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

AVU-E

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2022)
Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2022)
Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2022)

RECEIVED
2020 April 29,PM4:26
IDAHO PUBLIC
UTILITIES COMMISSION

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

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

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
Avista Corporation	**End of** 2019/Q4

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

IDENTIFICATION

01 Exact Legal Name of Respondent	02 Year/Period of Report
Avista Corporation	End of 2019/Q4

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

/ /

04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)*
1411 East Mission Avenue, Spokane, WA 99207

05 Name of Contact Person	06 Title of Contact Person
Ryan L. Krasselt	VP, Controller, Prin. Acctg

07 Address of Contact Person *(Street, City, State, Zip Code)*
1411 East Mission Avenue, Spokane, WA 99207

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(509) 495-2273	(1) [X] An Original (2) [ ] A Resubmission	04/15/2020

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

01 Name	03 Signature	04 Date Signed *(Mo, Da, Yr)*
Ryan L. Krasselt	Ryan L. Krasselt	04/15/2020
02 Title		
VP, Controller, Prin. Acctg Officer	Ryan L. Krasselt	

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	04/15/2020	End of 2019/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".

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2020	End of 2019/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

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	04/15/2020	End of 2019/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

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 to the Co's Subsidiary	100	1
2	Avista Development, Inc.	Investment in Real Estate	100	2
3	Pentzer Corporation	Parent of Bay Area Mfg and	100	3
4		Penture Venture Holdings		
5	Pentzer Venture Holdings II, Inc.	Inactive Holding Co.	100	4
6	Bay Area Manufacturing, Inc.	Holding Company	100	5
7	Avista Capital II	An affiliated business trust	100	6
8		issued pref. Trust Securit.		
9	Avista Northwest Resources, LLC	Owns an interest in a venture	100	7
10		fund investment		
11	Steam Plant Square, LLC	Comm office & retail leasg	100	8
12	Courtyard Office Center, LLC	Comm office & retail leasg	100	9
13	Steam Plant Brew Pub, LLC	Restaurant operations	100	10
14	Salix, Inc.	Liquified Natural Gas Opertns	100	11
15	Alaska Energy and Resources Company (AERC)	Parent co of Alaska Operatns	100	12
16	Alaska Electric Light and Power Company	Utility operations in Juneau	100	13
17	AJT Mining Properties, Inc.	Mining Co Holding Properties	100	14
18	Snettisham Electric Company	Rights to Purchase Snettisham	100	15
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Schedule Page: 103 Line No.: 1 Column: d
Parent to the company's subsidiaries.

Schedule Page: 103 Line No.: 2 Column: d
Maintains investment portfolio including real estate.

Schedule Page: 103 Line No.: 3 Column: d
Subsidiary of Avista Capital

Schedule Page: 103 Line No.: 5 Column: d
Subsidiary of Pentzer Corporation

Schedule Page: 103 Line No.: 6 Column: d
Subsidiary of Pentzer Coporation

Schedule Page: 103 Line No.: 7 Column: d
Affiliate of Avista Corporation

Schedule Page: 103 Line No.: 9 Column: d
Subsidiary of Avista Capital

Schedule Page: 103 Line No.: 11 Column: d
Subsidiary of Avista Development

Schedule Page: 103 Line No.: 12 Column: d
Subsidiary of Avista Development

Schedule Page: 103 Line No.: 13 Column: d
Subsidiary of Steam Plant Square, LLC

Schedule Page: 103 Line No.: 14 Column: d
Subsidiary of Avista Capital

Schedule Page: 103 Line No.: 15 Column: d
Subsidiary of Avista Corporation

Schedule Page: 103 Line No.: 16 Column: d
Subsidiary of AERC

Schedule Page: 103 Line No.: 17 Column: d
Subsidiary of AERC

Schedule Page: 103 Line No.: 18 Column: d
Subsidiary of AERC

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2020	End of 2019/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	President and Chief Executive Officer	D. P. Vermillion	
2	(effective 10/1/19)		
3			
4	Chairman of the Board	S. L. Morris	
5	and Chief Executive Officer (resigned 10/1/19)		
6			
7	Executive Vice President, Chief Financial Officer,	M. T. Thies	
8	and Treasurer (effective 10/1/19)		
9			
10	Senior Vice President, External Affairs	K. J. Christie	
11	and Chief Customer Officer (effective 10/1/19)		
12			
13	Sr Vice President, General Counsel, Chief Compliance	M. M. Durkin	
14	Officer, and Corporate Secretary		
15			
16	Senior Vice President and Chief Human Resources Officer	K. S. Feltes	
17	(resigned effective 3/1/2020)		
18			
19	Senior Vice President, Energy Delivery	H. L. Rosentrater	
20	(effective 10/1/19)		
21			
22	Senior Vice President, Energy Resources	J. R. Thackston	
23	and Environmental Compliance Officer		
24			
25	Vice President, Safety & HR Shared Services	B. A. Cox	
26			
27	Vice President, Chief Information Officer, and	J. M. Kensok	
28	Chief Security Officer		
29			
30	Vice President, Controller, and	R. L. Krasselt	
31	Principal Accounting Officer		
32			
33	Vice President and Chief Counsel for Regulatory	D. J. Meyer	
34	and Governmental Affairs		
35			
36	Vice President and Chief Strategy Officer	E. D. Schlect	
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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	04/15/2020	End of 2019/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)	
3		
4	Erik J. Anderson (resigned 5/9/19)	3720 Carillon Point, Kirkland, WA 98033
5		
6	Kristianne Blake***	P. O. Box 3727, Spokane, WA 99220
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 ***	1411 E. Mission Ave, Spokane, WA
23	(President and CEO, effective 10/1/19)	
24		
25	Jeffry L. Philipps (effective 11/1/19)	P.O. Box 9000, Spokane, WA 99209
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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	04/15/2020	End of 2019/Q4

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

Does the respondent have formula rates?	[ ] Yes [X] No

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

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
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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	04/15/2020	End of 2019/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	04/15/2020	End of 2019/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 18 of the Notes to Financial Statements for further information.
4. None
5. None
6. Reference is made to Notes 11 and 12 of the Notes to Financial Statements.
7. None
8. Average annual wage increases were 2.9% for non-exempt employees effective March 4, 2019. Average annual wage increases were 3.1% for exempt employees effective March 4, 2019. Officers received average increases of 4.1% effective February 18, 2019. Certain bargaining unit employees received increases of 3.0% effective March 26, 2019.
9. Reference is made to Note 16 of the Notes to Financial Statements.
10. None
11. Reserved
12. See page 123 of this report.

13. On March 22, 2019, Erik J. Anderson, member of the Board of Directors of Avista Corp., informed the Company that he would not stand for reelection to the Board of Directors for 2019. Mr. Anderson remained with the Board of Directors through the Annual Meeting of Shareholders held on May 9, 2019.

Mr. Anderson chose not to stand for reelection due to other professional commitments. There were no disagreements with the Company that contributed to Mr. Anderson's decision.

On May 10, 2019, Scott L. Morris, Chairman of the Board and Chief Executive Officer of Avista Corp., announced to the Company’s board of directors, that he will retire from the Company effective March 1, 2020. Following Mr. Morris’ announcement, the Company’s board of directors appointed Dennis P. Vermillion Chief Executive Officer effective October 1, 2019. Mr. Morris continued to serve as the Executive Chairman of the board of directors of the Company and then as the non-executive Chairman of the board of directors following his retirement. Mr. Vermillion will continue to serve on the Company’s board of directors.

On June 14, 2019, the Board of Directors of Avista Corp. increased the number of board members from 10 to 11, effective November 1, 2019, and elected Jeff L. Philipps to fill the vacancy and serve as a director on the board effective on that date. Mr. Philipps will stand for election to the Board at the next annual meeting of shareholders on May 11, 2020. Mr. Philipps will serve on the Finance Committee and the Environmental, Technology and Operations Committee of the Board.

On August 8, 2019, the Board of Directors named Mark T. Thies, Executive Vice President Chief Financial Officer and Treasurer of Avista Corp. effective October 1, 2019. Mr. Thies has served as the Company's Senior Vice President CFO and Treasurer since January 1, 2013 and previously served as the Company's Senior Vice President CFO since September 29, 2008.

In August 2019, Karen S. Feltes, Senior Vice President and Chief Human Resources Officer, informed the Board of Directors that she plans to retire effective March 1, 2020.

Effective October 1, 2019, Heather L. Rosentrater has been promoted from Vice President, Energy Delivery to Senior Vice President, Energy Delivery.

Effective October 1, 2019, Kevin J. Christie has been promoted from Vice President, External Affairs and Chief Customer Officer to Senior Vice President, External Affairs and Chief Customer Officer.

Effective January 1, 2020, Marian Durkin moved from Chief Compliance Officer to Chief Legal Officer. She retained her role as the Corporate Secretary. In addition, she informed the Board of Directors that she plans to retire effective August 1, 2020.

Effective January 1, 2020, Greg Hesler has been promoted from Senior Counsel II to Vice President, General Counsel Chief Compliance Officer.

Effective January 1, 2020, Latisha Hill has been promoted from Director of Business and Community Development to Vice President of Community and Economic Vitality.

14. Proprietary capital is not less than 30 percent.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2020	End of 2019/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	6,385,433,383	6,004,750,680
3	Construction Work in Progress (107)	200-201	157,909,990	156,563,570
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		6,543,343,373	6,161,314,250
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	2,121,893,905	1,991,240,383
6	Net Utility Plant (Enter Total of line 4 less 5)		4,421,449,468	4,170,073,867
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)		4,421,449,468	4,170,073,867
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)		4,340,610	4,474,923
19	(Less) Accum. Prov. for Depr. and Amort. (122)		176,234	140,360
20	Investments in Associated Companies (123)		11,547,000	11,547,000
21	Investment in Subsidiary Companies (123.1)	224-225	207,105,954	153,523,686
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)		77,973	1,711,072
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		22,034,002	18,794,801
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		922,948	4,842,426
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		245,852,253	194,753,548
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		3,067,240	4,737,049
36	Special Deposits (132-134)		4,434,090	26,809,063
37	Working Fund (135)		730,965	709,204
38	Temporary Cash Investments (136)		155,890	136,712
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		153,814,552	157,729,381
41	Other Accounts Receivable (143)		15,726,829	4,618,679
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		2,373,469	5,188,090
43	Notes Receivable from Associated Companies (145)		0	31,659,207
44	Accounts Receivable from Assoc. Companies (146)		222,671	154,548
45	Fuel Stock (151)	227	4,148,891	3,982,104
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	46,558,819	43,166,166
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)		14,305,397	11,609,184
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		24,682,259	20,211,526
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		129,823	166,418
60	Rents Receivable (172)		3,609,147	2,516,807
61	Accrued Utility Revenues (173)		0	0
62	Miscellaneous Current and Accrued Assets (174)		193,803	398,132
63	Derivative Instrument Assets (175)		1,780,327	10,394,941
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		922,948	4,842,426
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)		270,264,286	308,968,605
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		13,795,819	13,923,600
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	643,207,368	598,724,109
73	Prelim. Survey and Investigation Charges (Electric) (183)		0	2,313
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		131,978	28,530
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	18,484,386	30,900,539
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)		8,883,821	10,255,271
82	Accumulated Deferred Income Taxes (190)	234	177,056,526	187,450,520
83	Unrecovered Purchased Gas Costs (191)		-3,189,401	-40,713,156
84	Total Deferred Debits (lines 69 through 83)		858,370,497	800,571,726
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		5,802,928,580	5,481,359,822

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2020	end of 2019/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	1,176,498,977	1,110,871,767
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	-44,938,398	-36,316,031
11	Retained Earnings (215, 215.1, 216)	118-119	747,158,701	660,984,141
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-13,386,701	-16,389,107
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)	-10,258,024	-7,866,070
16	Total Proprietary Capital (lines 2 through 15)		1,934,254,640	1,773,220,051
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,904,200,000	1,814,200,000
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)		142,133	151,017
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		930,270	1,032,761
24	Total Long-Term Debt (lines 18 through 23)		1,871,258,863	1,781,165,256
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		65,565,105	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)		212,005,607	222,536,776
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		11,767,158	10,178,645
32	Long-Term Portion of Derivative Instrument Liabilities		19,684,476	10,300,047
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		20,338,053	18,265,985
35	Total Other Noncurrent Liabilities (lines 26 through 34)		329,605,399	261,526,453
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		182,300,000	190,000,000
38	Accounts Payable (232)		107,406,813	103,484,597
39	Notes Payable to Associated Companies (233)		14,722,348	0
40	Accounts Payable to Associated Companies (234)		0	7,329
41	Customer Deposits (235)		4,745,573	4,783,254
42	Taxes Accrued (236)	262-263	38,022,918	39,835,469
43	Interest Accrued (237)		15,282,041	15,509,062
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

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)		168,034	79,542
48	Miscellaneous Current and Accrued Liabilities (242)		50,808,479	56,358,807
49	Obligations Under Capital Leases-Current (243)		4,127,561	0
50	Derivative Instrument Liabilities (244)		30,612,670	14,252,910
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		19,684,476	10,300,047
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)		428,511,961	414,010,923
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		2,083,490	2,142,205
57	Accumulated Deferred Investment Tax Credits (255)	266-267	30,443,961	29,725,443
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	29,659,558	22,466,066
60	Other Regulatory Liabilities (254)	278	481,207,133	527,440,814
61	Unamortized Gain on Reaquired Debt (257)		1,448,359	1,577,896
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		514,870,007	497,875,564
64	Accum. Deferred Income Taxes-Other (283)		179,585,209	170,209,151
65	Total Deferred Credits (lines 56 through 64)		1,239,297,717	1,251,437,139
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		5,802,928,580	5,481,359,822

