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

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2019)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2019)
Form 3-Q Approved
OMB No.1902-0205
(Expires 12/31/2019)

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** 2018/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 2018/Q4
03 Previous Name and Date of Change *(if name changed during year)*	/ /
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 1411 East Mission Avenue, Spokane, WA 99207	
05 Name of Contact Person Ryan L. Krasselt	06 Title of Contact Person VP, Controller, Prin. Acctg
07 Address of Contact Person *(Street, City, State, Zip Code)* 1411 East Mission Avenue, Spokane, WA 99207	

08 Telephone of Contact Person, *Including Area Code* (509) 495-2273	09 This Report Is (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)* 04/15/2019

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 Ryan L. Krasselt 02 Title VP, Controller, Prin. Acctg Officer	03 Signature Ryan L. Krasselt Ryan L. Krasselt	04 Date Signed *(Mo, Da, Yr)* 04/15/2019

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/Q4

LIST OF SCHEDULES (Electric Utility)

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

LIST OF SCHEDULES (Electric Utility) (continued)

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

LIST OF SCHEDULES (Electric Utility) (continued)

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

Stockholders' Reports Check appropriate box:

[X] Two copies will be submitted

[ ] No annual report to stockholders is prepared

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/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.

R. Krasselt, Vice President, Controller, and Principal Accounting Officer
1411 E. Mission Avenue
Spokane, WA 99207

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

State of Washington, Incorporated March 15, 1889

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

Not Applicable

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

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

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/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	Avista Development, Inc.	Maintains an investment	100	Subsidiary of
4		portfolio inc Real Estate		Avista Capital
5	Avista Energy, Inc.	Inactive	100	Subsidiary of
6				Avista Capital
7	Pentzer Corporation	Parent of Bay Area Mfg and	100	Subsidiary of
8		Penture Venture Holdings		Avista Capital
9	Pentzer Venture Holdings II, Inc.	Inactive	100	Subsidiary of
10				Pentzer Corporation
11	Bay Area Manufacturing, Inc.	Holding Company	100	Subsidiary of
12				Pentzer Corporation
13	Advanced Manufacturing and Development, Inc.	Custom Sheet Metal	89.20	Subsidiary of
14	dba Metalfx	Fabrication		Bay Area
15				Manufacturing.
16	Avista Capital II	An affiliated business trust	100	Affliate of Avista
17		issued pref. Trust Securitis		Corp.
18	Avista Northwest Resources, LLC	Owns an interest in a venture	100	Subsidiary of
19		fund investment		Avista Capital
20	Steam Plant Square, LLC	Commercial office & retail	100	Subsidiary of
21		leasing.		Avista Development
22	Courtyard Office Center, LLC	Commercial office & retail	100	Subsidiary of
23		leasing.		Avista Development
24	Steam Plant Brew Pub, LLC	Restaurant operations	100	Subsidiary of Steam
25				Plant Square, LLC
26	Salix, Inc.	Liquified Natural Gas Oper	100	Subsidiary of
27		ations		Avista Capital

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2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Alaska Energy and Resources Company (AERC)	Parent company of Alaska	100	Subsidiary of
2		operations.		Avista Corp.
3	Alaska Electric Light and Power Company	Utility operations based in	100	Subsidiary of
4		the city & borough of Juneau		AERC
5	AJT Mining Properties, Inc.	Inactive mining company holdg	100	Subsidiary of
6		certain properties		AERC
7	Snettisham Electric Company	Holds certain rights to	100	Subsidiary of
8		purchase the Snettisham		AERC
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/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 (effective 1/1/18)	S. L. Morris	
2	and Chief Executive Officer		
3			
4	Senior Vice President, Chief Financial Officer,	M. T. Thies	
5	and Treasurer		
6			
7	Sr Vice President, General Counsel, Chief Compliance	M. M. Durkin	
8	Officer, and Corporate Secretary		
9			
10	Senior Vice President and Chief Human Resources Officer	K. S. Feltes	
11			
12	President (effective 1/1/18)	D. P. Vermillion	
13			
14	Senior Vice President, responsible for Energy Resources	J. R. Thackston	
15	and Environmental Compliance Officer (effective 5/10/18)		
16			
17	Vice President, Controller, and	R. L. Krasselt	
18	Principal Accounting Officer		
19			
20	Vice President, Chief Information Officer, and	J. M. Kensok	
21	Chief Security Officer		
22			
23	Vice President and Chief Counsel for Regulatory	D. J. Meyer	
24	and Governmental Affairs		
25			
26	Vice President, responsible for External Affairs	K. J. Christie	
27	and Chief Customer Officer (effective 1/1/2018)		
28			
29	Vice President, responsible for Energy Delivery	H. L. Rosentrater	
30			
31	Vice President and Chief Strategy Officer	E. D. Schlect	
32			
33	Vice President, Safety & HR Shared Services	B. A. COX	
34	(effective 1/1/18)		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/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 & CEO) (effective 1/1/18)	
3		
4	Erik J. Anderson	3720 Carillon Point, Kirkland, WA 98033
5		
6	Kristianne Blake***	P. O. Box 3727, Spokane WA 99220-3727
7		
8	Donald C. Burke	16 Ivy Court, Langhorne, PA 19047
9		
10	Heidi B. Stanley***	P.O. Box 2884, Spokane, WA 99220
11		
12	R. John Taylor***	111 Main Street, Lewiston, ID 83501
13		
14	Marc F. Racicot	28013 Swan Cove Dr., Big Fork, MT 59911
15		
16	Rebecca A. Klein	611 S. Congress Ave., Suite 125, Austin, TX 78704
17		
18	Janet D. Widmann	26 Sanford Ln., Lafayette, CA 94549
19		
20	Scott H. Maw	115 NW 78th St., Seattle, WA 98117
21		
22	Dennis P. Vermillion (effective 1/1/18)	1411 E. Mission Ave, Spokane, WA
23	(President)	
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INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates?

[ ] Yes

[X] No

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

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
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Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2019	Year/Period of Report End of 2018/Q4

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

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

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

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

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

Line No.	Page No(s).	Schedule	Column	Line No
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IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

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

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

1. None
2. None
3. On July 19, 2017, Avista Corp. entered into a definitive merger agreement to become an indirect, wholly-owned subsidiary of Hydro One Limited (Hydro One) in Ontario. On January 23, 2019, this transaction was terminated by mutual agreement between Avista Corp. and Hydro One and certain subsidiaries thereof. As a result, Hydro One paid Avista Corp. a $103 million termination fee. Reference is made to Note 17 of the Notes to Financial Statements for further information.
4. None
5. None
6. Reference is made to Notes 10 and 11 of the Notes to Financial Statements. In addition, the $375 million debt issuance referenced in Note 11 was approved by regulatory commissions as follows: WUTC (Docket Nos. UE-151822 Order 01 and U-171210 Order 01) IPUC (Case No. AUV-U-15-01 Order Nos. 33401 and 33978) and the OPUC (Docket No. UF 4302 Order No. 18-033).
7. None
8. Average annual wage increases were 2.4% for non-exempt employees effective March 5, 2018. Average annual wage increases were 2.9% for exempt employees effective March 5, 2018. Officers received average increases of 5.7% effective February 19, 2018. Certain bargaining unit employees received increases of 3.0% effective March 26, 2018.
9. Reference is made to Note 15 of the Notes to Financial Statements.
10. None
11. Reserved
12. See page 123 of this report.
13. On November 21, 2017, the Board of Directors of Avista Corp. named Dennis Vermillion as President of Avista Corp effective January 1, 2018. Prior to becoming President of Avista Corp., Mr. Vermillion, served as Avista Corp. Senior Vice President and Environmental Compliance Officer and President of Avista Utilities. Scott Morris, who was President of Avista Corp., will remain as Chairman of the Board and Chief Executive Officer.

Also on November 21, 2017, the Board of Directors of Avista Corp. increased the number of board members from 10 to 11 and elected Mr. Vermillion to fill the vacancy and serve as a director on the board, effective January 1, 2018.

Mr. Vermillion stood for election to the board at the annual meeting of shareholders on May 12, 2018, and was elected. As an employee director, Mr. Vermillion will receive no additional compensation, consistent with the other employee directors of Avista Corp., as disclosed in Avista Corp.'s definitive Proxy Statement dated March 31, 2017.

Effective January 1, 2018, Bryan Cox, has been named Vice President Safety and HR Shared Services. Prior to being named as Vice President, Mr. Cox was Senior Director of HR Operations.

14. Proprietary capital is not less than 30 percent.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/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	6,004,750,680	5,650,433,358
3	Construction Work in Progress (107)	200-201	156,563,570	151,271,170
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		6,161,314,250	5,801,704,528
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	1,991,240,383	1,876,263,672
6	Net Utility Plant (Enter Total of line 4 less 5)		4,170,073,867	3,925,440,856
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)		4,170,073,867	3,925,440,856
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		6,992,076	6,992,076
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		4,474,923	3,010,811
19	(Less) Accum. Prov. for Depr. and Amort. (122)		140,360	104,487
20	Investments in Associated Companies (123)		11,547,000	11,547,000
21	Investment in Subsidiary Companies (123.1)	224-225	153,523,686	161,131,682
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)		1,711,072	4,288,775
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		18,794,801	16,722,286
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		4,842,426	2,575,446
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		194,753,548	199,171,513
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		4,737,049	2,912,504
36	Special Deposits (132-134)		26,809,063	12,284,827
37	Working Fund (135)		709,204	1,149,696
38	Temporary Cash Investments (136)		136,712	50,305
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		157,729,381	174,683,071
41	Other Accounts Receivable (143)		4,618,679	5,614,311
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		5,188,090	5,170,026
43	Notes Receivable from Associated Companies (145)		31,659,207	11,659,191
44	Accounts Receivable from Assoc. Companies (146)		154,548	313,553
45	Fuel Stock (151)	227	3,982,104	3,958,296
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	43,166,166	38,180,423
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	0	0
55	Gas Stored Underground - Current (164.1)		11,609,184	11,738,607
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		20,211,526	19,333,312
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		166,418	172,493
60	Rents Receivable (172)		2,516,807	2,101,931
61	Accrued Utility Revenues (173)		0	0
62	Miscellaneous Current and Accrued Assets (174)		398,132	138,513
63	Derivative Instrument Assets (175)		10,394,941	6,197,881
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		4,842,426	2,575,446
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		308,968,605	282,743,442
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		13,923,600	10,945,098
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	598,724,109	621,273,693
73	Prelim. Survey and Investigation Charges (Electric) (183)		2,313	195,568
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	299
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		28,530	69,497
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	30,900,539	15,796,170
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)		10,255,271	11,879,551
82	Accumulated Deferred Income Taxes (190)	234	187,450,520	189,216,780
83	Unrecovered Purchased Gas Costs (191)		-40,713,156	-37,474,157
84	Total Deferred Debits (lines 69 through 83)		800,571,726	811,902,499
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		5,481,359,822	5,226,250,386

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	end of 2018/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	1,110,871,767	1,109,643,921
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		0	0
7	Other Paid-In Capital (208-211)	253	-10,696,711	-10,696,711
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	-36,316,031	-34,500,271
11	Retained Earnings (215, 215.1, 216)	118-119	660,984,141	604,413,488
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-16,389,107	56,139
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)	-7,866,070	-8,089,542
16	Total Proprietary Capital (lines 2 through 15)		1,773,220,051	1,729,827,566
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,814,200,000	1,711,700,000
19	(Less) Reaquired Bonds (222)	256-257	83,700,000	83,700,000
20	Advances from Associated Companies (223)	256-257	51,547,000	51,547,000
21	Other Long-Term Debt (224)	256-257	0	0
22	Unamortized Premium on Long-Term Debt (225)		151,017	159,900
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		1,032,761	786,481
24	Total Long-Term Debt (lines 18 through 23)		1,781,165,256	1,678,920,419
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		245,000	245,000
29	Accumulated Provision for Pensions and Benefits (228.3)		222,536,776	203,565,903
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		10,178,645	4,906,781
32	Long-Term Portion of Derivative Instrument Liabilities		10,300,047	10,456,971
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		18,265,985	17,481,829
35	Total Other Noncurrent Liabilities (lines 26 through 34)		261,526,453	236,656,484
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		190,000,000	105,000,000
38	Accounts Payable (232)		103,484,597	100,959,825
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		7,329	22,197
41	Customer Deposits (235)		4,783,254	4,431,306
42	Taxes Accrued (236)	262-263	39,835,469	36,514,038
43	Interest Accrued (237)		15,509,062	15,159,301
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	end of 2018/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)		79,542	1,533,187
48	Miscellaneous Current and Accrued Liabilities (242)		56,358,807	59,386,964
49	Obligations Under Capital Leases-Current (243)		0	2,402,917
50	Derivative Instrument Liabilities (244)		14,252,910	53,752,463
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		10,300,047	10,456,971
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		414,010,923	368,705,227
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		2,142,205	1,584,319
57	Accumulated Deferred Investment Tax Credits (255)	266-267	29,725,443	30,265,611
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	22,466,066	28,032,143
60	Other Regulatory Liabilities (254)	278	527,440,814	501,143,487
61	Unamortized Gain on Reaquired Debt (257)		1,577,896	1,707,433
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		497,875,564	481,835,128
64	Accum. Deferred Income Taxes-Other (283)		170,209,151	167,572,569
65	Total Deferred Credits (lines 56 through 64)		1,251,437,139	1,212,140,690
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		5,481,359,822	5,226,250,386

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/Q4

STATEMENT OF INCOME

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

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

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	1,416,798,041	1,464,122,332		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	804,773,049	820,637,125		
5	Maintenance Expenses (402)	320-323	63,628,892	71,114,817		
6	Depreciation Expense (403)	336-337	146,501,216	137,234,038		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	268,929	263,254		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	34,897,443	30,487,581		
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)		6,384,995	4,471,025		
13	(Less) Regulatory Credits (407.4)		11,255,061	8,041,294		
14	Taxes Other Than Income Taxes (408.1)	262-263	105,935,344	103,234,021		
15	Income Taxes - Federal (409.1)	262-263	21,463,627	22,710,789		
16	- Other (409.1)	262-263	536,050	540,802		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	9,917,224	61,887,452		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	836,768	1,719,631		
19	Investment Tax Credit Adj. - Net (411.4)	266	-540,168	-401,676		
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)		850,233	795,991		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,182,624,052	1,243,313,341		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		234,173,989	220,808,991		

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
986,405,322	989,932,258	430,392,719	474,190,074			2
						3
516,698,898	496,458,475	288,074,151	324,178,650			4
49,735,303	56,154,163	13,893,589	14,960,654			5
112,612,198	106,657,139	33,889,018	30,576,899			6
268,929	263,254					7
26,315,338	22,965,702	8,582,105	7,521,879			8
99,047	99,047					9
						10
						11
5,030,260	4,261,715	1,354,735	209,310			12
9,688,900	7,669,732	1,566,161	371,562			13
80,790,063	77,630,348	25,145,281	25,603,673			14
18,711,316	12,447,375	2,752,311	10,263,414			15
433,688	-14,769	102,362	555,571			16
5,726,144	46,542,613	4,191,080	15,344,839			17
953,010	1,507,061	-116,242	212,570			18
-520,104	-381,612	-20,064	-20,064			19
						20
						21
						22
						23
850,233	795,991					24
806,109,403	814,702,648	376,514,649	428,610,693			25
180,295,919	175,229,610	53,878,070	45,579,381			26

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)		234,173,989	220,808,991		
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)		6,931,684	9,648,685		
35	Nonoperating Rental Income (418)		-31,262	-24,801		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	2,392,004	2,517,761		
37	Interest and Dividend Income (419)		3,808,319	4,001,578		
38	Allowance for Other Funds Used During Construction (419.1)		4,281,829	6,441,370		
39	Miscellaneous Nonoperating Income (421)					
40	Gain on Disposition of Property (421.1)			19,733		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		3,519,206	3,306,956		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		13,251	-17,500		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		3,563,420	3,205,496		
46	Life Insurance (426.2)		2,793,863	2,967,371		
47	Penalties (426.3)		2,053	18,562		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		2,073,702	1,663,123		
49	Other Deductions (426.5)		5,342,674	17,741,930		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		13,788,963	25,578,982		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	293,278	175,689		
53	Income Taxes-Federal (409.2)	262-263	-5,085,932	-12,536,584		
54	Income Taxes-Other (409.2)	262-263	-220,461	-738,539		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	34,584	7,571,606		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	231,946	440,920		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-5,210,477	-5,968,748		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		-5,059,280	-16,303,278		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		87,093,842	82,342,603		
63	Amort. of Debt Disc. and Expense (428)		321,207	321,206		
64	Amortization of Loss on Reaquired Debt (428.1)		2,582,801	2,854,749		
65	(Less) Amort. of Premium on Debt-Credit (429)		8,883	8,883		
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)			677,027		
68	Other Interest Expense (431)		6,749,117	5,657,334		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		4,052,495	3,254,457		
70	Net Interest Charges (Total of lines 62 thru 69)		92,685,589	88,589,579		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		136,429,120	115,916,134		
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)		136,429,120	115,916,134		

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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		572,281,364	558,287,446
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Income Tax Reclass		1,742,362	
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)		1,742,362	
16	Balance Transferred from Income (Account 433 less Account 418.1)		134,037,116	113,398,373
17	Appropriations of Retained Earnings (Acct. 436)			
18			-5,320,848	(8,262,625)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-5,320,848	(8,262,625)
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			-98,046,075	(92,460,231)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-98,046,075	(92,460,231)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		18,837,251	1,318,400
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		623,531,170	572,281,363
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39			37,452,971	32,132,125
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/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)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)		37,452,971	32,132,125
	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)		37,452,971	32,132,125
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		660,984,141	604,413,488
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		56,140	(1,143,221)
50	Equity in Earnings for Year (Credit) (Account 418.1)		2,392,004	2,517,761
51	(Less) Dividends Received (Debit)		10,000,000	
52	Other Subsidiary Activity		-8,837,251	(1,318,400)
53	Balance-End of Year (Total lines 49 thru 52)		-16,389,107	56,140

Schedule Page: 118 Line No.: 52 Column: c

$8,000,000 of the total amount in 2018 represents a correction of dividends received from the subsidiaries in prior years that was not reflected in the activity of account 216100.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/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)	136,429,120	115,916,134
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	179,217,557	165,534,842
5	Amortization of Deferred Power and Natural Gas Costs	12,345,655	11,740,556
6	Amortization of Debt Expense	2,895,123	3,167,072
7	Amortization of Investment in Exchange Power	2,450,031	2,450,031
8	Deferred Income Taxes (Net)	8,882,835	67,298,507
9	Investment Tax Credit Adjustment (Net)	-540,168	-401,676
10	Net (Increase) Decrease in Receivables	17,548,393	-8,257,764
11	Net (Increase) Decrease in Inventory	-4,880,128	-4,858,369
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	1,753,920	49,034,221
14	Net (Increase) Decrease in Other Regulatory Assets	1,041,677	2,355,616
15	Net Increase (Decrease) in Other Regulatory Liabilities	28,600,265	-7,591,159
16	(Less) Allowance for Other Funds Used During Construction	6,331,723	6,441,370
17	(Less) Undistributed Earnings from Subsidiary Companies	2,392,004	2,517,761
18	Other (provide details in footnote):	9,488,941	-16,170,168
19	Allowance for Doubtful Accounts	3,900,000	5,235,000
20	Changes in Other Non-Current Assets and Liabilities	-4,783,663	25,628,277
21	Cash Paid for Settlement of Interest Rate Swaps	-32,174,169	-11,301,842
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	353,451,662	390,820,147
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-420,377,970	-406,201,555
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)	-420,377,970	-406,201,555
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	559,980	313,974
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	-19,855,879	-17,160,819
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48	Restricted Cash		-277
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	-2,002,301	-2,125,513
55	Dividends Received from Subsidiaries	10,000,000	2,000,000
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-431,676,170	-423,174,190
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	374,621,250	90,000,000
62	Preferred Stock		
63	Common Stock	1,206,734	56,380,425
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)	85,000,000	
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	460,827,984	146,380,425
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-274,902,917	-871,667
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):	-3,928,728	-3,551,786
77	Debt Issuance Costs	-4,255,295	-565,597
78	Net Decrease in Short-Term Debt (c)		-15,000,000
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-98,046,075	-92,460,231
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	79,694,969	33,931,144
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	1,470,461	1,577,101
87			
88	Cash and Cash Equivalents at Beginning of Period	4,112,505	2,535,404
89			
90	Cash and Cash Equivalents at End of period	5,582,966	4,112,505

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

Power and natural gas deferrals	3,653,810
Change in special deposits	(3,862,626)
Change in other current assets	(1,546,634)
Non-cash stock compensation	5,366,952
Cash received from settlement of interest rate swaps	5,594,067
Preliminary survey and investigation costs	193,554
Gain on sale of property and equipment	13,250
Other	76,568

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

Power and natural gas deferrals	1,889,235
Change in special deposits	(22,393,510)
Change in other current assets	(5,212,716)
Non-cash stock compensation	7,359,327
Cash received from settlement of interest rate swaps	2,478,520
Preliminary survey and investigation costs	(195,867)
Gain on sale of property and equipment	(37,232)
Other	(57,925)

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

Payment of minimum tax withholdings for share-based payment awards	(3,928,728)

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

Payment of minimum tax withholdings for share-based payment awards	(3,551,786)

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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 Corp. (the Company) is primarily an electric and natural gas utility with certain other business ventures. Avista Corp. provides electric distribution and transmission, and natural gas distribution services in parts of eastern Washington and northern Idaho. Avista Corp. also provides natural gas distribution service in parts of northeastern and southwestern Oregon. Avista Corp. has electric generating facilities in Washington, Idaho, Oregon and Montana. Avista Corp. also supplies electricity to a small number of customers in Montana, most of whom are employees who operate Avista Corp.'s Noxon Rapids generating facility.

Alaska Electric and Resources Company (AERC) is a wholly-owned subsidiary of Avista Corp. The primary subsidiary of AERC is Alaska Electric Light and Power (AEL&P), which comprises Avista Corp.'s regulated utility operations in Alaska.

Avista Capital, a wholly owned non-regulated subsidiary of Avista Corp., is the parent company of all of the subsidiary companies except AERC (and its subsidiaries).

On July 19, 2017, Avista Corp. entered into an Agreement and Plan of Merger (Merger Agreement) to become a wholly-owned subsidiary of Hydro One Limited (Hydro One). Consummation of the acquisition was subject to a number of approvals and the satisfaction or waiver of other specified conditions. On January 23, 2019, Avista Corp. and Hydro One mutually agreed to terminate the Merger Agreement. See Note 17 for additional information.

Basis of Reporting

The financial statements include the assets, liabilities, revenues and expenses of the Company and have been prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America (GAAP). As required by the FERC, the Company accounts for its investment in majority-owned subsidiaries on the equity method rather than consolidating the assets, liabilities, revenues, and expenses of these subsidiaries, as required by GAAP. The accompanying financial statements include the Company's proportionate share of utility plant and related operations resulting from its interests in jointly owned plants. In addition, under the requirements of the FERC, there are differences from GAAP in the presentation of (1) current portion of long-term debt (2) assets and liabilities for cost of removal of assets, (3) assets held for sale, (4) regulatory assets and liabilities, (5) deferred income taxes associated with accounts other than utility property, plant and equipment, (6) comprehensive income, (7) unamortized debt issuance costs, (8) operating revenues and resource costs associated with settled energy contracts that are "booked out" (not physically delivered) and (9) non-service portion of pension and other postretirement benefit costs.

Use of Estimates

The preparation of the financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported for assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Significant estimates include:

- determining the market value of energy commodity derivative assets and liabilities,
- pension and other postretirement benefit plan obligations,
- contingent liabilities,
- goodwill impairment testing for goodwill held at subsidiaries,
- recoverability of regulatory assets, and

- unbilled revenues.

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

System of Accounts

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

Regulation

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

Depreciation

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

	2018	2017	2016
Avista Corp.			
Ratio of depreciation to average depreciable property	3.17%	3.12%	3.11%

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

	Avista Corp.
Electric thermal/other production	41
Hydroelectric production	78
Electric transmission	58
Electric distribution	35
Natural gas distribution property	46
Other shorter-lived general plant	10

Allowance for Funds Used During Construction (AFUDC)

AFUDC represents the cost of both the debt and equity funds used to finance utility plant additions during the construction period. As prescribed by regulatory authorities, AFUDC is capitalized as a part of the cost of utility plant. The debt component of AFUDC is credited against total interest expense in the Statements of Income in the line item "capitalized interest." The equity component of AFUDC is included in the Statement of Income in the line item "other expense (income)-net." The Company is permitted, under established regulatory rate practices, to recover the capitalized AFUDC, and a reasonable return thereon, through its inclusion in rate base and the provision for depreciation after the related utility plant is placed in service. Cash inflow related to AFUDC does not occur until the related utility plant is placed in service and included in rate base.

The WUTC authorized Avista Corp. to calculate AFUDC using its allowed rate of return. Beginning in 2018, to the extent amounts calculated using this rate exceed the AFUDC amounts calculated using the FERC formula, Avista Corp. capitalizes the excess as a regulatory asset. The regulatory asset is being amortized over the average useful life of Avista Corp.'s utility plant which is approximately 30 years.

The effective AFUDC rate was the following for the years ended December 31:

	2018	2017	2016
Avista Corp.			
Effective AFUDC rate	7.43%	7.29%	7.29%

Income Taxes

Deferred income tax assets represent future income tax deductions the Company expects to utilize in future tax returns to reduce taxable income. Deferred income tax liabilities represent future taxable income the Company expects to recognize in future tax returns. Deferred tax assets and liabilities arise when there are temporary differences resulting from differing treatment of items for tax and accounting purposes. A deferred income tax asset or liability is determined based on the enacted tax rates that will be in effect when the temporary 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 income tax expense for the period is equal to the net change in the deferred income tax asset and liability accounts from the beginning to the end of the period. The effect on deferred income taxes from a change in tax rates is recognized in income in the period that includes the enactment date unless a regulatory order specifies deferral of the effect of the change in tax rates over a longer period of time. The Company establishes a valuation allowance when it is more likely than not that all, or a portion, of a deferred tax asset will not be realized. Deferred income tax liabilities and regulatory assets are established for income tax benefits flowed through to customers.

The Company's largest deferred income tax item is the difference between the book and tax basis of utility plant. This item results from the temporary difference on depreciation expense. In early tax years, this item is recorded as a deferred income tax liability that will eventually reverse and become subject to income tax in later tax years.

See Note 8 for discussion of the Tax Cuts and Jobs Act (TCJA) and its impacts on the Company's financial statements, as well as a tabular presentation of all the Company's deferred tax assets and liabilities.

The Company did not incur any penalties on income tax positions in 2018 or 2017. The Company would recognize interest accrued related to income tax positions as interest expense and any penalties incurred as income deductions.

Stock-Based Compensation

The Company currently issues three types of stock-based compensation awards - restricted shares, market-based awards and performance-based awards. Historically, these stock compensation awards have not been material to the Company's overall financial results. Compensation cost relating to share-based payment transactions is recognized in the Company's financial statements based on the fair value of the equity or liability instruments issued and recorded over the requisite service period.

The Company recorded stock-based compensation expense (included in other operating expenses) and income tax benefits in the Statements of Income of the following amounts for the years ended December 31 (dollars in thousands):

	2018	2017
Stock-based compensation expense	$ 5,367	$ 7,359
Income tax benefits (1)	1,127	2,576
Excess tax benefits on settled share-based employee payments	990	2,348

(1) For 2017 income tax benefits were calculated using a 35 percent income tax rate; however, due to the TCJA enactment, beginning on January 1, 2018 income tax benefits are calculated using a 21 percent tax rate.

Restricted share awards vest in equal thirds each year over a three-year period and are payable in Avista Corp. common stock at the end of each year if the service condition is met. In addition to the service condition, for restricted shares granted prior to 2018, the Company must meet a return on equity target in order for the Chief Executive Officer's restricted shares to vest. Restricted stock is valued at the close of market of the Company's common stock on the grant date.

Total Shareholder Return (TSR) awards are market-based awards and Cumulative Earnings Per Share (CEPS) awards are performance awards. Both types of awards vest after a period of three years and are payable in cash or Avista Corp. common stock at the end of the three-year period. The method of settlement is at the discretion of the Company and historically the Company has settled these awards through issuance of Avista Corp. common stock and intends to continue this practice. Both types of awards entitle the recipients to dividend equivalent rights, are subject to forfeiture under certain circumstances, and are subject to meeting specific market or performance conditions. Based on the level of attainment of the market or performance conditions, the amount of cash paid or common stock issued will range from 0 to 200 percent of the initial awards granted. Dividend equivalent rights are accumulated and paid out only on shares that eventually vest and have met the market and performance conditions.

For both the TSR awards and the CEPS awards, the Company accounts for them as equity awards and compensation cost for these awards is recognized over the requisite service period, provided that the requisite service period is rendered. For TSR awards, if the market condition is not met at the end of the three-year service period, there will be no change in the cumulative amount of compensation cost recognized, since the awards are still considered vested even though the market metric was not met. For CEPS awards, at the end of the three-year service period, if the internal performance metric of cumulative earnings per share is not met, all compensation cost for these awards is reversed as these awards are not considered vested.

The fair value of each TSR award is estimated on the date of grant using a statistical model that incorporates the probability of meeting the market targets based on historical returns relative to a peer group. The estimated fair value of the equity component of CEPS awards was estimated on the date of grant as the share price of Avista Corp. common stock on the date of grant, less the net present value of the estimated dividends over the three-year period.

The following table summarizes the number of grants, vested and unvested shares, earned shares (based on market metrics), and other pertinent information related to the Company's stock compensation awards for the years ended December 31:

	2018	2017
Restricted Shares		
Shares granted during the year	40,661	57,746
Shares vested during the year	(53,352)	(57,473)
Unvested shares at end of year	91,998	106,053
Unrecognized compensation expense at end of year (in thousands)	$ 1,964	$ 1,853
TSR Awards		
TSR shares granted during the year	80,724	114,390
TSR shares vested during the year	(107,342)	(107,649)
TSR shares earned based on market metrics	—	158,262
Unvested TSR shares at end of year	187,172	218,507
Unrecognized compensation expense (in thousands)	$ 3,706	$ 2,849
CEPS Awards		
CEPS shares granted during the year	40,329	57,223
CEPS shares vested during the year	(53,699)	(53,862)
CEPS shares earned based on market metrics	30,102	41,502

Unvested CEPS shares at end of year	93,579	108,581
Unrecognized compensation expense (in thousands)	$ 1,260	$ 1,856

Outstanding TSR and CEPS share awards include a dividend component that is paid in cash. This component of the share grants is accounted for as a liability award. These liability awards are revalued on a quarterly basis taking into account the number of awards outstanding, historical dividend rate, the change in the value of the Company's common stock relative to an external benchmark (TSR awards only) and the amount of CEPS earned to date compared to estimated CEPS over the performance period (CEPS awards only). Over the life of these awards, the cumulative amount of compensation expense recognized will match the actual cash paid. As of December 31, 2018 and 2017, the Company had recognized cumulative compensation expense and a liability of $0.3 million and $1.5 million, respectively, related to the dividend component on the outstanding and unvested share grants.

Cash and Cash Equivalents

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

Allowance for Doubtful Accounts

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

The cost of additions to utility plant in service, including AFUDC and replacements of units of property and improvements, is capitalized. The cost of depreciable units of property retired plus the cost of removal less salvage is charged to accumulated depreciation.

Asset Retirement Obligations (ARO)

The Company records the fair value of a liability for an ARO in the period in which it is incurred. When the liability is initially recorded, the associated costs of the ARO 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. In addition, if there are changes in the estimated timing or estimated costs of the AROs, adjustments are recorded during the period new information becomes available as an increase or decrease to the liability, with the offset recorded to the related long-lived asset. Upon retirement of the asset, the Company either settles the ARO for its recorded amount or recognizes a regulatory asset or liability for the difference, which will be surcharged/refunded to customers through the ratemaking process. The Company records regulatory assets and liabilities for the difference between asset retirement costs currently recovered in rates and AROs recorded since asset retirement costs are recovered through rates charged to customers (see Note 6 for further discussion of the Company's AROs).

Goodwill

Goodwill arising from acquisitions represents the future economic benefit arising from other assets acquired in a business combination that are not individually identified and separately recognized. The Company evaluates goodwill for impairment using a qualitative analysis (Step 0) for AEL&P and a combination of discounted cash flow models and a market approach for the other subsidiaries on at least an annual basis or more frequently if impairment indicators arise. The Company completed its annual evaluation of goodwill for potential impairment as of November 30, 2018 and determined that goodwill was not impaired at that time. There were no events or circumstances that changed between November 30, 2018 and December 31, 2018 that would more likely than not reduce the fair values of the reporting units below their carrying amounts. While, the Company does not have any goodwill amounts recorded on its

FERC balance sheets, it does have goodwill at its subsidiaries and the amounts for goodwill are reflected in the investment in subsidiary companies.

The following amounts were recorded as goodwill at the subsidiary companies and reflected through the investment in subsidiary companies on the FERC balance sheets (dollars in thousands):

	AEL&P	Other	Accumulated Impairment Losses	Total
Balance as of December 31, 2017 and 2018	$ 52,426	$ 12,979	$ (7,733)	$ 57,672

Accumulated impairment losses are attributable to the other businesses.

Derivative Assets and Liabilities

Derivatives are recorded as either assets or liabilities on the Balance Sheets measured at estimated fair value.

The Washington Utilities and Transportation Commission (WUTC) and the Idaho Public Utilities Commission (IPUC) issued accounting orders authorizing Avista Corp. to offset energy commodity derivative assets or liabilities with a regulatory asset or liability. This accounting treatment is intended to defer the recognition of mark-to-market gains and losses on energy commodity transactions until the period of delivery. Realized benefits and costs result in adjustments to retail rates through Purchased Gas Adjustments (PGA), the Energy Recovery Mechanism (ERM) in Washington, the Power Cost Adjustment (PCA) mechanism in Idaho, and periodic general rates cases. The resulting regulatory assets associated with energy commodity derivative instruments have been concluded to be probable of recovery through future rates.

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

For interest rate swap derivatives, Avista Corp. records all mark-to-market gains and losses in each accounting period as assets and liabilities, as well as offsetting regulatory assets and liabilities, such that there is no income statement impact. The interest rate swap derivatives are risk management tools similar to energy commodity derivatives. Upon settlement of interest rate swap derivatives, the regulatory asset or liability is amortized as a component of interest expense over the term of the associated debt. The Company records an offset of interest rate swap derivative assets and liabilities with regulatory assets and liabilities, based on the prior practice of the commissions to provide recovery through the ratemaking process.

The Company has multiple master netting agreements with a variety of entities that allow for cross-commodity netting of derivative agreements with the same counterparty (i.e. power derivatives can be netted with natural gas derivatives). In addition, some master netting agreements allow for the netting of commodity derivatives and interest rate swap derivatives for the same counterparty. The Company does not have any agreements which allow for cross-affiliate netting among multiple affiliated legal entities. The Company nets all derivative instruments when allowed by the agreement for presentation in the Balance Sheets.

Fair Value Measurements

Fair value represents the price that would be received when selling an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. Energy commodity derivative assets and liabilities, deferred compensation assets, as well as derivatives related to interest rate swap derivatives and foreign currency exchange derivatives, are reported at estimated fair value on the Balance Sheets. See Note 13 for the Company's fair value disclosures.

