500,808	220	103,632	6.58
12	32 Pumping Svc Res & Frm	2,936	175,336	40	73,400	5.97
13	47 Area Lighting-Sod. Vap.	56	6,726			12.01
14	49 Area Lighting-High-Press.	49	8,095			16.52
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		68,574			
24	Total	1,245,911	56,521,953	482	2,584,878	4.55
25	Industrial-Unbilled	(3,664)	53,055	0		
26						
27	**STREET AND HWY LIGHTING (444)**					
28	11 General Service					
29	41 Co.-Owned St. Lt. Service	116	15,246	5	23,200	13.14
30	42 Co.-Owned St. Lt. Service	6683	1,609,348	88	75,943	24.08
31	High-Press. Sod. Vap.					
32	43 Cust.-Owned St. Lt. Energy	25	2,039	1	25,000	8.16
33	and Maint. Service					
34	44 Cust.-Owned St. Lt. Energy	588	74,920	16	36,750	12.74
35	and Maint. Svce.-High-					
36	Press. Sod. Vap.					
37	45 Cust.Owned St. Lt. Energy Service	281	15,669	3	93,667	5.58
38	46 Cust.Owned St. Lt. Energy Service	1,023	75,249	11	93,000	7.36
39	High-Press. Sod. Vap.					
40	56 Centralia Credit					
41	58 Tax Adjustment		29,064			
42	Total	8,716	1,821,535	124	70,290	6.24
43	Street and Hwy Lighting-Unbilled					
44	Total Billed	3,471,022	215,254,261	120,757		6.20
45	Total Unbilled Rev. (See Instr. 6)	29,478	3,943,917	0		13.38
46	TOTAL	3,500,500	219,198,178	120,757		6.26

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)**	2,020	142,050	23	87,826	7.03
7	58 Tax Adjustment		29			
8	Total	2,020	142,079	23	87,826	7.03
9						
10	**SALES FOR RESALE (447) (1)**					
11	61 Sales to Other Utilities - ID	125,471	5,676,695			
12						
13						
14						
14	Total	125,471	5,676,695			
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	3,598,513	221,073,035	120,780	29,794	6.14
40	Total Unbilled Rev.	29,478	3,943,917	0		13.38
41	TOTAL	3,627,991	225,016,952	120,780	30,038	6.20

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Prior Year (c)
1	(1) POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	-	-
5	(501) Fuel	-	-
6	(502) Steam Expenses	-	-
7	(503) Steam from Other Sources	-	-
8	(Less) (504) Steam Transferred-Cr.	-	-
9	(505) Electric Expenses	-	-
10	(506) Miscellaneous Steam Power Expenses	29,469	26,809
11	(507) Rents	-	-
12	(509) Allowances	-	-
13	TOTAL Operation (Enter Total of Lines 4 thru 11)	29,469	26,809
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	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)	2,695	-
21	TOTAL Power Production Expenses-Steam Plant (Enter Total of lines 12 and 19)	32,165	26,809
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	576,382	717,192
45	(536) Water for Power	264,999	260,384
46	(537) Hydraulic Expenses	966,417	773,463
47	(538) Electric Expenses	1,381,772	1,298,931
48	(539) Miscellaneous Hydraulic Power Generation Expenses	369,894	313,222
49	(540) Rents	115,560	24,490
50	TOTAL Operation (Enter Total of lines 43 thru 48)	3,675,024	3,387,682