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2020	Year/Period of Report End of 2019/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	1,428,099,066	1,416,798,041		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	818,533,678	804,773,049		
5	Maintenance Expenses (402)	320-323	70,160,821	63,628,892		
6	Depreciation Expense (403)	336-337	163,503,287	146,501,216		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337		268,929		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	40,625,925	34,897,443		
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)		7,343,186	6,384,995		
13	(Less) Regulatory Credits (407.4)		24,373,462	11,255,061		
14	Taxes Other Than Income Taxes (408.1)	262-263	104,229,614	105,935,344		
15	Income Taxes - Federal (409.1)	262-263	1,016,853	21,463,627		
16	- Other (409.1)	262-263	-512,990	536,050		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	16,095,155	9,917,224		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	3,735,815	836,768		
19	Investment Tax Credit Adj. - Net (411.4)	266	718,518	-540,168		
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		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,193,703,817	1,182,624,052		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		234,395,249	234,173,989		

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2020	Year/Period of Report End of 2019/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

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

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
983,483,744	986,405,322	444,615,322	430,392,719			2
						3
515,395,521	516,698,898	303,138,157	288,074,151			4
54,542,409	49,735,303	15,618,412	13,893,589			5
126,679,057	112,612,198	36,824,230	33,889,018			6
	268,929					7
30,546,857	26,315,338	10,079,068	8,582,105			8
99,047	99,047					9
						10
						11
5,890,125	5,030,260	1,453,061	1,354,735			12
20,930,818	9,688,900	3,442,644	1,566,161			13
79,246,048	80,790,063	24,983,566	25,145,281			14
7,445,054	18,711,316	-6,428,201	2,752,311			15
-504,880	433,688	-8,110	102,362			16
5,035,837	5,726,144	11,059,318	4,191,080			17
2,388,896	953,010	1,346,919	-116,242			18
546,262	-520,104	172,256	-20,064			19
						20
						21
						22
						23
	850,233					24
801,601,623	806,109,403	392,102,194	376,514,649			25
181,882,121	180,295,919	52,513,128	53,878,070			26

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2020	Year/Period of Report End of 2019/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		234,395,249	234,173,989		
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)		14,612,589	6,931,684		
35	Nonoperating Rental Income (418)		-31,291	-31,262		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	13,582,269	2,392,004		
37	Interest and Dividend Income (419)		4,401,265	3,808,319		
38	Allowance for Other Funds Used During Construction (419.1)		-104,311	4,281,829		
39	Miscellaneous Nonoperating Income (421)					
40	Gain on Disposition of Property (421.1)		109,159			
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		3,344,502	3,519,206		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)			13,251		
44	Miscellaneous Amortization (425)		-33,721			
45	Donations (426.1)		11,332,979	3,563,420		
46	Life Insurance (426.2)		2,640,044	2,793,863		
47	Penalties (426.3)		21,180	2,053		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,718,553	2,073,702		
49	Other Deductions (426.5)		27,317,212	5,342,674		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		42,996,247	13,788,963		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	311,708	293,278		
53	Income Taxes-Federal (409.2)	262-263	-8,257,303	-5,085,932		
54	Income Taxes-Other (409.2)	262-263	-350,985	-220,461		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	-1,887,439	34,584		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	196,940	231,946		
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)		-10,380,959	-5,210,477		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		-29,270,786	-5,059,280		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		86,591,405	87,093,842		
63	Amort. of Debt Disc. and Expense (428)		321,206	321,207		
64	Amortization of Loss on Reaquired Debt (428.1)		2,266,506	2,582,801		
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)		489,554			
68	Other Interest Expense (431)		8,205,985	6,749,117		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		4,169,530	4,052,495		
70	Net Interest Charges (Total of lines 62 thru 69)		93,696,243	92,685,589		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		111,428,220	136,429,120		
72	Extraordinary Items					
73	Extraordinary Income (434)		102,999,990			
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)		102,999,990			
76	Income Taxes-Federal and Other (409.3)	262-263	22,478,603			
77	Extraordinary Items After Taxes (line 75 less line 76)		80,521,387			
78	Net Income (Total of line 71 and 77)		191,949,607	136,429,120		

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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	04/15/2020	End of 2019/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		623,531,170	572,281,364
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	AERC Reclass			
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)		178,367,338	134,037,116
17	Appropriations of Retained Earnings (Acct. 436)			
18			-3,725,554	(5,320,848)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-3,725,554	(5,320,848)
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			-102,772,642	(98,046,075)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-102,772,642	(98,046,075)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		10,579,864	18,837,251
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		705,980,176	623,531,170
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39			41,178,525	37,452,971
40				

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)		41,178,525	37,452,971
	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)		41,178,525	37,452,971
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		747,158,701	660,984,141
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-16,389,107	56,140
50	Equity in Earnings for Year (Credit) (Account 418.1)		13,582,269	2,392,004
51	(Less) Dividends Received (Debit)		10,000,000	10,000,000
52	Other Subsidiary Activity		-579,863	(8,837,251)
53	Balance-End of Year (Total lines 49 thru 52)		-13,386,701	(16,389,107)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2020	End of 2019/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)	191,949,607	136,429,120
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	202,496,251	179,217,557
5	Amortization of Deferred Power and Natural Gas Costs	-45,916,643	12,345,655
6	Amortization of Debt Expense	2,578,830	2,895,123
7	Amortization of Investment in Exchange Power	1,632,961	2,450,031
8	Deferred Income Taxes (Net)	10,274,962	8,882,835
9	Investment Tax Credit Adjustment (Net)	718,518	-540,168
10	Net (Increase) Decrease in Receivables	-9,860,829	17,548,393
11	Net (Increase) Decrease in Inventory	-6,255,653	-4,880,128
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	1,823,471	1,753,920
14	Net (Increase) Decrease in Other Regulatory Assets	-6,065,721	1,041,677
15	Net Increase (Decrease) in Other Regulatory Liabilities	-5,135,361	28,600,265
16	(Less) Allowance for Other Funds Used During Construction	6,434,430	6,331,723
17	(Less) Undistributed Earnings from Subsidiary Companies	13,582,269	2,392,004
18	Other (provide details in footnote):	74,394,412	9,488,941
19	Allowance for Doubtful Accounts	400,000	3,900,000
20	Changes in Other Non-Current Assets and Liabilities	10,396,693	-4,783,663
21	Cash Paid for Settlement of Interest Rate Swaps	-13,325,137	-32,174,169
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	390,089,662	353,451,662
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-439,249,001	-420,377,970
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)	-439,249,001	-420,377,970
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	882,641	559,980
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	-3,693,898	-19,855,879
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)		

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
54	Other	-1,750,738	-2,002,301
55	Dividends Received from Subsidiaries	10,000,000	10,000,000
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-433,810,996	-431,676,170
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	180,000,000	374,621,250
62	Preferred Stock		
63	Common Stock	64,572,145	1,206,734
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)	244,572,145	460,827,984
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-90,000,000	-274,902,917
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):	-891,513	-3,928,728
77	Debt Issuance Costs	-1,115,527	-4,255,295
78	Net Decrease in Short-Term Debt (c)	-7,700,000	
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-102,772,642	-98,046,075
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	42,092,463	79,694,969
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-1,628,871	1,470,461
87			
88	Cash and Cash Equivalents at Beginning of Period	5,582,966	4,112,505
89			
90	Cash and Cash Equivalents at End of period	3,954,095	5,582,966

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

Power and natural gas deferrals	4,692,134
Change in special deposits	63,973,598
Change in other current assets	(5,417,123)
Non-cash stock compensation	11,352,863
Gain on sale of property and equipment	(109,159)
Other	(97,901)

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

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.: 76 Column: b

Payment of minimum tax withholdings for share-based payment awards	(891,513)

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

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

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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 the Company'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).

Basis of Reporting

The financial statements include the assets, liabilities, revenues and expenses of the Company and have been prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America (U.S. GAAP). As required by the FERC, the Company accounts for its investment in majority-owned subsidiaries on the equity method rather than consolidating the assets, liabilities, revenues, and expenses of these subsidiaries, as required by U.S. GAAP. The accompanying financial statements include the Company’s proportionate share of utility plant and related operations resulting from its interests in jointly owned plants. In addition, under the requirements of the FERC, there are differences from U.S. GAAP in the presentation of (1) current portion of long-term debt (2) assets and liabilities for cost of removal of assets, (3) assets held for sale, (4) regulatory assets and liabilities, (5) deferred income taxes 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), (9) non-service portion of pension and other postretirement benefit costs and (10) leases.

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:

	2019	2018
Avista Corp.		
Ratio of depreciation to average depreciable property	3.28%	3.17%

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

	Avista Corp.
Electric thermal/other production	35
Hydroelectric production	81
Electric transmission	50
Electric distribution	38
Natural gas distribution property	45
Other shorter-lived general plant	9

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 and IPUC have 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 associated with plant in service is amortized over the average useful life of Avista Corp.' utility plant which is approximately 30 years. The regulatory asset associated with construction work in progress is not amortized until the plant is placed in service. The OPUC does not allow the Company to capitalize AFUDC that exceeds the FERC calculated rate.

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

	2019	2018
Avista Corp.		
Effective state AFUDC rate	7.39%	7.43%

Reclassification of AFUDC to Comply with Required FERC Regulatory Reporting

During the third quarter of 2019, the FERC completed an audit of Avista Corp. that covered the period January 1, 2015 through December 31, 2018. The FERC indicated that Avista's method of deferring taxes on AFUDC Equity should be changed from normalization to flow-through. Avista has historically normalized the AFUDC Equity book/tax timing difference by recognizing deferred tax expense with the result of spreading the benefit over the book life of the asset. Under the flow-through method, Avista will no longer recognize deferred tax expense on the AFUDC Equity timing difference and instead recognize a regulatory asset to be reversed over the book life of the asset. The flow-through method does not impact revenue requirement. A regulatory asset was recorded in 2018 for $1.7M to account for this change to the flow-through method on a prospective basis.

Additionally, Avista Corp.'s AFUDC rate, which is prescribed by state regulatory authorities, is different than the FERC approved method for calculating AFUDC. The FERC indicated that the difference in rates should be recorded as a regulatory asset rather than in utility plant. At the conclusion of the audit, the FERC required Avista Corp. to reclassify the excess AFUDC from Net utility plant to Non-current regulatory assets for the period January 1, 2010 (the effective date of the Company's current fixed transmission rates) to the present. As a result, Avista Corp. reclassified approximately $33 million (net of accumulated depreciation) from Net utility plant to Non-current regulatory assets as of December 31, 2019, which represents the cumulative adjustment for 2010 through 2017. The Company recorded the difference in AFUDC rates for 2018 and 2019 as a regulatory asset in the respective periods incurred. The Company did not adjust prior period Consolidated Balances Sheets since the FERC required the adjustment to be reflected on a cumulative basis at the end of the audit and required the AFUDC calculation to be modified on a prospective basis. The Company concluded that the differences were insignificant during each prior period and on a cumulative basis. The adjustment recorded during 2019 had no effect on net income or earnings per share.

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 9 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 2019 or 2018. The Company would recognize interest accrued related to income tax positions as interest expense and any penalties incurred as other 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):

	2019	2018
Stock-based compensation expense	$ 11,353	$ 5,367
Income tax benefits	2,384	1,127
Excess tax benefits (expenses) on settled share-based employee payments	(612)	990

Restricted share awards vest in equal thirds each year over 3 years 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 in 2017, 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 3 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:

	2019	2018

Restricted Shares		
Shares granted during the year	50,061	40,661
Shares vested during the year	(48,228)	(53,352)
Unvested shares at end of year	93,351	91,998
Unrecognized compensation expense at end of year (in thousands)	$ 2,054	$ 1,964
TSR Awards		
TSR shares granted during the year	99,214	80,724
TSR shares vested during the year	(106,858)	(107,342)
TSR shares earned based on market metrics	—	—
Unvested TSR shares at end of year	178,035	187,172
Unrecognized compensation expense (in thousands)	$ 3,377	$ 3,706
CEPS Awards		
CEPS shares granted during the year	49,609	40,329
CEPS shares vested during the year	(53,454)	(53,699)
CEPS shares earned based on market metrics	106,908	30,102
Unvested CEPS shares at end of year	88,990	93,579
Unrecognized compensation expense (in thousands)	$ 2,401	$ 1,260

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, 2019 and 2018, the Company had recognized cumulative compensation expense and a liability of $0.9 million and $0.3 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 7 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 fair value to carrying amount comparison (Step 1) for AEL&P. The Company completed its annual evaluation of goodwill for potential impairment as of November 30, 2019 and determined that goodwill was not impaired at that time (carrying value was less than the determined fair value). There were no events or circumstances that changed between November 30, 2019 and December 31, 2019 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 January 1, 2019	$ 52,426	$ 12,979	$ (7,733)	$ 57,672
Goodwill sold during the year	—	(12,979)	7,733	(5,246)
Balance as of December 31, 2019	$ 52,426	$ —	$ —	$ 52,426

Goodwill sold during the year relates to the sale of METALfx in April 2019. See Note 19 for further discussion. Accumulated impairment losses were attributable to METALfx, which was a part of 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 14 for the Company's fair value disclosures.