Regulatory Deferred Charges and Credits

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

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

Regulatory accounting practices require that certain costs and/or obligations (such as incurred power and natural gas costs not currently included in rates, but expected to be recovered or refunded in the future), are reflected as deferred charges or credits on the Balance Sheets. These costs and/or obligations are not reflected in the Statements of Income until the period during which matching revenues are recognized. The Company also has decoupling revenue deferrals. Decoupling revenue deferrals are recognized in the Statements of Income during the period they occur (i.e. during the period of revenue shortfall or excess due to fluctuations in customer usage), subject to certain limitations, and a regulatory asset/liability is established which will be surcharged or rebated to customers in future periods. GAAP requires that for any alternative regulatory revenue program, like decoupling, the revenue must be expected to be collected from customers within 24 months of the deferral to qualify for recognition in the current period Statement of Income. Any amounts included in the Company's decoupling program that are not expected to be collected from customers within 24 months are not recorded in the financial statements until the period in which revenue recognition criteria are met. This could ultimately result in decoupling revenue that arose during the current year being recognized in a future period.

If at some point in the future the Company determines that it no longer meets the criteria for continued application of regulatory accounting practices for all or a portion of its regulated operations, the Company could be:

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

Unamortized Debt Expense

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

Unamortized Gain/Loss on Reacquired Debt

For the Company's Washington regulatory jurisdiction and for any debt repurchases beginning in 2007 in all jurisdictions, premiums or discounts 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 amounts are amortized over the life of the new debt. In the Company's other regulatory jurisdictions, premiums or discounts 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. The premiums and discounts costs are recovered or returned to customers through retail rates as a component of interest expense.

Appropriated Retained Earnings

In accordance with the hydroelectric licensing requirements of section 10(d) of the Federal Power Act (FPA), the Company maintains an appropriated retained earnings account for any earnings in excess of the specified rate of return on the Company's investment in the licenses for its various hydroelectric projects. Per section 10(d) of the FPA, the Company must maintain these excess earnings in an appropriated retained earnings account until the termination of the licensing agreements or apply them to reduce the net investment in the licenses of the hydroelectric projects at the discretion of the FERC. The Company calculates the earnings in excess of the specified rate of return on an annual basis, usually during the second quarter.

The appropriated retained earnings amounts included in retained earnings were as follows as of December 31 (dollars in thousands):

	2018	2017
Appropriated retained earnings	$ 37,453	$ 32,132

Operating Leases

The Company has multiple lease arrangements involving various assets, with minimum terms ranging from 1 to 45 years. The following table details future minimum lease payments under these agreements (dollars in thousands):

	2019	2020	2021	2022	2023	Thereafter	Total
Avista Corp. (1)	$ 4,504	$ 4,394	$ 4,369	$ 4,292	$ 4,290	$ 98,962	$ 120,811

(1) The minimum lease payments for Avista Corp. are primarily related to a lease of the Montana riverbed for the Company's hydroelectric facilities on the Clark Fork River. These payments were disclosed as a generating facility contractual commitment at the Energy Purchase Contracts footnote in prior years. These payments are included as operating expenses for the Company's regulated operations and are recovered through base retail rates.

See Note 2 for discussion of the new lease standard that the Company adopted on January 1, 2019.

Equity in Earnings (Losses) of Subsidiaries

The Company records all the earnings (losses) from its subsidiaries under the equity method. The Company had the following equity in earnings (losses) of its subsidiaries for the years ended December 31 (dollars in thousands):

	2018	2017
Avista Capital	$ (5,660)	$ (6,942)
AERC	8,052	9,460
Total equity in earnings of subsidiary companies	$ 2,392	$ 2,518

Subsequent Events

Management has evaluated the impact of events occurring after December 31, 2018 up to February 19, 2019, the date that Avista Corp.'s GAAP financial statements were issued and has updated such evaluation for disclosure purposes through the date of this report. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

Contingencies

The Company has unresolved regulatory, legal and tax issues which have inherently uncertain outcomes. The Company accrues a loss contingency if it is probable that a liability has been incurred and the amount of the loss or impairment can be reasonably estimated. The Company also discloses loss contingencies that do not meet these conditions for accrual, if there is a reasonable possibility that a material loss may be incurred. As of December 31, 2018, the Company has not recorded any significant amounts related to unresolved contingencies. See Note 15 for further discussion of the Company's commitments and contingencies.

NOTE 2. NEW ACCOUNTING STANDARDS

ASU No. 2014-09, "Revenue from Contracts with Customers (Topic 606)"

On January 1, 2018, the Company adopted Accounting Standards Update (ASU) No. 2014-09, which outlines a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance.

The Company elected to use a modified retrospective method of adoption, which required a cumulative adjustment to opening retained earnings (if any were identified), as opposed to a full retrospective application. The Company did not identify any adjustments required to opening retained earnings related to the adoption of the new revenue standard. The Company applied the standards only to contracts that were not completed as of the implementation date. The Company did not apply the new guidance to contracts that were completed with all revenue recognized prior to the implementation date. In addition, total operating revenues on the Statements of Income in years prior to 2018 would not have changed if the Company had elected to apply the full retrospective method of adoption.

Since the majority of Avista Corp.'s revenue is from rate-regulated sales of electricity and natural gas to retail customers and revenue is recognized as energy is delivered to these customers, the Company does not expect any significant change in operating revenues or net income going forward as a result of the adoption of this standard.

The only changes in revenue that resulted from the adoption of this ASU were related to the timing of when revenue from self-generated RECs is recognized.

Under ASU No. 2014-09, revenue associated with the sale of RECs is recognized at the time of generation and sale of the credits as opposed to when the RECs are certified in the Western Renewable Energy Generation Information System, which generally occurs during a period subsequent to the sale. This represents a change from the Company's prior practice, which was to defer revenue recognition until the time of certification. Revenue associated with the sale of RECs is not material to the financial statements and almost all of the Company's REC revenue is deferred for future rebate to retail customers. As such, the change in the timing of revenue recognition does not have a material impact on net income.

See Note 3 for the Company's complete revenue disclosures.

ASU No. 2016-02 "Leases (Topic 842)"

In February 2016, the Financial Accounting Standards Board (FASB) issued ASU No. 2016-02. This ASU introduces a new lessee model that requires most leases to be capitalized and shown on the balance sheet with corresponding lease assets and liabilities. The standard also aligns certain of the underlying principles of the new lessor model with those in Topic 606, the FASB's new revenue recognition standard. Furthermore, this ASU addresses other issues that arise under the current lease model; for example, eliminating the required use of bright-line tests in current GAAP for determining lease classification (operating leases versus capital leases). This ASU also includes enhanced disclosures surrounding leases. This ASU is effective for periods beginning on or after December 15, 2018; however, early adoption is permitted. Under ASU No. 2016-02, upon adoption, the effects of this standard must be applied using a modified retrospective approach to the earliest period presented. The modified retrospective approach includes a number of optional practical expedients that entities may elect to apply. In July 2018, the FASB issued ASU No. 2018-11 which provides a practical expedient that allows companies to use an optional transition method. Under the optional transition method, a cumulative adjustment to retained earnings during the period of adoption is recorded and prior periods would not require restatement.

Upon adoption, the Company expects to elect a package of practical expedients that will allow it to not reassess whether any expired or existing contract is a lease or contains a lease, the lease classification of any expired or existing leases, and the initial direct costs for any existing leases. The Company also expects to elect practical expedients associated with hindsight, historical easements, and the optional transition method.

Adoption of the standard will impact the Company's Balance Sheet through recognition of right-of-use assets and lease liabilities for the Company's operating leases. As of December 31, 2018, the Company estimates that it will record a right-of-use asset and lease liability of between $65.0 million and $75.0 million.

ASU No. 2017-07 "Compensation-Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost"

On January 1, 2018, the Company adopted ASU No. 2017-07, which amended the income statement presentation of the components of net period benefit cost for an entity's defined benefit pension and other postretirement plans. Under previous GAAP, net benefit cost consisted of several components that reflected different aspects of an employer's financial arrangements as well as the cost of benefits earned by employees. These components were aggregated and reported net in the financial statements. ASU No. 2017-07 requires entities to (1) disaggregate the current service-cost component from the other components of net benefit cost (other components) and present it with other current compensation costs for related employees in the income statement and (2) present the other components elsewhere in the income statement and outside of income from operations.

In addition, only the service-cost component of net benefit cost is eligible for capitalization (e.g., as part of utility plant). This is a change from prior practice, under which entities capitalized the aggregate net benefit cost to utility plant when applicable, in accordance with FERC accounting guidance. Avista Corp. is a rate-regulated entity and all components of net benefit cost are currently recovered from customers as a component of utility plant and, under the new ASU, these costs will continue to be recovered from customers in the same manner over the depreciable lives of utility plant. As all such costs are expected to continue to be recoverable, the components that are no longer eligible to be recorded as a component of utility plant for GAAP will be recorded as regulatory assets.

The adoption of this ASU did not impact FERC regulatory reporting as the Company made an optional election to continue accounting for pension costs under the previous method for regulatory reporting.

ASU No. 2018-02 "Income Statement-Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income"

In February 2018, the FASB issued ASU No. 2018-02, which amended the guidance for reporting comprehensive income. This ASU allows a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the enactment of the TCJA in December 2017. This ASU is effective for periods beginning after December 15, 2018 and early adoption is permitted. Upon adoption, the requirements of this ASU must be applied either in the period of adoption or retrospectively to each period (or periods) in which the effect of the change in the U.S. federal corporate income tax rate in the TCJA is recognized. The Company early adopted this standard effective January 1, 2018 and elected to apply the guidance during the period of adoption rather than apply the standard retrospectively. As a result, the Company reclassified $1.7 million in tax benefits from accumulated other comprehensive loss to retained earnings during the year ended December 31, 2018.

For regulatory reporting, the reclassification to retained earnings is reflected in FERC account 439 – Adjustments to Retained Earnings. Per FERC Guidelines, the usage of account 439 requires prior FERC approval. During 2018, the Company filed a request with FERC for approval of the usage of account 439, which was approved by the FERC on December 21, 2018. The docket number for Avista Corp.'s request was AC19-9-000.

ASU 2018-13 "Fair Value Measurement (Topic 820)"

In August 2018, the FASB issued ASU No. 2018-13, which amends the fair value measurement disclosure requirements of ASC 820. The requirements of this ASU include additional disclosure regarding the range and weighted average used to develop significant unobservable inputs for Level 3 fair value estimates and the elimination of certain other previously required disclosures, such as the narrative description of the valuation process for Level 3 fair value measurements. This ASU is effective for periods beginning after December 15, 2019 and early adoption is permitted. Entities have the option to early adopt the eliminated or modified disclosure requirements and delay the adoption of all the new disclosure requirements until the effective date of the ASU. The Company is in the process of evaluating this standard; however, it has determined that it will not early adopt any portion of this standard as of December 31, 2018.

ASU No. 2018-14 "Compensation - Retirement Benefits - Defined Benefit Plans - General (Subtopic 715-20)"

In August 2018, the FASB issued ASU No. 2018-14, which amends ASC 715 to add, remove and/or clarify certain disclosure requirements related to defined benefit pension and other postretirement plans. The additional disclosure requirements are primarily narrative discussion of significant changes in the benefit obligations and plan assets. The removed disclosures are primarily information about accumulated other comprehensive income expected to be recognized over the next year and the effects of changes associated with assumed health care costs. This ASU is effective for periods beginning after December 15, 2021 and early adoption is permitted. The Company is in the process of evaluating this standard; however, it has determined that it will not early adopt this standard as of December 31, 2018.

NOTE 3. REVENUE

ASC 606, which outlines a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and superseded previous revenue recognition guidance, including industry-specific guidance, became effective on January 1, 2018. The core principle of the revenue model is that an entity should identify the various performance obligations in a contract, allocate the transaction price among the performance obligations and recognize revenue when (or as) the entity satisfies each performance obligation.

Utility Revenues

Revenue from Contracts with Customers

General

The majority of Avista Corp.'s revenue is from rate-regulated sales of electricity and natural gas to retail customers, which has two performance obligations, (1) having service available for a specified period (typically a month at a time) and (2) the delivery of energy to customers. The total energy price generally has a fixed component (basic charge) related to having service available and a usage-based component, related to the delivery and consumption of energy.

In addition, the sale of electricity and natural gas is governed by the various state utility commissions, which set rates, charges, terms and conditions of service, and prices. Collectively, these rates, charges, terms and conditions are included in a "tariff," which governs all aspects of the provision of regulated services. Tariffs are only permitted to be changed through a rate-setting process involving an independent, third-party regulator empowered by statute to establish rates that bind customers. Thus, all regulated sales by the Company are conducted subject to the regulator-approved tariff.

Tariff sales involve the current provision of commodity service (electricity and/or natural gas) to customers for a price that generally has a basic charge and a usage-based component. Tariff rates also include certain pass-through costs to customers such as natural gas costs, retail revenue credits and other miscellaneous regulatory items that do not impact net income, but can cause total revenue to fluctuate significantly up or down compared to previous periods. The commodity is sold and/or delivered to and consumed by the customer simultaneously, and the provisions of the relevant tariff determine the charges the Company may bill the customer, payment due date, and other pertinent rights and obligations of both parties. Generally, tariff sales do not involve a written contract. Given that all revenue recognition criteria are met upon the delivery of energy to customers, revenue is recognized immediately at that time.

Revenues from contracts with customers are presented in the Statements of Income in the line item "Utility revenues, exclusive of alternative revenue programs."

Unbilled Revenue from Contracts with Customers

The determination of the volume of energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month (once per month for each individual customer). 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. The Company's estimate of unbilled revenue is based on:

- the number of customers,
- current rates,
- meter reading dates,
- actual native load for electricity,
- actual throughput for natural gas, and
- electric line losses and natural gas system losses.

Any difference between actual and estimated revenue is automatically corrected in the following month when the actual meter reading and customer billing occurs.

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

	2018	2017
Unbilled accounts receivable	$ 64,463	$ 65,801

Non-Derivative Wholesale Contracts

The Company has certain wholesale contracts which are not accounted for as derivatives that are within the scope of ASC 606 and considered revenue from contracts with customers. Revenue is recognized as energy is delivered to the customer or the service is available for specified period of time, consistent with the discussion of tariff sales above.

Alternative Revenue Programs (Decoupling)

ASC 606 retained existing GAAP associated with alternative revenue programs, which specified that alternative revenue programs are contracts between an entity and a regulator of utilities, not a contract between an entity and a customer. GAAP requires that an entity present revenue arising from alternative revenue programs separately from revenues arising from contracts with customers on the face of the Statements of Income. The Company's decoupling mechanisms (also known as a FCA in Idaho) qualify as alternative revenue programs. Decoupling revenue deferrals are recognized in the Statements of Income during the period they occur (i.e. during the period of revenue shortfall or excess due to fluctuations in customer usage), subject to certain limitations, and a regulatory asset or liability is established which will be surcharged or rebated to customers in future periods. GAAP requires that for any alternative revenue program, like decoupling, the revenue must be expected to be collected from customers within 24 months of the deferral to qualify for recognition in the current period Statement of Income. Any amounts included in the Company's decoupling program that are not expected to be collected from customers within 24 months are not recorded in the financial statements until the period in which revenue recognition criteria are met. The amounts expected to be collected from customers within 24 months represents an estimate which must be made by the Company on an ongoing basis due to it being based on the volumes of electric and natural gas sold to customers on a go-forward basis.

Two acceptable methods of presenting decoupling revenue have evolved within the utility industry and a policy election is required by the Company. The two options relate to how the collection/refund of previously recognized decoupling revenue is presented within total revenue. The first option is the gross method, which is to amortize the decoupling regulatory asset/liability to the alternative revenue program line item on the Statement of Income as it is collected from or refunded to customers. The cash passing between the Company and the customers is presented in revenue from contracts with customers since it is a portion of the overall tariff paid by customers. This method results in a gross-up to both revenue from contracts with customers and revenue from alternative revenue programs, but has a net zero impact on total revenue. The second option is the net method, which requires the amortization of the decoupling regulatory asset/liability to be presented within revenue from contracts with customers such that, when netted against the cash passing between the Company and the customers within the same line item, there is a net zero impact to revenue from contracts with customers and total revenue. The Company has elected the gross method for the presentation of alternative revenue program revenue, consistent with historical practice. Depending on whether the previous deferral balance being amortized was a regulatory asset or regulatory liability, and depending on the size and direction of the current year deferral of surcharges and/or rebates to customers, it could result in negative alternative revenue program revenue during the year.

Derivative Revenue

Most wholesale electric and natural gas transactions (including both physical and financial transactions), and the sale of fuel are considered derivatives, which are scoped out of ASC 606. As such, these revenues are disclosed separately from revenue from contracts with customers. Revenue is recognized for these items upon the settlement/expiration of the derivative contract. Derivative revenue includes those transactions which are entered into and settled within the same month.

Other Utility Revenue

Other utility revenue includes rent, revenues from the lineman training school, sales of materials, late fees and other charges that do not represent contracts with customers. Other utility revenue also includes the provision for earnings sharing and the deferral and amortization of refunds to customers associated with the Tax Cuts and Jobs Act (TCJA), enacted in December 2017. This revenue is scoped out of ASC 606, as this revenue does not represent items where a customer is a party that has contracted with the Company to obtain goods or services that are an output of the Company's ordinary activities in exchange for consideration. As such, these revenues are presented separately from revenue from contracts with customers.

Other Considerations for Utility Revenues

Contracts with Multiple Performance Obligations

In addition to the tariff sales described above, which are stand-alone energy sales, the Company has bundled arrangements which contain multiple performance obligations including some combination of energy, capacity, energy reserves and RECs. Under these arrangements, the total contract price is allocated to the various performance obligations and revenue is recognized as the obligations are satisfied. Depending on the source of the revenue, it could either be included in revenue from contracts with customers or derivative revenue.

Gross Versus Net Presentation

Utility-related taxes collected from customers (primarily state excise taxes and city utility taxes) are taxes that are imposed on Avista Corp. as opposed to being imposed on its customers; therefore, Avista Corp. is the taxpayer and records these transactions on a gross basis in revenue from contracts with customers and operating expense (taxes other than income taxes).

Utility-related taxes that were included in revenue from contracts with customers were as follows for the years ended December 31 (dollars in thousands):

	2018	2017
Utility-related taxes	$ 58,730	$ 61,715

Significant Judgments and Unsatisfied Performance Obligations

The vast majority of the Company's revenues are derived from the rate-regulated sale of electricity and natural gas that have two performance obligations that are satisfied throughout the period and as energy is delivered to customers. In addition, the customers do not pay for energy in advance of receiving it. As such, the Company does not have any significant unsatisfied performance obligations or deferred revenues as of period-end associated with these revenues. Also, the only significant judgments involving revenue recognition are estimates surrounding unbilled revenue and receivables from contracts with customers (discussed in detail above) and estimates surrounding the amount of decoupling revenues which will be collected from customers within 24 months.

The Company has certain capacity arrangements, where the Company has a contractual obligation to provide either electric or natural gas capacity to its customers for a fixed fee. Most of these arrangements are paid for in arrears by the customers and do not result in deferred revenue and only result in receivables from the customers. The Company does have one capacity agreement where the customer makes payments throughout the year and depending on the timing of the customer payments, it can result in an immaterial amount of deferred revenue or a receivable from the customer. As of December 31, 2018, the Company estimates it had unsatisfied capacity performance obligations of $10.3 million, which will be recognized as revenue in future periods as the capacity is provided to the customers. These performance obligations are not reflected in the financial statements, as the Company has not received payment for these services.

Disaggregation of Total Operating Revenue

The following table disaggregates total operating revenue by source for the year ended December 31, 2018 (dollars in thousands):

	2018
Avista Corp.	
Revenue from contracts with customers	$ 1,147,935
Derivative revenues	277,048
Alternative revenue programs	908
Deferrals and amortizations for rate refunds to customers	(16,549)
Other utility revenues	7,456
Total Avista Corp. operating revenues	1,416,798

Utility Revenue from Contracts with Customers by Type and Service

The following table disaggregates revenue from contracts with customers associated with the Company's utility operations for the year ended December 31, 2018 (dollars in thousands):

	2018
	Avista Corp.
ELECTRIC OPERATIONS	
Revenue from contracts with customers	
Residential	$ 368,753
Commercial and governmental	314,532
Industrial	109,846
Public street and highway lighting	7,539
Total retail revenue	800,670
Transmission	17,864
Other revenue from contracts with customers	27,364
Total revenue from contracts with customers	$ 845,898
NATURAL GAS OPERATIONS	
Revenue from contracts with customers	
Residential	$ 194,340
Commercial	89,341
Industrial and interruptible	4,753
Total retail revenue	288,434
Transportation	9,103
Other revenue from contracts with customers	4,500
Total revenue from contracts with customers	$ 302,037

NOTE 4. DERIVATIVES AND RISK MANAGEMENT

Energy Commodity Derivatives

Avista Corp. is exposed to market risks relating to changes in electricity and natural gas commodity prices and certain other fuel prices. Market risk is, in general, the risk of fluctuation in the market price of the commodity being traded and is influenced primarily by supply and demand. Market risk includes the fluctuation in the market price of associated derivative commodity instruments. Avista Corp. utilizes derivative instruments, such as forwards, futures, swap derivatives and options in order to manage the various risks relating to these commodity price exposures. Avista Corp. has an energy resources risk policy and control procedures to manage these risks.

As part of Avista Corp.'s resource procurement and management operations in the electric business, the Company engages in an ongoing process of resource optimization, which involves the economic selection from available energy resources to serve Avista

Corp.'s load obligations and the use of these resources to capture available economic value through wholesale market transactions. These include sales and purchases of electric capacity and energy, fuel for electric generation, and derivative contracts related to capacity, energy and fuel. Such transactions are part of the process of matching resources with load obligations and hedging a portion of the related financial risks. These transactions range from terms of intra-hour up to multiple years.

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

Avista Corp. plans for sufficient natural gas delivery capacity to serve its retail customers for a theoretical peak day event. Avista Corp. generally has more pipeline and storage capacity than what is needed during periods other than a peak day. Avista Corp. optimizes its natural gas resources by using market opportunities to generate economic value that helps mitigate fixed costs. Avista Corp. also optimizes its natural gas storage capacity by purchasing and storing natural gas when prices are traditionally lower, typically in the summer, and withdrawing during higher priced months, typically during the winter. However, if market conditions and prices indicate that Avista Corp. should buy or sell natural gas during other times in the year, Avista Corp. engages in optimization transactions to capture value in the marketplace. Natural gas optimization activities include, but are not limited to, wholesale market sales of surplus natural gas supplies, purchases and sales of natural gas to optimize use of pipeline and storage capacity, and participation in the transportation capacity release market.

The following table presents the underlying energy commodity derivative volumes as of December 31, 2018 that are expected to be delivered in each respective year (in thousands of MWhs and mmBTUs):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical (1) MWh	Financial (1) MWh	Physical (1) mmBTUs	Financial (1) mmBTUs	Physical (1) MWh	Financial (1) MWh	Physical (1) mmBTUs	Financial (1) mmBTUs
2019	206	941	10,732	101,293	197	2,790	2,909	54,418
2020	—	—	1,138	47,225	123	959	1,430	14,625
2021	—	—	—	9,670	—	—	1,049	4,100
2022	—	—	—	—	—	—	—	—
2023	—	—	—	—	—	—	—	—
Thereafter	—	—	—	—	—	—	—	—

The following table presents the underlying energy commodity derivative volumes as of December 31, 2017 that were expected to be delivered in each respective year (in thousands of MWhs and mmBTUs):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical (1) MWh	Financial (1) MWh	Physical (1) mmBTUs	Financial (1) mmBTUs	Physical (1) MWh	Financial (1) MWh	Physical (1) mmBTUs	Financial (1) mmBTUs
2018	426	763	10,572	107,580	213	1,739	3,643	67,375

2019	235	737	610	61,073	94	1,420	1,345	35,438
2020	—	—	910	16,590	—	589	1,430	915
2021	—	—	—	—	—	—	1,049	—
2022	—	—	—	—	—	—	—	—
Thereafter	—	—	—	—	—	—	—	—

(1) Physical transactions represent commodity transactions in which Avista Corp. will take or make delivery of either electricity or natural gas; financial transactions represent derivative instruments with delivery of cash in the amount of the benefit or cost but with no physical delivery of the commodity, such as futures, swap derivatives, options, or forward contracts.

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

Foreign Currency Exchange Derivatives

A significant portion of Avista Corp.'s natural gas supply (including fuel for power generation) is obtained from Canadian sources. Most of those transactions are executed in U.S. dollars, which avoids foreign currency risk. A portion of Avista Corp.'s short-term natural gas transactions and long-term Canadian transportation contracts are committed based on Canadian currency prices and settled within 60 days with U.S. dollars. Avista Corp. hedges a portion of the foreign currency risk by purchasing Canadian currency exchange derivatives when such commodity transactions are initiated. The foreign currency exchange derivatives and the unhedged foreign currency risk have not had a material effect on Avista Corp.'s financial condition, results of operations or cash flows and these differences in cost related to currency fluctuations are included with natural gas supply costs for ratemaking.

The following table summarizes the foreign currency exchange derivatives that Avista Corp. has outstanding as of December 31 (dollars in thousands):

	2018	2017
Number of contracts	31	18
Notional amount (in United States dollars)	$ 4,018	$ 2,552
Notional amount (in Canadian dollars)	5,386	3,241

Interest Rate Swap Derivatives

Avista Corp. is affected by fluctuating interest rates related to a portion of its existing debt, and future borrowing requirements. Avista Corp. hedges a portion of its interest rate risk with financial derivative instruments, which may include interest rate swap derivatives and U.S. Treasury lock agreements. These interest rate swap derivatives and U.S. Treasury lock agreements are considered economic hedges against fluctuations in future cash flows associated with anticipated debt issuances.

The following table summarizes the unsettled interest rate swap derivatives that Avista Corp. has outstanding as of the balance sheet date indicated below (dollars in thousands):

Balance Sheet Date	Number of Contracts	Notional Amount	Mandatory Cash Settlement Date
December 31, 2018	6	70,000	2019
	6	60,000	2020
	2	25,000	2021

	7	80,000	2022
December 31, 2017	14	275,000	2018
	6	70,000	2019
	3	30,000	2020
	1	15,000	2021
	5	60,000	2022

During the second quarter 2018, in connection with the issuance and sale of $375.0 million of Avista Corp. first mortgage bonds (see Note 11), the Company cash-settled fourteen interest rate swap derivatives (notional aggregate amount of $275.0 million) and paid a net amount of $26.6 million. Upon settlement of interest rate swap derivatives, the cash payments made or received are recorded as a regulatory asset or liability and are subsequently amortized as a component of interest expense over the life of the associated debt. The settled interest rate swap derivatives are also included as a part of Avista Corp.'s cost of debt calculation for ratemaking purposes.

The fair value of outstanding interest rate swap derivatives can vary significantly from period to period depending on the total notional amount of swap derivatives outstanding and fluctuations in market interest rates compared to the interest rates fixed by the swaps. Avista Corp. is required to make cash payments to settle the interest rate swap derivatives when the fixed rates are higher than prevailing market rates at the date of settlement. Conversely, Avista Corp. receives cash to settle its interest rate swap derivatives when prevailing market rates at the time of settlement exceed the fixed swap rates.

Summary of Outstanding Derivative Instruments

The amounts recorded on the Balance Sheet as of December 31, 2018 and December 31, 2017 reflect the offsetting of derivative assets and liabilities where a legal right of offset exists.

The following table presents the fair values and locations of derivative instruments recorded on the Balance Sheet as of December 31, 2018 (in thousands):

	Fair Value			
Derivative and Balance Sheet Location	Gross	Gross	Collateral	Net Asset (Liability) on Balance Sheet
Foreign currency exchange derivatives				
Derivative instrument liabilities current	$ —	$ (45)	$ —	$ (45)
Interest rate swap derivatives				
Derivative instrument assets current	5,283	—	—	5,283
Long-term portion of derivative assets	5,283	(440)	—	4,843
Long-term portion of derivative liabilities	—	(7,391)	530	(6,861)
Energy commodity derivatives				
Derivative instrument assets current	400	(130)	—	270
Derivative instrument liabilities current	31,457	(73,155)	37,790	(3,908)
Long-term portion of derivative liabilities	4,426	(21,292)	13,427	(3,439)
Total derivative instruments recorded on the balance sheet	$ 46,849	$ (102,453)	$ 51,747	$ (3,857)

The following table presents the fair values and locations of derivative instruments recorded on the Balance Sheet as of December 31, 2017 (in thousands):

	Fair Value			
Derivative and Balance Sheet Location	Gross	Gross	Collateral	Net Asset (Liability) on Balance Sheet
Foreign currency exchange derivatives				
Derivative instrument assets current	$ 32	$ (1)	$ —	$ 31
Interest rate swap derivatives				
Derivative instrument assets current	2,597	(270)	—	2,327
Long-term portion of derivative assets	4,880	(2,304)	—	2,576
Derivative instrument liabilities current	—	(63,399)	28,952	(34,447)
Long-term portion of derivative liabilities	—	(7,540)	6,018	(1,522)
Energy commodity derivatives				
Derivative instrument assets current	1,386	(122)	—	1,264
Derivative instrument liabilities current	26,641	(52,895)	17,406	(8,848)
Long-term portion of derivative liabilities	15,970	(34,936)	10,032	(8,934)
Total derivative instruments recorded on the balance sheet	$ 51,506	$ (161,467)	$ 62,408	$ (47,553)

Exposure to Demands for Collateral

Avista Corp.'s derivative contracts often require collateral (in the form of cash or letters of credit) or other credit enhancements, or reductions or terminations of a portion of the contract through cash settlement. In the event of a downgrade in Avista Corp.'s credit ratings or changes in market prices, additional collateral may be required. In periods of price volatility, the level of exposure can change significantly. As a result, sudden and significant demands may be made against Avista Corp.'s credit facilities and cash. Avista Corp. actively monitors the exposure to possible collateral calls and takes steps to mitigate capital requirements.

The following table presents Avista Corp.'s collateral outstanding related to its derivative instruments as of as of December 31 (in thousands):

	2018	2017
Energy commodity derivatives		
Cash collateral posted	$ 78,025	$ 39,458
Letters of credit outstanding	6,500	23,000
Balance sheet offsetting (cash collateral against net derivative positions)	51,217	27,438
Interest rate swap derivatives		
Cash collateral posted	530	34,970
Letters of credit outstanding	—	5,000
Balance sheet offsetting (cash collateral against net derivative positions)	530	34,970

Certain of Avista Corp.'s derivative instruments contain provisions that require the Company to maintain an "investment grade" credit rating from the major credit rating agencies. If Avista Corp.'s credit ratings were to fall below "investment grade," it would be in violation of these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing collateralization on derivative instruments in net liability positions.

The following table presents the aggregate fair value of all derivative instruments with credit-risk-related contingent features that are in a liability position and the amount of additional collateral Avista Corp. could be required to post as of December 31 (in thousands):

	2018	2017
Energy commodity derivatives		
Liabilities with credit-risk-related contingent features	$ 2,193	$ 1,336
Additional collateral to post	2,193	1,336
Interest rate swap derivatives		
Liabilities with credit-risk-related contingent features	7,831	73,514
Additional collateral to post	6,579	18,770

NOTE 5. JOINTLY OWNED ELECTRIC FACILITIES

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

	2018	2017
Utility plant in service	$ 384,431	$ 379,970
Accumulated depreciation	(261,997)	(255,604)

See Note 6 for further discussion of AROs.

While the obligations and liabilities with respect to Colstrip are to be shared among the co-owners on a pro rata basis, many of the environmental liabilities are joint and several under the law, so that if any co-owner failed to pay its share of such liability, the other co-owners (or any one of them) could be required to pay the defaulting co-owner's share (or the entire liability).

NOTE 6. ASSET RETIREMENT OBLIGATIONS

The Company has recorded liabilities for future AROs to:

- restore coal ash containment 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, 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.

In 2015, the EPA issued a final rule regarding CCRs, also termed coal combustion byproducts or coal ash. Colstrip, of which Avista Corp. is a 15 percent owner of units 3 & 4, produces this byproduct. The CCR rule has been the subject of ongoing litigation. In August 2018, the D.C. Circuit struck down provisions of the rule. The rule includes technical requirements for CCR landfills and surface impoundments. The Colstrip owners developed a multi-year compliance plan to address the CCR requirements and existing state obligations.

The actual asset retirement costs related to the CCR rule requirements may vary substantially from the estimates used to record the ARO due to the uncertainty and evolving nature of the compliance strategies that will be used and the availability of data used to estimate costs, such as the quantity of coal ash present at certain sites and the volume of fill that will be needed to cap and cover certain impoundments. The Company expects to seek recovery of any increased costs related to complying with the CCR rule through customer rates.

In addition to the above, under a 2012 Administrative Order on Consent, the owners of Colstrip are required to provide financial assurance, primarily in the form of surety bonds, to secure each owner's pro rata share of various anticipated closure and remediation obligations. The amount of financial assurance required of each owner may, like the ARO, vary substantially due to the uncertainty and evolving nature of anticipated closure and remediation activities, and as those activities are completed over time.

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

	2018	2017
Asset retirement obligation at beginning of year	$ 17,482	$ 15,515
Liabilities incurred	—	1,171
Liabilities settled	(66)	—
Accretion expense	850	796
Asset retirement obligation at end of year	$ 18,266	$ 17,482

NOTE 7. PENSION PLANS AND OTHER POSTRETIREMENT BENEFIT PLANS

The pension and other postretirement benefit plans described below only relate to Avista Corp. AEL&P (not discussed below) participates in a defined contribution multiemployer plan for its union workers and a defined contribution money purchase pension plan for its nonunion workers. METALfx (not discussed below) has a defined contribution 401(k) plan. None of the subsidiary retirement plans, individually or in the aggregate, are significant to Avista Corp.

Avista Corp.

The Company has a defined benefit pension plan covering the majority of all regular full-time employees at Avista Corp. that were hired prior to January 1, 2014. Individual benefits under this plan are based upon the employee's years of service, date of hire and average compensation as specified in the plan. Non-union employees hired on or after January 1, 2014 participate in a defined contribution 401(k) plan in lieu of a defined benefit pension 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 $22.0 million in cash to the pension plan in 2018 and 2017. The Company expects to contribute $22.0 million in cash to the pension plan in 2019.

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

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

	2019	2020	2021	2022	2023	Total 2024-2028
Expected benefit payments	$ 37,920	$ 38,486	$ 38,433	$ 39,018	$ 39,405	$ 210,240

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

The Company provides certain health care and life insurance benefits for eligible retired employees that were hired prior to January 1, 2014. The Company accrues the estimated cost of postretirement benefit obligations during the years that employees provide services. The liability and expense of this plan are included as other postretirement benefits. Non-union employees hired on or after January 1, 2014, will have access to the retiree medical plan upon retirement; however, Avista Corp. will no longer provide a contribution toward their medical premium.

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

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

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

	2019	2020	2021	2022	2023	Total 2024-2028
Expected benefit payments	$ 6,766	$ 6,393	$ 6,566	$ 6,688	$ 6,740	$ 37,581

The Company expects to contribute $7.1 million to other postretirement benefit plans in 2019, representing expected benefit payments to be paid during the year excluding the Medicare Part D subsidy. The Company uses a December 31 measurement date for its pension and other postretirement benefit plans.