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
50	C. Hydraulic Power Generation (Continued)		
51	Maintenance		
52	(541) Maintenance Supervision and Engineering	59,208	74,597
53	(542) Maintenance of Structures	92,885	104,297
54	(543) Maintenance of Reservoirs, Dams, and Waterways	104,072	489,048
55	(544) Maintenance of Electric Plant	407,029	698,707
56	(545) Maintenance of Miscellaneous Hydraulic Plant	128,007	40,770
57	TOTAL Maintenance (Enter Total of lines 52 thru 56)	791,201	1,407,419
58	TOTAL Power Production Expenses-Hydraulic Power (Enter total of lines 49 and 57)	4,466,225	4,795,101
59	D. Other Power Generation		
60	Operation		
61	(546) Operation Supervision and Engineering	187,627	59,922
62	(547) Fuel	1,332,065	1,774,127
63	(548) Generation Expenses	143,951	131,564
64	(549) Miscellaneous Other Power Generation Expenses	208,643	305,120
65	(550) Rents	(12,034)	(11,976)
66	TOTAL Operation (Enter Total of lines 61 thru 65)	1,860,251	2,258,757
67	Maintenance		
68	(551) Maintenance Supervision and Engineering	54,201	27,113
69	(552) Maintenance of Structures	1,492	984
70	(553) Maintenance of Generating and Electric Plant	139,334	113,087
71	(554) Maintenance of Miscellaneous Other Power Generation Plant	59,690	103,451
72	TOTAL Maintenance (Enter Total of lines 68 thru 71)	254,717	244,636
73	TOTAL Power Production Expenses-Other Power (Enter Total of lines 66 and 72)	2,114,968	2,503,393
74	E. Other Power Supply Expenses		
75	(555) Purchased Power	98,504,379	67,677,804
76	(556) System Control and Load Dispatching	178,249	170,170
77	(557) Other Expenses	21,009,194	(2,598,752)
78	TOTAL Other Power Supply Expenses (Enter Total of lines 75 thru 77)	119,691,822	65,249,222
79	TOTAL Power Production Expenses (Enter Total of lines 20, 40, 58, 73 and 78)	126,305,180	72,574,525
80	2. TRANSMISSION EXPENSES		
81	Operation		
82	(560) Operation Supervision and Engineering	790,512	833,681
83	(561) Load Dispatching	694,403	673,726
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	80,512	69,524
93	(563) Overhead Line Expenses	201,791	63,877
94	(564) Underground Line Expenses	-	-
95	(565) Transmission of Electricity by Others	4,850,266	4,905,446
96	(566) Miscellaneous Transmission Expenses	466,456	312,386
97	(567) Rents	11,325	3,200
98	TOTAL Operation (Enter Total of lines 82 thru 89)	7,095,265	6,861,839
99	Maintenance		
100	(568) Maintenance Supervision and Engineering	155,286	107,540
101	(569) Maintenance of Structures	132,710	152,665
102	(570) Maintenance of Station Equipment	385,303	216,557
103	(571) Maintenance of Overhead Lines	483,364	406,653
104	(572) Maintenance of Underground Lines	-	-
105	(573) Maintenance of Miscellaneous Transmission Plant	4,893	35,274
106	TOTAL Maintenance (Enter Total of lines 92 thru 97)	1,161,555	918,689
107	TOTAL Transmission Expenses (Enter Total of lines 90 and 98)	8,256,821	7,780,528
108	3. DISTRIBUTION EXPENSES		
109	Operation		
110	(580) Operation Supervision and Engineering	454,876	380,998