Regulatory Deferred Charges and Credits

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

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

Regulatory accounting practices require that certain costs and/or obligations (such as incurred power and natural gas costs not currently reflected 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):

	2019	2018
Appropriated retained earnings	$ 41,179	$ 37,453

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, 2019, the Company has not recorded any significant amounts related to unresolved contingencies. See Note 16 for further discussion of the Company's commitments and contingencies.

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):

	2019	2018
Avista Capital	$ 6,404	$ (5,660)
AERC	7,178	8,052
Total equity in earnings of subsidiary companies	$ 13,582	$ 2,392

Subsequent Events

See footnote 21 - subsequent events for further details.

NOTE 2. NEW ACCOUNTING STANDARDS

Accounting Standards Update (ASU) No. 2016-02, "Leases (Topic 842)"
ASU No. 2018-01, "Leases (Topic 842): Land Easement Practical Expedient for Transition to Topic 842"
ASU No. 2018-11, "Leases (Topic 842): Targeted Improvements"

On January 1, 2019, the Company adopted ASU No. 2016-02, which outlines a model for entities to use in accounting for leases and supersedes previous lease accounting guidance, as well as several practical expedients in ASU Nos. 2018-01 and 2018-11.

The Company adopted ASU No. 2016-02 utilizing a modified retrospective adoption method with the "package of three" and hindsight practical expedients offered by the standard. The "package of three" provides for an entity to not reassess at adoption whether any expired or existing contracts are deemed, for accounting purposes, to be or contain leases, the classification of any expired or existing leases, and any initial direct costs for any existing leases. As a result, the Company did not reassess existing or expired contracts under the new lease guidance, and it did not reassess the classification of any existing leases. The Company used the benefit of hindsight in determining both term and impairments associated with any existing leases. Use of this practical expedient has resulted in lease terms that best represent management's expectations with respect to use of the underlying asset but did not result in recognition of any impairment.

The Company elected to adopt ASU No. 2018-01, which allows an entity to exclude from application of Topic 842 all easements executed prior to January 1, 2019. In addition, the Company elected to adopt the "comparatives under 840" practical expedient offered in ASU No. 2018-11, which allows an entity to apply the new lease standard at the adoption date, recognizing any necessary cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption and presenting comparative periods in the financial statements under Accounting Standards Codification (ASC) 840 (previous lease accounting guidance). Adoption of the standard did not result in a cumulative effect adjustment within the Company's financial statements.

As allowed by ASU No. 2016-02, the Company elected not to apply the requirements of the standard to short-term leases, those leases with an initial term of 12 months or less. These leases are not recorded on the balance sheet and are not material to the financial statements.

Adoption of the standard impacted the Company's Balance Sheet through recognition of right-of-use (ROU) assets and lease liabilities for the Company's operating leases. See Note 4 for further information on the Company's leases.

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 Financial Accounting Standards Board (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, 2019.

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, 2019.

NOTE 3. REVENUE

ASC 606 defines the core principle of the revenue recognition 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. The commodity is sold and/or delivered to and consumed by the customer simultaneously, and the provisions of the relevant utility commission authorization determine the charges the Company may bill the customer. Given that all revenue recognition criteria are met upon the delivery of energy to customers, revenue is recognized immediately.

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.

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):

	2019	2018
Unbilled accounts receivable	$ 60,560	$ 64,463

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.

The Company records alternative program revenues under 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. 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 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):

	2019	2018
Utility-related taxes	$ 59,528	$ 58,730

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, 2019, the Company estimates it had unsatisfied capacity performance obligations of $5.9 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 years ended December 31 (dollars in thousands):

	2019	2018
Avista Corp.		
Revenue from contracts with customers	$ 1,160,853	$ 1,147,935
Derivative revenues	246,355	277,048
Alternative revenue programs	9,614	908
Deferrals and amortizations for rate refunds to customers	1,093	(16,549)
Other utility revenues	10,184	7,456
Total Avista Corp.	1,428,099	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 electric operations for the years ended December 31 (dollars in thousands):

	2019	2018
ELECTRIC OPERATIONS		
Revenue from contracts with customers		
Residential	$ 369,102	$ 368,753
Commercial and governmental	317,589	314,532
Industrial	114,530	109,846
Public street and highway lighting	7,448	7,539

Total retail revenue	808,669	800,670
Transmission	18,180	17,864
Other revenue from contracts with customers	26,969	27,364
Total revenue from contracts with customers	$ 853,818	$ 845,898

The following table disaggregates revenue from contracts with customers associated with the Company's natural gas operations for the years ended December 31 (dollars in thousands):

	2019	2018
NATURAL GAS OPERATIONS		
Revenue from contracts with customers		
Residential	$ 196,430	$ 194,340
Commercial	92,168	89,341
Industrial and interruptible	5,263	4,753
Total retail revenue	293,861	288,434
Transportation	8,674	9,103
Other revenue from contracts with customers	4,500	4,500
Total revenue from contracts with customers	$ 307,035	$ 302,037

NOTE 4. LEASES

ASC 842, which outlines a model for entities to use in accounting for leases and supersedes previous lease accounting guidance, became effective on January 1, 2019. The core principle of the model is that an entity should recognize the ROU assets and liabilities that arise from leases on the balance sheet and depreciate or amortize the asset and liability over the term of the lease, as well as provide disclosure to enable users of the financial statements to assess the amount, timing, and uncertainty of cash flows arising from leases. For regulatory reporting, the FERC provided prescribed accounts for the ROU assets and lease liabilities, with the ROU assets being included in utility plant (FERC account 101) and the lease liabilities being included in capital lease obligations (FERC account 227). These accounts are different than the accounts allowed for in GAAP reporting, which results in a FERC/GAAP difference.

Significant Judgments and Assumptions

The Company determines if an arrangement is a lease, as well as its classification, at its inception.

ROU assets represent the Company's right to use an underlying asset for the lease term, and lease liabilities represent the Company's obligation to make lease payments arising from the lease. Operating lease ROU assets and lease liabilities are recognized at the commencement date of the agreement based on the present value of lease payments over the lease term. As most of the Company's leases do not provide an implicit rate, the Company uses its incremental borrowing rate based on the information available at the commencement date to determine the present value of lease payments. The implicit rate is used when it is readily determinable. The operating lease ROU assets also include any lease payments made and exclude lease incentives, if any, that accrue to the benefit of the lessee.

Lease terms may include options to extend or terminate the lease when it is reasonably certain that the Company will exercise that option. Lease expense for lease payments is recognized on a straight-line basis over the lease term. Any difference between lease expense and cash paid for leased assets is recognized as a regulatory asset or regulatory liability.

Description of Leases

Operating Leases

The Company's most significant operating lease is with the State of Montana associated with submerged land around the Company's hydroelectric facilities in the Clark Fork River basin, which expires in 2046. The terms of this lease are subject to renegotiation, depending on the outcome of ongoing litigation between Montana and NorthWestern Energy. In addition, the State of Montana and Avista Corp. are engaged in litigation regarding lease terms, including how much money, if any, the State of Montana will return to Avista Corp. The Company is currently paying all lease payments to the State of Montana into an escrow account until the litigation is resolved. As such, amounts recorded for this lease are uncertain and amounts may change in the future depending on the outcome of the ongoing litigation. Any reduction in future lease payments or the return of previously paid amounts to Avista Corp. will be included in the future ratemaking process.

In addition to the lease with the State of Montana, the Company also has other operating leases for land associated with its utility operations, as well as communication sites which support network and radio communications within its service territory. The Company's leases have remaining terms of 1 to 74 years. Most of the Company's leases include options to extend the lease term for periods of 5 to 50 years. Options are exercised at the Company's discretion.

Certain of the Company's lease agreements include rental payments which are periodically adjusted over the term of the agreement based on the consumer price index. The Company's lease agreements do not include any material residual value guarantees or material restrictive covenants.

Avista Corp. does not record leases with a term of 12 months or less in the Balance Sheet. Total short-term lease costs for the year ended December 31, 2019 are immaterial.

Leases that Have Not Yet Commenced

In March 2019, the Company signed a PPA with Clearway Energy Group (Clearway) to purchase all of the power generated from the Rattlesnake Flat Wind project in Adams County, Washington. The facility has a nameplate capacity of 144 MW and is expected to generate approximately 50 aMW annually. During negotiations with Clearway, Avista Corp. was involved in the selection of the preferred generation facility type. The PPA is a 20-year agreement with deliveries expected to begin in 2020. The PPA provides Avista Corp. with additional renewable energy, capacity and environmental attributes. Avista Corp. expects to recover the cost of the power purchased through its retail rates. This PPA is considered a lease under ASC 842; however, all of the payments are variable payments based on whether power is generated from the facility. Since all the payments are variable, the Company will not record a lease liability for the agreement, but the expense will be included in resource costs when it becomes operational in 2020.

The components of lease expense were as follows for the year ended December 31, 2019 (dollars in thousands):

	2019
Operating lease cost:	
Fixed lease cost	$ 4,425
Variable lease cost	988
Total operating lease cost	$ 5,413

Supplemental cash flow information related to leases was as follows for the year ended December 31, 2019 (dollars in thousands):

	2019

Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash outflows:		
Operating lease payments	$	4,375

Supplemental balance sheet information related to leases was as follows for December 31, 2019 (dollars in thousands):

		December 31, 2019
Operating Leases		
Operating lease ROU assets (Utility Plant)	$	69,746
Obligations under capital lease - current	$	4,128
Obligations under capital lease - noncurrent		65,565
Total operating lease liabilities	$	69,693
Weighted Average Remaining Lease Term		
Operating leases		26.60 years
Weighted Average Discount Rate		
Operating leases		3.82%

Maturities of lease liabilities (including principal and interest) were as follows as of December 31, 2019 (dollars in thousands):

		Operating Leases
2020	$	4,372
2021		4,375
2022		4,383
2023		4,399
2024		4,411
Thereafter		91,654
Total lease payments	$	113,594
Less: imputed interest		(43,901)
Total	$	69,693

Future minimum lease payments (including principal and interest) under Topic 840 as of December 31, 2018 (dollars in thousands):

		Operating Leases
2019	$	4,995
2020		4,876

2021		4,859
2022		4,782
2023		4,780
Thereafter		102,389
Total lease payments	$	126,681
Less: imputed interest		—
Total	$	126,681

NOTE 5. DERIVATIVES AND RISK MANAGEMENT

Energy Commodity Derivatives

Avista Corp. is exposed to market risks relating to changes in electricity and natural gas commodity prices and certain other fuel prices. Market risk is, in general, the risk of fluctuation in the market price of the commodity being traded and is influenced primarily by supply and demand. Market risk includes the fluctuation in the market price of associated derivative commodity instruments. 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 three 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, 2019 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
2020	2	442	9,813	78,803	133	1,724	2,984	37,848
2021	—	—	153	25,523	—	246	1,040	13,108
2022	—	—	225	4,725	—	—	—	675

As of December 31, 2019, there are no expected deliveries of energy commodity derivatives after 2022.

The following table presents the underlying energy commodity derivative volumes as of December 31, 2018 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
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

As of December 31, 2018, there were no expected deliveries of energy commodity derivatives after 2021.

(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):

	2019	2018

Number of contracts	20	31
Notional amount (in United States dollars)	$ 5,932	$ 4,018
Notional amount (in Canadian dollars)	7,828	5,386

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. These financial derivative instruments 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, 2019	7	70,000	2020
	3	35,000	2021
	10	110,000	2022
December 31, 2018	6	70,000	2019
	6	60,000	2020
	2	25,000	2021
	7	80,000	2022

See Note 12 for discussion of the bond purchase agreement and the related settlement of interest rate swaps in connection with the pricing of the bonds in September 2019.

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, 2019 and December 31, 2018 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, 2019 (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	$ 97	$ —	$ —	$ 97
Interest rate swap derivatives				

Derivative instrument assets current	589	—	—	589
Derivative instrument liabilities current	238	(9,379)	1,316	(7,825)
Long-term portion of derivative liabilities	725	(24,677)	5,454	(18,498)
Energy commodity derivatives				
Derivative instrument assets current	416	(245)	—	171
Long-term portion of derivative assets	6,369	(5,446)	—	923
Derivative instrument liabilities current	34,760	(41,241)	3,378	(3,103)
Long-term portion of derivative liabilities	28	(1,215)	—	(1,187)
Total derivative instruments recorded on the balance sheet	$ 43,222	$ (82,203)	$ 10,148	$ (28,833)

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)

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 December 31 (in thousands):

	2019	2018
Energy commodity derivatives		
Cash collateral posted	$ 7,812	$ 78,025

Letters of credit outstanding	17,400	6,500
Balance sheet offsetting (cash collateral against net derivative positions)	3,378	51,217
Interest rate swap derivatives		
Cash collateral posted	6,770	530
Balance sheet offsetting (cash collateral against net derivative positions)	6,770	530

There were no letters of credit outstanding related to interest rate swap derivatives as of December 31, 2019 and December 31, 2018.

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):

	2019	2018
Energy commodity derivatives		
Liabilities with credit-risk-related contingent features	$ 814	$ 2,193
Additional collateral to post	814	2,193
Interest rate swap derivatives		
Liabilities with credit-risk-related contingent features	34,056	7,831
Additional collateral to post	26,912	6,579

NOTE 6. 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):

	2019	2018
Utility plant in service	$ 387,860	$ 384,431
Accumulated depreciation	(268,637)	(261,997)

See Note 7 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 7. ASSET RETIREMENT OBLIGATIONS

The Company has recorded liabilities for future AROs to:

- restore coal ash containment ponds and coal holding areas at Colstrip,
- cap a landfill at the Kettle Falls Plant, and
- remove plant and restore the land at the Coyote Springs 2 site at the termination of the land lease.