The following table sets forth the pension and other postretirement benefit plan disclosures as of December 31, 2018 and 2017 and the components of net periodic benefit costs for the years ended December 31, 2018 and 2017 (dollars in thousands):

	Pension Benefits		Other Post-retirement Benefits	
	2018	2017	2018	2017
Change in benefit obligation:				
Benefit obligation as of beginning of year	$ 716,561	$ 666,472	$ 132,947	$ 136,453
Service cost	21,614	20,406	3,188	3,220
Interest cost	26,096	27,898	4,831	5,490
Actuarial (gain)/loss	(48,641)	39,743	(610)	(6,020)
Plan change	—	3,158	—	—

Benefits paid	(44,001)	(41,116)	(6,303)	(6,196)
Benefit obligation as of end of year	$ 671,629	$ 716,561	$ 134,053	$ 132,947
Change in plan assets:				
Fair value of plan assets as of beginning of year	$ 605,652	$ 540,914	$ 37,953	$ 33,365
Actual return on plan assets	(40,954)	82,476	(1,101)	4,588
Employer contributions	22,000	22,000	—	—
Benefits paid	(42,647)	(39,738)	—	—
Fair value of plan assets as of end of year	$ 544,051	$ 605,652	$ 36,852	$ 37,953
Funded status	$ (127,578)	$ (110,909)	$ (97,201)	$ (94,994)
Amounts recognized in the Balance Sheets:				
Current liabilities	(1,477)	(1,663)	(580)	(529)
Non-current liabilities	(126,101)	(109,246)	(96,621)	(94,465)
Net amount recognized	(127,578)	(110,909)	(97,201)	(94,994)
Accumulated pension benefit obligation	$ 586,398	$ 624,345	—	—
Accumulated postretirement benefit obligation:				
For retirees			$ 63,796	$ 60,354
For fully eligible employees			$ 29,902	$ 32,891
For other participants			$ 40,355	$ 39,702
Included in accumulated other comprehensive loss (income) (net of tax):				
Unrecognized prior service cost	$ 2,308	$ 2,066	$ (5,230)	$ (5,058)
Unrecognized net actuarial loss	138,516	102,624	52,441	44,382
Total	140,824	104,690	47,211	39,324
Less regulatory asset	(133,237)	(97,025)	(46,932)	(38,899)
Accumulated other comprehensive loss for unfunded benefit obligation for pensions and other postretirement benefit plans	$ 7,587	$ 7,665	$ 279	$ 425

	Pension Benefits		Other Post-retirement Benefits	
	2018	2017	2018	2017
Weighted-average assumptions as of December 31:				
Discount rate for benefit obligation	4.31%	3.71%	4.32%	3.72%
Discount rate for annual expense	3.71%	4.26%	3.72%	4.23%
Expected long-term return on plan assets	5.50%	5.87%	5.20%	5.69%
Rate of compensation increase	4.67%	4.69%		
Medical cost trend pre-age 65 – initial			6.00%	6.50%
Medical cost trend pre-age 65 – ultimate			5.00%	5.00%
Ultimate medical cost trend year pre-age 65			2023	2023

Medical cost trend post-age 65 – initial	6.25%	6.50%
Medical cost trend post-age 65 – ultimate	5.00%	5.00%
Ultimate medical cost trend year post-age 65	2024	2024

	Pension Benefits		Other Post-retirement Bene fits	
	2018	2017	2018	2017
Components of net periodic benefit cost:				
Service cost (a)	$ 21,614	$ 20,406	$ 3,188	$ 3,220
Interest cost	26,096	27,898	4,831	5,490
Expected return on plan assets	(33,018)	(31,626)	(1,973)	(1,899)
Amortization of prior service cost	257	2	(1,089)	(1,144)
Net loss recognition	7,879	9,793	4,232	4,934
Net periodic benefit cost	$ 22,828	$ 26,473	$ 9,189	$ 10,601

(a) Total service costs in the table above are recorded to the same accounts as labor expense. Labor and benefits expense is recorded to various projects based on whether the work is a capital project or an operating expense. Approximately 40 percent of all labor and benefits is capitalized to utility property and 60 percent is expensed to utility other operating expenses.

See Note 2 for discussion regarding the adoption of ASU No. 2017-07 and its impact to the presentation of pension and other postretirement benefits in the Statements of Income and the Balance Sheets.

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, 2018 by $8.1 million and the service and interest cost by $0.6 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, 2018 by $6.4 million and the service and interest cost by $0.5 million.

Plan Assets

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

The Company has contracted with investment consultants who are responsible for 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 in mutual funds, trusts and partnerships that hold marketable debt and equity securities, real estate, absolute return and commodity funds. In seeking to obtain a return that aligns with the funded status of the pension plan, the investment consultant recommends allocation percentages by asset classes. These recommendations are reviewed by the internal benefits committee, which then recommends their adoption by the Finance Committee. The Finance Committee has established target investment allocation percentages by asset classes and also investment ranges for each asset class. The target investment allocation percentages are typically the midpoint of the established range. The target investment allocation percentages by asset classes are indicated in the table below:

	2018	2017
Equity securities	37%	37%
Debt securities	45%	45%
Real estate	8%	8%
Absolute return	10%	10%

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

Pension plan and other postretirement plan assets whose fair values are measured using net asset value (NAV) are excluded from the fair value hierarchy and are included as reconciling items in the tables below.

Investments in common/collective trust funds are presented at estimated fair value, which is determined based on the unit value of the fund. Unit value is determined by an independent trustee, which sponsors the fund, by dividing the fund’s net assets by its units outstanding at the valuation date. The Company's investments in common/collective trusts have redemption limitations that permit quarterly redemptions following notice requirements of 45 to 60 days. The fair values of the closely held investments and partnership interests are based upon the allocated share of the fair value of the underlying net assets as well as the allocated share of the undistributed profits and losses, including realized and unrealized gains and losses. Most of the Company's investments in closely held investments and partnership interests have redemption limitations that range from bi-monthly to semi-annually following redemption notice requirements of 60 to 90 days. One investment in a partnership has a lock-up for redemption currently expiring in 2022 and is subject to extension.

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

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

The fair value of pension plan assets was determined as of December 31, 2018 and 2017.

The following table discloses by level within the fair value hierarchy (see Note 13 for a description of the fair value hierarchy) of the pension plan's assets measured and reported as of December 31, 2018 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ —	$ 7,061	$ —	$ 7,061
Fixed income securities:				
U.S. government issues	—	37,078	—	37,078
Corporate issues	—	175,908	—	175,908
International issues	—	31,561	—	31,561
Municipal issues	—	16,170	—	16,170
Mutual funds:				
U.S. equity securities	101,720	—	—	101,720
International equity securities	33,141	—	—	33,141
Absolute return (1)	2,249	—	—	2,249
Plan assets measured at NAV (not subject to hierarchy disclosure)				
Common/collective trusts:				
Real estate	—	—	—	43,303
International equity securities	—	—	—	30,944
Partnership/closely held investments:				
Absolute return (1)	—	—	—	60,612
Real estate	—	—	—	4,304
Total	$ 137,110	$ 267,778	$ —	$ 544,051

The following table discloses by level within the fair value hierarchy (see Note 13 for a description of the fair value hierarchy) of the pension plan's assets measured and reported as of December 31, 2017 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ —	$ 20,619	$ —	$ 20,619
Fixed income securities:				
U.S. government issues	—	20,305	—	20,305
Corporate issues	—	185,272	—	185,272

International issues	—	32,054	—	32,054
Municipal issues	—	20,201	—	20,201
Mutual funds:				
U.S. equity securities	127,742	—	—	127,742
International equity securities	40,755	—	—	40,755
Absolute return (1)	7,728	—	—	7,728
Plan assets measured at NAV (not subject to hierarchy disclosure)				
Common/collective trusts:				
Real estate	—	—	—	34,470
International equity securities	—	—	—	43,462
Partnership/closely held investments:				
Absolute return (1)	—	—	—	67,167
Private equity funds (2)	—	—	—	72
Real estate	—	—	—	5,805
Total	$ 176,225	$ 278,451	$ —	$ 605,652

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

The fair value of other postretirement plan assets invested in debt and equity securities was based primarily on market prices. The fair value of investment securities traded on a national securities exchange is determined based on the last reported sales price; securities traded in the over-the-counter market are valued at the last reported bid price. Investment securities for which market prices are not readily available are fair-valued by the investment manager based upon other inputs (including valuations of securities that are comparable in coupon, rating, maturity and industry). The target asset allocation was 60 percent equity securities and 40 percent debt securities in both 2018 and 2017.

The fair value of other postretirement plan assets was determined as of December 31, 2018 and 2017.

The following table discloses by level within the fair value hierarchy (see Note 13 for a description of the fair value hierarchy) of other postretirement plan assets measured and reported as of December 31, 2018 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Balanced index mutual funds (1)	$ 36,852	$ —	$ —	$ 36,852

The following table discloses by level within the fair value hierarchy (see Note 13 for a description of the fair value hierarchy) of other postretirement plan assets measured and reported as of December 31, 2017 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Balanced index mutual funds (1)	$ 37,953	$ —	$ —	$ 37,953

(1) The balanced index fund for 2018 and 2017 is a single mutual fund that includes a percentage of U.S. equity and fixed income securities and International equity and fixed income securities.

401(k) Plans and Executive Deferral Plan

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

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

	2018	2017
Employer 401(k) matching contributions	$ 10,044	$ 8,896

The Company has an Executive Deferral Plan. This plan allows executive officers and other key employees the opportunity to defer until the earlier of their retirement, termination, disability or death, up to 75 percent of their base salary and/or up to 100 percent of their incentive payments. Deferred compensation funds are held by the Company in a Rabbi Trust.

There were deferred compensation assets and corresponding deferred compensation liabilities on the Balance Sheets of the following amounts as of December 31 (dollars in thousands):

	2018	2017
Deferred compensation assets and liabilities	$ 8,400	$ 8,458

NOTE 8. ACCOUNTING FOR INCOME TAXES

Federal Income Tax Law Changes

On December 22, 2017, the TCJA was signed into law. The legislation included substantial changes to the taxation of individuals as well as U.S. businesses, multi-national enterprises, and other types of taxpayers. Highlights of provisions most relevant to Avista Corp. included:

- A permanent reduction in the statutory corporate tax rate from 35 percent to 21 percent, beginning with tax years after 2017;
- Statutory provisions requiring that excess deferred taxes associated with public utility property be normalized using the Average Rate Assumption Method (ARAM) or the Reverse South Georgia Method for determining the timing of the return of excess deferred taxes to customers. Excess deferred taxes result from revaluing deferred tax assets and liabilities based on the newly enacted tax rate instead of the previous tax rate, which, for most rate-regulated utilities like Avista Corp. results in a net benefit to customers that will be deferred as a regulatory liability and passed through to customers over future periods;
- Repeal of the corporate alternative minimum tax (AMT);
- Bonus depreciation (expensing of capital investment on an accelerated basis) was removed as a deduction for property predominantly used in certain rate-regulated businesses (like Avista Corp.), but is still allowed for the Company's non-regulated businesses; and
- NOL carryback deductions were eliminated, but carryforward deductions are allowed indefinitely with some annual limitations versus the previous 20-year limitation.

As a result of the TCJA and its reduction of the corporate income tax rate from 35 percent to 21 percent (among many other changes in the law), the Company recorded a regulatory liability associated with the revaluing of its deferred income tax assets and liabilities to the new corporate tax rate. The total net amount of the regulatory liability for excess deferred income taxes associated with the TCJA is $429.3 million as of December 31, 2018, compared to $434.6 million as of December 31, 2017, which reflects the amounts to be refunded to customers through the regulatory process. The Avista Corp. amounts related to utility plant commenced being returned to customers in 2018 and the Company expects they will be returned to customers over a period of approximately 36 years using the ARAM. The return of the regulatory liability attributable to non-plant excess deferred taxes of approximately $18.5 million (among all jurisdictions) as of December 31, 2018 will be determined by final orders from the WUTC, IPUC and the Oregon Public Utilities Commission (OPUC) during 2019.

Because most of the provisions of the TCJA were effective as of January 1, 2018 but customers' rates included a 35 percent corporate tax rate built in from prior general rate cases, the Company began accruing for a refund to customers for the change in federal income tax expense beginning January 1, 2018 forward. For Washington and Idaho, this accrual was recorded until all benefits prior to a permanent rate change were properly captured through the deferral process. Refunds have begun to Washington and Idaho customers through tariffs or other regulatory mechanisms or proceedings. For Oregon, a final order is expected during 2019 to determine the timing of refunds to customers.

As of December 31, 2018, excess accumulated deferred tax liabilities associated with the TCJA are classified as follows in the Balance Sheet (in thousands):

	Protected			Unprotected			Total		
	Washington	Idaho	Oregon	Washington	Idaho	Oregon	Washington	Idaho	Oregon
Deferred tax assets	59,201	26,657	8,820	2,725	1,465	71	61,926	28,122	8,891
Regulatory liabilities	256,837	115,647	38,265	11,824	6,409	306	268,661	122,056	38,571

The deferred tax assets in the table above represent the income tax gross-up of the excess deferred taxes (which, together with the excess deferred tax amount, reflects the revenue amounts to be refunded to customers through the regulatory process).

Excess accumulated deferred income taxes in 2018 were amortized in the Statement of Income as follows (in thousands):

	Protected			Unprotected			Total		
	Washington	Idaho	Oregon	Washington	Idaho	Oregon	Washington	Idaho	Oregon
Provision for deferred income taxes	(5,334)	(2,426)	(496)	(339)	290	—	(5,673)	(2,136)	(496)

Positive amounts reflect increases to the provision for deferred income taxes and negative amounts reflect reductions to the provision for deferred income taxes.

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

As of December 31, 2018, the Company had $21.0 million of state tax credit carryforwards. Of the total amount, the Company believes that it is more likely than not that it will only be able to utilize $7.3 million of the state tax credits. As such, the Company has recorded a valuation allowance of $13.7 million against the state tax credit carryforwards and reflected the net amount of $7.3 million as an asset as of December 31, 2018. State tax credits expire from 2020 to 2032.

Status of Internal Revenue Service (IRS) and State Examinations

The Company and its eligible subsidiaries file federal income tax returns. The Company also files state income tax returns in certain jurisdictions, including Idaho, Oregon, Montana and Alaska. Subsidiaries are charged or credited with the tax effects of their operations on a stand-alone basis. All tax years after 2013 are open for an IRS tax examination. The IRS is currently reviewing tax years 2014 through 2016 and the Company does not yet know the final status of these examinations.

The Idaho State Tax Commission notified the Company in 2018 that they would be auditing the Company's tax returns for the years 2014 through 2016. The statute of limitations for Montana and Oregon to review 2014 and earlier tax years has expired.

The Company believes that any open tax years for federal or state income taxes will not result in adjustments that would be significant to the financial statements.

Regulatory Assets and Liabilities Associated with Income Taxes

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

	2018	2017
Regulatory assets for deferred income taxes	$ 91,188	$ 90,315
Regulatory liabilities for deferred income taxes	446,187	453,817

NOTE 9. ENERGY PURCHASE CONTRACTS

Avista Corp. has contracts for the purchase of fuel for thermal generation, natural gas for resale and various agreements for the purchase or exchange of electric energy with other entities. The remaining term of the contracts range from one month to twenty-five years.

Total expenses for power purchased, natural gas purchased, fuel for generation and other fuel costs, which are included in utility resource costs in the Statements of Income, were as follows for the years ended December 31 (dollars in thousands):

	2018	2017	2016
Utility power resources	$ 357,656	$ 380,523	$ 402,575

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):

	2019	2020	2021	2022	2023	Thereafter	Total
Power resources	$ 199,239	$ 174,236	$ 163,608	$ 162,895	$ 154,935	$ 990,024	$ 1,844,937
Natural gas resources	70,159	61,017	37,318	33,900	33,130	298,253	533,777
Total	$ 269,398	$ 235,253	$ 200,926	$ 196,795	$ 188,065	$ 1,288,277	$ 2,378,714

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

The above future contractual commitments for power resources include fixed contractual amounts related to the Company's 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 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 utility resource costs in the Statements of Income. The contractual amounts included above consist of Avista Corp.'s share of existing debt service cost and its proportionate share of the variable operating expenses of these projects. The minimum amounts payable under these contracts are based in part on the proportionate share of the debt service requirements of the PUD's revenue bonds for which the Company is indirectly responsible. The Company's total future debt service obligation associated with the revenue bonds outstanding at December 31, 2018 (principal and interest) was $65.3 million.

In addition, Avista Corp. has operating agreements, settlements and other contractual obligations related to its generating facilities and transmission and distribution services. The following table details future contractual commitments under these agreements (dollars in thousands):

	2019	2020	2021	2022	2023	Thereafter	Total
Contractual obligations	$ 29,474	$ 33,311	$ 32,291	$ 28,142	$ 28,859	$ 195,743	$ 347,820

NOTE 10. NOTES PAYABLE

Avista Corp. has a committed line of credit with various financial institutions in the total amount of $400.0 million that expires in April 2021. The committed line of credit is secured by non-transferable first mortgage bonds of Avista Corp. issued to the agent bank that would only become due and payable in the event, and then only to the extent, that Avista Corp. defaults on its obligations under the committed line of credit.

The committed line of credit agreement contains customary covenants and default provisions. The credit agreement has a covenant which does not permit the ratio of "total debt" to "total capitalization" of Avista Corp. to be greater than 65 percent at any time. As of December 31, 2018, the Company was in compliance with this covenant.

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

	2018	2017
Balance outstanding at end of period	$ 190,000	$ 105,000
Letters of credit outstanding at end of period	$ 10,503	$ 34,420
Average interest rate at end of period	3.18%	2.26%

As of December 31, 2018 and 2017, the borrowings outstanding under Avista Corp.'s committed line of credit were classified as short-term borrowings on the Balance Sheet.

NOTE 11. BONDS

The following details long-term debt outstanding as of December 31 (dollars in thousands):

Maturity Year	Description	Interest Rate	2018	2017
Avista Corp. Secured Long-Term Debt				
2018	First Mortgage Bonds	5.95%	—	250,000
2018	Secured Medium-Term Notes	7.39%-7.45%	—	22,500
2019	First Mortgage Bonds	5.45%	90,000	90,000
2020	First Mortgage Bonds	3.89%	52,000	52,000
2022	First Mortgage Bonds	5.13%	250,000	250,000
2023	Secured Medium-Term Notes	7.18%-7.54%	13,500	13,500
2028	Secured Medium-Term Notes	6.37%	25,000	25,000
2032	Secured Pollution Control Bonds (1)	(1)	66,700	66,700
2034	Secured Pollution Control Bonds (1)	(1)	17,000	17,000
2035	First Mortgage Bonds	6.25%	150,000	150,000
2037	First Mortgage Bonds	5.70%	150,000	150,000
2040	First Mortgage Bonds	5.55%	35,000	35,000
2041	First Mortgage Bonds	4.45%	85,000	85,000
2044	First Mortgage Bonds	4.11%	60,000	60,000
2045	First Mortgage Bonds	4.37%	100,000	100,000
2047	First Mortgage Bonds	4.23%	80,000	80,000
2047	First Mortgage Bonds	3.91%	90,000	90,000
2048	First Mortgage Bonds (2)	4.35%	375,000	—
2051	First Mortgage Bonds	3.54%	175,000	175,000
	Total secured bonds		1,814,200	1,711,700
	Secured Pollution Control Bonds held by Avista Corporation (1)		(83,700)	(83,700)
	Total long-term debt		$ 1,730,500	$ 1,628,000

(1) In December 2010, $66.7 million and $17.0 million of the City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) due in 2032 and 2034, respectively, which had been held by Avista Corp. since 2008 and 2009, respectively, were refunded by new variable rate bond issues (Series 2010A and Series 2010B). The new bonds were not offered to the public and were purchased by Avista Corp. due to market conditions. The Company expects that at a later date, subject to market conditions, these bonds may be remarketed to unaffiliated investors. So long as Avista Corp. is the holder of these bonds, the bonds will not be reflected as an asset or a liability on Avista Corp.'s Balance Sheets.

(2) In May 2018, the Company issued and sold $375.0 million of 4.35 percent first mortgage bonds due in 2048 through a public offering. The total net proceeds from the sale of the bonds were used to repay maturing long-term debt of $272.5 million, repay the outstanding balance under Avista Corp.'s $400.0 million committed line of credit and for other general corporate purposes. In connection with the issuance and sale of the first mortgage bonds, the Company cash-settled fourteen interest rate swap derivatives (notional aggregate amount of $275.0 million) and paid a net amount of $26.6 million. See Note 4 for a discussion of interest rate swap derivatives.

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

	2019	2020	2021	2022	2023	Thereafter	Total
Debt maturities	$ 90,000	$ 52,000	$ —	$ 250,000	$ 13,500	$ 1,376,547	$ 1,782,047

Substantially all of Avista Corp.'s owned properties are subject to the lien of its mortgage indenture. Under the Mortgage and Deed of Trust (Mortgage) securing its first mortgage bonds (including secured medium-term notes), Avista Corp. may issue additional first mortgage bonds under its mortgage in an aggregate principal amount equal to the sum of:

- 66-2/3 percent of the cost or fair value (whichever is lower) of property additions which have not previously been made the basis of any application under the Mortgage, or
- an equal principal amount of retired first mortgage bonds which have not previously been made the basis of any application under the Mortgage, or
- deposit of cash.

Avista Corp. may not issue any additional first mortgage bonds (with certain exceptions in the case of bonds issued on the basis of retired bonds) unless it has "net earnings" (as defined in the Mortgage) for any period of 12 consecutive calendar months out of the preceding 18 calendar months that 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, 2018, property additions and retired bonds would have allowed, and the net earnings test would not have prohibited, the issuance of $1.2 billion in aggregate principal amount of additional first mortgage bonds at Avista Corp.

NOTE 12. ADVANCES FROM ASSOCIATED COMPANIES

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

The distribution rates paid were as follows during the years ended December 31:

	2018	2017	2016
Low distribution rate	2.36%	1.81%	1.29%
High distribution rate	3.61%	2.36%	1.81%
Distribution rate at the end of the year	3.61%	2.36%	1.81%

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

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

NOTE 13. FAIR VALUE

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

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

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

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

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

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

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

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

	2018		2017	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Long-term debt (Level 2)	$ 1,053,500	$ 1,142,292	$ 951,000	$ 1,067,783
Long-term debt (Level 3)	677,000	645,523	677,000	713,147
Long-term debt to affiliated trusts (Level 3)	51,547	38,145	51,547	41,882

These estimates of fair value of long-term debt and long-term debt to affiliated trusts were primarily based on available market information, which generally consists of estimated market prices from third party brokers for debt with similar risk and terms. The price ranges obtained from the third party brokers consisted of par values of 74.00 to 121.49, where a par value of 100.00 represents the carrying value recorded on the Balance Sheets. Level 2 long-term debt represents publicly issued bonds with quoted market prices; however, due to their limited trading activity, they are classified as Level 2 because brokers must generate quotes and make estimates using comparable debt with similar risk and terms if there is no trading activity near a period end. Level 3 long-term debt consists of private placement bonds and debt to affiliated trusts, which typically have no secondary trading activity. Fair values in Level 3 are estimated based on market prices from third party brokers using secondary market quotes for debt with similar risk and terms to generate quotes for Avista Corp. bonds.

The following table discloses by level within the fair value hierarchy the Company's assets and liabilities measured and reported on the Balance Sheets as of December 31, 2018 at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting (1)	Total
December 31, 2018					
Assets:					
Energy commodity derivatives	$ —	$ 36,252	$ —	$ (35,982)	$ 270
Level 3 energy commodity derivatives:					
Natural gas exchange agreements	—	—	31	(31)	—
Interest rate swap derivatives	—	10,566	—	(440)	10,126
Deferred compensation assets:					
Mutual Funds:					
Fixed income securities	1,745	—	—	—	1,745
Equity securities	6,157	—	—	—	6,157
Total	$ 7,902	$ 46,818	$ 31	$ (36,453)	$ 18,298
Liabilities:					
Energy commodity derivatives	$ —	$ 89,283	$ —	$ (87,199)	$ 2,084
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	2,805	(31)	2,774
Power exchange agreement	—	—	2,488	—	2,488
Power option agreement	—	—	1	—	1
Foreign currency exchange derivatives	—	45	—	—	45
Interest rate swap derivatives	—	7,831	—	(970)	6,861
Total	$ —	$ 97,159	$ 5,294	$ (88,200)	$ 14,253

The following table discloses by level within the fair value hierarchy the Company's assets and liabilities measured and reported on the Balance Sheets as of December 31, 2017 at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting (1)	Total
December 31, 2017					
Assets:					
Energy commodity derivatives	$ —	$ 43,814	$ —	$ (42,550)	$ 1,264
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	183	(183)	—
Foreign currency exchange derivatives	—	32	—	(1)	31
Interest rate swap derivatives	—	7,477	—	(2,574)	4,903

Deferred compensation assets:					
Mutual Funds:					
Fixed income securities	1,638	—	—	—	1,638
Equity securities	6,631	—	—	—	6,631
Total	$ 8,269	$ 51,323	$ 183	$ (45,308)	$ 14,467

Liabilities:					
Energy commodity derivatives	$ —	$ 71,342	$ —	$ (69,988)	$ 1,354
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	3,347	(183)	3,164
Power exchange agreement	—	—	13,245	—	13,245
Power option agreement	—	—	19	—	19
Foreign currency exchange derivatives	—	1	—	(1)	—
Interest rate swap derivatives	—	73,513	—	(37,544)	35,969
Total	$ —	$ 144,856	$ 16,611	$ (107,716)	$ 53,751

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

The difference between the amount of derivative assets and liabilities disclosed in respective levels in the table above and the amount of derivative assets and liabilities disclosed on the Balance Sheets is due to netting arrangements with certain counterparties. See Note 4 for additional discussion of derivative netting.

To establish fair value for energy commodity derivatives, the Company uses quoted market prices and forward price curves to estimate the fair value of energy commodity derivative instruments included in Level 2. In particular, electric derivative valuations are performed using market quotes, adjusted for periods in between quotable periods. Natural gas derivative valuations are estimated using New York Mercantile Exchange pricing for similar instruments, adjusted for basin differences, using market quotes. Where observable inputs are available for substantially the full term of the contract, the derivative asset or liability is included in Level 2.

To establish fair values for interest rate swap derivatives, the Company uses forward market curves for interest rates for the term of the swaps and discounts the cash flows back to present value using an appropriate discount rate. The discount rate is calculated by third party brokers according to the terms of the swap derivatives and evaluated by the Company for reasonableness, with consideration given to the potential non-performance risk by the Company. Future cash flows of the interest rate swap derivatives are equal to the fixed interest rate in the swap compared to the floating market interest rate multiplied by the notional amount for each period.

To establish fair value for foreign currency derivatives, the Company uses forward market curves for Canadian dollars against the US dollar and multiplies the difference between the locked-in price and the market price by the notional amount of the derivative. Forward foreign currency market curves are provided by third party brokers. The Company's credit spread is factored into the locked-in price of the foreign exchange contracts.

Deferred compensation assets and liabilities represent funds held by the Company in a Rabbi Trust for an executive deferral plan. These funds consist of actively traded equity and bond funds with quoted prices in active markets. The balance disclosed in the table above excludes cash and cash equivalents of $0.5 million as of December 31, 2018 and $0.2 million as of December 31, 2017.

Level 3 Fair Value

Under the power exchange agreement the Company purchases power at a price that is based on the average operating and maintenance (O&M) charges from three surrogate nuclear power plants around the country. To estimate the fair value of this agreement the Company estimates the difference between the purchase price based on the future O&M charges and forward prices for energy. The Company compares the Level 2 brokered quotes and forward price curves described above to an internally developed forward price which is based on the average O&M charges from the three surrogate nuclear power plants for the current year. The Company estimates the volumes of the transactions that will take place in the future based on historical average transaction volumes per delivery year (November to April). Significant increases or decreases in any of these inputs in isolation would result in a significantly higher or lower fair value measurement.

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

In addition to the above, the Company also has power option agreements which expire in June 2019. The Company uses the Black-Scholes-Merton valuation model to estimate the fair value, and this model includes significant inputs not observable or corroborated in the market. These inputs include: 1) the strike price (which is an internally derived price based on a combination of generation plant heat rate factors, natural gas market pricing, delivery and other O&M charges) and 2) estimated delivery volumes. Due to the short duration remaining for the power option agreements and their insignificant dollar value, the Company has elected to exclude these agreements from the below Level 3 disclosures.

The following table presents the quantitative information which was used to estimate the fair values of the Level 3 assets and liabilities above as of December 31, 2018 (dollars in thousands):

	Fair Value (Net) at December 31, 2018	Valuation Technique	Unobservable Input	Range
Power exchange agreement	$ (2,488)	Surrogate facility	O&M charges	$40.05-$52.59/MWh (1)
		pricing	Transaction volumes	173,465 MWhs
Natural gas exchange agreement	(2,774)	Internally derived weighted-average cost of gas	Forward purchase prices	$1.44 - $1.88/mmBTU
			Forward sales prices	$1.47 - $3.34/mmBTU
			Purchase volumes	115,000 - 310,000 mmBTUs
			Sales volumes	60,000 - 310,000 mmBTUs

(1) The average O&M charges for the delivery year beginning in November 2018 are $45.61 per MWh.

The valuation methods, significant inputs and resulting fair values described above were developed by the Company's management and are reviewed on at least a quarterly basis to ensure they provide a reasonable estimate of fair value each reporting period.

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

	Natural Gas Exchange Agreement	Power Exchange Agreement	Total
Year ended December 31, 2018:			
Balance as of January 1, 2018	$ (3,164)	$ (13,245)	$ (16,409)
Total gains or (losses) (realized/unrealized):			
Included in regulatory assets/liabilities (1)	326	5,027	5,353
Settlements	64	5,730	5,794
Ending balance as of December 31, 2018 (2)	$ (2,774)	$ (2,488)	$ (5,262)
Year ended December 31, 2017:			
Balance as of January 1, 2017	$ (5,885)	$ (13,449)	$ (19,334)
Total gains or (losses) (realized/unrealized):			
Included in regulatory assets/liabilities (1)	3,292	(7,674)	(4,382)
Settlements	(571)	7,878	7,307
Ending balance as of December 31, 2017 (2)	$ (3,164)	$ (13,245)	$ (16,409)

(1) All gains and losses are included in other regulatory assets and liabilities. There were no gains and losses included in either net income or other comprehensive income during any of the periods presented in the table above.
(2) There were no purchases, issuances or transfers from other categories of any derivatives instruments during the periods presented in the table above.

NOTE 14. COMMON STOCK

The payment of dividends on common stock could be limited by:

- certain covenants applicable to preferred stock (when outstanding) contained in the Company's Restated Articles of Incorporation, as amended (currently there are no preferred shares outstanding),
- certain covenants applicable to the Company's outstanding long-term debt and committed line of credit agreements,
- the hydroelectric licensing requirements of section 10(d) of the FPA (see Note 1), and
- certain requirements under the OPUC approval of the AERC acquisition in 2014. The OPUC's AERC acquisition order requires Avista Corp. to maintain a capital structure of no less than 40 percent common equity (inclusive of short-term debt). This limitation may be revised upon request by the Company with approval from the OPUC.

As of December 31, 2018, the acquisition of the Company by Hydro One had not yet been terminated. As such, the Merger Agreement was still in effect at that time. Under the Merger Agreement, the annual dividends were not to increase by more than $0.06 per year over the 2017 dividend rate, thus limiting annual dividends to $1.49 per share.

Now that the Merger Agreement has been terminated, the requirements of the OPUC approval of the AERC acquisition are the most restrictive. Under the OPUC restriction, the amount available for dividends at December 31, 2018 was limited to $231.1 million.

The Company has 10 million authorized shares of preferred stock. The Company did not have any preferred stock outstanding as of December 31, 2018 and 2017.

Equity Issuances

The Company has entered into four separate sales agency agreements under which the sales agents may offer and sell new shares of the Company's common stock from time to time. No shares were issued under these agreements during 2018. These agreements provide for the offering of a maximum of 3.8 million shares, of which approximately 1.1 million remain unissued as of December 31, 2018. Subject to the satisfaction of customary conditions (including any required regulatory approvals), the Company has the right to increase the maximum number of shares that may be offered under these agreements.

NOTE 15. COMMITMENTS AND CONTINGENCIES

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

California Refund Proceeding

In February 2016, APX, a market maker in the California Refund Proceedings in whose markets Avista Energy participated in the summer of 2000, asserted that Avista Energy and its other customer/participants may be responsible for a share of the disgorgement penalty APX may be found to owe to Pacific Gas & Electric, Southern California Edison, San Diego Gas & Electric, the California Attorney General, the California Department of Water Resources, and the California Public Utilities Commission (together, the "California Parties"). The penalty was the result of the FERC's finding that APX committed violations in the California market in the summer of 2000. APX made these assertions despite Avista Energy having been dismissed in FERC Opinion No. 536 from the on-going administrative proceeding at the FERC regarding potential wrongdoing in the California markets in the summer of 2000. APX identified Avista Energy's share of APX's exposure to be as much as $16.0 million even though no wrongdoing allegations were specifically attributable to Avista Energy. Avista Energy asserted its settlement with the California Parties in 2014 insulated it from any such liability and that as a dismissed party it would not be drawn back into the litigation. On May 3, 2018, the FERC issued an order, Order on Compliance Filings, resolving in the Company's favor the last indirect exposure the Company had related to the California Refund Proceedings. That order, which fully absolved the Company of any further exposure, was not challenged and is now final and not subject to appeal.

Cabinet Gorge Total Dissolved Gas Abatement Plan

Dissolved atmospheric gas levels (referred to as "Total Dissolved Gas" or "TDG") in the Clark Fork River exceed state of Idaho and federal water quality numeric standards downstream of Cabinet Gorge particularly during periods when excess river flows must be diverted over the spillway. Under the terms of the Clark Fork Settlement Agreement as incorporated in Avista Corp.'s FERC license for the Clark Fork Project, Avista Corp. has worked in consultation with agencies, tribes and other stakeholders to address this issue. Under the terms of a gas supersaturation mitigation plan, Avista Corp. is reducing TDG by constructing spill crest modifications on spill gates at the dam. These modifications have been shown to be effective in reducing TDG downstream. TDG monitoring and analysis is ongoing. Under the terms of the mitigation plan, Avista Corp. will continue to work with stakeholders to determine the degree to which TDG abatement reduces future mitigation obligations. The Company has sought, and will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to this issue.

Collective Bargaining Agreements

The Company's collective bargaining agreements with the IBEW represent approximately 45 percent of all of Avista Corp.'s employees. A three-year agreement with the local union in Washington and Idaho representing the majority (approximately 90 percent) of the Avista Corp.'s bargaining unit employees was approved in March 2016 and expires in March 2019. The Company is currently negotiating a new agreement with the IBEW.

A three-year agreement in Oregon, which covers approximately 50 employees will expire in March 2020.

There is a risk that if collective bargaining agreements expire and new agreements are not reached in each of our jurisdictions, employees could strike. Given the magnitude of employees that are covered by collective bargaining agreements, this could result in disruptions to our operations. However, the Company believes that the possibility of this occurring is remote.

Legal Proceedings Related to the Proposed Acquisition by Hydro One

See Note 17 for information regarding the termination of the proposed acquisition of the Company by Hydro One.

In connection with the now terminated acquisition, three lawsuits were filed in the United States District Court for the Eastern District of Washington and were subsequently voluntarily dismissed by the plaintiffs.