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES

Line No.	Account (a)	Amount for Current Year (b)	Amount for Prior Year (c)
103	3. DISTRIBUTION EXPENSES (Continued)		
104	(581) Load Dispatching	-	-
105	(582) Station Expenses	244,290	191,631
106	(583) Overhead Line Expenses	657,028	205,664
107	(584) Underground Line Expenses	288,975	539,789
108	(585) Street Lighting and Signal System Expenses	153,838	139,770
109	(586) Meter Expenses	6,837	(163,269)
110	(587) Customer Installations Expenses	448,342	410,704
111	(588) Miscellaneous Distribution Expenses	1,542,106	1,549,678
112	(589) Rents	62,715	52,633
113	TOTAL Operation (Enter Total of lines 102 thru 112)	3,859,008	3,307,599
114	Maintenance		
115	(590) Maintenance Supervision and Engineering	447,419	488,118
116	(591) Maintenance of Structures	61,480	88,938
117	(592) Maintenance of Station Equipment	158,009	172,321
118	(593) Maintenance of Overhead Lines	3,123,891	3,134,265
119	(594) Maintenance of Underground Lines	311,460	271,102
120	(595) Maintenance of Line Transformers	108,403	56,235
121	(596) Maintenance of Street Lighting and Signal Systems	142,400	147,910
122	(597) Maintenance of Meters	45,544	82,786
123	(598) Maintenance of Miscellaneous Distribution Plant	210,123	85,922
124	TOTAL Maintenance (Enter Total of lines 115 thru 123)	4,608,726	4,527,595
125	TOTAL Distribution Expenses (Enter Total of lines 113 and 124)	8,467,734	7,835,194
126	4. CUSTOMER ACCOUNTS EXPENSES		
127	Operation		
128	(901) Supervision	168,326	181,949
129	(902) Meter Reading Expenses	292,217	360,704
130	(903) Customer Records and Collection Expenses	2,513,513	2,651,442
131	(904) Uncollectible Accounts	661,036	557,614
132	(905) Miscellaneous Customer Accounts Expenses	50,568	64,805
133	TOTAL Customer Accounts Expenses (Enter Total of lines 128 thru 132)	3,685,659	3,816,514
134	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
135	Operation		
136	(907) Supervision	-	-
137	(908) Customer Assistance Expenses	3,881,823	3,834,782
138	(909) Informational and Instructional Expenses	32,428	17,111
139	(910) Miscellaneous Customer Service and Informational Expenses	49,825	39,932
140	TOTAL Cust. Service and Informational Expenses (Enter Total of lines 136 thru 139)	3,964,076	3,891,826
141	6. SALES EXPENSES		
142	Operation		
143	(911) Supervision	-	-
144	(912) Demonstrating and Selling Expenses	155,244	181,813
145	(913) Advertising Expenses	40,564	85,997
146	(916) Miscellaneous Sales Expenses	21	9
147	TOTAL Sales Expenses (Enter Total of lines 143 thru 146)	195,829	267,819
148	7. ADMINISTRATIVE AND GENERAL EXPENSES		
149	Operation		
150	(920) Administrative and General Salaries	6,574,227	6,761,163
151	(921) Office Supplies and Expenses	1,297,351	1,268,126
152	(Less) (922) Administrative expenses Transferred-Credit	(13,322)	(12,205)

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES

Line No.	Account (a)	Amount for Current Year (b)	Amount for Prior Year (c)
153	7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)		
154	(923) Outside Services Employed	3,772,598	4,079,254
155	(924) Property Insurance	348,360	393,879
156	(925) Injuries and Damages	1,023,022	1,146,285
157	(926) Employee Pensions and Benefits	377,208	316,075
158	(927) Franchise Requirements	5,950	6,327
159	(928) Regulatory Commission Expenses	1,763,403	1,496,154
160	(Less) (929) Duplicate Charges-Cr.	-	-
161	(930.1) General Advertising Expenses	-	980,183
162	(930.2) Miscellaneous General Expenses	1,030,973	-
163	(931) Rents	174,907	243,464
164	TOTAL Operation (Enter Total of lines 150 thru 163)	16,354,678	16,678,704
165	Maintenance		
166	(935) Maintenance of General Plant	1,896,567	1,860,751
167	TOTAL Administrative and General Expenses (Enter Total of lines 164 and 166)	18,251,244	18,539,455
168	TOTAL Electric Operation and Maintenance Expenses (Enter Total of lines 79,99,125,133,140,147,and 167)	169,126,543	114,705,862

NUMBER OF ELECTRIC DEPARTMENT EMPLOYEES

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

1 Payroll Period Ended (Date) December 31, 2007		
2 Total Regular Full-Time Employees	87	86
3 Total Part-Time and Temporary Employees	4	5
4 Allocation of General Employees	122	119
5 Total Employees (See Note 1)	213	210