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. 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 updates its estimates as new information becomes available. 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 2018 Administrative Order on Consent and ongoing negotiations with the Montana Department of Ecological Quality, 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 of the ash ponds and coal holding areas. 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):

	2019	2018
Asset retirement obligation at beginning of year	$ 18,266	$ 17,482
Liabilities incurred	2,699	—
Liabilities settled	(1,503)	(66)
Accretion expense	876	850
Asset retirement obligation at end of year	$ 20,338	$ 18,266

NOTE 8. 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. 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 2019 and 2018. The Company expects to contribute $22.0 million in cash to the pension plan in 2020.

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):

	2020	2021	2022	2023	2024	Total 2025-2029
Expected benefit payments	$ 39,647	$ 40,080	$ 40,652	$ 40,729	$ 41,767	$ 217,899

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):

	2020	2021	2022	2023	2024	Total 2025-2029
Expected benefit payments	$ 6,442	$ 6,782	$ 6,965	$ 7,088	$ 7,244	$ 38,305

The Company expects to contribute $6.7 million to other postretirement benefit plans in 2020, 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, 2019 and 2018 and the components of net periodic benefit costs for the years ended December 31, 2019 and 2018 (dollars in thousands):

	Pension Benefits	Other Post-retirement Benefits

	2019	2018	2019	2018
Change in benefit obligation:				
Benefit obligation as of beginning of year	$ 671,629	$ 716,561	$ 134,053	$ 132,947
Service cost	19,755	21,614	3,006	3,188
Interest cost	28,417	26,096	5,598	4,831
Actuarial (gain)/loss	57,829	(48,641)	23,344	(610)
Benefits paid	(35,248)	(44,001)	(6,705)	(6,303)
Benefit obligation as of end of year	$ 742,382	$ 671,629	$ 159,296	$ 134,053

Change in plan assets:				
Fair value of plan assets as of beginning of year	$ 544,051	$ 605,652	$ 36,852	$ 37,953
Actual return on plan assets	109,942	(40,954)	8,001	(1,101)
Employer contributions	22,000	22,000	—	—
Benefits paid	(33,930)	(42,647)	—	—
Fair value of plan assets as of end of year	$ 642,063	$ 544,051	$ 44,853	$ 36,852
Funded status	$ (100,319)	$ (127,578)	$ (114,443)	$ (97,201)
Amounts recognized in the Balance Sheets:				
Current liabilities	$ (1,602)	$ (1,477)	$ (640)	$ (580)
Non-current liabilities	(98,717)	(126,101)	(113,803)	(96,621)
Net amount recognized	$ (100,319)	$ (127,578)	$ (114,443)	$ (97,201)
Accumulated pension benefit obligation	$ 644,004	$ 586,398	—	—
Accumulated postretirement benefit obligation:				
For retirees			$ 72,816	$ 63,796
For fully eligible employees			$ 34,545	$ 29,902
For other participants			$ 51,935	$ 40,355
Included in accumulated other comprehensive loss (income) (net of tax):				
Unrecognized prior service cost	$ 2,105	$ 2,308	$ (4,400)	$ (5,230)
Unrecognized net actuarial loss	114,368	138,516	63,101	52,441
Total	116,473	140,824	58,701	47,211
Less regulatory asset	(107,395)	(133,237)	(57,520)	(46,932)
Accumulated other comprehensive loss for unfunded benefit obligation for pensions and other postretirement benefit	$ 9,078	$ 7,587	$ 1,181	$ 279

plans

	Pension Benefits		Other Post-retirement Benefits	
	2019	2018	2019	2018
Weighted-average assumptions as of December 31:				
Discount rate for benefit obligation	3.85%	4.31%	3.89%	4.32%
Discount rate for annual expense	4.31%	3.71%	4.32%	3.72%
Expected long-term return on plan assets	5.90%	5.50%	5.70%	5.20%
Rate of compensation increase	4.66%	4.67%		
Medical cost trend pre-age 65 – initial			5.75%	6.00%
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			6.50%	6.25%
Medical cost trend post-age 65 – ultimate			5.00%	5.00%
Ultimate medical cost trend year post-age 65			2026	2024

	Pension Benefits		Other Post-retirement Benefits	
	2019	2018	2019	2018
Components of net periodic benefit cost:				
Service cost (a)	$ 19,755	$ 21,614	$ 3,006	$ 3,188
Interest cost	28,417	26,096	5,598	4,831
Expected return on plan assets	(31,763)	(33,018)	(2,101)	(1,973)
Amortization of prior service cost	257	257	(981)	(1,089)
Net loss recognition	10,216	7,879	4,013	4,232
Net periodic benefit cost	$ 26,882	$ 22,828	$ 9,535	$ 9,189

(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.

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, 2019 by $13.9 million and the service and interest cost by $0.8 million. A one-percentage-point decrease in the assumed health care cost trend rate for each year would decrease the accumulated postretirement benefit obligation as of December 31, 2019 by $10.7 million and the service and interest cost by $0.6 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:

	2019	2018
Equity securities	35%	37%
Debt securities	49%	45%
Real estate	7%	8%
Absolute return	9%	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, 2019 and 2018.

The following table discloses by level within the fair value hierarchy (see Note 14 for a description of the fair value hierarchy) of the pension plan's assets measured and reported as of December 31, 2019 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ —	$ 2,852	$ —	$ 2,852
Fixed income securities:				
U.S. government issues	—	37,297	—	37,297
Corporate issues	—	207,222	—	207,222
International issues	—	35,836	—	35,836
Municipal issues	—	23,539	—	23,539
Mutual funds:				
U.S. equity securities	173,568	—	—	173,568
International equity securities	46,416	—	—	46,416
Absolute return (1)	16,720	—	—	16,720
Plan assets measured at NAV (not subject to hierarchy disclosure)				
Common/collective trusts:				
Real estate	—	—	—	31,473
Partnership/closely held investments:				
Absolute return (1)	—	—	—	59,260
Real estate	—	—	—	7,880
Total	$ 236,704	$ 306,746	$ —	$ 642,063

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

(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.

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 2019 and 2018.

The fair value of other postretirement plan assets was determined as of December 31, 2019 and 2018.

The following table discloses by level within the fair value hierarchy (see Note 14 for a description of the fair value hierarchy) of other postretirement plan assets measured and reported as of December 31, 2019 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Balanced index mutual funds (1)	$ 44,853	$ —	$ —	$ 44,853

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

(1) The balanced index fund for 2019 and 2018 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) plan that is a defined contribution plan 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):

	2019	2018
Employer 401(k) matching contributions	$ 10,362	$ 10,044

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):

	2019	2018
Deferred compensation assets and liabilities	$ 8,948	$ 8,400

NOTE 9. 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 $409.5 million as of December 31, 2019, compared to $429.3 million as of December 31, 2018, 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 has begun through tariffs or other regulatory mechanisms or proceedings.

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. For Oregon, this accrual was recorded through 2019 with new customer rates effective January 15, 2020. Refunds have begun to Washington, Idaho, and Oregon customers through tariffs or other regulatory mechanisms or proceedings.

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

	Protected			Unprotected			Total		
	Washington	Idaho	Oregon	Washington	Idaho	Oregon	Washington	Idaho	Oregon
As of December 31, 2019									
Deferred tax assets	58,068	25,576	8,181	2,530	—	26	60,598	25,576	8,207
Regulatory liabilities	251,921	110,958	35,491	10,978	—	112	262,899	110,958	35,603
As of December 31, 2018									
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 were amortized in the Statement of Income as follows for the years ended December 31 (in thousands):

	Protected			Unprotected			Total		
	Washington	Idaho	Oregon	Washington	Idaho	Oregon	Washington	Idaho	Oregon
2019									
Provision for deferred income taxes	(6,024)	(2,653)	(849)	(651)	(4,890)	(149)	(6,675)	(7,543)	(998)
2018									
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, 2019, the Company had $22.3 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 $6.0 million of the state tax credits. As such, the Company has recorded a valuation allowance of $16.3 million against the state tax credit carryforwards and reflected the net amount of $6.0 million as an asset as of December 31, 2019. State tax credits expire from 2020 to 2033.

Status of Internal Revenue Service (IRS) and State Examinations

The Company and its eligible subsidiaries file consolidated federal income tax returns. The Company also files state income tax returns in certain jurisdictions, including Idaho, Oregon, and Montana. Subsidiaries are charged or credited with the tax effects of their operations on a stand-alone basis. All tax years after 2016 are open for an IRS tax examination.

The Idaho State Tax Commission is currently reviewing tax years 2014 through 2017. The statute of limitations for Montana and Oregon to review 2015 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.

NOTE 10. ENERGY PURCHASE CONTRACTS

Avista Corp. has contracts for the purchase of fuel for thermal generation, natural gas for resale and various agreements for the purchase or exchange of electric energy with other entities. The 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):

	2019	2018
Utility power resources	$ 376,769	$ 357,656

The following table details Avista Corp.' future contractual commitments for power resources (including transmission contracts) and natural gas resources (including transportation contracts) (dollars in thousands):

	2020	2021	2022	2023	2024	Thereafter	Total
Power resources	$ 178,546	$ 180,417	$ 179,020	$ 179,640	$ 157,620	$ 1,172,072	$ 2,047,315
Natural gas resources	68,232	50,062	43,577	39,493	36,640	274,302	512,306
Total	$ 246,778	$ 230,479	$ 222,597	$ 219,133	$ 194,260	$ 1,446,374	$ 2,559,621

These energy purchase contracts were entered into as part of Avista Corp.' 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.' 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, 2019 (principal and interest) was $67.2 million.

In addition, Avista Corp. has operating agreements, settlements and other contractual obligations related to its generating facilities and transmission and distribution services. The expenses associated with these agreements are reflected as other operating expenses in the Statements of Income. The following table details future contractual commitments under these agreements (dollars in thousands):

	2020	2021	2022	2023	2024	Thereafter	Total
Contractual obligations	$ 33,116	$ 34,081	$ 24,645	$ 25,190	$ 28,585	$ 191,873	$ 337,490

NOTE 11. 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 "consolidated total debt" to "consolidated total capitalization" of Avista Corp. to be greater than 65 percent at any time. As of December 31, 2019, 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):

	2019	2018
Balance outstanding at end of period	$ 182,300	$ 190,000
Letters of credit outstanding at end of period	$ 21,473	$ 10,503
Average interest rate at end of period	2.64%	3.18%

As of December 31, 2019 and 2018, the borrowings outstanding under Avista Corp.'s committed line of credit were classified as short-term borrowings on the Balance Sheet.

NOTE 12. BONDS

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

Maturity Year	Description	Interest Rate	2019	2018
Avista Corp. Secured Long-Term Debt				
2019	First Mortgage Bonds	5.45%	—	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	4.35%	375,000	375,000
2049	First Mortgage Bonds (2)	3.43%	180,000	—
2051	First Mortgage Bonds	3.54%	175,000	175,000
	Total Avista Corp. secured bonds		1,904,200	1,814,200
	Secured Pollution Control Bonds held by Avista Corporation (1)		(83,700)	(83,700)
	Total long-term debt		$ 1,820,500	$ 1,730,500

(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 November 2019, the Company issued and sold $180.0 million of 3.43 percent first mortgage bonds due in 2049 pursuant to a bond purchase agreement with institutional investors in the private placement market. The total net proceeds from the sale of the bonds were used to repay maturing long-term debt of $90.0 million, repay a portion of 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 six interest rate swap derivatives (notional aggregate amount of $70.0 million) and paid a net amount of $13.3 million. See note 5 for a discussion of interest rate swap derivatives.

The following table details future long-term debt maturities including long-term debt to affiliated trusts (see Note 13) (dollars in thousands):

	2020	2021	2022	2023	2024	Thereafter	Total
Debt maturities	$ 52,000	$ —	$ 250,000	$ 13,500	$ 15,000	$ 1,541,547	$ 1,872,047

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 each 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, 2019, property additions and retired bonds would have allowed, and the net earnings test would not have prohibited, the issuance of $1.5 billion in an aggregate principal amount of additional first mortgage bonds at Avista Corp.

NOTE 13. 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:

	2019	2018
Low distribution rate	2.79%	2.36%
High distribution rate	3.61%	3.61%
Distribution rate at the end of the year	2.79%	3.61%

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 14. FAIR VALUE

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

The 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):

	2019		2018	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Long-term debt (Level 2)	$ 963,500	$ 1,124,649	$ 1,053,500	$ 1,142,292
Long-term debt (Level 3)	857,000	946,674	677,000	645,523
Long-term debt to affiliated trusts (Level 3)	51,547	41,238	51,547	38,145

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 80.00 to 134.11, 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, 2019 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, 2019					
Assets:					
Energy commodity derivatives	$ —	$ 41,546	$ —	$ (40,452)	$ 1,094
Level 3 energy commodity derivatives:					
Natural gas exchange agreements	—	—	27	(27)	—

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting (1)	Total
Foreign currency exchange derivatives	—	97	—	—	97
Interest rate swap derivatives	—	1,552	—	(963)	589
Deferred compensation assets:					
Mutual Funds:					
Fixed income securities	2,232	—	—	—	2,232
Equity securities	6,271	—	—	—	6,271
Total	$ 8,503	$ 43,195	$ 27	$ (41,442)	$ 10,283
Liabilities:					
Energy commodity derivatives	$ —	$ 45,144	$ —	$ (43,830)	$ 1,314
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	3,003	(27)	2,976
Interest rate swap derivatives	—	34,056	—	(7,733)	26,323
Total	$ —	$ 79,200	$ 3,003	$ (51,590)	$ 30,613

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 agreement	—	—	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

(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 5 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 $0.4 million as of December 31, 2019 and $0.5 million as of December 31, 2018.