One lawsuit was filed in the Superior Court for the State of Washington in and for Spokane County, captioned as follows:

- *Fink v. Morris, et al.,* No. 17203616-6 (filed September 15, 2017, amended complaint filed October 25, 2017).

This lawsuit was filed against Hydro One Limited, Olympus Holding Corp., Olympus Corp. and Bank of America Merrill Lynch, as well as all members of the Company's Board of Directors, namely Erik Anderson, Kristianne Blake, Donald Burke, Rebecca Klein, Scott Maw, Scott Morris, Marc Racicot, Heidi Stanley, John Taylor and Janet Widmann. While Avista Corp. is not a named defendant in this lawsuit, the Company has the obligation to indemnify members of its Board of Directors.

The complaint generally alleges that the members of the Board breached their fiduciary duties by, among other things, conducting an allegedly inadequate sale process and agreeing to the acquisition at a price that allegedly undervalues Avista Corporation, and that Hydro One Limited, Olympus Holding Corp., and Olympus Corp. aided and abetted those purported breaches of duty. The aiding and abetting claims were brought only against Hydro One Limited, Olympus Holding Corp. and Olympus Corp. The complaint seeks various remedies, including monetary damages, attorneys' fees and expenses. The complaint was stayed by the court until the closing of the transaction at which time the plaintiff would have the option to file an amended complaint within 30 days of such closing. If the amended complaint was not filed within the 30 days the suit would be dismissed. Since the transaction will not close, the status of this lawsuit is unknown.

All defendants deny any wrongdoing in connection with the proposed acquisition and plan to vigorously defend against all pending claims; however, the Company cannot at this time predict the eventual outcome.

2015 Washington General Rate Cases

In January 2016, the Company received an order (Order 05) that concluded its electric and natural gas general rate cases that were originally filed with the WUTC in February 2015. New electric and natural gas rates were effective on January 11, 2016.

WUTC Order Denying Industrial Customers of Northwest Utilities / Public Counsel Joint Motion for Clarification, WUTC Staff Motion to Reconsider and WUTC Staff Motion to Reopen Record

In January 2016, the Industrial Customers of Northwest Utilities, the Public Counsel Unit of the Washington State Office of the

Attorney General (PC) and the WUTC Staff, which is a separate party in the general rate case proceedings from the WUTC Advisory Staff, filed Motions for Clarification requesting the WUTC to clarify their attrition adjustment and the end result electric revenue amounts. The Motions for Clarification suggested that the electric revenue decrease should have been significantly larger than what was included in Order 05.

In February 2016, the WUTC issued an order (Order 06) denying the Motions summarized above and affirming Order 05, including an $8.1 million decrease in electric base revenue.

PC Petition for Judicial Review

In March 2016, PC filed in Thurston County Superior Court a Petition for Judicial Review of the WUTC's Order 05 and Order 06 described above. In April 2016, this matter was certified for review directly by the Court of Appeals, an intermediate appellate court in the State of Washington.

On August 7, 2018, the Court of Appeals issued a "Published Opinion" (Opinion) which concluded that the WUTC's use of an attrition allowance to calculate Avista Corp.'s rate base violated Washington law. In the Opinion, the Court stated that because the projected additions to rate base in the future were not "used and useful" for service at the time the request for the rate increase was made, they may not lawfully be included in the Company's rate base to justify a rate increase. Accordingly, the Court concluded that the WUTC erred in including an attrition allowance in the calculation of Avista Corp.'s electric and natural gas rate base. The Court noted, however, that the law does not prohibit an attrition allowance in the calculation, for ratemaking purposes, of recoverable operating and maintenance expense. Since the WUTC order provided one lump sum attrition allowance without distinguishing what portion was for rate base and which was for operating and maintenance expenses or other considerations, the Court struck all portions of the attrition allowance attributable to Avista Corp.'s rate base and reversed and remanded the case for the WUTC to recalculate Avista Corp.'s rates without including an attrition allowance in the calculation of rate base. On October 1, 2018, the Court of Appeals terminated its review of this case, remanding it back to the Thurston County Superior Court.

The total attrition allowance approved by the WUTC in Order 05 and reaffirmed in Order 06 was $35.2 million, with $28.3 million related to electric and $6.9 million related to natural gas. The Company believes the potential amount to return to customers is limited to the 2015 general rate cases because in subsequent Washington general rate cases (specifically those approved in April 2018), the WUTC did not include any attrition allowance on rate base. Even though the Company believes the issue only relates to the 2015 general rate cases, the Company cannot predict the outcome of this matter at this time and cannot estimate how much, if any, of the attrition allowance may be removed from the general rate cases or if other amounts from subsequent general rate cases will be included. The Company will participate in any regulatory process that is yet to be established by the WUTC.

Other Contingencies

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

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

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

Under the federal licenses for its hydroelectric projects, the Company is obligated to protect its property rights, including water rights. In addition, the company holds additional non-hydro water rights. The state of Montana is examining the status of all water right claims within state boundaries through a general adjudication. Claims within the Clark Fork River basin could adversely affect the energy production of the Company's Cabinet Gorge and Noxon Rapids hydroelectric facilities. The state of Idaho has initiated adjudication in northern Idaho, which will ultimately include the lower Clark Fork River, the Spokane River and the Coeur d'Alene basin. The Company is and will continue to be a participant in these and any other relevant adjudication processes. The complexity of such adjudications makes each unlikely to be concluded in the foreseeable future. As such, it is not possible for the Company to estimate the impact of any outcome at this time. The Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to this issue.

NOTE 16. REGULATORY MATTERS

Power Cost Deferrals and Recovery Mechanisms

Deferred power supply costs are recorded as a deferred charge or liability on the Balance Sheets for future prudence review and recovery or rebate 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, availability and optimization of hydroelectric generation,
- the level and availability of thermal generation (including changes in fuel prices),
- retail loads, and
- sales of surplus transmission capacity.

In Washington, the ERM allows Avista Corp. to periodically increase or decrease electric rates with WUTC approval to reflect changes in power supply costs. The ERM is an accounting method used to track certain differences between actual power supply costs, net of wholesale sales and sales of fuel, and the amount included in base retail rates for Washington customers and defer these differences (over the $4.0 million deadband and sharing bands) for future surcharge or rebate to customers. For 2018, the Company recognized a pre-tax benefit of $6.1 million under the ERM in Washington compared to a benefit of $4.6 million for 2017. Total net deferred power costs under the ERM were a liability of $34.4 million as of December 31, 2018 and a liability of $23.7 million as of December 31, 2017. These deferred power cost balances represent amounts due to customers. These deferred power cost balances represent amounts due to customers. Pursuant to WUTC requirements, should the cumulative deferral balance exceed $30 million in the rebate or surcharge direction, the Company must make a filing with the WUTC to adjust customer rates to either return the balance to customers or recover the balance from customers. Avista Corp. makes an annual filing on or before April 1 of each year to provide the opportunity for the WUTC staff and other interested parties to review the prudence of and audit the ERM deferred power cost transactions for the prior calendar year. The filing in 2019 will also contain a proposed rate adjustment or refund, effective July 1, 2019, due to the rebate balance exceeding $30 million.

Avista Corp. has a PCA mechanism in Idaho that allows it to modify electric rates on October 1 of each year with 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. The October 1 rate adjustments recover or rebate power costs deferred during the preceding July-June twelve-month period. Total net power supply costs deferred under the PCA mechanism were a liability of $7.6 million as of December 31, 2018 and a liability of $6.1 million as of December 31, 2017. These deferred power cost balances represent amounts due to customers.

Natural Gas Cost Deferrals and Recovery Mechanisms

Avista Corp. files a 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. Total net deferred natural gas costs to be refunded to customers were a liability of $40.7 million as of December 31, 2018 and a liability of $37.5 million as of December 31, 2017. These balances represent amounts due to customers.

Decoupling and Earnings Sharing Mechanisms

Decoupling (also known as an FCA in Idaho) is a mechanism designed to sever the link between a utility's revenues and consumers' energy usage. In each of Avista Corp.'s jurisdictions, Avista Corp.'s electric and natural gas revenues are adjusted so as to be based on the number of customers in certain customer rate classes and assumed "normal" kilowatt hour and therm sales, rather than being based on actual kilowatt hour and therm sales. The difference between revenues based on the number of customers and "normal" sales and revenues based on actual usage is deferred and either surcharged or rebated to customers beginning in the following year. Only residential and certain commercial customer classes are included in decoupling mechanisms.

Washington Decoupling and Earnings Sharing

In Washington, the WUTC approved the Company's decoupling mechanisms for electric and natural gas for a five-year period beginning January 1, 2015. In February 2019, the WUTC approved an all-party agreement that extends the life of the mechanisms through the end of the Company's next general rate case, or April 1, 2020, whichever comes first. In that general rate case the Company will seek to either make permanent or extend the mechanisms for an additional multi-year term. Electric and natural gas decoupling surcharge rate adjustments to customers are limited to a 3 percent increase on an annual basis, with any remaining surcharge balance carried forward for recovery in a future period. There is no limit on the level of rebate rate adjustments.

The decoupling mechanisms each include an after-the-fact earnings test. At the end of each calendar year, separate electric and natural gas earnings calculations are made for the calendar year just ended. These earnings tests reflect actual decoupled revenues, normalized power supply costs and other normalizing adjustments. If the Company earns more than its authorized ROR in Washington, 50 percent of excess earnings are rebated to customers through adjustments to decoupling surcharge or rebate balances. See below for a summary of cumulative balances under the decoupling and earnings sharing mechanisms.

Idaho FCA and Earnings Sharing Mechanisms

In Idaho, the IPUC approved the implementation of FCAs for electric and natural gas (similar in operation and effect to the Washington decoupling mechanisms) for an initial term of three years, beginning January 1, 2016. During the first quarter of 2018, the FCA in Idaho was extended for a one-year term through December 31, 2019. The Company expects to seek an extension of the FCAs in its next general rate case, expected in the second quarter of 2019.

Oregon Decoupling Mechanism

In February 2016, the OPUC approved the implementation of a decoupling mechanism for natural gas, similar to the Washington and Idaho mechanisms described above. The decoupling mechanism became effective on March 1, 2016. There will be an opportunity for interested parties to review the mechanism and recommend changes, if any, by September 2019. In Oregon, an earnings review is conducted on an annual basis. In the annual earnings review, if the Company earns more than 100 basis points above its allowed ROE, one-third of the earnings above the 100 basis points would be deferred and later returned to customers. The earnings review is separate from the decoupling mechanism and was in place prior to decoupling. See below for a summary of cumulative balances under the decoupling and earnings sharing mechanisms.

Cumulative Decoupling and Earnings Sharing Mechanism Balances

As of December 31, 2018 and December 31, 2017, the Company had the following cumulative balances outstanding related to decoupling and earnings sharing mechanisms in its various jurisdictions (dollars in thousands):

	December 31, 2018	December 31, 2017
Washington		
Decoupling surcharge	$ 12,671	$ 14,240
Provision for earnings sharing rebate	(693)	(3,420)
Idaho		
Decoupling surcharge	$ 2,150	$ 3,471
Provision for earnings sharing rebate	(774)	(2,350)
Oregon		
Decoupling rebate	$ (898)	$ (1,168)
Provision for earnings sharing rebate	—	—

NOTE 17. TERMINATION OF PROPOSED ACQUISITION BY HYDRO ONE

On July 19, 2017, Avista Corp. entered into a Merger Agreement that provided for Avista Corp. to become an indirect, wholly-owned subsidiary of Hydro One, subject to the satisfaction or waiver of specified closing conditions, including approval by regulatory agencies. Hydro One, based in Toronto, is Ontario’s largest electricity transmission and distribution provider.

At the effective time of the acquisition, each share of Avista Corp. common stock issued and outstanding, other than shares of Avista Corp. common stock that are owned by Hydro One and its affiliates, were to be converted automatically into the right to receive an amount in cash equal to $53, without interest.

Denial by Regulatory Commissions

The closing of the acquisition was subject to various conditions, including, among others, receipt of regulatory approval from the WUTC, IPUC, MPSC, OPUC, and the RCA.

Washington - On March 27, 2018, Avista Corp. and Hydro One filed an all-parties (including the WUTC Staff), all-issues settlement agreement with the WUTC recommending approval of the acquisition of the Company by Hydro One. The settlement agreement was subject to WUTC approval.

On December 5, 2018, the Company and Hydro One received a decision from the WUTC, denying the proposed acquisition. On December 17, 2018, the Company and Hydro One filed a petition requesting that the WUTC reconsider its December 5, 2018 order denying approval of the acquisition, together with a petition requesting that the WUTC rehear the matter to accept new evidence. Under Washington State law, the WUTC had 20 days to act on the petition for reconsideration.

On January 8, 2019, the WUTC provided notice of its deemed denial by operation of law of the filed petition to reconsider the denial of approval for the acquisition. The WUTC did not take action on the petition within the required 20 days of its filing so the petition was automatically denied under the state's Administrative Procedure Act. In the same notice, the WUTC also denied the petition for a rehearing on the basis that it does not apply.

Idaho - On April 13, 2018, Avista Corp. and Hydro One filed an all-issues settlement agreement (to which the IPUC Staff was a party) with the IPUC recommending approval of the acquisition of the Company by Hydro One. The settlement agreement was subject to IPUC approval.

On January 3, 2019, the Company and Hydro received a decision from the IPUC, finding that the proposed acquisition was not permitted by Idaho law**.** Avista Corp. and Hydro One had until January 24, 2019 to file a petition for reconsideration with the IPUC, which they did not file.

Oregon - On May 25, 2018, Avista Corp. and Hydro One filed an all-parties (including the OPUC Staff), all-issues settlement agreement with the OPUC related to the Oregon merger proceeding. The settlement agreement was subject to review and approval by the OPUC.

On January 15, 2019, due to the denial of the acquisition by the WUTC and IPUC, the OPUC issued an order suspending indefinitely the procedural schedule in its merger docket until Hydro One and Avista Corp. informed the OPUC that they had sought a reversal of the denial decisions through appeal or other means that would provide a justiciable issue for the OPUC to address.

Termination of the Merger Agreement

On January 23, 2019, Avista Corp., Hydro One and certain subsidiaries thereof, entered into a Termination Agreement indicating their mutual agreement to terminate the Merger Agreement, effective immediately. Pursuant to the terms of the Termination Agreement, Hydro One paid Avista Corp. a $103 million termination fee on January 24, 2019. The termination fee will be used for reimbursing the Company's transaction costs incurred from 2017 to 2019. The balance of the termination fee remaining after payment of 2019 transaction costs and applicable income taxes will be used for general corporate purposes and reduces the Company's need for external financing.

Other Information Related to the Terminated Acquisition

Due to the termination of the acquisition, all the financial commitments that were included in the various settlement agreements with the commissions for the proposed acquisition will not occur.

The Company incurred significant acquisition costs associated with the acquisition consisting primarily of consulting, banking fees, legal fees and employee time, and these costs are not being passed through to customers. When the Company was assuming the transaction was going to be completed, a significant portion of these costs were not deductible for income tax purposes. Now that the transaction has been terminated, the Company expects more of the previously incurred transaction costs to be deductible so it expects additional tax benefits from these costs in 2019.

See Note 15 for discussion of shareholder lawsuits filed against the Company, the Company’s directors, Hydro One, Olympus Holding Corp., and Olympus Corp. in relation to the Merger Agreement and the proposed acquisition.

NOTE 18. SUPPLEMENTAL CASH FLOW INFORMATION

Supplemental cash flow information consisted of the following items for the years ended December 31 (dollars in thousands):

	2018	2017
Cash paid for interest	$ 90,394	$ 88,368
Cash paid for income taxes	16,576	3,832
Cash received for income tax refunds	(3,025)	(46,916)

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2019	Year/Period of Report End of 2018/Q4

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

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

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year		(7,567,509)		
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value		(522,033)		
4	Total (lines 2 and 3)		(522,033)		
5	Balance of Account 219 at End of Preceding Quarter/Year		(8,089,542)		
6	Balance of Account 219 at Beginning of Current Year		(8,089,542)		
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income		(1,742,363)		
8	Current Quarter/Year to Date Changes in Fair Value		1,965,835		
9	Total (lines 7 and 8)		223,472		
10	Balance of Account 219 at End of Current Quarter/Year		(7,866,070)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/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 [Insert Footnote at Line 1 to 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			(7,567,509)		
2					
3			(522,033)		
4			(522,033)	115,916,134	115,394,101
5			(8,089,542)		
6			(8,089,542)		
7			(1,742,363)		
8			1,965,835		
9			223,472	136,429,120	136,652,592
10			(7,866,070)		

Schedule Page: 122(a)(b)   Line No.: 7   Column: c

During the first quarter of 2018, Accounting Standards Update No. 2018-02 was adopted, which resulted in a $1.7 million balance sheet only reclassification from Accumulated Other Comprehensive Loss to account 439 - Adjustments to Retained Earnings. The reclassification was the result of the change in federal income tax rates from 35 percent to 21 percent. Usage of account 439 requires prior FERC approval. See Page 123 Note 2 for further discussion of the adoption of ASU No. 2018-02 as well as the prior FERC approval.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/Q4

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

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

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	5,995,428,313	4,157,842,860
4	Property Under Capital Leases		
5	Plant Purchased or Sold	286,320	286,320
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	5,995,714,633	4,158,129,180
9	Leased to Others		
10	Held for Future Use	9,036,047	8,130,526
11	Construction Work in Progress	156,563,570	113,918,710
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	6,161,314,250	4,280,178,416
14	Accum Prov for Depr, Amort, & Depl	1,991,240,383	1,450,183,104
15	Net Utility Plant (13 less 14)	4,170,073,867	2,829,995,312
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	1,895,743,265	1,426,663,880
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	95,497,118	23,519,224
22	Total In Service (18 thru 21)	1,991,240,383	1,450,183,104
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	1,991,240,383	1,450,183,104

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
1,238,294,830				599,290,623	3
					4
					5
					6
					7
1,238,294,830				599,290,623	8
					9
190,585				714,936	10
4,595,404				38,049,456	11
					12
1,243,080,819				638,055,015	13
378,705,925				162,351,354	14
864,374,894				475,703,661	15
					16
					17
377,778,951				91,300,434	18
					19
					20
926,974				71,050,920	21
378,705,925				162,351,354	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
378,705,925				162,351,354	33

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2019	Year/Period of Report End of 2018/Q4

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

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents	44,651,922	
4	(303) Miscellaneous Intangible Plant	22,557,104	3,653,286
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	67,209,026	3,653,286
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	3,577,689	
9	(311) Structures and Improvements	134,944,679	1,034,991
10	(312) Boiler Plant Equipment	171,469,669	5,345,256
11	(313) Engines and Engine-Driven Generators	6,770	
12	(314) Turbogenerator Units	63,985,254	1,445,281
13	(315) Accessory Electric Equipment	28,369,273	364,308
14	(316) Misc. Power Plant Equipment	18,554,134	794,098
15	(317) Asset Retirement Costs for Steam Production	14,327,505	625
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	435,234,973	8,984,559
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	62,609,600	1,203,674
28	(331) Structures and Improvements	81,012,072	6,699,817
29	(332) Reservoirs, Dams, and Waterways	190,208,719	8,307,868
30	(333) Water Wheels, Turbines, and Generators	226,782,330	9,965,669
31	(334) Accessory Electric Equipment	62,376,922	5,604,645
32	(335) Misc. Power PLant Equipment	13,148,877	956,737
33	(336) Roads, Railroads, and Bridges	3,634,544	706,917
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	639,773,064	33,445,327
36	D. Other Production Plant		
37	(340) Land and Land Rights	905,167	
38	(341) Structures and Improvements	17,065,465	79,268
39	(342) Fuel Holders, Products, and Accessories	21,468,767	9,310
40	(343) Prime Movers	23,909,470	
41	(344) Generators	217,074,024	614,662
42	(345) Accessory Electric Equipment	20,992,996	1,125,415
43	(346) Misc. Power Plant Equipment	1,744,341	4,195
44	(347) Asset Retirement Costs for Other Production	351,683	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	303,511,913	1,832,850
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,378,519,950	44,262,736

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

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

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

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

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
					2
			44,651,922		3
1,331,233			24,879,157		4
1,331,233			69,531,079		5
					6
					7
		783	3,578,472		8
215,933		3,772,370	139,536,107		9
1,514,790		5,690,091	180,990,226		10
			6,770		11
311,471		-8,340,899	56,778,165		12
9,466		861,084	29,585,199		13
14,312		-2,208,755	17,125,165		14
625			14,327,505		15
2,066,597		-225,326	441,927,609		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			63,813,274		27
536,294			87,175,595		28
4,006,928			194,509,659		29
577,449			236,170,550		30
927,344			67,054,223		31
824			14,104,790		32
2,372			4,339,089		33
					34
6,051,211			667,167,180		35
					36
			905,167		37
9,313			17,135,420		38
89,855			21,388,222		39
401,409			23,508,061		40
280,407			217,408,279		41
15,912			22,102,499		42
			1,748,536		43
			351,683		44
796,896			304,547,867		45
8,914,704		-225,326	1,413,642,656		46

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	27,620,102	2,897,147
49	(352) Structures and Improvements	24,994,681	1,262,819
50	(353) Station Equipment	255,649,181	14,474,504
51	(354) Towers and Fixtures	17,175,333	123,115
52	(355) Poles and Fixtures	243,705,147	20,789,629
53	(356) Overhead Conductors and Devices	145,560,399	3,072,992
54	(357) Underground Conduit	3,138,696	49,664
55	(358) Underground Conductors and Devices	2,450,362	85,914
56	(359) Roads and Trails	2,103,635	-49,736
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	722,397,536	42,706,048
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	10,530,766	6,587
61	(361) Structures and Improvements	24,047,759	10,127,465
62	(362) Station Equipment	130,313,022	9,923,629
63	(363) Storage Battery Equipment	2,597,845	-38,230
64	(364) Poles, Towers, and Fixtures	381,898,431	25,716,217
65	(365) Overhead Conductors and Devices	253,180,672	15,629,118
66	(366) Underground Conduit	112,539,526	6,369,404
67	(367) Underground Conductors and Devices	197,371,598	12,451,392
68	(368) Line Transformers	254,595,622	15,331,567
69	(369) Services	166,356,249	7,480,962
70	(370) Meters	49,703,049	7,673,370
71	(371) Installations on Customer Premises	1,088,704	402,122
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	59,315,945	5,337,031
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,643,539,188	116,410,634
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	398,664	100,006
87	(390) Structures and Improvements	8,239,126	116,798
88	(391) Office Furniture and Equipment	3,079,138	115,466
89	(392) Transportation Equipment	42,828,565	5,583,261
90	(393) Stores Equipment	399,249	
91	(394) Tools, Shop and Garage Equipment	4,554,286	1,085,417
92	(395) Laboratory Equipment	1,472,998	181,365
93	(396) Power Operated Equipment	31,946,905	567,676
94	(397) Communication Equipment	64,470,097	2,073,945
95	(398) Miscellaneous Equipment	149,694	2,322
96	SUBTOTAL (Enter Total of lines 86 thru 95)	157,538,722	9,826,256
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)	157,538,722	9,826,256
100	TOTAL (Accounts 101 and 106)	3,969,204,422	216,858,960
101	(102) Electric Plant Purchased (See Instr. 8)		286,320
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)	3,969,204,422	217,145,280

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
1,009		-2,034,829	28,481,411		48
22,140			26,235,360		49
2,547,005			267,576,680		50
7,300			17,291,148		51
1,955,104			262,539,672		52
1,341,419			147,291,972		53
			3,188,360		54
			2,536,276		55
			2,053,899		56
					57
5,873,977		-2,034,829	757,194,778		58
					59
			10,537,353		60
83,430			34,091,794		61
1,909,532			138,327,119		62
			2,559,615		63
1,525,305			406,089,343		64
126,202			268,683,588		65
28,303			118,880,627		66
356,458			209,466,532		67
272,196			269,654,993		68
47,102			173,790,109		69
831,066			56,545,353		70
			1,490,826		71
					72
1,447,568			63,205,408		73
					74
6,627,162			1,753,322,660		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			498,670		86
113,762			8,242,162		87
459,071			2,735,533		88
1,753,003		32,553	46,691,376		89
			399,249		90
175,456		169,204	5,633,451		91
101,594			1,552,769		92
383,921		23,569	32,154,229		93
451,810			66,092,232		94
			152,016		95
3,438,617		225,326	164,151,687		96
					97
					98
3,438,617		225,326	164,151,687		99
26,185,693		-2,034,829	4,157,842,860		100
			286,320		101
					102
					103
26,185,693		-2,034,829	4,158,129,180		104

Schedule Page: 204 Line No.: 101 Column: c

In August 2018, Avista acquired certain tap lines and easements associated with those tap lines from Bonneville Power Administration (BPA). The purchase price for the transmission assets was $0. As consideration, Avista transferred certain equipment to BPA. Avista recorded the difference in Net Book Value between the two companies in account 102, Electric plant purchased or sold. In August 2018, Avista filed Application for Authorization Pursuant to Section 203 of the Federal Power Act, Docket No. EC18-147 and included proposed accounting entries to record the exchange to account 102 and subsequently clear the account to 114. In November 2018, the FERC, in Docket No. EC18-147-000, prospectively authorized the acquisition of facilities. In January 2019, Avista filed a Supplement to Compliance Filing after a discussion with FERC to include the amortization entry required for Account 114.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.
2. For property having an original cost of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2				
3				
4	Distribution Plant Land, Carlin Bay, Idaho	Dec 2010		162,352
5	Distribution Plant Land, Spokane, Washington	Mar 2011	2021-2026	540,307
6	Transmission Plant Land, Spokane, Washington	Dec 2011	2021-2026	431,600
7	Transmission Plant Land, Spokane, Washington	July 2014		62,168
8	Other Production Plant Land, Spokane, Washington	Dec 2011		40,896
9	Steam Production Plant Land, Spokane, Washington	Dec 2015	2026	3,544,725
10	Transmission Plant Land, Noxon, Montana	Mar 2016	2026	3,292,167
11	Transmission Plant Land, Spokane, Washington	Jan 2017		56,311
12				
13				
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21	Other Property:			
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46				
47	Total			8,130,526

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Cabinet Gorge Fish Passage	19,643,033
2	Substation Rebuilds	12,671,037
3	Saddle Mountain Integration	10,403,483
4	South Region Transmission Voltage Control	6,732,065
5	Lind-Warden 115kV Transmission Line Rebuild	5,851,041
6	Little Falls Powerhouse Redevelopment	4,557,815
7	Irvin Sub - New Construction	4,175,311
8	Substation Asset Mgmt Capital Maintenance	2,870,610
9	Noxon 230 kV Substation - Rebuild	2,494,838
10	Transmission Minor Rebuild	2,201,510
11	Benton-Othello 115 Recond	2,141,318
12	Low Priority Ratings Mitigation	2,033,904
13	Distribution - Spokane North & West	1,998,863
14	Westside 230 kV Substation - Rebuild	1,987,857
15	WSDOT Highway Franchise Consolidation	1,969,708
16	CG HED - Gantry Crane Replacement	1,826,767
17	Transportation Equip	1,661,677
18	CG HED Automation Replacement	1,568,915
19	Productivity Initiative	1,460,546
20	Noxon and Clark Fork Living Facilty Remodel	1,269,469
21	CIP v5 Transition - Cyber Asset Electronic Access	1,141,531
22	Saddle Mountain Integration Phase 2	1,098,966
23	Security Systems	1,052,978
24	Minor Projects <$1M	16,364,223
25		
26	Research, Development, and Demonstrating Projects:	
27	Strategic Initiatives	4,741,245
28		
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43	TOTAL	113,918,710

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/Q4

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

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

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	1,355,247,552	1,355,247,552		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	95,919,425	95,919,425		
4	(403.1) Depreciation Expense for Asset Retirement Costs	268,929	268,929		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	5,818,810	5,818,810		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	-338,327	-338,327		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	101,668,837	101,668,837		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	23,603,721	23,603,721		
13	Cost of Removal	4,213,777	4,213,777		
14	Salvage (Credit)	359,759	359,759		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	27,457,739	27,457,739		
16	Other Debit or Cr. Items (Describe, details in footnote):	-2,794,770	-2,794,770		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	1,426,663,880	1,426,663,880		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	299,160,100	299,160,100		
21	Nuclear Production				
22	Hydraulic Production-Conventional	135,229,633	135,229,633		
23	Hydraulic Production-Pumped Storage				
24	Other Production	126,744,918	126,744,918		
25	Transmission	218,216,511	218,216,511		
26	Distribution	566,893,370	566,893,370		
27	Regional Transmission and Market Operation				
28	General	80,419,348	80,419,348		
29	TOTAL (Enter Total of lines 20 thru 28)	1,426,663,880	1,426,663,880		

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

Includes:

Depreciation offset for non-recoverable plant of ($299,796) for Kettle Falls and Boulder Park
AFUDC Adjustment of ($38,531)

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

Includes:

Change in Removal Work in Progress ($2,794,770)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/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	Investment in Avista Capital	1997		206,138,971
3	Avista Capital - Equity in Earnings			-153,588,304
4	Investment in AERC	2014		89,816,380
5	AERC - Equity in Earnings			18,764,635
6				
7				
8				
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41				
42	Total Cost of Account 123.1 $ 0		TOTAL	161,131,682

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/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
		206,138,971		2
-5,660,192		-159,248,496		3
		89,816,380		4
8,052,196	10,000,000	16,816,831		5
				6
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2,392,004	10,000,000	153,523,686		42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/Q4

MATERIALS AND SUPPLIES

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

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	3,958,296	3,982,104	(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)	25,905,191	30,587,855	
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	3,271,031	3,406,236	(1)
8	Transmission Plant (Estimated)	68,875	69,743	(1)
9	Distribution Plant (Estimated)	367,760	464,542	(1)
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	8,567,566	8,637,790	(1),(2)
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	38,180,423	43,166,166	
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)	42,138,719	47,148,270	

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

(1) Electric

(2) Natural Gas

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

(1) Electric

(2) Natural Gas

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

(1) Electric

(2) Natural Gas

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

(1) Electric

(2) Natural Gas

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

(1) Electric

(2) Natural Gas

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

(1) Electric

(2) Natural Gas

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2019	Year/Period of Report End of 2018/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	EDP Renewables TSR	3,712	186200	3,712	186210
3					
4					
5					
6					
7					
8					
9					
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11					
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13					
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19					
20					
21	**Generation Studies**				
22	Clearwater Wind Interconnect	2,059	186200		
23	Gordon Butte Project #50	2,358	186200		
24	Broadview Solar II Project #51	2,501	186200		
25	Taunton Solar Project #52	57,899	186200		
26	Tokio Solar Project #54	57,762	186200		
27	Kulm Solar Farm Project #57	6,419	186200		
28	Rosenoff Solar Project #58	12,685	186200		
29	Aurora Solar Project #59	18,511	186200		
30	Harrington Solar Project #61	5,655	186200		
31	Clarkston Hts Solar Project #60	27,912	186200		
32	Rattlesnake II Wind Proj #62	7,275	186200		
33	Post Falls HED Project #63	5,507	186200		
34	Kettle Falls Upgrade Proj #66	257	186200		
35	Old Milwaukee Solar Proj #67	1,064	186200		
36	Clearwater Wind II Proj #68	448	186200		
37	Clearwater Wind III Proj #69	786	186200		
38	EnerNOC Batt. Storage Proj #70	6,201	186200		
39	Geronimo Solar Proj #71	2,352	186200		
40	Geronimo Solar Proj #72	984	186200		

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
7					
8					
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11					
12					
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20					
21	**Generation Studies**				
22	Sprague Solar Project #73	1,310	186200		
23	Plum River Solar Project #75	1,711	186200		
24	Royal City Solar Project #76	588	186200		
25	Rattlesnake Flats Project #49	63,199	186200	63,199	186210
26	Lind Solar Project #53	34,919	186200	34,919	186210
27	Saddle Mountain East	92,743	186200	92,743	186210
28	Stump Farmers	179	186200	179	186210
29	Basalt Solar Farm Project #56	847	186200	847	186210
30	Marengo Solar Project #64	1,651	186200	1,651	186210
31	Marcellus Solar Project #65	450	186200	450	186210
32					
33					
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40					

Schedule Page: 231 Line No.: 2 Column: b
Total life to date costs.

Schedule Page: 231 Line No.: 2 Column: d
Total life to date reimbursements. Project closed Q1.

Schedule Page: 231 Line No.: 22 Column: b
Total life to date costs.

Schedule Page: 231 Line No.: 23 Column: b
Total life to date costs.

Schedule Page: 231 Line No.: 24 Column: b
Total life to date costs.

Schedule Page: 231 Line No.: 25 Column: b
Total life to date costs.

Schedule Page: 231 Line No.: 26 Column: b
Total life to date costs.

Schedule Page: 231 Line No.: 27 Column: b
Total life to date costs.

Schedule Page: 231 Line No.: 28 Column: b
Total life to date costs.

Schedule Page: 231 Line No.: 29 Column: b
Total life to date costs.

Schedule Page: 231 Line No.: 30 Column: b
Total life to date costs.

Schedule Page: 231 Line No.: 31 Column: b
Total life to date costs.

Schedule Page: 231 Line No.: 32 Column: b
Total life to date costs.

Schedule Page: 231 Line No.: 33 Column: b
Total life to date costs.

Schedule Page: 231 Line No.: 34 Column: b
Total life to date costs.

Schedule Page: 231 Line No.: 35 Column: b
Total life to date costs.

Schedule Page: 231 Line No.: 36 Column: b
Total life to date costs.

Schedule Page: 231 Line No.: 37 Column: b
Total life to date costs.

Schedule Page: 231 Line No.: 38 Column: b
Total life to date costs.

Schedule Page: 231 Line No.: 39 Column: b
Total life to date costs.

Schedule Page: 231 Line No.: 40 Column: b
Total life to date costs.

Schedule Page: 231.1 Line No.: 22 Column: b
Total life to date costs.

Schedule Page: 231.1 Line No.: 23 Column: b
Total life to date costs.

Schedule Page: 231.1 Line No.: 24 Column: b
Total life to date costs.

Schedule Page: 231.1 Line No.: 25 Column: b
Total life to date costs.

Schedule Page: 231.1 Line No.: 25 Column: d
Total life to date reimbursements. Project closed Q1.

Schedule Page: 231.1 Line No.: 26 Column: b
Total life to date costs.

Schedule Page: 231.1 Line No.: 26 Column: d
Total life to date reimbursements. Project closed Q1.

Schedule Page: 231.1 Line No.: 27 Column: b
Total life to date reimbursements.

Schedule Page: 231.1 Line No.: 27 Column: d
Total life to date reimbursements. Project closed Q1.

Schedule Page: 231.1 Line No.: 28 Column: b
Total life to date costs.

Schedule Page: 231.1 Line No.: 28 Column: d
Total life to date reimbursements. Project closed Q3.

Schedule Page: 231.1 Line No.: 29 Column: b
Total life to date costs.

Schedule Page: 231.1 Line No.: 29 Column: d
Total life to date reimbursements. Project closed Q3.

Schedule Page: 231.1 Line No.: 30 Column: b
Total life to date costs.

Schedule Page: 231.1 Line No.: 30 Column: d
Total life to date reimbursements. Project closed Q4.

Schedule Page: 231.1 Line No.: 31 Column: b
Total life to date costs.

Schedule Page: 231.1 Line No.: 31 Column: d
Total life to date reimbursements. Project closed Q4.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS: Written off During the Quarter /Year Account Charged (d)	CREDITS: Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	WA Excess Nat Gas Line Extension Allowance	6,628,783	3,058,661			9,687,444
2	Reg Asset Post Ret Liab	211,784,076	18,857,361			230,641,437
3	Regulatory Asset FAS109 Utility Plant	81,590,853		283	249,912	81,340,941
4	Regulatory Asset FAS109 DSIT Non Plant	1,673,881		283	252,984	1,420,897
5	Regulatory Asset FAS109 WNP3	269,399		283	161,700	107,699
6	Regulatory Asset- Spokane River Relicense	228,682		407	78,737	149,945
7	Regulatory Asset- Spokane River PM&E	209,327		557	73,312	136,015
8	Regulatory Asset- Lake CDA Fund	8,382,273		407	211,065	8,171,208
9	Regulatory Asset- Lake CDA IPA Fund	2,000,000				2,000,000
10	Regulatory Asset- Spokane River TDG Idaho	234,447		407	117,223	117,224
11	Reg Assets- Decouplings Surcharge	25,021,786		456	23,245,216	1,776,570
12	Regulatory Asset- Lake CDA DEF Costs	1,179,263		407	32,719	1,146,544
13	DEF CS2 & COLSTRIP	1,314,448		407	1,314,448	
14	Commodity MTM ST Regulatory Asset	24,990,699	16,437,341			41,428,040
15	Commodity MTM LT Regulatory Asset	18,966,686		244	2,100,663	16,866,023
16	Regulatory Asset FAS143 Asset Retirement Obligation	3,571,371	1,119,162			4,690,533
17	Reg Asset AN- CDA Lake Settlement	31,863,920		407	884,086	30,979,834
18	Reg Asset WA-CDA Lake Settlement	443,678		407	152,118	291,560
19	Regulatory Asset Workers Comp	983,900		407	349,836	634,064
20	Settled Interest Rate Swap Asset	98,764,463	27,698,273			126,462,736
21	DSM Asset	24,620,221		242	4,946,147	19,674,074
22	Unsettled Interest Rate Swaps Asset	70,939,403		245	63,548,634	7,390,769
23	Deferred ITC	4,123,891		254	70,968	4,052,923
24	Regulatory Asset MDM System	671,660	3,358,495			4,030,155
25	Regulatory Asset BPA Residential Exchange	137,139		254	46,709	90,430
26	Regulatory Asset FISERV	679,444	1,251,075			1,930,519
27	Regulatory Asset - AFUDC & Equity DFIT		3,506,418			3,506,418
28	Other Regulatory Assets		107			107
29						
30						
31						
32						
33						
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43						
44	**TOTAL :**	621,273,693	75,286,893		97,836,477	598,724,109

MISCELLANEOUS DEFFERED DEBITS (Account 186)

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

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1						
2	Colstrip Common Facility	1,110,999				1,110,999
3	Colstrip Common Facility	2,355,642				2,355,642
4	Prepaid Plane Lease LT-3 yr Amo	49,108		931	49,108	
5	Misc DD-Plane Lease- 3 yr Amort	57,267		VAR	57,267	
6	Plant Alloc of Clearing Journal	4,213,974		VAR	517,273	3,696,701
7	Nez Perce Settlement	134,689		557	5,188	129,501
8	Reg Asset ID-Lake CDA 10 yr amt	85,181		506	30,974	54,207
9	Credit Union Labor and Exp	73,909		VAR	13,982	59,927
10	Misc. Work Orders <$50,000	24,136		VAR	5,751	18,385
11	Subsidiary Billings	1,307,882		VAR	785,662	522,220
12	Reg Asset - Decoupling Deferred	3,187,126	17,814,438			21,001,564
13	Optional Wind Power	-40,745	3,175			-37,570
14	Gas Telemetry Equipment	8,893	10,894			19,787
15	Deferred Proj Compass - ID 4 yr	1,673,450		407	836,726	836,724
16	Saddle Mountain East Trans Line	1,182		235	1,182	
17	AMI Suspense A Base Change Out	758,720		107	758,720	
18	Misc. Deferred Debits (AN)	448,694	21,799			470,493
19	Bluff Road Restoration	216,553		426	216,553	
20	CIP v5 Electronic Access Contr	129,510		107	129,510	
21	Clarkston Heights Solar Project		27,912			27,912
22	Mutual Assistance Reimbursable		576,148			576,148
23	Taunton Solar Project #52		57,899			57,899
24						
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46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	15,796,170				30,900,539

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/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		10,161,086	14,294,336
3			
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	10,161,086	14,294,336
9	Gas		
10		2,120,542	3,071,820
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15	2,120,542	3,071,820
17	Other	176,935,152	170,084,364
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	189,216,780	187,450,520

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	04/15/2019	End of 2018/Q4

CAPITAL STOCKS (Account 201 and 204)

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

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Account 201 - Common Stock Issued			
2	No Par Value	200,000,000		
3	Restricted shares			
4	Total Common	200,000,000		
5				
6				
7	Account 204 - Preferred Stock Issued	10,000,000		
8				
9				
10	Cumulative			
11				
12				
13	Total Preferred	10,000,000		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/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
65,688,356	1,110,871,767					2
				91,998	4,741,577	3
65,688,356	1,110,871,767			91,998	4,741,577	4
						5
						6
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Schedule Page: 250 Line No.: 3 Column: i

Restricted share awards vest in equal thirds each year over a three-year period and are payable in Avista Corp. common stock at the end of each year if the service condition is met. In addition to the service condition, the Company must meet a return on equity target in order for the CEO's restricted shares to vest. Restricted stock is valued at the close of market of the Company's common stock on the grant date.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/Q4

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

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.
(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.
(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Equity transactions of subsidiaries	-10,696,711
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40	TOTAL	-10,696,711

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/Q4

CAPITAL STOCK EXPENSE (Account 214)

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

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Common Stock - no par	-36,316,031
2		
3		
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22	TOTAL	-36,316,031

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/Q4

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	FMBS - SERIES A - 7.53% DUE 05/05/2023	5,500,000	42,712
2	FMBS - SERIES A - 7.54% DUE 5/05/2023	1,000,000	7,766
3	FMBS - SERIES A - 7.39% DUE 5/11/2018	7,000,000	54,364
4	FMBS - SERIES A - 7.45% DUE 6/11/2018	15,500,000	120,377
5	Discount - FMBS - SERIES A - 7.45% DUE 6/11/2018		
6	FMBS - SERIES A - 7.18% DUE 8/11/2023	7,000,000	54,364
7	ADVANCE ASSOCIATED-AVISTA CAPITAL II (ToPRS)	51,547,000	1,296,086
8	FMBS - 6.37% SERIES C	25,000,000	158,304
9	FMBS - 5.45% SERIES	90,000,000	1,192,681
10	Discount- FMBS - 5.45% SERIES		239,400
11	FMBS - 6.25% SERIES	150,000,000	1,812,935
12	Discount- FMBS - 6.25% SERIES		367,500
13	FMBS - 5.70% SERIES	150,000,000	4,702,304
14	Discount- FMBS - 5.70% SERIES		222,000
15	FMBS - 5.95% SERIES	250,000,000	2,246,419
16	Discount- FMBS - 5.95% SERIES		835,000
17	FMBS - 5.125% SERIES	250,000,000	2,284,788
18	Discount- FMBS - 5.125% SERIES		575,000
19	COLSTRIP 2010A PCRBs DUE 2032	66,700,000	
20	COLSTRIP 2010B PCRBs DUE 2034	17,000,000	
21	FMBS - 3.89% SERIES	52,000,000	385,129
22	FMBS - 5.55% SERIES	35,000,000	258,834
23	4.45% SERIES DUE 12-14-2041	85,000,000	692,833
24	4.23% SERIES DUE 11-29-2047	80,000,000	730,833
25	FMBS- 4.11% SERIES	60,000,000	428,205
26	FMBS- 4.37% SERIES	100,000,000	590,761
27	FMBS- 3.54% SERIES	175,000,000	1,042,569
28	FMBS 3.91% SERIES	90,000,000	552,539
29	FMBS 4.35% SERIES	375,000,000	4,246,448
30			
31			
32			
33	TOTAL	2,138,247,000	25,140,151

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
05-06-1993	05-05-2023	05-06-1993	05-05-2023	5,500,000	414,150	1
05-07-1993	05-05-2023	05-07-1993	05-05-2023	1,000,000	75,400	2
05-11-1993	05-11-2018	05-11-1993	05-11-2018		186,803	3
06-09-1993	06-11-2018	06-09-1993	06-11-2018		513,222	4
						5
08-12-1993	08-11-2023	08-12-1993	08-11-2023	7,000,000	502,600	6
06-03-1997	06-01-2037	06-03-1997	06-01-2037	51,547,000	1,221,118	7
06-19-1998	06-19-2028	06-19-1998	06-19-2028	25,000,000	1,592,500	8
11-18-2004	12-01-2019	11-18-2004	12-01-2019	90,000,000	4,905,000	9
						10
11-17-2005	12-01-2035	11-17-2005	12-01-2035	150,000,000	9,375,000	11
						12
12-15-2006	07-01-2037	12-15-2006	07-01-2037	150,000,000	8,550,000	13
						14
04-02-2008	06-01-2018	04-02-2008	06-01-2018		6,197,917	15
						16
09-22-2009	04-01-2022	09-22-2009	04-01-2022	250,000,000	12,812,500	17
						18
12-15-2010	10-1-2032	12-15-2010	10-1-2032	66,700,000		19
12-15-2010	3-1-2034	12-15-2010	3-1-2034	17,000,000		20
12-20-2010	12-20-2020	12-20-2010	12-20-2020	52,000,000	2,022,800	21
12-20-2010	12-20-2040	12-20-2010	12-20-2040	35,000,000	1,942,500	22
12-14-2011	12-14-2041	12-14-2011	12-14-2041	85,000,000	3,782,500	23
11-30-2012	11-29-2047	11-30-2012	11-29-2047	80,000,000	3,384,000	24
12-18-2014	12-1-2044	12-18-2014	12-1-2044	60,000,000	2,466,000	25
12-16-2015	12-1-2045	12-16-2015	12-1-2045	100,000,000	4,370,000	26
12-15-2016	12-1-2051	12-15-2016	12-1-2051	175,000,000	6,195,000	27
12-14-2017	12-1-2047	12-14-2017	12-1/2047	90,000,000	3,519,000	28
05-22-2018	06-01-2048	06-1-2018	06-1-2048	375,000,000	9,962,543	29
						30
						31
						32
				1,865,747,000	83,990,553	33

Schedule Page: 256 Line No.: 3 Column: a

Matured in 2018. Fully amortitized.

Schedule Page: 256 Line No.: 4 Column: a

Matured in 2018. Fully amortitized.

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

Upon issuance Avista Capital II issued $1.5 million of Common Trust Securities to the Company. In December 2000, the Company purchased $10.0 million of these Preferred Trust Securities.

Schedule Page: 256 Line No.: 15 Column: a

Matured in 2018. Fully amortitized.

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

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

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

The Company reacquired these bonds in 2010.

Schedule Page: 256 Line No.: 20 Column: a

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

Schedule Page: 256 Line No.: 20 Column: c

The Company reacquired these bonds in 2010.

Schedule Page: 256 Line No.: 29 Column: a

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

1. Order of the Washington Utilities and Transportation Commission in Docket No. UE-151822 entered October 29, 2015 and Docket No.U-171210 entered January 11, 2018;

2. Order of the Idaho Public Utilities Commission, Order No. 33401, entered October 23, 2015 and Order No. 33978 entered January 30, 2018;

3. Order of the Public Utility Commission of Oregon, Order No. 18-033, entered February 1, 2018;

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/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)	136,429,120
2		
3		
4	Taxable Income Not Reported on Books	
5		7,471,039
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		61,088,735
11	Federal Income Tax Expense	24,498,059
12	State Income Tax Expense Adj	256,428
13		
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		-104,131,981
21		
22		
23		
24	Equity in Subs Earnings	-2,392,004
25	Corporate Overhead Unallocated Subs	1,059,811
26		
27	Federal Tax Net Income	124,279,207
28	Show Computation of Tax:	
29		
30	Federal Tax at 21%	26,098,633
31		
32	Prior Year True Ups	-9,720,938
33		
34	Total Federal Tax Expense	16,377,695
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

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 2013					
3	Income Tax 2014	840,072				-592,424
4	Income Tax 2016	-571,914				51,503
5	Income Tax 2017	1,438,214		-13,201,943	-2,731,101	9,032,628
6	Income Tax (Current)			26,220,217	14,591,100	-8,491,707
7	Retained Earnings (Current)					
8	Prior Retained Earnings					
9	Total Federal	1,706,372		13,018,274	11,859,999	
10						
11	STATE OF WASHINGTON:					
12	Property Tax (2017)	16,443,031		745,564	17,188,595	
13	Property Tax (2018)			18,651,695	-5,584	
14	Excise Tax (2016)	892,951				
15	Excise Tax (2017)	2,805,220		21,137	2,826,357	
16	Excise Tax (2018)			26,659,277	24,043,614	
17	Natural Gas Use Tax	500		3,049	3,053	
18	Municipal Occupation Tax	3,010,959		23,922,427	24,130,655	
19	Community Solar			-582,394	-576,993	-17,305
20	Sales & Use Tax (2017)	153,053		-12	153,041	
21	Sales & Use Tax (2018)			1,446,221	1,354,076	
22	Total Washington	23,305,714		70,866,964	69,116,814	-17,305
23						
24	STATE OF IDAHO:					
25	Income Tax (2017)			-175,305	-294,385	-119,080
26	Income Tax (2018)			343,757	210,000	
27	Property Tax (2017)	3,874,217		25,067	3,899,284	
28	Property Tax (2018)			7,988,205	4,029,755	25,047
29	Sales & Use Tax (2016)	1				-1
30	Sales & Use Tax (2017)	10,650		-545	10,105	
31	Sales & Use Tax (2018)			201,308	197,215	
32	KWH Tax (2017)	34,973		-5,058	29,916	
33	KWH Tax (2018)			418,040	386,213	
34	Franchise Tax (2017)	1,102,379			1,102,410	30
35	Franchise Tax (2018)			4,731,532	3,712,217	-30
36	Total Idaho	5,022,220		13,527,001	13,282,730	-94,034
37						
38	STATE OF MONTANA:					
39	Income Tax (2015)	439,238				-439,238
40	Income Tax (2016)	118,720				-118,720
41	TOTAL	36,514,038		119,667,849	116,845,212	504,722

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
						2
247,648						3
-520,411						4
		297,235			-13,499,178	5
3,137,410		26,032,636			187,581	6
						7
						8
2,864,647		26,329,871			-13,311,597	9
						10
						11
		648,162			97,402	12
18,657,279		14,726,881			3,924,814	13
892,951						14
		21,803			-666	15
2,615,663		21,013,778			5,645,499	16
496		3,049				17
2,802,731		18,624,892			5,297,535	18
-22,706					-582,394	19
					-12	20
92,145					1,446,221	21
25,038,559		55,038,565			15,828,399	22
						23
						24
		-137,147			-38,158	25
133,757		292,195			51,562	26
		-846			25,913	27
3,983,497	25,046	6,226,432			1,761,773	28
						29
					-545	30
4,093					201,308	31
-1		-5,058				32
31,827		423,968			-5,928	33
						34
1,019,285		3,613,869			1,117,663	35
5,172,458	25,046	10,413,413			3,113,588	36
						37
						38
						39
						40
39,835,469	3,977,459	107,553,958			12,113,891	41

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
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	Income Tax (2017)	-557,908			50	557,958
2	Income Tax (2018)			253,640	250,000	
3	Property Tax (2017)	5,210,680		-13,875	5,196,805	
4	Property Tax (2018)			11,167,531	5,599,893	-1
5	Colstrip Generation Tax			3,294	3,294	
6	KWH Tax (2017)	257,400		-62	257,338	
7	KWH Tax (2018)			1,106,158	858,599	
8	Consumer Council Fee	53		32	25	
9	Public Commission Fee	28		124	133	
10	Total Montana	5,468,211		12,516,842	12,166,137	-1
11						
12	STATE OF OREGON:					
13	Income Tax (2018)			100,000	100,000	
14	Property Tax (2017)			3,323,021		-3,323,021
15	Property Tax (2018)			3,952,253	7,904,666	3,952,413
16	Franchise Tax (2017)	1,008,688			1,008,688	
17	Franchise Tax (2018)			3,630,921	2,675,549	1
18	Total Oregon	1,008,688		11,006,195	11,688,903	629,393
19						
20	STATE OF CALIFORNIA:					
21	Income Tax (2018)			1,600	1,600	
22	Total California			1,600	1,600	
23						
24	MISCELLANEOUS STATES:					
25	Income Tax (Current)	1				1
26	Total Misc States	1				1
27						
28	MISCELLANEOUS OTHER					
29	CTR Credit (2017)			-1,510	-1,510	
30	Timber Excise Tax (2017)					
31	WA Renewable Energy			-1,339,881	-1,303,272	
32	Misc Distribution			25,046	-13,332	-13,332
33	Thermal Fuel Tax	2,832		47,318	47,143	
34	Total Other	2,832		-1,269,027	-1,270,971	-13,332
35						
36						
37						
38						
39						
40						
41	TOTAL	36,514,038		119,667,849	116,845,212	504,722

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2019	Year/Period of Report End of 2018/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (I) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (I) 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 (I) 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
3,640		253,640				2
		-13,875				3
5,567,637		11,167,531				4
		3,294				5
		-62				6
247,559		1,106,158				7
60		32				8
19		124				9
5,818,915		12,516,842				10
						11
						12
		25,000			75,000	13
		1,483,707			1,839,314	14
	3,952,413	1,746,224			2,206,029	15
						16
955,373					3,630,921	17
955,373	3,952,413	3,254,931			7,751,264	18
						19
						20
		336			1,264	21
		336			1,264	22
						23
						24
1						25
1						26
						27
						28
					-1,510	29
						30
-42,537					-1,339,881	31
25,046					25,046	32
3,007					47,318	33
-14,484					-1,269,027	34
						35
						36
						37
						38
						39
						40
39,835,469	3,977,459	107,553,958			12,113,891	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%						
6		30,222,231			411	520,104	
7							
8	TOTAL	30,222,231				520,104	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Gas Property (100%	10,422			411	5,232	
11		32,958			411	14,832	
12	TOTAL PROPERTY	43,380				20,064	
13							
14							
15							
16							
17							
18							
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48							

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

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
			5
29,702,127			6
			7
29,702,127			8
			9
5,190			10
18,126			11
23,316			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
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			47
			48

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2019	Year/Period of Report End of 2018/Q4

OTHER DEFFERED CREDITS (Account 253)

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

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Defer Gas Exchange	1,125,000				1,125,000
2	Rathdrum Refund	70,463	550	33,823		36,640
3	Kettle Falls Diesel Leak	260,093	186	147,652		112,441
4	Bills Pole Rentals	163,907			20,128	184,035
5	DOC EECE Grant	26,105	134	26,105		
6	Defer Comp Active Execs	8,463,265	128	62,908		8,400,357
7	Executive Incent Plan	140,000				140,000
8	Unbilled Revenue	2,014,366	908	433,940		1,580,426
9	WA Energy Recovery Mechanism	1,684,801			8,011,463	9,696,264
10	Misc Deferred Credits	1,163	186	1,013		150
11	Decoupling Deferred Credits	11,666,738	456	11,421,754		244,984
12	WA REC	176,311			675,442	851,753
13	Deferred Treasury Suspense	2,127,252	131	2,122,255		4,997
14	Conservation Program Projects	112,679	186	23,660		89,019
15						
16						
17						
18						
19						
20						
21						
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36						
37						
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39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	28,032,143		14,273,110	8,707,033	22,466,066

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ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	319,934,303	4,280,311	
3	Gas	75,471,104	3,060,450	
4	Other	86,429,721	2,857,477	
5	TOTAL (Enter Total of lines 2 thru 4)	481,835,128	10,198,238	
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	481,835,128	10,198,238	
10	Classification of TOTAL			
11	Federal Income Tax	481,835,128	10,198,238	
12	State Income Tax			
13	Local Income Tax			

NOTES

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2019	Year/Period of Report End of 2018/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS						
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits Account Credited (g)	Debits Amount (h)	Credits Account Debited (i)	Credits Amount (j)	Balance at End of Year (k)	Line No.
							1
					3,351,367	327,565,981	2
					1,427,084	79,958,638	3
					1,063,747	90,350,945	4
					5,842,198	497,875,564	5
							6
							7
							8
					5,842,198	497,875,564	9
							10
					5,842,198	497,875,564	11
							12
							13

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Electric	6,410,231	-1,830,486	490,318
4				
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	6,410,231	-1,830,486	490,318
10	Gas			
11	Gas	-5,496,818	-1,176,216	
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	-5,496,818	-1,176,216	
18	Other	166,659,156	4,853,234	
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	167,572,569	1,846,532	490,318
20	Classification of TOTAL			
21	Federal Income Tax	167,572,569	1,846,532	490,318
22	State Income Tax			
23	Local Income Tax			

NOTES

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2019	Year/Period of Report End of 2018/Q4

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

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

CHANGES DURING YEAR		ADJUSTMENTS						
		Debits		Credits				
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
			92,766			3,996,661	3
							4
							5
							6
							7
							8
			92,766			3,996,661	9
							10
			7,876			-6,680,910	11
							12
							13
							14
							15
							16
			7,876			-6,680,910	17
105,283					1,275,727	172,893,400	18
105,283			100,642		1,275,727	170,209,151	19
							20
105,283			100,642		1,275,727	170,209,151	21
							22
							23

NOTES (Continued)

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2019	Year/Period of Report End of 2018/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Idaho Investment Tax Credit	7,468,113	190	1,222,862		6,245,251
2	Oregon BETC Credit	1,111,427				1,111,427
3	Settled Int Rate Swaps	13,735,249			4,217,866	17,953,115
4	Unsettled Int Rate Swaps	4,902,566			5,222,833	10,125,399
5	FAS 109 Invest Credit	11,839	190	5,472		6,367
6	Nez Perce	572,324	557	22,008		550,316
7	Idaho Earnings Test	862,780	191	88,796		773,984
8	Decoupling Rebate				8,609,963	8,609,963
9	Other Regulatory Liabilities	1,407,145			34,284	1,441,429
10	WA ERM	22,048,815			2,699,539	24,748,354
11	ID PCA	6,139,347			1,420,562	7,559,909
12	Deferred Federal ITC	8,247,784	190	141,936		8,105,848
13	Plant Excess Deferred	416,959,206	282	6,209,812		410,749,394
14	Non Plant Excess Deferred	17,634,985			903,143	18,538,128
15	Reg Liability MDM System	41,907			263,219	305,126
16	AFUDC Equity Tax Deferral				1,692,177	1,692,177
17	Exist Meters/ERTS Excess Depr Deferred				188,620	188,620
18	DSM Tariff Rider				284,139	284,139
19	Low Income Energy Assistance				1,343,384	1,343,384
20	Deferred CS2 & Colstrip O&M				658,833	658,833
21	Reg Liability - Tax Reform Amortization				6,449,651	6,449,651
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	501,143,487		7,690,886	****************	527,440,814

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/Q4

ELECTRIC OPERATING REVENUES (Account 400)

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

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	368,752,670	381,682,174
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	314,532,129	311,592,956
5	Large (or Ind.) (See Instr. 4)	109,846,315	110,982,373
6	(444) Public Street and Highway Lighting	7,538,909	7,483,805
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales	1,385,654	1,277,422
10	TOTAL Sales to Ultimate Consumers	802,055,677	813,018,730
11	(447) Sales for Resale	91,775,470	88,779,014
12	TOTAL Sales of Electricity	893,831,147	901,797,744
13	(Less) (449.1) Provision for Rate Refunds	10,290,335	1,181,583
14	TOTAL Revenues Net of Prov. for Refunds	883,540,812	900,616,161
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	299,355	360,115
18	(453) Sales of Water and Water Power	506,000	363,668
19	(454) Rent from Electric Property	2,982,930	2,767,738
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	83,116,369	69,867,100
22	(456.1) Revenues from Transmission of Electricity of Others	15,959,856	15,957,476
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	102,864,510	89,316,097
27	TOTAL Electric Operating Revenues	986,405,322	989,932,258

ELECTRIC OPERATING REVENUES (Account 400)

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

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
3,626,870	3,840,417	340,308	334,848	2
				3
3,156,248	3,222,374	42,618	42,153	4
1,772,281	1,814,733	1,318	1,328	5
18,423	20,054	594	569	6
				7
				8
13,717	13,148	138	129	9
8,587,539	8,910,726	384,976	379,027	10
3,777,497	3,070,079			11
12,365,036	11,980,805	384,976	379,027	12
				13
12,365,036	11,980,805	384,976	379,027	14

Line 12, column (b) includes $ -3,219,061 of unbilled revenues.
Line 12, column (d) includes -90,856 MWH relating to unbilled revenues

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2019	Year/Period of Report End of 2018/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	RESIDENTIAL SALES (440)					
2	1 Residential Service	3,517,106	343,442,574	323,195	10,882	0.0976
3	2 Residential Service	4,939	320,729	398	12,410	0.0649
4	3 Residential Service					
5	12 Res. & Farm Gen. Service	85,629	12,532,570	14,916	5,741	0.1464
6	15 MOPS II Residential					
7	22 Res. & Farm Lg. Gen. Service	39,187	3,588,437	65	602,877	0.0916
8	30 Pumping-Special	1	477	2	500	0.4770
9	32 Res. & Farm Pumping Service	8,518	1,116,657	1,732	4,918	0.1311
10	48 Res. & Farm Area Lighting	3,677	1,150,721			0.3130
11	49 Area Lighting-High-Press.	48	18,772			0.3911
12	56 Centralia Refund					
13	95 Wind Power		158,169			
14	72 Residential Service					
15	73 Residential Service					
16	74 Residential Service					
17	76 Residential Service					
18	77 Residential Service					
19	58A Tax Adjustment		-32,066			
20	58 Tax Adjustment		10,196,982			
21	SubTotal	3,659,105	372,494,022	340,308	10,752	0.1018
22	Residential-Unbilled	-32,235	-3,741,352			0.1161
23	Total Residential Sales	3,626,870	368,752,670	340,308	10,658	0.1017
24						
25	COMMERCIAL SALES (442)					
26	2 General Service					
27	3 General Service					
28	11 General Service	897,095	104,501,103	38,601	23,240	0.1165
29	12 Res. & Farm Gen. Service					
30	16 MOPS II Commercial					
31	19 Contract-General Service					
32	21 Large General Service	1,800,374	165,422,222	2,780	647,617	0.0919
33	25 Extra Lg. Gen. Service	335,045	21,818,726	13	25,772,692	0.0651
34	28 Contract-Extra Large Serv					
35	31 Pumping Service	108,538	9,587,165	1,224	88,675	0.0883
36	47 Area Lighting-Sod. Vap	5,290	1,461,053			0.2762
37	49 Area Lighting-High-Press.	2,384	670,555			0.2813
38	56 Centralia Refune					
39	95 Wind Power		87,407			
40	74 Large General Service					
41	TOTAL Billed	12,274,181	890,612,086	384,976	31,883	0.0726
42	Total Unbilled Rev.(See Instr. 6)	90,856	3,219,061	0	0	0.0354
43	TOTAL	12,365,037	893,831,147	384,976	32,119	0.0723

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2019	Year/Period of Report End of 2018/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	75 Large General Service					
2	76 Large General Service					
3	77 General Service					
4	58A Tax Adjustment		-46,226			
5	58 Tax Adjustment		11,043,715			
6	SubTotal	3,148,726	314,545,720	42,618	73,883	0.0999
7	Commercial-Unbilled	7,522	-13,591			-0.0018
8	Total Commercial	3,156,248	314,532,129	42,618	74,059	0.0997
9						
10	INDUSTRIAL SALES (442)					
11	2 General Service	11,114	1,306,983	248	44,815	0.1176
12	3 General Service					
13	8 Lg Gen Time of Use					
14	11 General Service					
15	12 Res. & Farm Gen. Service					
16	21 Large General Service	154,891	14,363,038	136	1,138,904	0.0927
17	25 Extra Lg. Gen. Service	1,400,217	78,617,473	20	70,010,850	0.0561
18	28 Contract - Extra Large Service					
19	29 Contract Lg. Gen. Service					
20	30 Pumping Service - Special	31,333	2,291,400	48	652,771	0.0731
21	31 Pumping Service	54,032	4,955,885	738	73,214	0.0917
22	32 Pumping Svc Res & Firm	4,932	455,832	128	38,531	0.0924
23	47 Area Lighting-Sod. Vap.	136	31,973			0.2351
24	49 Area Lighting - High-Press	58	16,116			0.2779
25	95 Wind Power		840			
26	48 Area Lighting-Sod. Vap.					
27	73 General Service					
28	74 Large General Service					
29	75 Large General Service					
30	76 Pumping Service					
31	77 General Service					
32	58A Tax Adjustment		-1,368			
33	58 Tax Adjustment		834,139			
34	SubTotal	1,656,713	102,872,311	1,318	1,256,990	0.0621
35	Industrial-Unbilled	115,568	6,974,004			0.0603
36	Total Industrial	1,772,281	109,846,315	1,318	1,344,675	0.0620
37						
38	STREET AND HWY LIGHTING (444)					
39	6 Mercury Vapor St. Ltg.					
40	7 HP Sodium Vap. St. Ltg					
41	TOTAL Billed	12,274,181	890,612,086	384,976	31,883	0.0726
42	Total Unbilled Rev.(See Instr. 6)	90,856	3,219,061	0	0	0.0354
43	TOTAL	12,365,037	893,831,147	384,976	32,119	0.0723

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.
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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	66	13,587	7	9,429	0.2059
3	42 Co-Owned St. Lt. Service					
4	High-Press. Sod. Vap.	15,085	6,921,341	486	31,039	0.4588
5	43 Cust-Owned St. Lt. Energy					
6	and Maint. Service					
7	44 Cust-Owned St. Lt. Energy					
8	and Maint. Svce - High-Pres					
9	Sodium Vapor	360	56,200	22	16,364	0.1561
10	45 Cust. Owned St. Lt. Energy Svc	782	65,680	14	55,857	0.0840
11	46 Cust. Owned St. Lt. Energy Svc	2,130	231,215	65	32,769	0.1086
12	58A Tax Adjustment		-750			
13	58 Tax Adjustment		251,636			
14	SubTotal	18,423	7,538,909	594	31,015	0.4092
15	Street & Hwy Lighting-Unbilled					
16	Total Street & Hwy Lighting	18,423	7,538,909	594	31,015	0.4092
17						
18	OTHER SALES TO PUBLIC					
19	(445)					
20	None					
21						
22	INTERDEPARTMENTAL SALES	13,717	1,384,736	138	99,399	0.1010
23	58 Tax Adjustment		918			
24	Total Interdepartmental	13,717	1,385,654	138	99,399	0.1010
25						
26	SALES FOR RESALE (447)					
27	61 Sales to Other Utilities (NDA)	3,777,497	91,775,470			0.0243
28						
29						
30	Total Sales for Resale	3,777,497	91,775,470			0.0243
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	12,274,181	890,612,086	384,976	31,883	0.0726
42	Total Unbilled Rev.(See Instr. 6)	90,856	3,219,061	0	0	0.0354
43	TOTAL	12,365,037	893,831,147	384,976	32,119	0.0723

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/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	Avangrid Renewables, LLC	SF	Tariff 9			
2	Avangrid Renewables, LLC	SF	Tariff 9			
3	Avangrid Renewables, LLC	LF	Tariff 12			
4	BP Energy Company	SF	Tariff 9			
5	Black Hills Power, Inc.	SF	Tariff 9			
6	Bonneville Power Administration	LF	Tariff 8			
7	Bonneville Power Administration	LF	Tariff 8			
8	Bonneville Power Administration	SF	Tariff 9			
9	Bonneville Power Administration	LF	Tariff 12			
10	British Columbia Hydro and Power Author	LF	Tariff 12			
11	Brookfield Energy Marketing, LP	SF	Tariff 9			
12	California Independent System Operator	SF	Tariff 9			
13	Calpine Energy Services LP	SF	Tariff 9			
14	Chelan County PUD No. 1	LF	Tariff 12			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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.
490,849		10,377,967		10,377,967	1
	861,538			861,538	2
16		746		746	3
2,704		56,892		56,892	4
111		1,573		1,573	5
14,100		400,597		400,597	6
513		24,091		24,091	7
79,680		1,990,058		1,990,058	8
102		1,627		1,627	9
34		626		626	10
200		3,550		3,550	11
257,128		8,755,959		8,755,959	12
82,455		2,122,819		2,122,819	13
10		566		566	14
0	0	0	0	0	
3,777,497	3,158,135	91,881,048	-3,263,713	91,775,470	
3,777,497	**3,158,135**	**91,881,048**	**-3,263,713**	**91,775,470**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Citigroup Energy, Inc.	SF	Tariff 9			
2	Clatskanie Peoples PUD	SF	Tariff 9			
3	ConocoPhillips	SF	Tariff 9			
4	Direct Energy Business Marketing, LLC	LF	Tariff 9			
5	Douglas County PUD No. 1	SF	Tariff 9			
6	EDF Trading North America, LLC	SF	Tariff 9			
7	Energy Keepers, Inc.	SF	Tariff 9			
8	Eugene Water & Electric Board	SF	Tariff 9			
9	Exelon Generation Company, LLC	SF	Tariff 9			
10	Grant County PUD No. 2	LF	Tariff 12			
11	Gridforce Energy Management, LLC	LF	Tariff 12			
12	Idaho Power Company	SF	Tariff 9			
13	Idaho Power Company	LF	Tariff 12			
14	Idaho Power Company	IF	Tariff 9			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
29,000		1,373,836		1,373,836	1
2,886		82,013		82,013	2
13,200		416,726		416,726	3
447,026		14,968,814		14,968,814	4
9,974		387,111		387,111	5
79,623		2,396,083		2,396,083	6
14,074		855,603		855,603	7
31,417		797,238		797,238	8
39,972		1,054,950		1,054,950	9
41		583		583	10
438		17,371		17,371	11
3,600		223,140		223,140	12
9		233		233	13
865		33,928		33,928	14
0	0	0	0	0	
3,777,497	3,158,135	91,881,048	-3,263,713	91,775,470	
3,777,497	**3,158,135**	**91,881,048**	**-3,263,713**	**91,775,470**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Idaho Power Company Balancing	SF	Tariff 9			
2	Idaho Power Company Balancing	IF	Tariff 9			
3	Kootenai Electric Cooperative	LF	Tariff 8			
4	Macquarie Energy, LLC	SF	Tariff 9			
5	Macquarie Energy, LLC	IF	Tariff 9			
6	Mizuho Securities USA, Inc.	OS	NA			
7	Morgan Stanley Capital Group, Inc.	SF	Tariff 9			
8	Morgan Stanley Capital Group, Inc.	IF	Tariff 9			
9	Morgan Stanley Capital Group, Inc.	SF	Tariff 9			
10	Morgan Stanley Capital Group, Inc.	SF	Tariff 9			
11	Morgan Stanley Capital Group, Inc.	SF	Tariff 9			
12	NaturEner Power Watch, LLC	LF	Tariff 9			
13	NaturEner Power Watch, LLC	LF	Tariff 9			
14	NaturEner Power Watch, LLC	LF	Tariff 12			
	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.
41,072		1,030,659		1,030,659	1
5,294		260,629		260,629	2
1,673		46,772		46,772	3
192,107		5,972,278		5,972,278	4
167		5,956		5,956	5
			-10,305,796	-10,305,796	6
189,759		4,437,819		4,437,819	7
16,691		580,692		580,692	8
	275,940			275,940	9
	645,860			645,860	10
	350,784			350,784	11
14		335		335	12
473		9,839		9,839	13
115		2,177		2,177	14
0	0	0	0	0	
3,777,497	3,158,135	91,881,048	-3,263,713	91,775,470	
3,777,497	**3,158,135**	**91,881,048**	**-3,263,713**	**91,775,470**	