Level 3 Fair Value

Under the power exchange agreement, which expired on June 30, 2019, the Company purchased power at a price that was 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 estimated the difference between the purchase price based on the future O&M charges and forward prices for energy. The Company compared the Level 2 brokered quotes and forward price curves described above to an internally developed forward price which was based on the average O&M charges from the three surrogate nuclear power plants for the current year. The Company estimated the volumes of the transactions that would 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.

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, 2019 (dollars in thousands):

	Fair Value (Net) at December 31, 2019	Valuation Technique	Unobservable Input	Range
Natural gas exchange agreement	(2,976)	Internally derived weighted-average cost of gas	Forward purchase prices	\$1.49 - \$2.38/mmBTU
			Forward sales prices	\$1.60 - \$3.80/mmBTU
			Purchase volumes	50,000 - 310,000 mmBTUs
			Sales volumes	60,000 - 310,000 mmBTUs

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, 2019:			
Balance as of January 1, 2019	\$ (2,774)	\$ (2,488)	\$ (5,262)
Total gains or (losses) (realized/unrealized):			
Included in regulatory assets/liabilities (1)	8,175	435	8,610
Settlements	(8,377)	2,053	(6,324)
Ending balance as of December 31, 2019 (2)	\$ (2,976)	\$ —	\$ (2,976)
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)

(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 15. 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 35 percent common equity (inclusive of short-term debt). This limitation may be revised upon request by the Company with approval from the OPUC.

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, 2019 was limited to $293.9 million.

The Company has 10 million authorized shares of preferred stock. The Company did not have any preferred stock outstanding as of December 31, 2019 and 2018.

Equity Issuances

The Company issued equity in 2019 for total net proceeds of $64.6 million. Most of these issuances came through the Company's four separate sales agency agreements under which the sales agents may offer and sell new shares of common stock from time to time. These agreements provide for the offering of a maximum of 4.6 million shares, of which approximately 3.2 million remain unissued as of December 31, 2019. In 2019, 1.4 million shares were issued under these agreements resulting in total net proceeds of $63.6 million. 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. These agreements expire on February 29, 2020. The Company expects to negotiate and enter into new sales agency agreements in the second quarter of 2020.

NOTE 16. 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.

Collective Bargaining Agreements

The Company’s collective bargaining agreements with the IBEW represent approximately 45 percent of all of Avista Corp.’ employees. A three-year agreement with the local union in Washington and Idaho representing the majority (approximately 90 percent) of the Avista Corp.' bargaining unit employees will expire in March 2021. A three-year agreement in Oregon, which covers approximately 50 employees will also expire on April 1, 2020.

The Company is in the process of negotiating new agreements with each of these represented bargaining units. However, 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 Terminated Acquisition by Hydro One

See Note 18 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).

The complaint generally alleged that the members of the Board of Directors of Avista Corp. breached their fiduciary duties by, among other things, conducting an allegedly inadequate sale process and agreeing to the acquisition at a price that allegedly undervalued Avista Corporation, and that Hydro One Limited, Olympus Holding Corp., and Olympus Corp. aided and abetted those purported breaches of duty. The complaint sought various remedies, including monetary damages, attorneys' fees and expenses. Subsequent to the termination of the proposed acquisition in January 2019, the complaint was voluntarily dismissed by the plaintiffs.

Boyds Fire (State of Washington Department of Natural Resources v. Avista)

On August 19, 2019, the Company was served with a complaint filed by the State of Washington Department of Natural Resources, seeking recovery of fire suppression costs and related expenses incurred in connection with a wildfire that occurred in Ferry County, Washington in August 2018. Specifically, the complaint alleges that the fire, which became known as the "Boyds Fire," was caused by a dead ponderosa pine tree falling into an overhead distribution line, and that Avista Corp. was negligent in failing to identify and remove it before the tree came into contact with the line. Avista Corp. disputes that the tree in question was the cause of the fire, and that it was negligent in failing to identify and remove it. The case is in the early stages of discovery and the plaintiff has not yet provided a statement specifying damages. Because the resolution of this claim remains uncertain, legal counsel cannot express an opinion on the extent, if any, of the Company's liability, nor is it possible for the Company to estimate the impact of any outcome at this time. The Company intends to vigorously defend itself in the litigation.

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 analysis 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.' 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 17. 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 2019, the Company recognized a pre-tax benefit of $4.4 million under the ERM in Washington compared to a benefit of $6.1 million for 2018. Total net deferred power costs under the ERM were a liability of $40.0 million as of December 31, 2019 and a liability of $34.4 million as of December 31, 2018. 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 cumulative rebate balance exceeds $30 million and as a result, the Company's 2019 filing contained a proposed rate refund, effective July 1, 2019 over a three-year period. Subsequent to this filing, the WUTC approved the ERM rebate over a two-year period.

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 an asset of $0.3 million as of December 31, 2019 and a liability of $7.6 million as of December 31, 2018. Deferred power cost assets represent amounts due from customers and liabilities 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 $3.2 million as of December 31, 2019 and a liability of $40.7 million as of December 31, 2018. 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.' jurisdictions, Avista Corp.' 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 March 2020, th WUTC extended the electric and natural gas decoupling mechanisms through March 31, 2025. 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. On December 13, 2019, the IPUC approved an extension of the FCAs through March 31, 2025.

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. Changes related to deferral interest rates were recommended by the parties in Avista Corp.'s 2019 general rate case and were implemented effective January 15, 2020. 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, 2019 and December 31, 2018, the Company had the following cumulative balances outstanding related to decoupling and earnings sharing mechanisms in its various jurisdictions (dollars in thousands):

	December 31, 2019	December 31, 2018
Washington		
Decoupling surcharge	$ 22,440	$ 12,671
Provision for earnings sharing rebate	—	(693)
Idaho		
Decoupling surcharge	$ 2,549	$ 2,150
Provision for earnings sharing rebate	(686)	(774)
Oregon		
Decoupling rebate	$ (739)	$ (898)
Provision for earnings sharing rebate	—	—

NOTE 18. 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.

Termination of the Merger Agreement

Due to the denial of the proposed merger by certain of the Company's regulatory commissions, 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 was 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 was used for general corporate purposes and reduced the Company's need for external financing. The 2019 costs totaled $19.7 million pre-tax and included financial advisers' fees, legal fees, consulting fees and employee time.

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 be required to be performed or observed.

The Company incurred significant transaction costs 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, more of the previously incurred transaction costs are deductible so it has recorded additional tax benefits from these costs in 2019.

See Note 16 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 19. SALE OF METALfx

In April 2019, Bay Area Manufacturing, Inc., a non-regulated subsidiary of Avista Corp., entered into a definitive agreement to sell its interest in METALfx to an independent third party. The transaction was a stock sale for a total cash purchase price of $17.5 million, plus cash on-hand, subject to customary closing adjustments. The transaction closed on April 18, 2019, and as of that date the Company has no further involvement with METALfx.

The purchase price of $17.5 million, as adjusted, was divided among the security holders of METALfx, including the minority shareholder, pro-rata based on ownership (Avista Corp. owned 89.2 percent of the equity of METALfx). As required under the purchase agreement, $1.2 million (7 percent of the purchase price) will be held in escrow for 24 months from the closing of the transaction to satisfy certain indemnification obligations.

When all escrow amounts are released, the sales transaction is expected to provide cash proceeds to Avista Corp., net of payments to the minority holder, contractually obligated compensation payments and other transaction expenses, of $16.5 million and result in a net gain after-tax of $3.3 million. The Company expects to receive the full amount of its portion of the escrow accounts; therefore, the full amounts are included in the gain calculation.

NOTE 20. SUPPLEMENTAL CASH FLOW INFORMATION

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

	2019	2018
Cash paid for interest	$ 92,681	$ 90,394
Cash paid for income taxes	26,164	16,576
Cash received for income tax refunds	(589)	(3,025)

NOTE 21. SUBSEQUENT EVENTS

The Company as evaluated its subsequent events as of April 14th, 2020.

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.

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 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 March 6, 2020, the Company received an order from the WUTC that will require it to refund $8.5 million to electric and natural gas customers. The Company will refund $4.9 million to electric customers and $3.6 million to natural gas customers. The Company recorded a customer refund liability of $8.5 million in 2019.

Colstrip Units 3 & 4 Outage and Replacement Power Costs

In 2019, the Company filed a case with the WUTC to recover costs associated with an unplanned power outage at Colstrip Units 3 and 4. The primary issue is related to the cost of replacement power incurred in July and August 2018 due to a forced outage at Colstrip Units 3 & 4. That outage occurred due to the plant exceeding certain air quality standards. In testimony filed by WUTC Staff and Public Counsel on January 10, 2020, the parties recommend the WUTC disallow $3.3 million in replacement power costs. Avista Corp. filed testimony on January 23, 2020, and provided support for no disallowance, but if the WUTC believes a disallowance is appropriate, the level of disallowance would be $2.4 million.

On March 20, 2020, the Company received an order from the WUTC related to costs associated with a an unplanned outage of Colstrip Units 3 and 4 in 2018. In its order, the WUTC disallowed approximately $3 million for the cost of replacement power during the unplanned outage.

2019 Washington General Rate Cases

On March 25, 2020, the Company received an order from the WUTC that approved the partial multi-party settlement agreement that was filed on November 21, 2019. The approved rates are designed to increase annual base electric revenues by $28.5 million, or 5.7 percent, and annual natural gas base revenues by $8.0 million, or 8.5 percent, effective April 1, 2020. The revenue increases are based on a 9.4 percent return on equity with a common equity ratio of 48.5 percent and a rate of return on rate base of 7.21 percent.

As part of the WUTC order, the Company will return approximately $40 million from the ERM rebate to customers over a two-year period. The ERM rebate includes approximately $3 million that was recently disallowed by the Commission for the cost of replacement power during an unplanned outage at the Colstrip generating facility in 2018. The Commission directed the Company to return a larger portion of the ERM money during the first year to achieve a net-zero billed impact to electric customers.

Included in the WUTC order is the acceleration of depreciation of Colstrip Units 3 & 4, to reflect a remaining useful life through December 31, 2025. The order utilizes certain electric tax benefits associated with the 2018 tax reform to partially offset these increased costs. The order also sets aside $3 million for community transition efforts to mitigate the impacts of the eventual closure of Colstrip, half funded by customers and half funded by Company shareholders.

In addition, a recent order received from the WUTC on the 2015 remand cases requires the Company to refund $8.5 million to electric and natural gas customers. The Company will refund $4.9 million to electric customers and $3.6 million to natural gas customers over a one year period, which will partially offset the increase in base rates.

Lastly, the order includes the extension of electric and natural gas decoupling mechanisms through March 31, 2025.

Credit Agreement

On April 6, 2020, the Company entered into a Credit Agreement with U.S. Bank National Association, as Lender and Administrative Agent, and CoBank, ACB, as Lender in the amount of $100 million with a maturity date of April 5, 2021. Loans under this agreement are unsecured and will have a variable annual interest rate determined by either the Eurodollar rate or the Alternative Base Rate depending on the type of loan selected by Avista Corp.

The Credit Agreement contains customary covenants and default provisions, including a covenant not to permit the ratio of "consolidated total debt" to "consolidated total capitalization" of Avista Corp. to be greater than 65 percent at any time.

The Company has borrowed the entire $100 million available under this agreement, which is expected to be used to provide additional liquidity and for general corporate purposes.

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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	04/15/2020	End of 2019/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		(8,089,542)		
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income		(1,742,363)		
3	Preceding Quarter/Year to Date Changes in Fair Value		1,965,835		
4	Total (lines 2 and 3)		223,472		
5	Balance of Account 219 at End of Preceding Quarter/Year		(7,866,070)		
6	Balance of Account 219 at Beginning of Current Year		(7,866,070)		
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value		(2,391,954)		
9	Total (lines 7 and 8)		(2,391,954)		
10	Balance of Account 219 at End of Current Quarter/Year		(10,258,024)		

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			(8,089,542)	[redacted]	[redacted]
2			(1,742,363)	[redacted]	[redacted]
3			1,965,835	[redacted]	[redacted]
4			223,472	136,429,120	136,652,592
5			(7,866,070)	[redacted]	[redacted]
6			(7,866,070)	[redacted]	[redacted]
7				[redacted]	[redacted]
8			(2,391,954)	[redacted]	[redacted]
9			(2,391,954)	196,979,195	194,587,241
10			(10,258,024)	[redacted]	[redacted]

Schedule Page: 122(a)(b) Line No.: 2 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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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)	6,302,457,210	4,320,051,737
4	Property Under Capital Leases	69,745,591	
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	6,372,202,801	4,320,051,737
9	Leased to Others		
10	Held for Future Use	12,951,318	12,045,797
11	Construction Work in Progress	157,909,990	130,627,836
12	Acquisition Adjustments	279,264	279,264
13	Total Utility Plant (8 thru 12)	6,543,343,373	4,463,004,634
14	Accum Prov for Depr, Amort, & Depl	2,121,893,905	1,528,306,319
15	Net Utility Plant (13 less 14)	4,421,449,468	2,934,698,315
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	1,995,071,690	1,503,624,342
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	126,822,215	24,681,977
22	Total In Service (18 thru 21)	2,121,893,905	1,528,306,319
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)	2,121,893,905	1,528,306,319

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
1,330,407,424				651,998,049	3
				69,745,591	4
					5
					6
					7
1,330,407,424				721,743,640	8
					9
190,585				714,936	10
2,416,941				24,865,213	11
					12
1,333,014,950				747,323,789	13
395,724,780				197,862,806	14
937,290,170				549,460,983	15
					16
					17
394,754,186				96,693,162	18
					19
					20
970,594				101,169,644	21
395,724,780				197,862,806	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
395,724,780				197,862,806	33

Schedule Page: 200   Line No.: 4   Column: h

ROU Asset - $69,745,591

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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	04/15/2020	End of 2019/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	24,879,157	4,564,389
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	69,531,079	4,564,389
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	3,578,472	
9	(311) Structures and Improvements	139,536,107	256,857
10	(312) Boiler Plant Equipment	180,990,226	5,564,604
11	(313) Engines and Engine-Driven Generators	6,770	1,409
12	(314) Turbogenerator Units	56,778,165	830,269
13	(315) Accessory Electric Equipment	29,585,199	114,675
14	(316) Misc. Power Plant Equipment	17,125,165	-499,400
15	(317) Asset Retirement Costs for Steam Production	14,327,505	2,699,146
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	441,927,609	8,967,560
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	63,813,274	200,941
28	(331) Structures and Improvements	87,175,595	12,424,075
29	(332) Reservoirs, Dams, and Waterways	194,509,659	3,127,848
30	(333) Water Wheels, Turbines, and Generators	236,170,550	3,187,134
31	(334) Accessory Electric Equipment	67,054,223	4,768,783
32	(335) Misc. Power PLant Equipment	14,104,790	1,374,204
33	(336) Roads, Railroads, and Bridges	4,339,089	-677,646
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	667,167,180	24,405,339
36	D. Other Production Plant		
37	(340) Land and Land Rights	905,167	
38	(341) Structures and Improvements	17,135,420	40,508
39	(342) Fuel Holders, Products, and Accessories	21,388,222	8,759
40	(343) Prime Movers	23,508,061	
41	(344) Generators	217,408,279	2,134,819
42	(345) Accessory Electric Equipment	22,102,499	370,246
43	(346) Misc. Power Plant Equipment	1,748,536	-40,440
44	(347) Asset Retirement Costs for Other Production	351,683	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	304,547,867	2,513,892
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,413,642,656	35,886,791

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2020	End of 2019/Q4

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

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

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

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

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
					2
		-278,068	44,373,854		3
3,148,323		-871,522	25,423,701		4
3,148,323		-1,149,590	69,797,555		5
					6
					7
			3,578,472		8
33,153		-84,856	139,674,955		9
-6,193,119		-91,514	192,656,435		10
			8,179		11
308,718		-61,693	57,238,023		12
43,756		-95,044	29,561,074		13
		-1,356	16,624,409		14
			17,026,651		15
-5,807,492		-334,463	456,368,198		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
		-4	64,014,211		27
522,886		-2,057,278	97,019,506		28
1,106,820		-4,100,469	192,430,218		29
64,690		-4,733,313	234,559,681		30
273,111		-1,822,560	69,727,335		31
21,676		-278,222	15,179,096		32
		-12,343	3,649,100		33
					34
1,989,183		-13,004,189	676,579,147		35
					36
			905,167		37
		-6,711	17,169,217		38
		-6,628	21,390,353		39
		-689	23,507,372		40
144,769		-77,281	219,321,048		41
86,990		-34,863	22,350,892		42
		-5,417	1,702,679		43
			351,683		44
231,759		-131,589	306,698,411		45
-3,586,550		-13,470,241	1,439,645,756		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	04/15/2020	End of 2019/Q4

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	28,481,411	1,304,214
49	(352) Structures and Improvements	26,235,360	-377,374
50	(353) Station Equipment	267,576,680	23,063,717
51	(354) Towers and Fixtures	17,291,148	-130,449
52	(355) Poles and Fixtures	262,539,672	18,566,462
53	(356) Overhead Conductors and Devices	147,291,972	12,158,671
54	(357) Underground Conduit	3,188,360	64,880
55	(358) Underground Conductors and Devices	2,536,276	66,166
56	(359) Roads and Trails	2,053,899	59,152
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	757,194,778	54,775,439
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	10,537,353	1,293,834
61	(361) Structures and Improvements	34,091,794	110,533
62	(362) Station Equipment	138,327,119	10,327,916
63	(363) Storage Battery Equipment	2,559,615	
64	(364) Poles, Towers, and Fixtures	406,089,343	31,925,943
65	(365) Overhead Conductors and Devices	268,683,588	12,516,684
66	(366) Underground Conduit	118,880,627	4,858,990
67	(367) Underground Conductors and Devices	209,466,532	10,841,097
68	(368) Line Transformers	269,654,993	11,298,322
69	(369) Services	173,790,109	6,683,792
70	(370) Meters	56,545,353	31,952,939
71	(371) Installations on Customer Premises	1,490,826	629,903
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	63,205,408	3,467,876
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,753,322,660	125,907,829
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	498,670	8,696
87	(390) Structures and Improvements	8,242,162	255,671
88	(391) Office Furniture and Equipment	2,735,533	532,831
89	(392) Transportation Equipment	46,691,376	4,243,064
90	(393) Stores Equipment	399,249	35,487
91	(394) Tools, Shop and Garage Equipment	5,633,451	726,477
92	(395) Laboratory Equipment	1,552,769	302,155
93	(396) Power Operated Equipment	32,154,229	354,121
94	(397) Communication Equipment	66,092,232	2,019,197
95	(398) Miscellaneous Equipment	152,016	47,643
96	SUBTOTAL (Enter Total of lines 86 thru 95)	164,151,687	8,525,342
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant		
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	164,151,687	8,525,342
100	TOTAL (Accounts 101 and 106)	4,157,842,860	229,659,790
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)	4,158,129,180	229,659,790

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
69,872		-68,505	29,647,248		48
17,218		-482,549	25,358,219		49
638,457		-2,988,304	287,013,636		50
			17,160,699		51
887,580		-1,584,528	278,634,026		52
315,401		-545,477	158,589,765		53
			3,253,240		54
			2,602,442		55
		-5,492	2,107,559		56
					57
1,928,528		-5,674,855	804,366,834		58
					59
291		-15,916	11,814,980		60
112,985		-557,275	33,532,067		61
690,631		-1,087,819	146,876,585		62
		-130,863	2,428,752		63
1,422,788		-328,373	436,264,125		64
116,166		-555,756	280,528,350		65
17,148		-138,002	123,584,467		66
203,018		-288,463	219,816,148		67
190,179		-78,221	280,684,915		68
41,267		-17,029	180,415,605		69
15,567,087		-47,143	72,884,062		70
		-6,123	2,114,606		71
					72
857,355		-1,258	65,814,671		73
					74
19,218,915		-3,252,241	1,856,759,333		75
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					84
					85
		-89	507,277		86
88,896		66,457	8,475,394		87
1,380,209		-449,277	1,438,878		88
1,038,211		32,429	49,928,658		89
42,840		-66	391,830		90
194,706		-2,572	6,162,650		91
43,804		-9,608	1,801,512		92
710,224		-557	31,797,569		93
18,137,009		-1,189,279	48,785,141		94
6,068		-241	193,350		95
21,641,967		-1,552,803	149,482,259		96
					97
					98
21,641,967		-1,552,803	149,482,259		99
42,351,183		-25,099,730	4,320,051,737		100
		-286,320			101
					102
					103
42,351,183		-25,386,050	4,320,051,737		104

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2020	End of 2019/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	Distribution Plant Land, Carlin Bay, Idaho	Dec 2010	2022-2026	162,352
4	Distribution Plant Land, Spokane, Washington	Mar 2011	2022-2026	540,307
5	Transmission Plant Land, Spokane, Washington	Dec 2011	2022-2026	431,600
6	Transmission Plant Land, Spokane, Washington	July 2014	2022-2026	62,168
7	Other Production Plant Land, Spokane, Washington	Dec 2011	2022-2026	40,896
8	Steam Production Plant Land, Spokane, Washington	Dec 2015	2022-2026	3,544,725
9	Transmission Plant Land, Noxon, Montana	Mar 2016	2022-2026	3,292,167
10	Transmission Plant Land, Spokane, Washington	Jan 2017	2022-2026	56,311
11	Distribution Plant Land, Spokane, Washington	June 2019	2022-2026	2,869,104
12	Distribution Plant Land, Colville, Washington	June 2019	2022-2026	104,527
13	Transmission Plant Land, Sandpoint, Idaho	July 2019	2022-2026	486,299
14	Transmission Plant Land, Spokane Washington	July 2019	2022-2026	378,392
15				
16				
17				
18				
19				
20				
21	Other Property:			
22				
23				
24				
25	Distribution Structure and Improvement Spokane, WA	July 2019	2022-2026	32,824
26	Transmission Structure and Improvement, Spokane, WA	July 2019	2022-2026	44,125
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46				
47	Total			12,045,797

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	29,312,177
2	Saddle Mountain Integration	17,824,894
3	Rattlesnake Flat 115kV Wind Farm Project	8,740,483
4	Irvin Sub - New Construction	5,737,854
5	Substation Rebuilds	5,462,653
6	Westside 230 kV Substation - Rebuild	5,261,666
7	Benton-Othello 115 Recond	5,101,013
8	New Substations	3,687,834
9	CG HED Automation Replacement	3,214,648
10	Substation Asset Mgmt Capital Maintenance	2,798,513
11	KF Fuel Yard Equipment Replacement	2,518,408
12	WSDOT Highway Franchise Consolidation	2,239,114
13	Low Priority Ratings Mitigation	2,153,077
14	Long Lake Plant Upgrades	1,967,782
15	Protection System Upgrades for PRC-002	1,889,717
16	Distribution Line Relocations	1,826,331
17	Downtown Network - Performance & Capacity	1,667,533
18	FAS 143 ARO	1,566,149
19	Noxon Hydro-Noxon Switchyard 230kV Trans Line Rbld	1,467,572
20	Electric Revenue Blanket	1,426,915
21	LL HED Stability Enhancement	1,298,232
22	Energy Imbalance Market	1,238,074
23	CG HED Station Service Replacement	1,154,840
24	Metro-Post St 115kV Underground Tx Line Rebuild	1,117,742
25	Saddle Mountain Integration Phase 2	1,096,680
26	Minor Projects <$1M	12,996,475
27		
28	R&D/Strategic Initiatives	5,861,460
29		
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42		
43	TOTAL	130,627,836

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2020	End of 2019/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	1,426,663,880	1,426,663,880		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	108,490,436	108,490,436		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts	4,815,190	4,815,190		
8	Other Accounts (Specify, details in footnote):	16,120,838	16,120,838		
9		-168,072	-168,072		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	129,258,392	129,258,392		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	46,443,932	46,443,932		
13	Cost of Removal	5,155,029	5,155,029		
14	Salvage (Credit)	452,583	452,583		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	51,146,378	51,146,378		
16	Other Debit or Cr. Items (Describe, details in footnote):	-1,151,552	-1,151,552		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	1,503,624,342	1,503,624,342		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	321,428,595	321,428,595		
21	Nuclear Production				
22	Hydraulic Production-Conventional	144,618,326	144,618,326		
23	Hydraulic Production-Pumped Storage				
24	Other Production	136,957,489	136,957,489		
25	Transmission	229,897,098	229,897,098		
26	Distribution	602,862,062	602,862,062		
27	Regional Transmission and Market Operation				
28	General	67,860,772	67,860,772		
29	TOTAL (Enter Total of lines 20 thru 28)	1,503,624,342	1,503,624,342		

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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			-159,248,496
4	Investment in AERC	2014		89,816,380
5	AERC - Equity in Earnings			16,816,831
6				
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41				
42	Total Cost of Account 123.1 $ 0		TOTAL	153,523,686

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2020	End of 2019/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
	-50,000,000	256,138,971		2
6,404,043		-152,844,453		3
		89,816,380		4
7,178,226	10,000,000	13,995,056		5
				6
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				41
13,582,269	-40,000,000	207,105,954		42

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)	3,982,104	4,148,891	(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)	30,587,855	29,944,453	
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	3,406,236	3,443,631	(1)
8	Transmission Plant (Estimated)	69,743	-4,267	(1)
9	Distribution Plant (Estimated)	464,542	585,679	(1)
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	8,637,790	12,589,323	(1),(2)
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	43,166,166	46,558,819	
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)	47,148,270	50,707,710	

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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2020	End of 2019/Q4