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	NaturEner Power Watch, LLC	SF	Tariff 9			
2	NaturEner Power Watch, LLC	SF	Tariff 9			
3	Nevada Power Company	SF	Tariff 9			
4	NorthWestern Energy LLC	SF	Tariff 9			
5	Northwestern Energy LLC	IF	Tariff 9			
6	NorthWestern Energy LLC	LF	Tariff 12			
7	NorthWestern Energy LLC	LF	Tariff 9			
8	Okanogan County PUD	SF	Tariff 9			
9	PacifiCorp	SF	Tariff 9			
10	PacifiCorp	LF	Tariff 12			
11	PacifiCorp	LF	Tariff 9			
12	Pacific Northwest Generating Coop	SF	Tariff 9			
13	Pend Oreille Public Utility District	IF	Tariff 9			
14	Pend Oreille Public Utility District	IF	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.
	91,980			91,980	1
	13,703			13,703	2
1,120		30,900		30,900	3
38,586		989,684		989,684	4
375		10,885		10,885	5
157		4,450		4,450	6
7,396		220,308		220,308	7
7,888		294,469		294,469	8
200,766		7,462,539		7,462,539	9
223		7,596		7,596	10
4,708		140,196		140,196	11
16,000		828,429		828,429	12
	681,081			681,081	13
19,020		513,402		513,402	14
0	0	0	0	0	
3,777,497	3,158,135	91,881,048	-3,263,713	91,775,470	
3,777,497	**3,158,135**	**91,881,048**	**-3,263,713**	**91,775,470**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/Q4

SALES FOR RESALE (Account 447)

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Pend Oreille Public Utility District	SF	Tariff 9			
2	Portland General Electric Company	SF	Tariff 9			
3	Portland General Electric Company	LF	Tariff 12			
4	Powerex	SF	Tariff 9			
5	Puget Sound Energy	LF	Tariff 9			
6	Puget Sound Energy	SF	Tariff 9			
7	Puget Sound Energy	LF	Tariff 12			
8	Rainbow Energy Marketing	SF	Tariff 9			
9	Rainbow Energy Marketing	IF	Tariff 9			
10	Sacramento Municipal Utility District	SF	Tariff 9			
11	Sacramento Municipal Utility District	LF	Tariff 12			
12	Seattle City Light	SF	Tariff 9			
13	Seattle City Light	LF	Tariff 9			
14	Seattle City Light	LF	Tariff 12			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2019	Year/Period of Report End of 2018/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.
122,844		2,381,023		2,381,023	1
167,460		4,879,465		4,879,465	2
63		2,787		2,787	3
263,509		4,994,263		4,994,263	4
21,517		640,897		640,897	5
149,719		4,642,555		4,642,555	6
72		2,511		2,511	7
3,200		63,000		63,000	8
16		627		627	9
40		1,240		1,240	10
26		1,122		1,122	11
34,665		862,411		862,411	12
532		14,356		14,356	13
5		152		152	14
0	0	0	0	0	
3,777,497	3,158,135	91,881,048	-3,263,713	91,775,470	
3,777,497	**3,158,135**	**91,881,048**	**-3,263,713**	**91,775,470**	

SALES FOR RESALE (Account 447)

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/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.
228,887		8,305,419		8,305,419	1
	89,580			89,580	2
7		98		98	3
27,085		681,332		681,332	4
	147,669			147,669	5
12,077		405,017		405,017	6
10,620		286,873		286,873	7
1,480		45,216		45,216	8
1		43		43	9
16,808		500,701		500,701	10
558		24,434		24,434	11
48,641		1,504,354		1,504,354	12
2		199		199	13
289,617		6,836,127		6,836,127	14
0	0	0	0	0	
3,777,497	3,158,135	91,881,048	-3,263,713	91,775,470	
3,777,497	**3,158,135**	**91,881,048**	**-3,263,713**	**91,775,470**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/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	TransAlta Energy Marketing	IF	Tariff 9			
2	TransAlta Energy Marketing	OS	Tariff 9			
3	Turlock Irrigation District	LF	Tariff 12			
4	Vitol, Inc.	SF	Tariff 9			
5	Wells Fargo securities, LLC	OS	NA			
6	IntraCompany Wheeling	LF				
7	IntraCompany Generation	LF				
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/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.
12		392		392	1
			150	150	2
3		87		87	3
34,400		1,220,318		1,220,318	4
			-10,930,934	-10,930,934	5
		-15,610,685	15,610,685		6
			2,362,182	2,362,182	7
					8
					9
					10
					11
					12
					13
					14
0	0	0	0	0	
3,777,497	3,158,135	91,881,048	-3,263,713	91,775,470	
3,777,497	**3,158,135**	**91,881,048**	**-3,263,713**	**91,775,470**	

Schedule Page: 310 Line No.: 2 Column: b
Capacity
Schedule Page: 310 Line No.: 3 Column: b
NWPP Reserve Sharing Sales
Schedule Page: 310 Line No.: 6 Column: b
BPA Contract Terminates September 30, 2028.
Schedule Page: 310 Line No.: 7 Column: b
Effective October 1, 2018 - This Scheduling Agreement shall remain in effect until such time as BPA is no longer the designated scheduling agent for any Federal Load.
Schedule Page: 310 Line No.: 9 Column: b
NWPP Reserve Sharing Sales
Schedule Page: 310 Line No.: 10 Column: b
NWPP Reserve Sharing Sales
Schedule Page: 310 Line No.: 14 Column: b
NWPP Reserve Sharing Sales
Schedule Page: 310.1 Line No.: 4 Column: b
Contract terminates December 31, 2019.
Schedule Page: 310.1 Line No.: 10 Column: b
NWPP Reserve Sharing Sales
Schedule Page: 310.1 Line No.: 11 Column: b
NWPP Reserve Sharing Sales
Schedule Page: 310.1 Line No.: 13 Column: b
NWPP Reserve Sharing Sales
Schedule Page: 310.1 Line No.: 14 Column: b
Financially Settled Transmission Losses
Schedule Page: 310.2 Line No.: 2 Column: b
Financially Settled Transmission Losses
Schedule Page: 310.2 Line No.: 3 Column: b
Kootenai Contract Terminates March 31,2019
Schedule Page: 310.2 Line No.: 5 Column: b
Financially Settled Transmission Losses
Schedule Page: 310.2 Line No.: 6 Column: b
Financial SWAP
Schedule Page: 310.2 Line No.: 8 Column: b
Financially Settled Transmission Losses
Schedule Page: 310.2 Line No.: 9 Column: b
Capacity
Schedule Page: 310.2 Line No.: 10 Column: b
Capacity
Schedule Page: 310.2 Line No.: 11 Column: b
Reserves
Schedule Page: 310.2 Line No.: 12 Column: b
Financially Settled Transmission Losses
Schedule Page: 310.2 Line No.: 13 Column: b
Energy Associated with Dynamic Capacity and Energy Service Agreement
Schedule Page: 310.2 Line No.: 14 Column: b
NWPP Reserve Sharing Sales
Schedule Page: 310.3 Line No.: 1 Column: b
Capacity
Schedule Page: 310.3 Line No.: 2 Column: b
Capacity
Schedule Page: 310.3 Line No.: 5 Column: b
Financially Settled Transmission Losses
Schedule Page: 310.3 Line No.: 6 Column: b

NWPP Reserve Sharing Sales

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

NorthWestern Energy LLC sale expires October 31, 2023.

Schedule Page: 310.3 Line No.: 10 Column: b

NWPP Reserve Sharing Sales

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

PacifiCorp sale terminates October 31, 2023.

Schedule Page: 310.3 Line No.: 13 Column: b

Contract expires 9/30/2019.

Schedule Page: 310.3 Line No.: 14 Column: b

Contract expires 9/30/2019.

Schedule Page: 310.4 Line No.: 3 Column: b

NWPP Reserve Sharing Sales

Schedule Page: 310.4 Line No.: 5 Column: b

Puget Sound Energy sale terminates October 31, 2023.

Schedule Page: 310.4 Line No.: 7 Column: b

NWPP Reserve Sharing Sales

Schedule Page: 310.4 Line No.: 9 Column: b

Financially Settled Transmission Losses

Schedule Page: 310.4 Line No.: 11 Column: b

NWPP Reserve Sharing Sales

Schedule Page: 310.4 Line No.: 13 Column: b

Financially Settled Transmission Losses

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

NWPP Reserve Sharing Sales

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

Reserves

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

NWPP Reserve Sharing Sales

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

Sovereign Power contract terminates 9-30-2019

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

Sovereign Power Contract terminates 9-30-2019

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

Financially Settled Transmission Losses

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

NWPP Reserve Sharing Sales

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

Talen Energy sale terminates October 31,2023.

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

Financially Settled Transmission Losses

Schedule Page: 310.6 Line No.: 1 Column: b

Financially Settled Transmission Losses

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

Pond - Other

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

NWPP Reserve Sharing Sales

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

Financial SWAP

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

IntraCompany Wheeling terminates 09/30/2023.

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

IntraCompany Generation - Sale of Ancillary Services.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/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	345,980	351,615
5	(501) Fuel	27,775,865	28,164,386
6	(502) Steam Expenses	4,055,476	4,498,751
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	934,119	1,240,901
10	(506) Miscellaneous Steam Power Expenses	3,306,135	2,798,619
11	(507) Rents	34,621	39,448
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	36,452,196	37,093,720
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	479,496	500,387
16	(511) Maintenance of Structures	529,070	704,022
17	(512) Maintenance of Boiler Plant	5,335,916	6,404,383
18	(513) Maintenance of Electric Plant	1,458,737	2,866,901
19	(514) Maintenance of Miscellaneous Steam Plant	466,688	1,373,253
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	8,269,907	11,848,946
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	44,722,103	48,942,666
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	2,619,276	2,483,025
45	(536) Water for Power	1,156,275	1,126,313
46	(537) Hydraulic Expenses	8,434,948	8,017,097
47	(538) Electric Expenses	5,741,274	7,342,763
48	(539) Miscellaneous Hydraulic Power Generation Expenses	1,148,251	971,164
49	(540) Rents	6,344,885	6,308,734
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	25,444,909	26,249,096
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	1,152,932	916,539
54	(542) Maintenance of Structures	406,234	379,782
55	(543) Maintenance of Reservoirs, Dams, and Waterways	2,130,811	2,963,625
56	(544) Maintenance of Electric Plant	3,020,296	3,068,063
57	(545) Maintenance of Miscellaneous Hydraulic Plant	1,154,554	696,335
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	7,864,827	8,024,344
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	33,309,736	34,273,440

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	344,393	623,537
63	(547) Fuel	63,237,753	69,526,481
64	(548) Generation Expenses	2,286,764	1,711,153
65	(549) Miscellaneous Other Power Generation Expenses	350,643	491,137
66	(550) Rents	-33,822	-32,172
67	TOTAL Operation (Enter Total of lines 62 thru 66)	66,185,731	72,320,136
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	585,982	721,322
70	(552) Maintenance of Structures	68,190	194,208
71	(553) Maintenance of Generating and Electric Plant	3,927,388	4,471,719
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	358,281	423,855
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	4,939,841	5,811,104
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	71,125,572	78,131,240
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	136,263,902	130,674,108
77	(556) System Control and Load Dispatching	598,799	734,819
78	(557) Other Expenses	75,953,261	75,130,324
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	212,815,962	206,539,251
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	361,973,373	367,886,597
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	1,868,255	2,705,830
84			
85	(561.1) Load Dispatch-Reliability	39,842	77,944
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,045,793	1,471,441
87	(561.3) Load Dispatch-Transmission Service and Scheduling	1,017,880	1,407,937
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	506,799	2,609,186
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	460,703	318,441
94	(563) Overhead Lines Expenses	438,645	426,023
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	17,529,488	17,569,670
97	(566) Miscellaneous Transmission Expenses	2,414,323	2,048,338
98	(567) Rents	189,784	153,496
99	TOTAL Operation (Enter Total of lines 83 thru 98)	25,511,512	28,788,306
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	538,347	860,108
102	(569) Maintenance of Structures	632,439	800,208
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	697,405	1,712,538
108	(571) Maintenance of Overhead Lines	1,346,716	1,069,453
109	(572) Maintenance of Underground Lines	188	492
110	(573) Maintenance of Miscellaneous Transmission Plant	91,275	117,575
111	TOTAL Maintenance (Total of lines 101 thru 110)	3,306,370	4,560,374
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	28,817,882	33,348,680

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	2,922,781	3,865,697
135	(581) Load Dispatching		
136	(582) Station Expenses	688,490	747,725
137	(583) Overhead Line Expenses	2,245,066	2,142,515
138	(584) Underground Line Expenses	1,470,722	1,414,741
139	(585) Street Lighting and Signal System Expenses	4,104	6,619
140	(586) Meter Expenses	1,559,238	1,856,753
141	(587) Customer Installations Expenses	709,280	822,859
142	(588) Miscellaneous Expenses	6,977,162	7,314,051
143	(589) Rents	364,153	385,866
144	TOTAL Operation (Enter Total of lines 134 thru 143)	16,940,996	18,556,826
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	1,099,667	1,414,040
147	(591) Maintenance of Structures	384,683	508,452
148	(592) Maintenance of Station Equipment	721,467	1,042,345
149	(593) Maintenance of Overhead Lines	9,778,342	9,317,466
150	(594) Maintenance of Underground Lines	802,329	905,731
151	(595) Maintenance of Line Transformers	333,165	522,741
152	(596) Maintenance of Street Lighting and Signal Systems	181,548	194,354
153	(597) Maintenance of Meters	25,312	39,978
154	(598) Maintenance of Miscellaneous Distribution Plant	185,260	334,614
155	TOTAL Maintenance (Total of lines 146 thru 154)	13,511,773	14,279,721
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	30,452,769	32,836,547
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	119,601	242,260
160	(902) Meter Reading Expenses	2,228,677	3,187,082
161	(903) Customer Records and Collection Expenses	7,653,010	9,762,223
162	(904) Uncollectible Accounts	2,043,405	2,752,406
163	(905) Miscellaneous Customer Accounts Expenses	225,469	246,534
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	12,270,162	16,190,505

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	36,541,837	29,150,863
169	(909) Informational and Instructional Expenses	898,729	904,617
170	(910) Miscellaneous Customer Service and Informational Expenses	340,964	326,924
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	37,781,530	30,382,404
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	58,715	
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	58,715	
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	25,654,940	31,907,256
182	(921) Office Supplies and Expenses	4,547,185	4,037,875
183	(Less) (922) Administrative Expenses Transferred-Credit	121,108	127,148
184	(923) Outside Services Employed	9,023,010	7,648,426
185	(924) Property Insurance	1,281,469	1,226,498
186	(925) Injuries and Damages	4,285,035	3,288,356
187	(926) Employee Pensions and Benefits	28,396,015	1,461,496
188	(927) Franchise Requirements	1,200	1,685
189	(928) Regulatory Commission Expenses	5,724,225	6,576,717
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses		
192	(930.2) Miscellaneous General Expenses	4,027,640	3,645,390
193	(931) Rents	417,575	671,679
194	TOTAL Operation (Enter Total of lines 181 thru 193)	83,237,186	60,338,230
195	Maintenance		
196	(935) Maintenance of General Plant	11,842,584	11,629,675
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	95,079,770	71,967,905
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	566,434,201	552,612,638

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/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	Adams Nielson Solar, LLC	LU	PURPA			
2	Avangrid Renewables, LLC	SF	Tariff 9			
3	Black Hills Power, Inc.	SF	Tariff 9			
4	Bonneville Power Administration	LF	WNP#3 Agr.			
5	Bonneville Power Administration	SF	Tariff 9			
6	Bonneville Power Administration	LF	NWPP			
7	Bonneville Power Administration	LF	Tariff 8			
8	Bonneville Power Administration	LF	Tariff 8			
9	Bonneville Power Administration	OS	BPA OATT			
10	Brookfield Energy Marketing LP	SF	Tariff 9			
11	California Independent System Operator	SF	Tariff 9			
12	Calpine Energy Services LP	SF	Tariff 9			
13	City of Spokane	LU	PURPA			
14	City of Spokane	IU	PURPA			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/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)	
1,614				50,868		50,868	1
115,265				2,969,201		2,969,201	2
2,600				97,350		97,350	3
375,377				16,181,507		16,181,507	4
210,978				3,104,310		3,104,310	5
74				2,034		2,034	6
34,636				1,152,352		1,152,352	7
177				7,945	6,757	14,702	8
					33,685	33,685	9
1,166				8,137		8,137	10
11,962				312,262		312,262	11
33,230				1,115,488		1,115,488	12
51,563				2,895,230		2,895,230	13
123,284				5,596,512		5,596,512	14
5,494,361	9,415	87,355	16,096,371	134,506,689	-14,339,158	136,263,902	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2019	Year/Period of Report End of 2018/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	Chelan County PUD	IU	Rocky Reach			
2	Chelan County PUD	SF	Tariff 9			
3	Chelan County PUD	LF	NWPP			
4	Chelan County PUD	IU	Chelan Sys			
5	Citigroup Energy	SF	Tariff 9			
6	Clark Fork Hydro	LU	PURPA			
7	Clatskanie PUD	SF	Tariff 9			
8	Clearwater Power Company	RQ	NA			
9	Community Solar	LU	PURPA			
10	ConocoPhillips Company	SF	Tariff 9			
11	Deep Creek Energy, LLC	IU	PURPA			
12	Douglas County PUD No. 1	LU	Wells			
13	Douglas County PUD No. 1	LU	Wells Settlement			
14	Douglas County PUD No. 1	SF	Tariff 9			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
-24,085							1
18,600				728,800		728,800	2
1				19		19	3
469,979			14,053,042			14,053,042	4
3,200				87,900		87,900	5
1,042				53,403		53,403	6
800				18,890		18,890	7
120				12,516		12,516	8
538				27,317		27,317	9
1,400				90,400		90,400	10
163				6,923		6,923	11
194,662			2,043,329			2,043,329	12
23,844				831,236		831,236	13
36,323				1,058,191		1,058,191	14
5,494,361	9,415	87,355	16,096,371	134,506,689	-14,339,158	136,263,902	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2019	Year/Period of Report End of 2018/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	Douglas County PUD No. 1	LF	NWPP			
2	Douglas County PUD No. 1	EX	Tariff 9			
3	EDF Trading No America	SF	Tariff 9			
4	Energy Keepers, Inc.	SF	Tariff 9			
5	Eugene Water & Electric Board	SF	Tariff 9			
6	Exelon Generation Company, LLC	SF	Tariff 9			
7	Ford Hydro Limited Partnership	LU	PURPA			
8	Grant County PUD No. 2	LU	Priest Rapids			
9	Grant County PUD No. 2	LF	NWPP			
10	Grant County PUD No. 2	EX	FERC #104			
11	Gridforce Energy Management, LLC	LF	NWPP			
12	Hydro Technology Systems	IU	PURPA			
13	Idaho County Power & Light	LU	PURPA			
14	Idaho Power Company	SF	Tariff 9			
	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.
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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)	
1				19		19	1
		77,315			-282,422	-282,422	2
5,219				163,190		163,190	3
760				43,432		43,432	4
2,079				40,262		40,262	5
43,380				1,375,470		1,375,470	6
4,231				299,317		299,317	7
356,915				7,594,105		7,594,105	8
6				180		180	9
					15,178	15,178	10
4				194		194	11
10,736				475,652		475,652	12
2,893				151,155		151,155	13
401,644				5,880,644		5,880,644	14
5,494,361	9,415	87,355	16,096,371	134,506,689	-14,339,158	136,263,902	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/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.
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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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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.

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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)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Idaho Power Company	IF	Tariff 9			
2	Idaho Power Company Balancing	SF	Tariff 9			
3	Inland Power & Light Company	RQ	208			
4	Kootenai Electric Cooperative	LF	Tariff 8			
5	Macquarie Energy LLC	SF	Tariff 9			
6	Mizuho Securities USA, Inc.	OS	NA			
7	Morgan Stanley Capital Group	SF	Tariff 9			
8	Nevada Power Company	SF	Tariff 9			
9	NextEra Energy Power Marketing LLC	SF	Tariff 9			
10	NorthWestern Energy LLC	SF	Tariff 9			
11	NorthWestern Energy LLC	LF	NWPP			
12	Okanogan County PUD No. 1	SF	Tariff 9			
13	PacifiCorp	SF	Tariff 9			
14	PacifiCorp	LF	NWPP			
	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)	
29				420		420	1
406				2,270		2,270	2
128				9,178		9,178	3
1,655				48,178		48,178	4
21,186				948,086		948,086	5
					-8,144,561	-8,144,561	6
58,801				1,792,306		1,792,306	7
20				3,249		3,249	8
3,351				98,960		98,960	9
45,120				1,423,164		1,423,164	10
7				251		251	11
17,380				324,197		324,197	12
72,595				1,704,347		1,704,347	13
17				481		481	14
5,494,361	9,415	87,355	16,096,371	134,506,689	-14,339,158	136,263,902	

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	PacifiCorp	IF	Tariff 9			
2	Palouse Wind LLC	LU	PPA			
3	Pend Oreille County PUD No. 1	SF	Pend O'			
4	Pend Oreille County PUD No. 1	IF	Pend O'			
5	Phillips Ranch	LU	PURPA			
6	Portland General Electric Company	EX	Tariff 9			
7	Portland General Electric Company	SF	Tariff 9			
8	Portland General Electric Company	LF	NWPP			
9	Portland General Electric Company	IF	Tariff 9			
10	Powerex Corp	SF	Tariff 9			
11	Public Service Company of Colorado	SF	Tariff 9			
12	Puget Sound Energy	SF	Tariff 9			
13	Puget Sound Energy	LF	NWPP			
14	Puget Sound Energy	IF	Tariff 9			
	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.
38				520		520	1
327,172				19,795,858		19,795,858	2
131,826				3,156,932		3,156,932	3
17,297				384,827		384,827	4
56				1,515		1,515	5
	9,415	9,413					6
41,124				1,489,789		1,489,789	7
14				430		430	8
12,298				318,474		318,474	9
140,155				8,608,019		8,608,019	10
800				7,200		7,200	11
87,154				2,802,828		2,802,828	12
13				439		439	13
104				3,199		3,199	14
5,494,361	9,415	87,355	16,096,371	134,506,689	-14,339,158	136,263,902	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Rainbow Energy Marketing Co.	SF	Tariff 9			
2	Rathdrum Power LLC	LU	Lancaster			
3	Sacramento Municipal Utility District	SF	Tariff 9			
4	Seattle City Light	SF	Tariff 9			
5	Seattle City Light	LF	NWPP			
6	Sheep Creek Hydro	LU	PURPA			
7	Shell Energy	SF	Tariff 9			
8	Snohomish County PUD No. 1	SF	Tariff 9			
9	Sovereign Power	LF	Sovereign			
10	Spokane County	LU	PURPA			
11	Stimson Lumber	IU	PURPA			
12	Tacoma Power	SF	Tariff 9			
13	Tacoma Power	LF	NWPP			
14	Talen Energy Marketing	SF	Tariff 9			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/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)	
6,212				289,775		289,775	1
1,591,391				27,615,866		27,615,866	2
75				8,875		8,875	3
20,301				588,471		588,471	4
9				288		288	5
6,419				330,772		330,772	6
145,586				2,863,575		2,863,575	7
50,486				909,255		909,255	8
8,235				158,702		158,702	9
1,250				58,436		58,436	10
33,180				1,683,832		1,683,832	11
11,355				369,490		369,490	12
1				19		19	13
80				3,200		3,200	14
5,494,361	9,415	87,355	16,096,371	134,506,689	-14,339,158	136,263,902	

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 Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	The City of Cove	LU	PURPA			
2	The Energy Authority	SF	Tariff 9			
3	TransAlta Energy Marketing	SF	Tariff 9			
4	Turlock Irrigation District	SF	Tariff 9			
5	Vitol Inc.	SF	Tariff 9			
6	Wells Fargo Securities, LLC	OS	NA			
7	IntraCompany Generation Services	OS	OATT			
8	Other - Inadvertent Interchange	EX				
9						
10						
11						
12						
13						
14						
	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.
151				7,846		7,846	1
9,356				170,363		170,363	2
110,697				3,905,936		3,905,936	3
50				1,100		1,100	4
4,400				183,360		183,360	5
					-8,329,977	-8,329,977	6
					2,362,182	2,362,182	7
		627					8
							9
							10
							11
							12
							13
							14
5,494,361	9,415	87,355	16,096,371	134,506,689	-14,339,158	136,263,902	

Schedule Page: 326 Line No.: 4 Column: a
BPA Contract Terminates June 30, 2019
Schedule Page: 326 Line No.: 6 Column: a
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
Schedule Page: 326 Line No.: 7 Column: a
BPA Contract Terminates September 30, 2028
Schedule Page: 326 Line No.: 8 Column: a
Effective October 1, 2018 - This Scheduling Agreement shall remain in effect until such time as BPA is no longer the designated scheduling agent for any Federal Load.
Schedule Page: 326 Line No.: 9 Column: a
Ancillary Services - Spinning & Supplemental
Schedule Page: 326.1 Line No.: 3 Column: a
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
Schedule Page: 326.1 Line No.: 8 Column: a
Service to Ahsahka, Idaho from Clearwater Power Company. No demand charges associated with the agreement.
Schedule Page: 326.2 Line No.: 1 Column: a
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
Schedule Page: 326.2 Line No.: 2 Column: a
Exchange
Schedule Page: 326.2 Line No.: 9 Column: a
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
Schedule Page: 326.2 Line No.: 11 Column: a
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
Schedule Page: 326.3 Line No.: 1 Column: a
Financially Settled Transmission Losses
Schedule Page: 326.3 Line No.: 3 Column: a
Service to Deer Lake from Inland Power and Light. No demand charges associated with the agreement.
Schedule Page: 326.3 Line No.: 4 Column: a
Kootenai Contract Terminates March 31, 2019
Schedule Page: 326.3 Line No.: 6 Column: a
Financial SWAP
Schedule Page: 326.3 Line No.: 11 Column: a
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
Schedule Page: 326.3 Line No.: 14 Column: a
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
Schedule Page: 326.4 Line No.: 1 Column: a
Financially Settled Transmission Losses
Schedule Page: 326.4 Line No.: 8 Column: a
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
Schedule Page: 326.4 Line No.: 9 Column: a
Financially Settled Transmission Losses
Schedule Page: 326.4 Line No.: 13 Column: a
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
Schedule Page: 326.4 Line No.: 14 Column: a
Financially Settled Transmission Losses
Schedule Page: 326.5 Line No.: 5 Column: a
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
Schedule Page: 326.5 Line No.: 9 Column: a
Sovereign Contract Terminates September 30, 2019
Schedule Page: 326.5 Line No.: 13 Column: a
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
Schedule Page: 326.6 Line No.: 6 Column: a

Financial SWAP

Schedule Page: 326.6 Line No.: 7 Column: a

Ancillary Services

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	PacifiCorp	PacifiCorp	PacifiCorp	OLF
2	Seattle City Light	Seattle City Light	Grant County PUD	OLF
3	Tacoma Power	Tacoma Power	Grant County PUD	OLF
4	Grant County Public Utility District	Grant County PUD	Grant County PUD	OLF
5	Spokane Tribe	Bonneville Power Administration	Spokane Tribe of Indians	LFP
6	East Greenacres	Bonneville Power Administration	East Greenacres	LFP
7	Consolidated Irrigation District	Bonneville Power Administration	Consolidated Irrigation District	LFP
8	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	FNO
9	City of Spokane	City of Spokane	Avista Corporation	OLF
10	Stimson	Plummer	Avista Corporation	OLF
11	Hydro Tech Industries	Meyers Falls	Avista Corporation	OLF
12	First Wind Energy Marketing	Palouse Wind	Avista Corporation	OLF
13	Deep Creek Hydro	Deep Creek	Avista Corporation	OLF
14	Shell Energy North America (US) LP	Bonneville Power Administration	Idaho Power Company	SFP
15	Shell Energy North America (US) LP	Grant County PUD	Idaho Power Company	SFP
16	Morgan Stanley Capital Group	Avista Corporation	Idaho Power Company	SFP
17	Morgan Stanley Capital Group	Avista Corporation	Bonneville Power Administration	SFP
18	Morgan Stanley Capital Group	Avista Corporation	NorthWestern Energy	SFP
19	Morgan Stanley Capital Group	Bonneville Power Administration	Idaho Power Company	SFP
20	Morgan Stanley Capital Group	Bonneville Power Administration	NorthWestern Energy	SFP
21	Morgan Stanley Capital Group	NorthWestern Energy	Idaho Power Company	SFP
22	Morgan Stanley Capital Group	NorthWestern Energy	Bonneville Power Administration	SFP
23	Morgan Stanley Capital Group	PacifiCorp	Idaho Power Company	SFP
24	Morgan Stanley Capital Group	Grant County PUD	Idaho Power Company	SFP
25	Morgan Stanley Capital Group	Grant County PUD	NorthWestern Energy	SFP
26	Morgan Stanley Capital Group	Chelan County PUD	Idaho Power Company	SFP
27	Morgan Stanley Capital Group	Chelan County PUD	NorthWestern Energy	SFP
28	Puget Sound Energy	NorthWestern Energy	Puget Sound Energy	SFP
29	PacifiCorp	PacifiCorp	PacifiCorp	SFP
30	Idaho Power Company	Avista Corporation	Idaho Power Company	SFP
31	Idaho Power Company	Avista Corporation	NorthWestern Energy	SFP
32	Idaho Power Company	Bonneville Power Administration	Idaho Power Company	SFP
33	Idaho Power Company	Bonneville Power Administration	NorthWestern Energy	SFP
34	Idaho Power Company	PacifiCorp	Idaho Power Comany	SFP
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
FERC No. 182	Dry Gulch	Dry Gulch		56,450	56,450	1
FERC Trf No. 8	Chelan-Stratford	Stratford		228,653	228,653	2
FERC Trf No. 8	Chelan-Stratford	Stratford		228,636	228,636	3
FERC No. 104	Stratford	Coulee City/Wilson		90,300	90,300	4
FERC Trf No. 8	AVA.BPAT	AVA.SYS	3	2,967	2,967	5
FERC Trf No. 8	AVA.BPAT	AVA.SYS	3	3,451	3,451	6
FERC Trf No. 8	AVA.BPAT	AVA.SYS	4	6,646	6,646	7
FERC Trf No. 8	AVA.BPAT	AVA.SYS		1,969,712	1,969,712	8
						9
						10
						11
FERC Trf No. 8						12
						13
FERC Trf No. 8				4,483	4,483	14
FERC Trf No. 8				160,556	160,556	15
FERC Trf No. 8				877	877	16
FERC Trf No. 8				50	50	17
FERC Trf No. 8				50	50	18
FERC Trf No. 8				15,626	15,626	19
FERC Trf No. 8				2,710	2,710	20
FERC Trf No. 8				59,077	59,077	21
FERC Trf No. 8				23,946	23,946	22
FERC Trf No. 8				258	258	23
FERC Trf No. 8				13,741	13,741	24
FERC Trf No. 8				9,677	9,677	25
FERC Trf No. 8				366,053	366,053	26
FERC Trf No. 8				1,660	1,660	27
FERC Trf No. 8				12,320	12,320	28
FERC Trf No. 8				2,608	2,608	29
FERC Trf No. 8				3,790	3,790	30
FERC Trf No. 8				700	700	31
FERC Trf No. 8				81,362	81,362	32
FERC Trf No. 8				1,250	1,250	33
FERC Trf No. 8				1,525	1,525	34
			13	**3,945,529**	**3,945,529**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2019	Year/Period of Report End of 2018/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.
219,077			219,077	1
146,816		90,228	237,044	2
208,000		90,228	298,228	3
28,145			28,145	4
28,800		6,946	35,746	5
10,800		6,418	17,218	6
32,160		9,609	41,769	7
5,892,820		2,317,335	8,210,155	8
		27,973	27,973	9
		9,480	9,480	10
		6,120	6,120	11
				12
		603	603	13
20,997			20,997	14
623,890			623,890	15
3,293			3,293	16
174			174	17
174			174	18
51,688			51,688	19
8,858			8,858	20
214,023			214,023	21
96,754			96,754	22
887			887	23
44,450			44,450	24
33,641			33,641	25
1,270,406			1,270,406	26
5,502			5,502	27
64,610			64,610	28
71,994			71,994	29
13,958			13,958	30
3,489			3,489	31
318,563			318,563	32
4,042			4,042	33
5,229			5,229	34
12,196,716	**0**	**3,511,489**	**15,708,205**	

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Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2019	Year/Period of Report End of 2018/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	Idaho Power Company	Chelan County PUD	Idaho Power Company	SFP
2	Idaho Power Company	Douglas County PUD	Idaho Power Company	SFP
3	Powerex	Bonneville Power Administration	NorthWestern Energy	SFP
4	Powerex	NorthWestern Energy	Bonneville Power Administration	SFP
5	Bonneville Power Administration	Bonneville Power Administration	Avista Corporation	NF
6	Bonneville Power Administration	Bonneville Power Administration	Idaho Power Company	NF
7	Shell Energy North America (US) LP	Bonneville Power Administration	Idaho Power Company	NF
8	Shell Energy North America (US) LP	Bonneville Power Administration	NorthWestern Energy	NF
9	Shell Energy North America (US) LP	NorthWestern Energy	Bonneville Power Administration	NF
10	Shell Energy North America (US) LP	NorthWestern Energy	Grant County Public Utility	NF
11	Kootenai Electric	Avista Corporation	Idaho Power Company	LFP
12	Morgan Stanley Capital Group	Avista Corporation	Idaho Power Company	NF
13	Shell Energy North America (US) LP	NorthWestern Energy	Grant County PUD	SFP
14	Shell Energy North America (US) LP	NorthWestern Energy	Bonneville Power Administration	SFP
15	Morgan Stanley Capital Group	Bonneville Power Administration	Idaho Power Company	NF
16	Morgan Stanley Capital Group	Bonneville Power Administration	NorthWestern Energy	NF
17	Morgan Stanley Capital Group	NorthWestern Energy	Bonneville Power Administration	NF
18	Morgan Stanley Capital Group	NorthWestern Energy	Chelan County PUD	NF
19	Morgan Stanley Capital Group	NorthWestern Energy	Idaho Power Company	NF
20	Morgan Stanley Capital Group	NorthWestern Energy	Grant County PUD	NF
21	Morgan Stanley Capital Group	NorthWestern Energy	Pacific Corp	NF
22	Morgan Stanley Capital Group	Portland General Electric	NorthWestern Energy	NF
23	Morgan Stanley Capital Group	Avista Corporation	Bonneville Power Administration	NF
24	Morgan Stanley Capital Group	Grant County PUD	Idaho Power Company	NF
25	Morgan Stanley Capital Group	Grant County PUD	NorthWestern Energy	NF
26	Morgan Stanley Capital Group	Chelan County PUD	Idaho Power Company	NF
27	Morgan Stanley Capital Group	Chelan County PUD	NorthWestern Energy	NF
28	Morgan Stanley Capital Group	Avista Corporation	NorthWestern Energy	NF
29	Puget Sound Energy	NorthWestern Energy	Bonneville Power Administration	NF
30	Powerex	Bonneville Power Administration	Idaho Power Company	NF
31	Transalta Energy Marketing	Bonneville Power Administration	Idaho Power Company	NF
32	PacifiCorp	PacifiCorp	Bonneville Power Administration	NF
33	PacifiCorp	PacifiCorp	Idaho Power Company	NF
34	PacifiCorp	Idaho Power Company	PacifiCorp	NF
	TOTAL			