Transmission Service and Generation Interconnection Study Costs

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

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
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11					
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20					
21	**Generation Studies**				
22	Clearwater Wind Interconnect	6,724	186200		
23	Gordon Butte Project #50	2,818	186200		
24	Broadview Solar II Project #51	5,439	186200		
25	Aurora Solar Project #59	68,945	186200		
26	Clarkston Hts Solar Project #60	110,267	186200		
27	Rattlesnake II Wind Proj #62	32,102	186200		
28	Post Falls HED Project #63	12,198	186200		
29	Kettle Falls Upgrade Proj #66	677	186200		
30	Old Milwaukee Solar Proj #67	4,928	186200		
31	Clearwater Wind II Proj #68	597	186200		
32	Clearwater Wind III Proj #69	936	186200		
33	EnerNOC Batt. Storage Proj #70	6,611	186200		
34	Geronimo Solar Project #71	11,389	186200		
35	Geronimo Solar Project #72	4,622	186200		
36	Sprague Solar Project #73	5,577	186200		
37	Royal City Solar Project #76	4,239	186200		
38	Bafus Solar Project #77	12,033	186200		
39	Elf II Solar Project #79	5,502	186200		
40	Elf I Solar Project #80	5,389	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					
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9					
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11					
12					
13					
14					
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20					
21	**Generation Studies**				
22	Ralston Solar Project #81	3,767	186200		
23	Haymaker Wind Proj #82	1,526	186200		
24	Martinsdale Wind Proj #83	1,221	186200		
25	Rainier Solar Project #85	840	186200		
26	Acadia Solar Project #84	882	186200		
27	Little Falls Solar Project #86	1,096	186200		
28	Geronimo6 Solar Project #94	205	186200		
29	Geronimo2 Solar Project #90	205	186200		
30	Jane Wind 2 Proj #96	739	186200		
31	Jane Wind Proj #95	500	186200		
32	Lolo Solar Project #97	2,416	186200		
33	Rattlesnake Optional Study	20,341	186200		
34	Stratford Solar Project #98	2,685	186200		
35	Wahatis Solar Project #99	3,136	186200		
36	Stringtown Solar #100	2,869	186200		
37	North Cheyenne #101	1,237	186200		
38	Kulm Solar Farm Project #57	6,419	186200	6,419	186210
39	Rosenoff Solar Project #58	12,685	186200	12,685	186210
40	Tokio Solar Project #54	59,712	186200	59,712	186210

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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2020	End of 2019/Q4

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**				
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12					
13					
14					
15					
16					
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20					
21	**Generation Studies**				
22	Plum River Solar Project #75	3,239	186200	3,239	186210
23	Harrington Solar Project #61	9,712	186200	9,712	186210
24	Purcell Batt. Storage Proj #74	1,420	186200	1,420	186210
25	Malden Solar Project #78	1,273	186200	1,273	186210
26	Taunton Solar Project #52	57,899	186200	57,899	186210
27	Geronimo5 Solar Project #93	50	186200	50	186210
28	Geronimo4 Solar Project #92	50	186200	50	186210
29	Geronimo3 Solar Project #91	50	186200	50	186210
30	Geronimo1 Solar Project #89	50	186200	50	186210
31	Geronimo Solar Project #88	50	186200	50	186210
32	Jantz Solar Project #87	285	186200	285	186210
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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
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Schedule Page: 231 Line No.: 26 Column: b
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Schedule Page: 231 Line No.: 27 Column: b
Total Life to Date Costs
Schedule Page: 231 Line No.: 28 Column: b
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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
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Schedule Page: 231.1 Line No.: 26 Column: b
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Schedule Page: 231.1 Line No.: 29 Column: b

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Schedule Page: 231.1 Line No.: 30 Column: b

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Schedule Page: 231.1 Line No.: 31 Column: b

Total Life to Date Costs

Schedule Page: 231.1 Line No.: 32 Column: b

Total Life to Date Costs

Schedule Page: 231.1 Line No.: 33 Column: b

Total Life to Date Costs

Schedule Page: 231.1 Line No.: 34 Column: b

Total Life to Date Costs

Schedule Page: 231.1 Line No.: 35 Column: b

Total Life to Date Costs

Schedule Page: 231.1 Line No.: 36 Column: b

Total Life to Date Costs

Schedule Page: 231.1 Line No.: 37 Column: b

Total Life to Date Costs

Schedule Page: 231.1 Line No.: 38 Column: b

Total Life to Date Costs

Schedule Page: 231.1 Line No.: 38 Column: d

Total Life to Date Reimbursements. Project completed Q1

Schedule Page: 231.1 Line No.: 39 Column: b

Total Life to Date Costs

Schedule Page: 231.1 Line No.: 39 Column: d

Total Life to Date Reimbursements. Project completed Q1

Schedule Page: 231.1 Line No.: 40 Column: b

Total Life to Date Costs

Schedule Page: 231.1 Line No.: 40 Column: d

Total Life to Date Reimbursements. Project completed Q2

Schedule Page: 231.2 Line No.: 22 Column: b

Total Life to Date Costs

Schedule Page: 231.2 Line No.: 22 Column: d

Total Life to Date Reimbursements. Project completed Q2

Schedule Page: 231.2 Line No.: 23 Column: b

Total Life to Date Costs

Schedule Page: 231.2 Line No.: 23 Column: d

Total Life to Date Reimbursements. Project completed Q3

Schedule Page: 231.2 Line No.: 24 Column: b

Total Life to Date Costs

Schedule Page: 231.2 Line No.: 24 Column: d

Total Life to Date Reimbursements. Project completed Q3

Schedule Page: 231.2 Line No.: 25 Column: b

Total Life to Date Costs

Schedule Page: 231.2 Line No.: 25 Column: d

Total Life to Date Reimbursements. Project completed Q3

Schedule Page: 231.2 Line No.: 26 Column: b

Total Life to Date Costs

Schedule Page: 231.2 Line No.: 26 Column: d

Total Life to Date Reimbursements. Project completed Q4

Schedule Page: 231.2 Line No.: 27 Column: b

Total Life to Date Costs

Schedule Page: 231.2 Line No.: 27 Column: d

Total Life to Date Reimbursements. Project completed Q4

Schedule Page: 231.2 Line No.: 28 Column: b

Total Life to Date Costs

Schedule Page: 231.2 Line No.: 28 Column: d

Total Life to Date Reimbursements. Project completed Q4

Schedule Page: 231.2 Line No.: 29 Column: b

Total Life to Date Costs

Schedule Page: 231.2 Line No.: 29 Column: d

Total Life to Date Reimbursements. Project completed Q4

Schedule Page: 231.2 Line No.: 30 Column: b

Total Life to Date Costs

Schedule Page: 231.2 Line No.: 30 Column: d

Total Life to Date Reimbursements. Project completed Q4

Schedule Page: 231.2 Line No.: 31 Column: b

Total Life to Date Costs

Schedule Page: 231.2 Line No.: 31 Column: d

Total Life to Date Reimbursements. Project completed Q4

Schedule Page: 231.2 Line No.: 32 Column: b

Total Life to Date Costs

Schedule Page: 231.2 Line No.: 32 Column: d

Total Life to Date Reimbursements. Project completed Q4

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2020	Year/Period of Report End of 2019/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	9,687,444	1,264,114	407	606,842	10,344,716
2	Reg Asset Post Ret Liab	230,641,437	3,403,831	228, 283	23,244,061	210,801,207
3	Regulatory Asset FAS109 Utility Plant	81,340,941	3,207,946	283	1,192,953	83,355,934
4	Regulatory Asset FAS109 DSIT Non Plant	1,420,897	1,682,091	283	79,787	3,023,201
5	Regulatory Asset FAS109 WNP3	107,699		283	107,699	
6	Regulatory Asset- Spokane River Relicense	403,183		407, 537	269,272	133,911
7	Regulatory Asset- Lake CDA Settlement - Varies	42,589,145		407	1,279,988	41,309,157
8	Reg Assets- Decouplings Surcharge - 2 years	1,776,570	23,550,873	182	6,000,822	19,326,621
9	Reg Asset - Colstrip		4,945,687			4,945,687
10	Commodity MTM ST & LT Regulatory Asset	58,294,063		244, 175	51,720,475	6,573,588
11	Regulatory Asset FAS143 Asset Retirement Obligation	4,690,533	653,201	182	3,543,528	1,800,206
12	Regulatory Asset Workers Comp	634,064	612,173	242	119,941	1,126,296
13	Interest Rate Swap Asset	133,853,505	397,270,942	244, 175	362,530,376	168,594,071
14	DSM Asset	19,674,074	49,213,659	242	56,717,534	12,170,199
15	Deferred ITC	4,052,923		283, 410	70,968	3,981,955
16	Regulatory Asset MDM System	4,030,155	9,396,022	431	31,356	13,394,821
17	Regulatory Asset BPA Residential Exchange	90,430	1,421,535	254, 407	185,080	1,326,885
18	Regulatory Asset FISERV - 3 years	1,930,519	1,739,188	805	75,672	3,594,035
19	Regulatory Asset - AFUDC (PIS,WIP) & Equity DFIT	3,506,418	42,079,953	108, 282	1,492,712	44,093,659
20	Regulatory Asset ID PCA Deferral - 1 year		256,594			256,594
21	Existing Meters/ERTS Retirement Def		13,052,304			13,052,304
22	Other Regulatory Assets	109	2,212			2,321
23						
24						
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30						
31						
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33						
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35						
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44	**TOTAL :**	598,724,109	553,752,325		509,269,066	643,207,368

Schedule Page: 232 Line No.: 1 Column: a
Residential Schedule 101 customers who receive a natural gas line extension as part of conversion to natural gas from another fuel source. Amortization for a period of 3 years on the excess allowance exceeding the cost of the line extension.

Schedule Page: 232 Line No.: 2 Column: a
Recognition of the overfunded and underfunded status of a defined benefit postretirement plan based on ASC 715 for financial reporting.

Schedule Page: 232 Line No.: 3 Column: a
Amortized over remaining book life of pre-1986 vintage assets. Amortization amount varies yearly.

Schedule Page: 232 Line No.: 6 Column: a
Amortization for TDG Idaho ended on December 2019. Spokane River relicensing amortization costs will end on 11/30/2020.

Schedule Page: 232 Line No.: 7 Column: a
WA Docket UE-080416 & ID Order AVU-E-08-01. Amortization thru 2059.

Schedule Page: 232 Line No.: 8 Column: a
Decoupling revenue deferrals are recognized during the period they occur, subject to certain limitations. Revenue is expected to be collected within 24 months of the deferral.

Schedule Page: 232 Line No.: 9 Column: a
For Washington Electric,we are currently deferring ARO expenses. Amortization period to be determined. For Idaho Electric, amortization is for 34 years as per Order 34276, AVU-E-18-03.

Schedule Page: 232 Line No.: 10 Column: a
Washington Docket# UE-002066 and Idaho Order# 28648

Schedule Page: 232 Line No.: 11 Column: a
Reclass of Regulatory Assets related to Colstrip to state jurisdictions.

Schedule Page: 232 Line No.: 12 Column: a
Quarterly adjustments to workers comp reserve for current unpaid claims.

Schedule Page: 232 Line No.: 13 Column: a
Settled swaps are amortized over the life of the associated debt.

Schedule Page: 232 Line No.: 14 Column: a
Amortization period varies depending on timing of transactions.

Schedule Page: 232 Line No.: 15 Column: a
Amortization period varies depending on underlying transactions.

Schedule Page: 232 Line No.: 16 Column: a
Washington Docket#s UE-180418, UG-180419

Schedule Page: 232 Line No.: 17 Column: a
Avista is a participant in the Residential Exchange Program with Bonneville Power Administration. Customers served under Schedules 1, 12, 22, 32 and 48 are given a rate adjustment based on Schedule 59 for Washington and Idaho. Amortization is based on customer usage.

Schedule Page: 232 Line No.: 18 Column: a
Idaho Order# 33494, Docket Nos. AVU-E-16-01 and Stipulation and Settlement Docket# AVU-E-19-04

Schedule Page: 232 Line No.: 19 Column: a
Deferring the difference between FERC formula and State approved AFUDC rates primarily from 2010-2017.