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
FERC Trf No. 8				9,600	9,600	1
FERC Trf No. 8				400	400	2
FERC Trf No. 8				7,040	7,040	3
FERC Trf No. 8				1,300	1,300	4
FERC Trf No. 8				216	216	5
FERC Trf No. 8				14,130	14,130	6
FERC Trf No. 8				450	450	7
FERC Trf No. 8				157	157	8
FERC Trf No. 8				9,023	9,023	9
FERC Trf No. 8				5,383	5,383	10
FERC Trf No. 8	AVA.SYS	LOLO	3	14,193	14,193	11
FERC Trf No. 8				164	164	12
FERC Trf No. 8				14,433	14,433	13
FERC Trf No. 8				601	601	14
FERC Trf No. 8				2,784	2,784	15
FERC Trf No. 8				8,104	8,104	16
FERC Trf No. 8				17,797	17,797	17
FERC Trf No. 8				2,907	2,907	18
FERC Trf No. 8				2,561	2,561	19
FERC Trf No. 8				522	522	20
FERC Trf No. 8				4,034	4,034	21
FERC Trf No. 8				70	70	22
FERC Trf No. 8				32	32	23
FERC Trf No. 8				623	623	24
FERC Trf No. 8				935	935	25
FERC Trf No. 8				4,155	4,155	26
FERC Trf No. 8				3,298	3,298	27
FERC Trf No. 8				115	115	28
FERC Trf No. 8				975	975	29
FERC Trf No. 8				303	303	30
FERC Trf No. 8				208	208	31
FERC Trf No. 8				1,934	1,934	32
FERC Trf No. 8				964	964	33
FERC Trf No. 8				1,860	1,860	34
			13	**3,945,529**	**3,945,529**	

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.
29,792			29,792	1
1,371			1,371	2
40,612			40,612	3
70,729			70,729	4
1,754			1,754	5
109,405			109,405	6
3,052			3,052	7
906			906	8
62,117			62,117	9
35,198			35,198	10
72,000		22,549	94,549	11
1,054			1,054	12
59,976			59,976	13
2,571			2,571	14
18,872			18,872	15
54,315			54,315	16
118,741			118,741	17
19,066			19,066	18
17,239			17,239	19
3,488			3,488	20
27,214			27,214	21
467			467	22
206			206	23
4,229			4,229	24
6,588			6,588	25
27,791			27,791	26
21,315			21,315	27
715			715	28
6,232			6,232	29
1,969			1,969	30
1,200			1,200	31
12,636			12,636	32
11,645			11,645	33
8,763			8,763	34
12,196,716	**0**	**3,511,489**	**15,708,205**	

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Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2019	Year/Period of Report End of 2018/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	Idaho Power Company	Bonneville Power Administration	Idaho Power Company	NF
2	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	OS
3	Morgan Stanley Capital Group	Idaho Power Company	Bonneville Power Administration	NF
4	Shell Energy North America (US) LP	Idaho Power Company	Bonneville Power Administration	NF
5	Shell Energy North America (US) LP	Grant County Public Utility	Idaho Power Company	NF
6	Tacoma City Light	NorthWestern Energy	Bonneville Power Administration	NF
7	NorthWestern Energy	Bonneville Power Administration	NorthWestern Energy	NF
8	Portland General Electric	NorthWestern Energy	Bonneville Power Administration	NF
9	Avangrid Renewables	Bonneville Power Administration	Idaho Power Company	NF
10	Avangrid Renewables	NorthWestern Energy	Bonneville Power Administration	NF
11	Shell Energy North America (US) LP	Idaho Power Company	Grant County Public Utility	NF
12	Energy Keepers, Inc.	Bonneville Power Administration	NorthWestern Energy	NF
13	EDF Trading N.A. LLC	NorthWestern Energy	Bonneville Power Administration	NF
14	Macquarie Energy LLC	Bonneville Power Administration	NorthWestern Energy	NF
15	Idaho Power Company	PacifiCorp	Idaho Power Company	NF
16	Macquarie Energy LLC	Douglas County PUD	NorthWestern Energy	NF
17	Morgan Stanley Capital Group	PacifiCorp	NorthWestern Energy	NF
18	NorthWestern Energy	NorthWestern Energy	Bonneville Power Administration	NF
19	NorthWestern Energy	NorthWestern Energy	Chelan County PUD	NF
20	NorthWestern Energy	NorthWestern Energy	Grant County Public Utility	NF
21	PacifiCorp	Bonneville Power Administration	Idaho Power Company	NF
22	PacifiCorp	PacifiCorp	Idaho Power Company	NF
23	Portland General Electric	Bonneville Power Administration	NorthWestern Energy	NF
24	Portland General Electric	NorthWestern Energy	Portland General Electric	NF
25	Puget Sound Energy	NorthWestern Energy	Puget Sound Energy	NF
26	Powerex	Bonneville Power Administration	NorthWestern Energy	NF
27	Powerex	NorthWestern Energy	Bonneville Power Administration	NF
28	Powerex	NorthWestern Energy	Chelan County PUD	NF
29	Rainbow Energy Marketing Corp	NorthWestern Energy	Bonneville Power Administration	NF
30	Rainbow Energy Marketing Corp	Grant County Pubilic Utility	Idaho Power Company	NF
31	Seattle City Light	NorthWestern Energy	Bonneville Power Administration	NF
32	The Energy Authority	Bonneville Power Administration	NorthWestern Energy	NF
33	The Energy Authority	NorthWestern Energy	Bonneville Power Administration	NF
34	Transalta Energy Marketing	Bonneville Power Administration	PacifiCorp	NF
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
FERC Trf No. 8				70,036	70,036	1
T1110						2
FERC Trf No. 8				7	7	3
FERC Trf No. 8				281	281	4
FERC Trf No. 8				12,291	12,291	5
FERC Trf No. 8				35	35	6
FERC Trf No. 8				8,461	8,461	7
FERC Trf No. 8				3,947	3,947	8
FERC Trf No. 8				213	213	9
FERC Trf No. 8				90	90	10
FERC Trf No. 8				1,335	1,335	11
FERC Trf No, 8				407	407	12
FERC Trf No. 8				1,058	1,058	13
FERC Trf No. 8				206	206	14
FERC Trf No. 8				2,073	2,073	15
FERC Trf No. 8				363	363	16
FERC Trf No. 8				155	155	17
FERC Trf No. 8				3,891	3,891	18
FERC Trf No. 8				18	18	19
FERC Trf No. 8				60	60	20
FERC Trf No. 8				318	318	21
FERC Trf No. 8				40	40	22
FERC Trf No. 8				45	45	23
FERC Trf No. 8				8,434	8,434	24
FERC Trf No. 8				1,550	1,550	25
FERC Trf No. 8				612	612	26
FERC Trf No. 8				3,085	3,085	27
FERC Trf No. 8				61	61	28
FERC Trf No. 8				184	184	29
FERC Trf No. 8				330	330	30
FERC Trf No. 8				186	186	31
FERC Trf No. 8				80	80	32
FERC Trf No. 8				57	57	33
FERC Trf No. 8				1	1	34
			13	**3,945,529**	**3,945,529**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2019	Year/Period of Report End of 2018/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.
255,311			255,311	1
		924,000	924,000	2
46			46	3
1,955			1,955	4
81,305			81,305	5
202			202	6
54,925			54,925	7
23,228			23,228	8
1,304			1,304	9
519			519	10
8,561			8,561	11
2,348			2,348	12
6,105			6,105	13
1,189			1,189	14
12,500			12,500	15
2,095			2,095	16
998			998	17
23,470			23,470	18
105			105	19
348			348	20
3,260			3,260	21
231			231	22
260			260	23
49,531			49,531	24
8,955			8,955	25
4,834			4,834	26
19,217			19,217	27
406			406	28
1,148			1,148	29
2,308			2,308	30
1,073			1,073	31
525			525	32
329			329	33
6			6	34
12,196,716	**0**	**3,511,489**	**15,708,205**	

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/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	Transalta Energy Marketing	NorthWestern Energy	Bonneville Power Administration	NF
2	Transalta Energy Marketing	NorthWestern Energy	Grant County Public Utility	NF
3	Shell Energy North America (US) LP	Idaho Power Company	Bonneville Power Administration	SFP
4	Shell Energy North America (US) LP	Idaho Power Company	Grant County Public Utility	SFP
5	Idaho Power Company	Puget Sound Energy	Idaho Power Company	SFP
6	Idaho Power Company	Grant County Public Utility	Idaho Power Company	SFP
7	Idaho Power Company	Idaho Power Company	Bonneville Power Administration	SFP
8	Idaho Power Company	Idaho Power Company	Grant County Public Utility	SFP
9	Macquarie Energy LLC	Avista Corporation	NorthWestern Energy	SFP
10	Macquarie Energy LLC	Bonneville Power Administration	NorthWestern Energy	SFP
11	Morgan Stanley Capital Group	NorthWestern Energy	Chelan County PUD	SFP
12	Morgan Stanley Capital Group	NorthWestern Energy	Grant County Public Utility	SFP
13	Morgan Stanley Capital Group	NorthWestern Energy	PacifiCorp	SFP
14	Morgan Stanley Capital Group	NorthWestern Energy	Avista Corporation	SFP
15	Morgan Stanley Capital Group	Idaho Power Company	Bonneville Power Administration	SFP
16	Morgan Stanley Capital Group	Idaho Power Company	Avista Corporation	SFP
17	PacifiCorp	NorthWestern Energy	PacifiCorp	SFP
18	PacifiCorp	Idaho Power Company	PacifiCorp	SFP
19	Powerex	Idaho Power Company	Bonneville Power Administration	SFP
20	Powerex	Chelan County PUD	NorthWestern Energy	SFP
21	Powerex	Avista Corporation	NorthWestern Energy	SFP
22	Shell Energy North America (US) LP	Grant County Public Utility	NorthWestern Energy	SFP
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) 04/15/2019	Year/Period of Report End of 2018/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				187	187	1
FERC Trf No. 8				15	15	2
FERC Trf No. 8				16,128	16,128	3
FERC Trf No. 8				1,664	1,664	4
FERC Trf No. 8				2,800	2,800	5
FERC Trf No. 8				2,904	2,904	6
FERC Trf No. 8				10,794	10,794	7
FERC Trf No. 8				18,000	18,000	8
FERC Trf No. 8				3,600	3,600	9
FERC Trf No. 8				1,400	1,400	10
FERC Trf No. 8				239	239	11
FERC Trf No. 8				900	900	12
FERC Trf No. 8				2,000	2,000	13
FERC Trf No. 8				350	350	14
FERC Trf No. 8				6,724	6,724	15
FERC Trf No. 8				4,008	4,008	16
FERC Trf No. 8				17,960	17,960	17
FERC Trf No. 8				253,660	253,660	18
FERC Trf No. 8				538	538	19
FERC Trf No. 8				160	160	20
FERC Trf No. 8				800	800	21
FERC Trf No. 8				383	383	22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			13	**3,945,529**	**3,945,529**	

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.
1,111			1,111	1
89			89	2
68,990			68,990	3
6,908			6,908	4
9,782			9,782	5
11,026			11,026	6
50,765			50,765	7
50,000			50,000	8
14,953			14,953	9
5,815			5,815	10
941			941	11
3,600			3,600	12
8,023			8,023	13
1,383			1,383	14
26,980			26,980	15
15,661			15,661	16
66,786			66,786	17
971,516			971,516	18
29,271			29,271	19
923			923	20
4,615			4,615	21
2,513			2,513	22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
12,196,716	**0**	**3,511,489**	**15,708,205**	

Schedule Page: 328 Line No.: 2 Column: m
Use of facilities.

Schedule Page: 328 Line No.: 3 Column: m
Use of facilities.

Schedule Page: 328 Line No.: 5 Column: m
Ancillary services.

Schedule Page: 328 Line No.: 6 Column: m
Ancillary services.

Schedule Page: 328 Line No.: 7 Column: m
Ancillary services.

Schedule Page: 328 Line No.: 8 Column: m
Ancillary services.

Schedule Page: 328 Line No.: 9 Column: e
PURPA Interconnection under state jurisdiction.

Schedule Page: 328 Line No.: 9 Column: m
Use of facilities.

Schedule Page: 328 Line No.: 10 Column: e
PURPA Interconnection under state jurisdiction.

Schedule Page: 328 Line No.: 10 Column: m
Use of facilities.

Schedule Page: 328 Line No.: 11 Column: e
PURPA Interconnection under state jurisdiction.

Schedule Page: 328 Line No.: 11 Column: m
Use of facilities.

Schedule Page: 328 Line No.: 13 Column: e
PURPA Interconnection under state jurisdiction.

Schedule Page: 328 Line No.: 13 Column: m
Use of facilities.

Schedule Page: 328.1 Line No.: 11 Column: m
Ancillary services.

Schedule Page: 328.2 Line No.: 2 Column: m
Parallel Capacity Support Agreement.

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2019	Year/Period of Report End of 2018/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			1,498,275			1,498,275
2	Bonneville Power Admin	LFP			10,109,292		2,206,344	12,315,636
3	Bonneville Power Admin	LFP			943,402			943,402
4	Bonneville Power Admin	OS					54,432	54,432
5	Bonneville Power Admin	FNS			1,069,393		219,033	1,288,426
6	Bonneville Power Admin	NF	9,392	9,392		48,463		48,463
7	Idaho Power Company	NF	2,012	2,012		8,502	321	8,823
8	Nevada Power Company	NF	1,755	1,755		8,144	-612	7,532
9	Kootenai Electric Coop	LFP			45,222			45,222
10	Northern Lights	LFP			135,749			135,749
11	NorthWestern Energy	SFP			187,135		15,710	202,845
12	NorthWestern Energy	NF	28,783	28,783		124,630		124,630
13	Portland General Elec	LFP			628,000		14,989	642,989
14	Portland General Elec	NF	52,348	52,348		76,038		76,038
15	Snohomish County PUD	NF	49,666	49,666		70,597		70,597
16	Puget Sound Energy	NF	9,476	9,476		23,754	122	23,876
	TOTAL		183,049	183,049	14,616,468	402,681	2,510,339	17,529,488

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/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	Energy Keepers, Inc.	NF	1,274	1,274		3,797		3,797
2	Seattle City Light	NF	26,183	26,183		31,844		31,844
3	PacifiCorp	NF	1,532	1,532		6,271		6,271
4	Shell Energy North Amer	NF	100	100		125		125
5	The Energy Authority	NF	528	528		516		516
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		183,049	183,049	14,616,468	402,681	2,510,339	17,529,488

Name of Respondent Avista Corporation	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2019	Year/Period of Report 2018/Q4

FOOTNOTE DATA

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

Schedule Page: 332 Line No.: 4 Column: g
Use of Facilities

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

Schedule Page: 332 Line No.: 7 Column: g
EIM Settlement Charges Related to Transmission

Schedule Page: 332 Line No.: 8 Column: g
Transmission credit due to congestion on the system.

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

Schedule Page: 332 Line No.: 13 Column: g
Ancillary Services

Schedule Page: 332 Line No.: 16 Column: g
Other Transmission Charges Related to CAISO Transactions

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	843,510
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	291,641
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Community Relations	8,223
7	Director Expenses	562,412
8	Education & Information	31,528
9	Rating Agency Fees	141,061
10	Aircraft Operation and fees	250,328
11	Misc Vendors > 5000	1,664,036
12	Misc Vendors < 5000	234,901
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
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41		
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43		
44		
45		
46	TOTAL	4,027,640

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/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			3,882,724		3,882,724
2	Steam Production Plant	8,278,220	268,929			8,547,149
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	12,063,425				12,063,425
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	9,804,229			2,450,031	12,254,260
7	Transmission Plant	12,893,891				12,893,891
8	Distribution Plant	49,842,005				49,842,005
9	Regional Transmission and Market Operation					
10	General Plant	3,037,655		48,030		3,085,685
11	Common Plant-Electric	16,692,773		19,934,553		36,627,326
12	TOTAL	112,612,198	268,929	23,865,307	2,450,031	139,196,465

B. Basis for Amortization Charges

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	57,305	70.00	-10.00	1.56	S1.5	22.10
15	312	84,667	60.00	-10.00	1.93	R1	21.50
16	313	3					
17	314	23,672	40.00	-5.00	2.79	R0.5	19.40
18	315	10,097	50.00		1.73	R3	21.00
19	316	9,740	53.00		1.46	R2	20.90
20	Subtotal	185,484					
21							
22	Colstrip No. 4						
23	311	53,528	70.00	-10.00	1.68	S1.5	23.90
24	312	58,047	60.00	-10.00	2.20	R1	23.30
25	313	3					
26	314	15,320	40.00	-5.00	2.88	R0.5	20.90
27	315	7,142	50.00		1.88	R3	22.90
28	316	4,713	53.00		1.62	R2	22.70
29	Subtotal	138,753					
30							
31	Kettle Falls					0	
32	310	148			1.45	SQ	18.00
33	311	28,703	70.00	-10.00	1.51	S1.5	17.10
34	312	45,606	60.00	-10.00	1.93	R1	16.70
35	314	17,786	40.00	-5.00	2.12	R0.5	14.90
36	315	12,348	50.00		1.56	R3	16.40
37	316	2,672	53.00		1.74	R2	16.80
38	Subtotal	107,263					
39							
40	HYDRO PLANT						
41	Cabinet Gorge						
42	330	9,378	100.00		2.00	R4	43.20
43	331	16,491	110.00	-20.00	1.50	R2	51.50
44	332	44,778	100.00		1.13	R1	47.70
45	333	48,037	65.00	-10.00	2.04	R1.5	43.90
46	334	9,251	38.00	-5.00	2.97	R2.5	19.70
47	335	4,594	65.00		0.38	R1.5	49.90
48	336	1,671	55.00		1.96	S2	19.00
49	Subtotal	134,200					
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	04/15/2019	End of 2018/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	Noxon Rapids						
13	330	30,477	100.00		1.80	R4	48.80
14	331	22,190	110.00	-20.00	1.48	R2	58.40
15	332	35,353	100.00		1.12	R1	52.60
16	333	88,683	65.00	-10.00	1.98	R1.5	47.50
17	334	17,016	38.00	-5.00	2.79	R2.5	29.50
18	335	4,156	65.00		0.80	R1.5	53.60
19	336	260	55.00		1.89	S2	32.00
20	Subtotal	198,135					
21							
22	Post Falls						
23	330	2,908	75.00		2.81	R3	25.20
24	331	3,734	110.00	-20.00	2.09	R2	45.60
25	332	26,438	100.00		1.71	R1	44.70
26	333	2,234	65.00	-10.00	2.42	R1.5	29.60
27	334	1,239	38.00	-5.00	2.78	R2.5	18.20
28	335	743	65.00		1.15	R1.5	42.10
29	336	578	55.00		1.96	S2.5	26.20
30	Subtotal	37,874					
31							
32	Long Lake						
33	330	418	75.00		4.42	R3	11.00
34	331	8,769	110.00	-20.00	1.99	R2	38.90
35	332	36,239	100.00		1.65	R1	40.00
36	333	8,738	65.00	-10.00	2.46	R1.5	33.30
37	334	3,228	38.00	-5.00	2.63	R2.5	22.50
38	335	790	65.00		1.22	R1.5	39.40
39	336	678	55.00		1.89	S2.5	26.20
40	Subtotal	58,860					
41							
42	Little Falls						
43	330	4,217	100.00		3.35	R4	24.40
44	331	3,703	110.00	-20.00	1.94	R2	42.30
45	332	5,165	100.00		1.72	R1	43.60
46	333	34,779	65.00	-10.00	2.40	R1.5	33.60
47	334	9,332	38.00	-5.00	2.74	R2.5	22.20
48	335	549	65.00		0.69	R1.5	40.60
49	Subtotal	57,745					
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	04/15/2019	End of 2018/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	Upper Falls						
13	330	64	100.00		3.66	R4	22.20
14	331	975	110.00	-20.00	1.77	R2	41.40
15	332	7,607	100.00		1.85	R1	45.20
16	333	1,166	65.00	-10.00	2.53	R1.5	30.00
17	334	4,269	38.00	-5.00	2.81	R2.5	35.10
18	335	104	65.00		1.05	R1.5	41.20
19	336	508	55.00		1.94	S2	26.20
20	Subtotal	14,693					
21							
22	Nine Mile						
23	330	11	100.00		2.48	R4	35.90
24	331	19,235	110.00	-20.00	1.98	R2	46.50
25	332	29,222	100.00		1.83	R1	45.10
26	333	41,581	65.00	-10.00	2.17	R1.5	40.30
27	334	19,194	38.00	-5.00	2.80	R2.5	22.50
28	335	3,141	65.00		0.88	R1.5	41.20
29	336	595	55.00		1.93	S2	36.20
30	Subtotal	112,979					
31							
32	Monroe Street						
33	331	12,121	110.00	-20.00	1.71	R2	56.90
34	332	9,972	100.00		1.39	R1	53.20
35	333	11,027	65.00	-10.00	1.95	R1.5	45.50
36	334	3,589	38.00	-5.00	2.82	R2.5	23.40
37	335	34	65.00		1.19	R1.5	48.30
38	336	50	55.00		1.86	S2	36.60
39	Subtotal	36,793					
40							
41	OTHER PRODUCTION						
42	Northeast Turbine						
43	341	751	55.00		1.64	S4	8.00
44	342	31	55.00	-10.00	2.93	R3	8.00
45	343	9,058	55.00		0.81	S2.5	8.00
46	344	2,604	45.00		2.50	R1	7.40
47	345	1,243	20.00	-5.00	12.49	S2	7.90
48	346	399	35.00		2.51	R3	7.80
49	Subtotal	14,086					
50							

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	Rathdrum Turbine						
13	341	3,554	55.00		3.12	S4	24.00
14	342	1,696	55.00	-10.00	3.57	R3	23.50
15	343	5,722	55.00		2.77	S2.5	23.50
16	344	49,712	45.00		3.77	R1	21.60
17	345	3,185	20.00	-5.00	5.89	S2	15.20
18	346	308	35.00		2.51	R3	7.80
19	Subtotal	64,177					
20							
21	Kettle Falls CT						
22	341	9	55.00	-10.00	1.36	S4	24.00
23	342	89	55.00	-10.00	3.66	R3	17.70
24	343	8,670	55.00		3.24	S2.5	17.80
25	344	737	45.00		4.09	R1	16.60
26	345	13	20.00	-5.00	6.68	S2	11.40
27	Subtotal	9,518					
28							
29	Boulder Park						
30	341	1,263	55.00		2.54	S4	31.90
31	342	162	55.00	-10.00	2.62	R3	30.40
32	343	57	55.00		2.52	S2.5	30.90
33	344	30,994	45.00		2.94	R1	26.90
34	345	646	20.00	-5.00	6.03	S2	14.30
35	346	39	35.00		2.87	R3	26.20
36	Subtotal	33,161					
37							
38	Coyote Springs 2						
39	341	11,559	55.00		2.34	S4	32.80
40	342	19,318	55.00	-10.00	2.72	R3	31.40
41	344	135,306	45.00		3.00	R1	27.90
42	345	16,933	20.00	-5.00	6.14	S2	13.40
43	346	1,003	35.00		2.95	R3	27.40
44	Subtotal	184,119					
45							
46	Solar Power						
47	344 & 345	482	25.00		5.30	S2.5	17.90
48	Subtotal	482					
49							
50	Lancaster						

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	342	92	55.00	-10.00	3.67	R3	29.40
13	344	209	45.00		3.70	R1	26.60
14	345	49	20.00		5.00	S1.5	18.00
15	Subtotal	350					
16							
17	TRANSMISSION PLANT						
18	350	21,714	75.00		1.30	R4	56.80
19	352	26,258	60.00	-5.00	1.65	S2	48.00
20	353	267,788	45.00	-10.00	2.33	R2.5	33.10
21	354	17,291	70.00	-15.00	1.80	R4	41.00
22	355	262,716	65.00	-15.00	1.38	R2.5	54.70
23	356	147,348	65.00	-10.00	1.59	R2.5	50.20
24	357	3,188	60.00		1.64	R4	51.70
25	358	2,537	50.00		2.02	S2	35.40
26	359	2,054	65.00		1.66	R4	39.70
27	Subtotal	750,894					
28							
29	DISTRIBUTION PLANT						
30	360	2,962	75.00		1.34	R4	74.40
31	361	34,129	60.00	-10.00	1.62	R2.5	47.30
32	362	138,395	45.00		1.97	R1.5	34.20
33	363	2,598					
34	364	406,104	55.00	-25.00	2.31	R2.5	41.10
35	365	268,711	50.00	-20.00	2.82	R3	32.70
36	366	118,895	50.00	-25.00	2.71	S2	37.60
37	367	209,477	28.00	-20.00	5.63	S2	16.80
38	368	269,658	44.00	-5.00	2.11	R2	33.00
39	369	173,791	55.00	-40.00	2.70	R4	37.55
40	370 - AN	157	15.00		7.65	S2.5	12.50
41	370.2 - ID	22,929	15.00		7.65	S2.5	12.50
42	370.3 - WA	33,473	35.00		3.39	S0.5	23.60
43	371	1,492					
44	373	22,531	35.00	-25.00	1.91	R2.5	26.45
45	373.4	26,039	35.00	-25.00	3.48	R2.5	26.80
46	373.5	14,636	35.00	-25.00	3.48	R2.5	26.80
47	Subtotal	1,745,977					
48							
49	GENERAL PLANT						
50	390.1	8,242	48.00	-5.00	1.67	S2	39.00

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	391.1	2,744	5.00		21.28	SQ	3.30
13	393	399	25.00		4.58	SQ	19.40
14	394	5,633	20.00		4.78	SQ	10.20
15	395	1,553	15.00		13.73	SQ	4.00
16	397	66,119	15.00		2.81	SQ	11.70
17	398	152	10.00		13.31	SQ	7.00
18	Subtotal	84,842					
19							
20	MISC POWER						
21	392	7,418	15.00	20.00	1.83	L2.5	13.70
22	396	3,866	16.00	5.00	5.79	S0.5	11.80
23	Subtotal	11,284					
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34	TOTAL COMPANY	3,981,669					
35							
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	Federal Energy Regulatory Commission				
2	Charges include annual fee and license fees				
3	for the Spokane River Project, the Cabinet				
4	Gorge Project and the Noxon Rapids Project.	2,595,769	104,489	2,700,258	
5					
6					
7					
8					
9	Washington Utilities and Transportation				
10	Commission: includes annual fee and various				
11	other electric dockets	1,103,122	497,527	1,600,649	
12					
13	Includes annual fee and various other natural				
14	gas dockets	342,265	143,351	485,616	
15					
16	Idaho Public Utilities Commission				
17	Includes annual fee and various other electric				
18	dockets	577,500	159,921	737,421	
19					
20	Includes annual fee and various other natural				
21	gas dockets	148,781	40,034	188,815	
22					
23	Public Utility Commission of Oregon				
24	Includes annual fees and various other natural				
25	gas dockets	605,703	153,477	759,180	
26					
27	Not directly assigned electric		685,897	685,897	
28	Not directly assigned natural gas		351,469	351,469	
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	5,373,140	2,136,165	7,509,305	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
							2
							3
Electric	928	2,707,060					4
							5
							6
							7
							8
							9
							10
Electric	928	1,671,938					11
							12
							13
Gas	928	501,029					14
							15
							16
							17
Electric	928	748,986					18
							19
							20
Gas	928	194,806					21
							22
							23
							24
Gas	928	790,725					25
							26
Electric	928	1,044,677					27
Gas	928	456,940					28
							29
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		8,116,161					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
- (1) Generation
  - a. hydroelectric
    - i. Recreation fish and wildlife
    - ii Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) Transmission
  - a. Overhead
  - b. Underground
- (3) Distribution
- (4) Regional Transmission and Market Operation
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $50,000.)
- (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	A 3 Electric - Distribution	Battery Storage and Electric Vehicle Supply Equipment
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	04/15/2019	End of 2018/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
783,985	2,342,279	107	3,126,265		1
84	97,020	584	97,104		2
	118,331	587	118,331		3
1,924	12,198	598	14,122		4
	11,060	909	11,060		5
4,365	54,350	912	58,715		6
50,981		920	50,981		7
527	4,308	930	4,834		8
					9
					10
					11
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/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	12,440,584		
4	Transmission	3,623,837		
5	Regional Market			
6	Distribution	8,781,520		
7	Customer Accounts	7,560,552		
8	Customer Service and Informational	618,095		
9	Sales			
10	Administrative and General	20,423,547		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	53,448,135		
12	Maintenance			
13	Production	5,091,038		
14	Transmission	1,063,818		
15	Regional Market			
16	Distribution	3,656,607		
17	Administrative and General			
18	TOTAL Maintenance (Total of lines 13 thru 17)	9,811,463		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	17,531,622		
21	Transmission (Enter Total of lines 4 and 14)	4,687,655		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	12,438,127		
24	Customer Accounts (Transcribe from line 7)	7,560,552		
25	Customer Service and Informational (Transcribe from line 8)	618,095		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	20,423,547		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	63,259,598	8,557,638	71,817,236
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply	915,001		
34	Storage, LNG Terminaling and Processing	9,900		
35	Transmission			
36	Distribution	5,724,403		
37	Customer Accounts	3,268,072		
38	Customer Service and Informational	458,819		
39	Sales			
40	Administrative and General	8,450,852		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	18,827,047		
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	1,439,174		

DISTRIBUTION OF SALARIES AND WAGES (Continued)

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Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution	2,948,156		
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	4,387,330		
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)	915,001		
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru	9,900		
56	Transmission (Lines 35 and 47)	1,439,174		
57	Distribution (Lines 36 and 48)	8,672,559		
58	Customer Accounts (Line 37)	3,268,072		
59	Customer Service and Informational (Line 38)	458,819		
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)	8,450,852		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	23,214,377	2,970,413	26,184,790
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	86,473,975	11,528,051	98,002,026
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	41,798,020	6,925,464	48,723,484
69	Gas Plant	11,590,993	2,573,090	14,164,083
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	53,389,013	9,498,554	62,887,567
72	Plant Removal (By Utility Departments)			
73	Electric Plant	2,346,812	243,309	2,590,121
74	Gas Plant	449,275	46,579	495,854
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	2,796,087	289,888	3,085,975
77	Other Accounts (Specify, provide details in footnote):			
78	Stores Expense	2,283,886	-2,283,886	
79	Prelliminary Survey and investigation	7,004		7,004
80	Small tools	4,242,236	-4,242,236	
81	Miscellaneous Deferred Debits	1,256,088		1,256,088
82	Non operating expenses	439,261		439,261
83	Retirement bonus/SERP/HRA Settlement	39,876		39,876
84	Activies	2,223,990		2,223,990
85	Employee incentive plan	14,790,366	-14,790,366	
86	DSM Tariff Rider	23,095,267		23,095,267
87	Stock Compensation	149,394		149,394
88	Taxes other than income	104		104
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	48,527,472	-21,316,488	27,210,984
96	TOTAL SALARIES AND WAGES	191,186,547	5	191,186,552

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/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	256,351,833
389	Land and Land Rights	11,956,183
390	Structures and Improvements	137,178,916
391	Office Furniture and Equipment	80,707,510
392	Transportation Equipment	13,824,689
393	Stores Equipment	4,953,936
394	Tools, Shop & Garage Equipment	14,546,041
395	Laboratory Equipment	1,269,693
396	Power Operated Equipment	1,854,077
397	Communications Equipment	76,631,226
398	Miscellaneous Equipment	507,797
399	Asset Retirement Cost	0

	Total Common Plant	599,781,901
	Const. Work in Progress	38,049,455

	Total Utility Plant	637,831,356
	Acc. Prov. for Dep. & Amort.	162,351,353

	Net Utility Plant	475,480,003

3. Common Expenses allocated to Electric and Gas departments:

Acct. No.	Description	Allocation to Total	Allocated to Electric Dept	Gas Dept	Basis of Allocation
901	Cust acct/collect supervision	258,651	135,520	123,131	# of Customers
902	Meter reading expenses	3,956,997	2,409,099	1,547,898	# of Customers
903	Cust rec & collectn expenses	14,864,628	8,063,755	6,800,873	# of Customers
904	Uncollectible accounts	3,900,000	2,043,405	1,856,595	# of Customers
905	Misc cust acct expenses	467,134	244,755	222,379	# of Customers
907	Cust svce & Info exp supervision	0	0	0	
908	Cust assistance expenses	807,190	486,570	320,620	# of Customers
909	Info & instruct advert expenses	1,500,987	911,098	589,889	# of Customers
910	Misc cust serv & info expenses	665,931	348,931	317,000	# of Customers
911	Sales expense -supervision	0	0	0	
912	Demo and selling expenses	0	0	0	
913	Advertising expenses	0	0	0	
916	Misc sales expenses	0	0	0	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report *(Mo, Da, Yr)* 04/15/2019	Year/Period of Report End of 2018/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.

920	Admin & gen salaries	34,396,746	24,201,221	10,195,525	Four Factor
921	Office supplies & expenses	6,272,287	4,405,129	1,867,158	Four Factor
922	Admin expenses tranf-credit	377	293	84	Four Factor
923	Outside services employed	12,208,741	8,572,062	3,636,679	Four Factor
924	Property insurance	1,462,930	1,026,026	436,904	Four Factor
925	Injuries and damages	6,609,700	4,775,852	1,833,848	Four Factor
926	Employee pensions&benefits	85,182,974	59,745,916	25,437,058	Four Factor
927	Franchise requirement	0	0	0	
928	Regulatory commission expenses	1,468,594	1,057,061	411,533	Four Factor
929	Duplicate charges-credit	0	0	0	
930.1	General advertising expenses	0	0	0	
930.2	Misc general expenses	4,316,141	3,048,896	1,267,245	Four Factor
931	Rents	616,661	457,507	159,154	Four Factor
935	Maint of general plant	14,692,477	10,445,985	4,246,492	Four Factor
403	Depreciation	23,587,761	16,692,772	6,894,989	Four Factor
404	Amort of LTD term plant	28,380,903	19,973,084	8,407,819	Four Factor

Note 1: The 4 factor allocator is made up of 25% each -customer counts, direct labor, direct O&M & Net direct plant

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

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AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

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

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	24,772	35,894	140,189	310,047
3	Net Sales (Account 447)	(2,608,458)	(4,337,533)	(6,662,554)	(8,713,419)
4	Transmission Rights				
5	Ancillary Services	(8,298)	(19,986)	(25,878)	(32,176)
6	Other Items (list separately)				
7	Access Charge	296	7,361	21,606	46,316
8	Cost Recovery	(1,031)	(3,036)	(416)	177
9	Day Ahead Energy-Congestion Losses	(341)	(321)	(14,204)	(16,394)
10	FERC Fees	5	50	138	304
11	GMC	34,989	67,067	93,273	113,339
12	Hour Ahead Scheduling Process-RT	13	147	2,445	2,646
13	Other	25	(38)	102	10
14					
15					
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45					
46	TOTAL	(2,558,028)	(4,250,395)	(6,445,299)	(8,289,150)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/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.

Line No.	Type of Ancillary Service (a)	Amount Purchased for the Year - Usage - Related Billing Determinant - Number of Units (b)	Unit of Measure (c)	Dollars (d)	Amount Sold for the Year - Usage - Related Billing Determinant - Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch						
2	Reactive Supply and Voltage						
3	Regulation and Frequency Response				75	MW	967,727
4	Energy Imbalance	36,290	MWh	1,208,475	16,285	MWh	471,459
5	Operating Reserve - Spinning				57	MW	725,796
6	Operating Reserve - Supplement				57	MW	668,660
7	Other	811	MW	10,155,013	811	MW	10,155,013
8	Total (Lines 1 thru 7)	37,101		11,363,488	17,285		12,988,655

Schedule Page: 398 Line No.: 4 Column: d

Includes both Energy Imbalance and Generator Imbalance.

Schedule Page: 398 Line No.: 4 Column: g

Includes both Energy Imbalance and Generator Imbalance.

Schedule Page: 398 Line No.: 7 Column: d

Amounts reported are offsetting imputed amounts reflecting the self-provision of ancillary service for bundled retail native load customers under state jurisdiction.

Schedule Page: 398 Line No.: 7 Column: g

Amounts reported are offsetting imputed amounts reflecting the self-provision of ancillary service for bundled retail native load customers under state jurisdiction.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/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	2,398	2	1800	1,471	326	288	19	313	150
2	February	2,667	23	800	1,458	356	288	19	565	237
3	March	2,342	7	800	1,315	301	295	21	431	580
4	Total for Quarter 1				4,244	983	871	59	1,309	967
5	April	2,098	2	900	1,211	267	305	12	315	91
6	May	1,955	15	1900	1,250	237	302	25	166	271
7	June	2,122	27	1800	1,183	239	299	34	402	246
8	Total for Quarter 2				3,644	743	906	71	883	608
9	July	2,579	18	1700	1,492	286	299	30	502	604
10	August	2,804	10	1700	1,678	324	303	26	500	413
11	September	2,041	7	1700	1,245	235	296	22	265	117
12	Total for Quarter 3				4,415	845	898	78	1,267	1,134
13	October	1,879	16	800	1,187	264	294	21	134	46
14	November	2,377	27	1800	1,264	260	288	10	565	107
15	December	2,610	7	800	1,459	347	288	21	517	31
16	Total for Quarter 4				3,910	871	870	52	1,216	184
17	Total Year to Date/Year				16,213	3,442	3,545	260	4,675	2,893

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/Q4

ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY	
2	Generation (Excluding Station Use):	
3	Steam	1,725,973
4	Nuclear	
5	Hydro-Conventional	4,029,375
6	Hydro-Pumped Storage	
7	Other	1,697,829
8	Less Energy for Pumping	
9	Net Generation (Enter Total of lines 3 through 8)	7,453,177
10	Purchases	5,494,361
11	Power Exchanges:	
12	Received	9,415
13	Delivered	87,355
14	Net Exchanges (Line 12 minus line 13)	-77,940
15	Transmission For Other (Wheeling)	
16	Received	3,945,529
17	Delivered	3,945,529
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)	12,869,598

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	8,587,539
23	Requirements Sales for Resale (See instruction 4, page 311.)	
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	3,777,497
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	12,811
27	Total Energy Losses	491,751
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	12,869,598

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month	Total Monthly Energy	Monthly Non-Requirments Sales for Resale & Associated Losses	MONTHLY PEAK		
				Megawatts (See Instr. 4)	Day of Month	Hour
	(a)	(b)	(c)	(d)	(e)	(f)
29	January	1,383,994	531,522	1,499	2	1800
30	February	1,163,482	378,959	1,555	21	0800
31	March	1,290,125	496,474	1,329	7	0800
32	April	1,282,430	578,362	1,239	2	1000
33	May	976,609	289,424	1,245	15	1900
34	June	1,009,910	335,755	1,298	20	1700
35	July	1,062,566	265,774	1,610	30	1600
36	August	1,034,193	228,111	1,716	10	1600
37	September	803,969	142,509	1,251	7	1700
38	October	813,994	109,516	1,207	16	0800
39	November	1,017,857	250,797	1,332	26	1800
40	December	1,030,469	170,294	1,469	7	0800
41	TOTAL	12,869,598	3,777,497			

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2019	Year/Period of Report End of 2018/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	Plant Name: Coyote Springs 2 (b)			Plant Name: Spokane N.E. (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Not Applicable			Not Applicable		
3	Year Originally Constructed	2003			1978		
4	Year Last Unit was Installed	2003			1978		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	295.00			61.80		
6	Net Peak Demand on Plant - MW (60 minutes)	319			68		
7	Plant Hours Connected to Load	5916			25		
8	Net Continuous Plant Capability (Megawatts)	295			65		
9	When Not Limited by Condenser Water	295			0		
10	When Limited by Condenser Water	295			0		
11	Average Number of Employees	15			1		
12	Net Generation, Exclusive of Plant Use - KWh	1495191000			1515000		
13	Cost of Plant: Land and Land Rights	0			138753		
14	Structures and Improvements	11559412			751025		
15	Equipment Costs	172559047			13335295		
16	Asset Retirement Costs	351682			0		
17	Total Cost	184470141			14225073		
18	Cost per KW of Installed Capacity (line 17/5) Including	625.3225			230.1792		
19	Production Expenses: Oper, Supv, & Engr	143456			842		
20	Fuel	28233984			43506		
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	1679253			41451		
26	Misc Steam (or Nuclear) Power Expenses	134585			7429		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	229198			8707		
30	Maintenance of Structures	66189			1319		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	3371147			62193		
33	Maintenance of Misc Steam (or Nuclear) Plant	202457			45985		
34	Total Production Expenses	34060269			211432		
35	Expenses per Net KWh	0.0228			0.1396		
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	10007466	0	0	18202	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	2.821	0.000	0.000	2.390	0.000	0.000
41	Average Cost of Fuel per Unit Burned	2.821	0.000	0.000	2.390	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	2.766	0.000	0.000	2.343	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.019	0.000	0.000	0.029	0.000	0.000
44	Average BTU per KWh Net Generation	6827.000	0.000	0.000	12255.000	0.000	0.000

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
		96			224			161	6
		8445			7726			1180	7
		54			222			167	8
		54			222			0	9
		54			222			0	10
		29			316			1	11
		336936000			1389037000			145074000	12
		2289077			1289395			621682	13
		28703454			110832815			3553637	14
		78411958			213405057			60623141	15
		450687			13876819			0	16
		109855176			339404086			64798460	17
		2166.7688			1454.1735			389.1799	18
		188097			157865			2875	19
		8380770			19679460			3953847	20
		0			0			0	21
		610353			3444843			0	22
		0			0			0	23
		0			0			0	24
		846624			85835			252846	25
		335062			2864944			23204	26
		0			34621			0	27
		0			0			0	28
		116821			348210			20852	29
		74077			453422			0	30
		1435763			3887494			0	31
		1120072			347908			108504	32
		271982			192817			34419	33
		13379621			31497419			4396547	34
		0.0397			0.0227			0.0303	35
WOOD	GAS		COAL	OIL		GAS			36
TON	MCF		TON	BBL		MCF			37
559442	3682	0	887609	2601	0	1723019	0	0	38
8600000	1020000	0	16970000	5880000	0	1020000	0	0	39
14.966	2.188	0.000	21.888	96.580	0.000	2.295	0.000	0.000	40
14.966	2.188	0.000	21.888	96.580	0.000	2.295	0.000	0.000	41
1.740	2.146	0.000	1.290	16.425	0.000	2.250	0.000	0.000	42
0.025	0.030	0.000	0.014	0.000	0.000	0.027	0.000	0.000	43
14291.000	0.000	0.000	10855.000	0.000	0.000	12114.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/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	2064	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	2	0
12	Net Generation, Exclusive of Plant Use - KWh	47931000	0
13	Cost of Plant: Land and Land Rights	185629	0
14	Structures and Improvements	1262510	0
15	Equipment Costs	31899130	0
16	Asset Retirement Costs	0	0
17	Total Cost	33347269	0
18	Cost per KW of Installed Capacity (line 17/5) Including	1355.5800	0
19	Production Expenses: Oper, Supv, & Engr	4123	0
20	Fuel	1117749	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	253060	0
26	Misc Steam (or Nuclear) Power Expenses	53414	0
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	38480	0
30	Maintenance of Structures	0	0
31	Maintenance of Boiler (or reactor) Plant	0	0
32	Maintenance of Electric Plant	344632	0
33	Maintenance of Misc Steam (or Nuclear) Plant	57268	0
34	Total Production Expenses	1868726	0
35	Expenses per Net KWh	0.0390	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	430890	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	2.594	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	2.594	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	2.543	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.023	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	9170.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/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	0	0	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/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: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/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	0	0	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

(d)			(e)			(f)			Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

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: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/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	0	0	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

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

Operated by Portland General Electric.

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

Designed for peak load service

Schedule Page: 403 Line No.: -1 Column: e

Jointly owned project operated by Talen Montana LLC.

Schedule Page: 403 Line No.: -1 Column: f

Designed for peak load service

Schedule Page: 402.1 Line No.: -1 Column: b

Designed for peak load service

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 2545 Plant Name: Monroe Street (b)	FERC Licensed Project No. 2545 Plant Name: Upper Falls (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Run-of-River
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1890	1922
4	Year Last Unit was Installed	1992	1922
5	Total installed cap (Gen name plate Rating in MW)	14.80	10.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	29	18
7	Plant Hours Connect to Load	5,820	7,951
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	15	10
10	(b) Under the Most Adverse Oper Conditions	15	10
11	Average Number of Employees	4	4
12	Net Generation, Exclusive of Plant Use - Kwh	81,033,000	61,161,000
13	Cost of Plant		
14	Land and Land Rights	51,600	1,081,854
15	Structures and Improvements	12,113,062	974,617
16	Reservoirs, Dams, and Waterways	9,972,020	7,607,241
17	Equipment Costs	14,369,280	5,539,522
18	Roads, Railroads, and Bridges	50,448	508,242
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	36,556,410	15,711,476
21	Cost per KW of Installed Capacity (line 20 / 5)	2,470.0277	1,571.1476
22	Production Expenses		
23	Operation Supervision and Engineering	19	825
24	Water for Power	0	0
25	Hydraulic Expenses	3,633	5,936
26	Electric Expenses	540,492	501,952
27	Misc Hydraulic Power Generation Expenses	26,630	27,737
28	Rents	0	0
29	Maintenance Supervision and Engineering	2,705	42
30	Maintenance of Structures	4,849	23,662
31	Maintenance of Reservoirs, Dams, and Waterways	101,595	86,192
32	Maintenance of Electric Plant	39,722	74,231
33	Maintenance of Misc Hydraulic Plant	5,673	6,307
34	Total Production Expenses (total 23 thru 33)	725,318	726,884
35	Expenses per net KWh	0.0090	0.0119

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

FERC Licensed Project No. 2545 Plant Name: Nine Mile Falls (d)	FERC Licensed Project No. 2545 Plant Name: Post Falls (e)	FERC Licensed Project No. 2058 Plant Name: Cabinet Gorge (f)	Line No.
Run-of-River	Storage	Storage	1
Conventional	Conventional	Outdoor	2
1908	1906	1952	3
1994	1980	1953	4
37.60	14.80	265.00	5
58	16	268	6
6,168	6,778	7,066	7
			8
34	18	255	9
34	18	295	10
5	5	13	11
143,308,000	72,493,000	1,159,246,000	12
			13
33,429	3,672,815	16,374,973	14
18,872,946	3,733,995	16,491,456	15
29,222,054	26,437,786	44,778,014	16
63,916,486	4,215,739	61,832,530	17
594,870	577,944	1,671,013	18
0	0	0	19
112,639,785	38,638,279	141,147,986	20
2,995.7390	2,610.6945	532.6339	21
			22
2,778	2,554	75,892	23
0	0	0	24
3,590	3,404	200	25
588,998	627,160	1,125,170	26
102,851	83,786	217,689	27
0	0	0	28
1,648	9,235	37,434	29
100,139	60,478	38,433	30
43,716	531,320	269,200	31
84,280	77,199	271,947	32
13,937	10,777	36,254	33
941,937	1,405,913	2,072,219	34
0.0066	0.0194	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	04/15/2019	End of 2018/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 2058 Plant Name: Noxon Rapids (b)	FERC Licensed Project No. 2545 Plant Name: Long Lake (c)
1	Kind of Plant (Run-of-River or Storage)	Storage	Storage
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional
3	Year Originally Constructed	1959	1915
4	Year Last Unit was Installed	1977	1924
5	Total installed cap (Gen name plate Rating in MW)	487.80	70.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	547	91
7	Plant Hours Connect to Load	5,684	6,729
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	581	90
10	(b) Under the Most Adverse Oper Conditions	623	90
11	Average Number of Employees	11	5
12	Net Generation, Exclusive of Plant Use - Kwh	1,840,622,000	505,089,000
13	Cost of Plant		
14	Land and Land Rights	35,772,759	2,500,473
15	Structures and Improvements	21,362,071	8,768,915
16	Reservoirs, Dams, and Waterways	35,352,708	36,239,123
17	Equipment Costs	109,403,039	12,755,567
18	Roads, Railroads, and Bridges	259,750	677,646
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	202,150,327	60,941,724
21	Cost per KW of Installed Capacity (line 20 / 5)	414.4123	870.5961
22	Production Expenses		
23	Operation Supervision and Engineering	92,800	18,427
24	Water for Power	0	0
25	Hydraulic Expenses	71,540	8,401
26	Electric Expenses	1,112,154	605,143
27	Misc Hydraulic Power Generation Expenses	212,763	94,605
28	Rents	0	0
29	Maintenance Supervision and Engineering	635,710	1,664
30	Maintenance of Structures	44,730	64,463
31	Maintenance of Reservoirs, Dams, and Waterways	204,034	697,320
32	Maintenance of Electric Plant	1,351,177	143,612
33	Maintenance of Misc Hydraulic Plant	108,771	4,618
34	Total Production Expenses (total 23 thru 33)	3,833,679	1,638,253
35	Expenses per net KWh	0.0021	0.0032

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

FERC Licensed Project No. 2545 Plant Name: Little Falls (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
Run-of-River			1
Conventional			2
1910			3
1911			4
40.40	0.00	0.00	5
33	0	0	6
4,670	0	0	7
			8
37	0	0	9
37	0	0	10
5	0	0	11
166,423,000	0	0	12
			13
4,325,371	0	0	14
3,702,660	0	0	15
5,165,489	0	0	16
44,659,523	0	0	17
0	0	0	18
0	0	0	19
57,853,043	0	0	20
1,432.0060	0.0000	0.0000	21
			22
8,026	0	0	23
0	0	0	24
8,214	0	0	25
537,826	0	0	26
24,162	0	0	27
983,259	0	0	28
0	0	0	29
38,446	0	0	30
68,512	0	0	31
165,682	0	0	32
3,192	0	0	33
1,837,319	0	0	34
0.0110	0.0000	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/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	8,118,000	9,544,854
2						
3						
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/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.
1,320,758	157,866	236,548	39,605	Nat Gas	252	1
						2
						3
						4
						5
						6
						7
						8
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						45
						46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/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 #4	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	3.00		1
8	Beacon Sub #5	BPA Bell Sub	230.00	230.00	H Type	3.00		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	41.00		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	Steel Pole	12.00		2
14	Beacon Sub	Lolo Sub	230.00	230.00	H Type	87.00		1
15	Beacon Sub	Lolo Sub	230.00	230.00	H Type	8.00		1
16	Benewah	Shawnee	230.00	230.00	Steel Pole	1.00		1
17	Benewah	Shawnee	230.00	230.00	Steel Pole	59.00		1
18	Noxon Plant	Pine Creek Sub	230.00	230.00	Steel Pole	29.00		1
19	Noxon Plant	Pine Creek Sub	230.00	230.00	H Type	1.00		1
20	Noxon Plant	Pine Creek Sub	230.00	230.00	H Type	14.00		1
21	Cabinet Gorge Plant	Noxon	230.00	230.00	H Type	2.00		1
22	Cabinet Gorge Plant	Noxon	230.00	230.00	H Type	17.00		1
23	Benewah Sw. Station	Pine Creek Sub	230.00	230.00	H Type	43.00		1
24	Divide Creek	Lolo Sub	230.00	230.00	H Type	43.00		1
25	N. Lewiston	Walla Walla	230.00	230.00	H Type	39.00		1
26	N. Lewiston	Walla Walla	230.00	230.00	H Type	4.00		1
27	N. Lewiston	Walla Walla	230.00	230.00	Steel Pole	4.00		1
28	N. Lewiston	Shawnee	230.00	230.00	Steel Pole	7.00		1
29	N. Lewiston	Shawnee	230.00	230.00	H Type	27.00		1
30	Walla Walla	Wanapum	230.00	230.00	H Type	15.00		1
31	Walla Walla	Wanapum	230.00	230.00	H Type	63.00		1
32	BPA (Libby)	Noxon Plant	230.00	230.00	Steel Tower	1.00		1
33	BPA/Hot Springs #1	Noxon Plant	230.00	230.00	Steel Tower	1.00		1
34	BPA/Hot Springs #2	Noxon Plant (dead)	230.00	230.00	Steel Tower		2.00	1
35	BPA/Hot Springs #2	Noxon Plant	230.00	230.00	Steel Pole	2.00		1
36					TOTAL	2,230.00	3.00	40

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2019	Year/Period of Report End of 2018/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	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
	136,038	636,193	772,231					1
								2
	11,436,727	223,387,893	234,824,620	185,509	725,408		910,917	3
								4
1272 ACSS								5
1272 ACSS	17,912	1,429,560	1,447,472		19,241		19,241	6
1272 ACSS								7
1272 ACSS	30,323	3,275,357	3,305,680		1,997		1,997	8
1590 ACSS								9
1590 ACSS								10
1590 ACSR	1,156,196	41,777,661	42,933,857		66,620		66,620	11
1590 ACSS								12
1590 ACSS								13
1272 AAC								14
1272 ACSS	456,162	23,092,168	23,548,330					15
1622 ACSS								16
1590 ACSS	570,207	48,748,733	49,318,940		6,948		6,948	17
1272 ACSR								18
1590 ACSS								19
954 AAC	1,097,679	19,137,055	20,234,734	4,762	235,487		240,249	20
795 ACSR								21
954 AAC	184,211	1,787,763	1,971,974	4,464	289		4,753	22
954 AAC	350,325	5,182,523	5,532,848	212	11,777		11,989	23
1272 AAC	86,228	6,860,731	6,946,959		23,893		23,893	24
1272 AAC								25
1272 ACSR								26
1272 ACSR	623,984	7,779,351	8,403,335					27
1272 ACSR								28
1272 ACSR	872,150	10,044,196	10,916,346	27,588			27,588	29
1272 ACSR								30
1272 AAC	205,347	8,214,739	8,420,086	1,410	24,466		25,876	31
1272 ACSR								32
1272 ACSR		19,521	19,521	3,629	15,543		19,172	33
1272 McMAL								34
1272 ACSR								35
	21,828,052	447,739,342	469,567,394	338,682	1,305,121	89,690	1,733,493	36

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2019	Year/Period of Report End of 2018/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	BPA/Hot Springs #2	Noxon Plant	230.00	230.00	H Type	66.00		1
2	Coulee	West Side Sub	230.00	230.00	Steel Pole	1.00		2
3	BPA Line	West Side Sub	230.00	230.00	Steel Pole	1.00		2
4	Hatwai	N. Lewiston Sub	230.00	230.00	H Type	7.00		1
5	Divide Creek	Imnaha	230.00	230.00	H Type	20.00		1
6	Colstrip Plant	Broadview	500.00	500.00				
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	2,230.00	3.00	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	04/15/2019	End of 2018/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.
1272 McMAL	3,603,324	10,069,035	13,672,359	1,601	35,626		37,227	1
1272 ACSR	8,482		8,482					2
1272 ACSR	36,462	594,543	631,005		389		389	3
1590 ACSR	155,244	2,610,009	2,765,253	8,101	4,512		12,613	4
1272 AAC	205,262	1,312,224	1,517,486					5
	595,789	31,780,087	32,375,876	101,406	132,925	89,690	324,021	6
								7
								8
								9
								10
								11
								12
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								32
								33
								34
								35
	21,828,052	447,739,342	469,567,394	338,682	1,305,121	89,690	1,733,493	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/Q4

TRANSMISSION LINES ADDED DURING YEAR

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

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)	(c)	Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1	Shawnee-Sunset Line	4 Lakes Substation	6.00	H Frame	8.00	1	1
2	S. Fairchild Tap	Cheney	9.00	H Frame	8.00	1	1
3							
4							
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43							
44	TOTAL		15.00		16.00	2	2

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage KV (Operating)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)	(k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
266.8	ACSR	Horizontal	115						1
266.8	ACSR	Horizontal	115	185,000	467,000	233,000		885,000	2
									3
									4
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									41
									42
									43
				185,000	467,000	233,000		885,000	44

Schedule Page: 424 Line No.: 2 Column: c

These lines were acquired from BPA in 2018. The costs shown are estimated.

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Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2019	Year/Period of Report End of 2018/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	Airway Heights	Distr. Unattended	115.00	13.80	
3	Barker Road	Distr. Unattended	115.00	13.80	
4	Beacon	Trnsm. & Distr Unatt	230.00	115.00	13.80
5	Boulder	Trnsm. Unattended	230.00	115.00	13.80
6	Chester	Distr. Unattended	115.00	13.80	
7	Chewelah 115Kv	Distr. Unattended	115.00	13.80	
8	Colbert	Distr. Unattended	115.00	13.80	
9	College & Walnut	Distr. Unattended	115.00	13.80	
10	Colville 115Kv	Distr. Unattended	115.00	13.80	
11	Critchfield	Distr. Unattended	115.00	13.80	
12	Deer Park	Dist. Unattended	115.00	13.80	
13	Dry Creek	Transm. Unattended	230.00	115.00	13.80
14	Dry Gulch	Distr. Unattended	115.00	13.80	
15	East Colfax	Distr. Unattended	115.00	13.80	
16	East Farms	Distr. Unattended	115.00	13.80	
17	Fort Wright	Distr. Unattended	115.00	13.80	
18	Francis and Cedar	Distr. Unattended	115.00	13.80	
19	Gifford	Distr. Unattended	115.00	34.00	
20	Glenrose	Distr. Unattended	115.00	13.80	
21	Greenwood	Distr. Unattended	115.00	13.80	
22	Hallett & White	Distr. Unattended	115.00	13.80	
23	Indian Trail	Dist. Unattended	115.00	13.80	
24	Industrial Park	Dist. Unattended	115.00	13.80	
25	Kettle Falls	Distr. Unattended	115.00	13.80	
26	Lee & Reynolds	Distr. Unattended	115.00	13.80	
27	Liberty Lake	Distr. Unattended	115.00	13.80	
28	Lind	Dist. Unattended	115.00	13.80	
29	Little Falls 115/34Kv	Distr. Unattended	115.00	34.00	
30	Lyons & Standard	Distr. Unattended	115.00	13.80	
31	Mead	Distr. Unattended	115.00	13.80	
32	Metro	Distr. Unattended	115.00	13.80	
33	Milan	Distr. Unattended	115.00	13.80	
34	Millwood	Dist. Unattended	115.00	13.80	
35	Ninth & Central	Dist. Unattended	115.00	13.80	
36	Northeast	Distr. Unattended	115.00	13.80	
37	Northwest	Distr. Unattended	115.00	13.80	
38	Opportunity	Dist. Unattended	115.00	13.80	
39	Othello	Distr. Unattended	115.00	13.80	
40	Post Street	Distr. Unattended	115.00	13.80	

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
24	2		Frcd Oil&Air Fan&Cap	39	40	2
12	1		Two Stage Fan	1	20	3
536	4		Two Stage Fan	2	560	4
300	2		Two Stage Fan	2	500	5
24	2		Frcd Oil & Air Fan	2	40	6
12	1		Two Stage Fan	1	20	7
12	1		Frcd Oil & Air Fan	16	20	8
36	2		Two Stage Fan	2	60	9
32	3		Frcd Oil & Air Fan	3	49	10
12	1		Two Stage Fan	1	20	11
12	1		Two Stage Fan	1	20	12
150	1		Two Stage Fan & Caps	223	250	13
24	2		Frcd Oil & Air Fan	2	40	14
12	1		FrOil/Air Fan	1	20	15
12	1		Two Stage Fan	1	20	16
24	2		Fr Oil/Air/2StgFan	2	40	17
36	2		Two Stage Fan	2	60	18
12	1					19
12	1		Frcd Oil & Air Fan	1	20	20
12	1		Two Stage Fan	1	20	21
18	1		Two Stage Fan	1	30	22
12	1		Two Stage Fan	1	20	23
24	2		Two Stg/Pt/Frcd Oil	14	40	24
12	1		Frcd Oil & Air Fan	1	20	25
18	1		Two Stage Fan	1	30	26
24	2		Two Stage Fan	2	40	27
12	1		Two Stage Fan	1	20	28
12	1					29
36	2		Two Stage Fan	2	60	30
18	1		Two Stage Fan	1	30	31
24	2		Two Stage Fan	2	40	32
24	2		Frcd Oil & Air Fan	2	40	33
24	2		Two Stage Fan	2	40	34
36	2		Two Stage Fan	2	60	35
24	2		Two Stage Fan	2	40	36
24	2		Two Stage Fan	2	40	37
12	1		Two Stage Fan	1	20	38
24	2		FrOil/AirFan	2	40	39
36	2		Frcd Oil & Wt Fan	2	60	40

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	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Pound Lane	Distr. Unattended	115.00	13.80	
2	Ross Park	Distr. Unattended	115.00	13.80	
3	Roxboro	Distr. Unattended	115.00	24.00	
4	Shawnee	Trans. Unattended	230.00	115.00	13.80
5	Silver Lake	Distr. Unattended	115.00	13.80	
6	Southeast	Distr. Unattended	115.00	13.80	
7	South Othello	Distr. Unattended	115.00	13.80	
8	South Pullman	Distr. Unattended	115.00	13.80	
9	Sunset	Distr. Unattended	115.00	13.80	
10	Terre View	Dist. Unattended	115.00	13.80	
11	Third & Hatch	Distr. Unattended	115.00	13.80	
12	Turner	Dist. Unattended	115.00	13.80	
13	Waikiki	Distr. Unattended	115.00	13.80	
14	West Side	Trans. Unattended	230.00	115.00	13.80
15	Other: 27 substa less than 10MVA	Distr. Unattended			
16					
17	STATE OF IDAHO				
18	Appleway	Dist. Unattended	115.00	13.80	
19	Avondale	Dist. Unattended	115.00	13.80	
20	Benewah	Trans. Unattended	230.00	115.00	13.80
21	Big Creek	Distr. Unattended	115.00	13.80	
22	Blue Creek	Distr. Unattended	115.00	13.80	
23	Bunker Hill Limited	Distr. Unattended	115.00	13.80	
24	Cabinet Gorge (Switchyard)	Trans. Unattended	230.00	115.00	13.80
25	Clark Fork	Distr. Unattended	115.00	21.80	
26	Coeur d'Alene 15th Ave	Distr. Unattended	115.00	13.80	
27	Cottonwood	Distr. Unattended	115.00	24.90	
28	Dalton	Distr. Unattended	115.00	13.80	
29	Grangeville	Distr. Unattended	115.00	13.80	
30	Holbrook	Distr. Unattended	115.00	13.80	
31	Huetter	Distr. Unattended	115.00	13.80	
32	Idaho Road	Distr Unattended	115.00	13.80	
33	Juliaetta	Distr. Unattended	115.00	13.80	
34	Kamiah	Dist. Unattended	115.00	13.80	
35	Kooskia	Distr. Unattended	115.00	13.80	
36	Lewiston Mill Rd	Distr. Unattended	115.00	13.20	
37	Lolo	Tran & Dist Unattnd	230.00	115.00	13.80
38	Moscow	Distr. Unattended	115.00	13.80	
39	Moscow 230Kv	Tran & Dist Unattnd	230.00	115.00	13.80
40	North Moscow	Distr. Unattended	115.00	13.80	

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
24	2		Two Stage Fan	2	40	1
30	2		Two Stage Fan	2	54	2
24	2		Two Stage Fan	2	40	3
150	1		Two Stage Fan	1	250	4
12	1		Two Stage Fan	2	20	5
30	2		Two Stage Fan	2	50	6
12	1		Two Stage Fan	1	20	7
30	2		Two Stage Fan	2	50	8
33	2		Two Stage Fan & Caps	50	55	9
12	1		Two Stage Fan	1	20	10
54	3		Two Stg Fan & Cap	103	90	11
36	2		Two Stg Fan	2	60	12
24	2		Two Stage Fan	2	40	13
275	2		Two Stage Fan	1	375	14
161	31					15
						16
						17
36	2		Two Stage Fan	2	60	18
12	1		Two Stage Fan	1	20	19
75	1		Two Stage Fan & Caps	223	125	20
18	2		Portable Fan	2	22	21
12	1		Two Stage Fan	1	20	22
12	1		Frcd Air Fan	1	16	23
75	1		Two Stage Fan	1	125	24
10	1		Frcd Air Fan	1	13	25
36	2		Two Stage Fan	2	60	26
12	1		Two Stage Fan	1	20	27
24	2		FrcOil/Air2StgFan	2	40	28
25	4		FrcdOil/Air/Pt Fan&C	17	34	29
12	1		Two Stage Fan	1	20	30
12	1		Two Stage Fan	1	20	31
12	1		Two Stage Fan	1	20	32
12	1		Frcd Oil & Air Fan	1	20	33
12	1		Two Stage Fan	1	20	34
15	3		Frcd Air Fan	3	20	35
18	1		Two Stage Fan	1	30	36
262	3		Frcd Oil/Air/Two Stg	1	270	37
24	2		FrOil/Air/2Stg Fan	2	40	38
162	2		Frcd Air Fan & Caps	76	270	39
12	1		Two Stage Fan	1	20	40

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2019	Year/Period of Report End of 2018/Q4

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	 Secondary (d)	 Tertiary (e)
1	North Lewiston 230kV	Tran & Dist Unattnd	230.00	115.00	13.80
2	Oden	Distr. Unattended	115.00	21.80	
3	Oldtown	Distr. Unattended	115.00	21.80	
4	Orofino	Distr. Unattended	115.00	13.80	
5	Osburn	Distr. Unattended	115.00	13.80	
6	Pine Creek	Tran & Dist Unattnd	230.00	115.00	13.80
7	Pleasant View	Distr. Unattended	115.00	13.80	
8	Plummer	Dist Unattended	115.00	13.80	
9	Post Falls	Distr. Unattended	115.00	13.80	
10	Potlatch	Distr. Unattended	115.00	13.80	
11	Prarie	Distr. Unattended	115.00	13.80	
12	Priest River	Distr. Unattended	115.00	20.80	
13	Rathdrum	Trans & Distr Unattd	230.00	115.00	13.80
14	Sagle	Dist. Unattended	115.00	20.80	
15	Sandpoint	Distr. Unattended	115.00	20.80	
16	South Lewiston	Distr. Unattended	115.00	13.80	
17	Sweetwater	Distr. Unattended	115.00	24.90	
18	St. Maries	Distr. Unattended	115.00	23.90	
19	Tenth & Stewart	Distr. Unattended	115.00	13.80	
20					
21	Other: 13 substa less than 10 MVA	Distr. Unattended			
22					
23	STATE OF MONTANA				
24	1 substation less than 10 MVA	Distr. Unattended			
25					
26	SUBSTA. @ GENERATING PLANTS				
27	STATE OF WASHINGTON				
28	Boulder Park	Trans. Attended	115.00	13.80	
29	Kettle Falls	Trans. Attended	115.00	13.80	
30	Long Lake	Trans. Attended	115.00	4.00	
31	Nine Mile	Trans. Attended	115.00	13.80	
32	Little Falls	Trans. Attended	115.00	4.00	
33	Northeast	Trans. Attended	115.00	13.80	
34	Post Street	Trans. Attended	13.80	4.00	
35					
36	STATE OF IDAHO				
37	Cabinet Gorge (HED)	Trans. Attended	230.00	13.80	
38	Post Falls	Trans. Attended	115.00	2.30	
39	Rathdrum	Trans. Attended	115.00	13.80	
40					

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.
258	2		Frcd Air Fan & Caps	48	260	1
10	1		Frcd Air Fan	1	13	2
18	2		Frcd Air Fan	2	22	3
20	2		Frcd Oil & Air Fan	1	28	4
12	1		Portable Fan	1	15	5
212	3		Two Stg Fan/Capacito	45	270	6
12	1		Two Stage Fan	1	20	7
12	1		Two Stage Fan	1	20	8
18	1		Two Stage Fan	1	30	9
15	2		Portable Fan	2	19	10
12	1		Frcd Oil & Air Fan	1	20	11
10	1		Frcd Air Fan	1	13	12
474	4		Frcd Oil & Air Fan	50	490	13
12	1		Two Stage Fan	1	20	14
30	3		Frcd Air Fan	3	38	15
27	4		Port Fan/FrcdOil/Air	4	39	16
12	1		Frcd Oil & Air Fan	1	20	17
24	2		Two Stage Fan	2	40	18
30	2		Frcd Oil/Air/Two Stg	2	50	19
						20
73	13					21
						22
						23
5	1					24
						25
						26
						27
36	1		Two Stage Fan	1	60	28
34	1	1	Two Stage Fan	1	62	29
80	4	1				30
42	2		Two Stage Fan	1	56	31
24	2		Frcd Oil & Air Fan	2	40	32
36	1		Two Stage Fan	1	60	33
35	2					34
						35
						36
300	6	1	Frcd Oil and Air Fan			37
16	2		Frcd Air/Oil/Air Fan	2	21	38
114	2	1	Two Stage Fan	2	190	39
						40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2019	End of 2018/Q4

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	STATE OF MONTANA				
2	Noxon	Trans. Attended	230.00	13.80	
3					
4	STATE OF OREGON				
5	Coyote Springs II	Trans. Attended	500.00	13.80	18.00
6					
7	SUMMARY:				
8	Washington:				
9	4 subs	Trans. Unattended			
10	75 subs	Distr. Unattended			
11	1 subs	Tran & Dist Unattnd			
12	7 subs	Trans. Attended			
13	Idaho:				
14	2 subs	Trans. Unattended			
15	48 subs	Distr. Unattended			
16	5 subs	Tran & Dist Unattnd			
17	3 subs	Trans. Attended			
18	Montana: 1 sub	Trans. Attended			
19	1 sub	Distr. Unattended			
20	Oregon: 1 sub	Trans. Unattended			
21	System: 148 subs				
22					
23					
24					
25					
26					
27					
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33					
34					
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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) 04/15/2019	Year/Period of Report End of 2018/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
						1
435	9	1	Two Stage Fan	2	635	2
						3
						4
213	1		Two Stage fan	1	355	5
						6
						7
						8
875						9
1216						10
536						11
287						12
						13
150						14
670						15
1368						16
430						17
435						18
5						19
213						20
6185						21
						22
						23
						24
						25
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						30
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						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	04/15/2019	End of 2018/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
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20	**Non-power Goods or Services Provided for Affiliate**			
21	Corporate Support	Salix Inc.	146000	342,114
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