Schedule Page: 232 Line No.: 21 Column: a
Washington Docket#s UE-180418 and UG-180419. Amortization period to be determined.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2020	End of 2019/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

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

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1						
2	Colstrip Common Facility	1,110,999				1,110,999
3	Colstrip Common Facility	2,355,642				2,355,642
4	Plant Alloc of Clearing Journal	3,696,701	1,119,286			4,815,987
5	Intercompany Clearing		8,132			8,132
6	Misc. Deferred Debits (AN)	470,493	26,488			496,981
7	Misc. Deferred Debits (WA)		540,265			540,265
8	Reg Asset - Decoupling Deferred	21,001,564		VAR	12,449,795	8,551,769
9	Deferred Proj Compass - ID 4 yr	836,724		407	836,724	
10	Reg Asset ID-Lake CDA 10 yr amt	54,206		506	30,975	23,231
11	Conservation Project Programs		46,298			46,298
12	Nez Perce Settlement	129,501		557	5,188	124,313
13	Subsidiary Billings	522,220		VAR	499,633	22,587
14	Misc. Work Orders <$40,000	757,584		VAR	446,807	310,777
15	Aurora Solar Project #59	67,956	989			68,945
16	Build Farm Taps	60,951		VAR	6,156	54,795
17	Clarkston Hts Solar Project#60	84,080	26,187			110,267
18	Credit Union Labor & Expenses	96,382		VAR	36,639	59,743
19	Optional Wind Power	-83,782	17,737			-66,045
20	Smart Hoist Suspense		76,518			76,518
21	Timber Harvest Revenue	-260,682	33,864			-226,818
22						
23						
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46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	30,900,539				18,484,386

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	04/15/2020	End of 2019/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		14,294,336	20,510,338
3			
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	14,294,336	20,510,338
9	Gas		
10		3,071,820	3,791,114
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15	3,071,820	3,791,114
17	Other	170,084,364	152,755,074
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	187,450,520	177,056,526

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	04/15/2020	End of 2019/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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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
67,176,996	1,176,498,977					2
				93,351	3,824,590	3
67,176,996	1,176,498,977			93,351	3,824,590	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	04/15/2020	End of 2019/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	04/15/2020	End of 2019/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	-44,938,398
2		
3		
4		
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21		
22	TOTAL	-44,938,398

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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	04/15/2020	End of 2019/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 - 7.18% DUE 8/11/2023	7,000,000	54,364
4	ADVANCE ASSOCIATED-AVISTA CAPITAL II (ToPRS)	51,547,000	1,296,086
5	FMBS - 6.37% SERIES C	25,000,000	158,304
6	FMBS - 5.45% SERIES	90,000,000	1,192,681
7	Discount- FMBS - 5.45% SERIES		239,400
8	FMBS - 6.25% SERIES	150,000,000	1,812,935
9	Discount- FMBS - 6.25% SERIES		367,500
10	FMBS - 5.70% SERIES	150,000,000	4,702,304
11	Discount- FMBS - 5.70% SERIES		222,000
12	FMBS - 5.125% SERIES	250,000,000	2,284,788
13	Discount- FMBS - 5.125% SERIES		575,000
14	COLSTRIP 2010A PCRBs DUE 2032	66,700,000	
15	COLSTRIP 2010B PCRBs DUE 2034	17,000,000	
16	FMBS - 3.89% SERIES	52,000,000	385,129
17	FMBS - 5.55% SERIES	35,000,000	258,834
18	4.45% SERIES DUE 12-14-2041	85,000,000	692,833
19	4.23% SERIES DUE 11-29-2047	80,000,000	730,833
20	FMBS- 4.11% SERIES	60,000,000	428,205
21	FMBS- 4.37% SERIES	100,000,000	590,761
22	FMBS- 3.54% SERIES	175,000,000	1,042,569
23	FMBS 3.91% SERIES	90,000,000	552,539
24	FMBS 4.35% SERIES	375,000,000	4,246,448
25	Discount- FMBS - 4.350% SERIES		378,750
26	FMBS 3.43% SERIES	180,000,000	1,111,577
27			
28			
29			
30			
31			
32			
33	TOTAL	2,045,747,000	23,374,318

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
08-12-1993	08-11-2023	08-12-1993	08-11-2023	7,000,000	502,600	3
06-03-1997	06-01-2037	06-03-1997	06-01-2037	51,547,000	1,342,492	4
06-19-1998	06-19-2028	06-19-1998	06-19-2028	25,000,000	1,592,500	5
11-18-2004	12-01-2019	11-18-2004	12-01-2019		4,496,250	6
						7
11-17-2005	12-01-2035	11-17-2005	12-01-2035	150,000,000	9,375,000	8
						9
12-15-2006	07-01-2037	12-15-2006	07-01-2037	150,000,000	8,550,000	10
						11
09-22-2009	04-01-2022	09-22-2009	04-01-2022	250,000,000	12,812,500	12
						13
12-15-2010	10-1-2032	12-15-2010	10-1-2032	66,700,000		14
12-15-2010	3-1-2034	12-15-2010	3-1-2034	17,000,000		15
12-20-2010	12-20-2020	12-20-2010	12-20-2020	52,000,000	2,022,800	16
12-20-2010	12-20-2040	12-20-2010	12-20-2040	35,000,000	1,942,500	17
12-14-2011	12-14-2041	12-14-2011	12-14-2041	85,000,000	3,782,500	18
11-30-2012	11-29-2047	11-30-2012	11-29-2047	80,000,000	3,384,000	19
12-18-2014	12-1-2044	12-18-2014	12-1-2044	60,000,000	2,466,000	20
12-16-2015	12-1-2045	12-16-2015	12-1-2045	100,000,000	4,370,000	21
12-15-2016	12-1-2051	12-15-2016	12-1-2051	175,000,000	6,195,000	22
12-14-2017	12-1-2047	12-14-2017	12-1/2047	90,000,000	3,519,000	23
05-22-2018	06-01-2048	06-1-2018	06-1-2048	375,000,000	16,312,500	24
						25
11-26-2019	12-01-2049	12-01-2019	12-01-2049	180,000,000	600,250	26
						27
						28
						29
						30
						31
						32
				1,955,747,000	83,755,442	33

Schedule Page: 256 Line No.: 4 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.: 6 Column: a

Matured in 2019 and fully amortized.

Schedule Page: 256 Line No.: 14 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.: 14 Column: c

The Company reacquired these bonds in 2010.

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

The Company reacquired these bonds in 2010.

Schedule Page: 256 Line No.: 26 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.U-171210 entered January 11, 2018;

2. Order of the Idaho Public Utilities Commission ,Order No. 33978 entered January 30, 2018;

3. Order of the Public Utility Commission of Oregon, Order No. 19-249, entered July 30, 2019

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	04/15/2020	End of 2019/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)	191,949,607
2		
3		
4	Taxable Income Not Reported on Books	
5		8,218,407
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		264,780,968
11	Federal Income Tax Expense	23,748,485
12	State Income Tax Expense Adj	671,886
13		
14	Income Recorded on Books Not Included in Return	
15		-16,761,381
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		-392,739,644
21		
22		
23		
24	Equity in Subs Earnings	-13,582,269
25	Corporate Overhead Unallocated Subs	734,005
26		
27	Federal Tax Net Income	67,020,064
28	Show Computation of Tax:	
29		
30	Federal Tax at 21%	14,074,213
31		
32	Prior Year True Ups	89,757
33		
34	Total Federal Tax Expense	14,163,970
35		
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44		

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2020	Year/Period of Report End of 2019/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	FEDERAL:					
2	Income Tax 2014	247,648				
3	Income Tax 2016	-520,411				
4	Income Tax 2017			-104,399		
5	Income Tax 2018	3,137,410		-668,591	3,721,124	
6	Income Tax (Current)			14,258,252	20,801,640	
7	Retained Earnings (Current)					
8	Prior Retained Earnings					
9	Total Federal	2,864,647		13,485,262	24,522,764	
10						
11	STATE OF WASHINGTON:					
12	Property Tax (2018)	18,657,279		-2,265,643	16,386,052	
13	Property Tax (2019)			18,740,467		
14	Excise Tax (2016)	892,951				
15	Excise Tax (2018)	2,615,663		42,618	2,658,281	
16	Excise Tax (2019)			27,166,921	24,251,919	
17	Natural Gas Use Tax	496		3,211	3,216	
18	Municipal Occupation Tax	2,802,731		24,214,721	23,887,401	
19	Community Solar	-22,706		-607,289	-598,266	
20	Sales & Use Tax (2018)	92,145			89,476	
21	Sales & Use Tax (2019)			1,416,689	1,130,161	
22	Total Washington	25,038,559		68,711,695	67,808,240	
23						
24	STATE OF IDAHO:					
25	Income Tax (2018)	133,757		14,064	147,821	
26	Income Tax (2019)			10,384	330,000	
27	Property Tax (2018)	3,983,497	25,096	50	3,983,547	
28	Property Tax (2019)			7,685,062	3,867,706	
29	Sales & Use Tax (2018)	4,093			4,093	
30	Sales & Use Tax (2019)			135,001	125,660	
31	KWH Tax (2017)					
32	KWH Tax (2018)	31,826		-3,875	27,952	
33	KWH Tax (2019)			372,268	345,991	
34	Franchise Tax (2018)	1,019,285			1,019,264	
35	Franchise Tax (2019)			4,662,921	3,559,640	
36	Total Idaho	5,172,458	25,096	12,875,875	13,411,674	
37						
38	STATE OF MONTANA:					
39	Income Tax (2018)	3,640		2,175	5,815	
40	Income Tax (2019)			235,666	360,000	
41	TOTAL	39,835,469	3,977,509	117,673,438	127,911,617	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2020	End of 2019/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
	247,648					2
	-520,411					3
	-104,399				-104,399	4
	-1,252,305	5,573			-674,164	5
	-6,543,388	7,388,769	21,404,419		-14,534,936	6
						7
						8
	-8,172,855	7,394,342	21,404,419		-15,313,499	9
						10
						11
5,584		-1,863,845			-401,799	12
18,740,467		14,808,462			3,932,005	13
892,951						14
		33,109			9,509	15
2,915,002		21,424,963			5,741,959	16
490		3,211				17
3,130,051		18,880,001			5,334,720	18
-31,729					-607,289	19
2,669						20
286,528					1,416,689	21
25,942,013		53,285,901			15,425,794	22
						23
						24
		11,954			2,110	25
	-319,616	-483,678	710,714		-216,652	26
		50				27
3,817,356		6,017,580			1,667,482	28
						29
9,341					135,001	30
						31
		-3,875				32
26,277		373,583			-1,315	33
21						34
1,103,281		3,543,617			1,119,304	35
4,956,276	-319,616	9,459,231	710,714		2,705,930	36
						37
						38
		2,175				39
	-124,334	-60,656	363,470		-67,147	40
38,022,918	-12,378,042	86,135,184	22,478,603		9,059,651	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2020	End of 2019/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	Property Tax (2018)	5,567,637			5,567,637	
2	Property Tax (2019)			11,552,453	5,784,643	
3	Colstrip Generation Tax			2,863	2,863	
4	KWH Tax (2018)	247,559			247,559	
5	KWH Tax (2019)			1,080,780	854,170	
6	Consumer Council Fee	60		-18	27	
7	Public Commission Fee	19		118	86	
8	Total Montana	5,818,915		12,874,037	12,822,800	
9						
10	STATE OF OREGON:					
11	Income Tax (2019)			100,000	100,000	
12	Property Tax (2018)		3,952,413	3,952,413		
13	Property Tax (2019)			3,759,492	7,519,140	
14	Franchise Tax (2018)	955,373			911,958	
15	Franchise Tax (2019)			3,637,043	2,590,653	
16	Total Oregon	955,373	3,952,413	11,448,948	11,121,751	
17						
18	STATE OF CALIFORNIA:					
19	Income Tax (2019)			1,600	1,600	
20	Total California			1,600	1,600	
21						
22	MISCELLANEOUS STATES:					
23	Income Tax (Current)			460	2,050	
24	Total Misc States			460	2,050	
25						
26	MISCELLANEOUS OTHER					
27	CTR Credit (2018)			-1,553	-1,553	
28	Timber Excise Tax (2017)					
29	WA Renewable Energy	-42,537		-1,824,133	-1,841,624	25,047
30	Misc Distribution	25,047		31,320	-1,839	-25,047
31	Thermal Fuel Tax	3,007		69,927	65,754	
32	Total Other	-14,483		-1,724,439	-1,779,262	
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	39,835,469	3,977,509	117,673,438	127,911,617	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2020	End of 2019/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
5,767,811		11,552,453				2
		2,863				3
						4
226,610		1,080,780				5
15		-18				6
51		118				7
5,994,487	-124,334	12,577,715	363,470		-67,147	8
						9
						10
		25,000			75,000	11
						12
	-3,759,647	3,392,995			4,318,910	13
43,414						14
1,046,390					3,637,042	15
1,089,804	-3,759,647	3,417,995			8,030,952	16
						17
						18
					1,600	19
					1,600	20
						21
						22
	-1,590				460	23
	-1,590				460	24
						25
						26
					-1,553	27
						28
					-1,824,133	29
33,158					31,320	30
7,180					69,927	31
40,338					-1,724,439	32
						33
						34
						35
						36
						37
						38
						39
						40
38,022,918	-12,378,042	86,135,184	22,478,603		9,059,651	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2020	End of 2019/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%						
6	Fed ITC	29,702,127			411	520,104	
7	Idaho ITC		411	1,159,014	411	92,648	
8	TOTAL	29,702,127		1,159,014		612,752	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Gas Property (100%	23,316			411	16,200	
11	Idaho ITC		411	204,829	411	16,373	
12	TOTAL PROPERTY	23,316		204,829		32,573	
13							
14							
15							
16							
17							
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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	04/15/2020	End of 2019/Q4

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

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
			5
29,182,023			6
1,066,366			7
30,248,389			8
			9
7,116			10
188,456			11
195,572			12
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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) 04/15/2020	Year/Period of Report End of 2019/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	Deferred Gas Exchange - 1 year	1,125,000				1,125,000
2	Kettle Falls Diesel Leak	112,441	514, 545	319,835	504,472	297,078
3	Bills Pole Rentals	184,035	172	591,655	600,725	193,105
4	Defer Comp Active Execs	8,400,357	128	1,063,486	1,610,808	8,947,679
5	Executive Incent Plan	140,000				140,000
6	Unbilled Revenue	1,580,426	908	336,456		1,243,970
7	WA Energy Recovery Mechanism	9,696,264	Various		4,458,218	14,154,482
8	Misc Deferred Credits	130,806	186, 550	122,858	23,418	31,366
9	Decoupling Deferred Credits	244,984	182	11,791,840	15,073,734	3,526,878
10	WA REC	851,753	186	851,753		
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45						
46						
47	TOTAL	22,466,066		15,077,883	22,271,375	29,659,558

Schedule Page: 269   Line No.: 1   Column: a

FortisBC and Avista exchange volumes of gas on a firm delivery basis during different time periods. Amortization is recorded monthly every year. This contract ends April 15, 2021.

Schedule Page: 269   Line No.: 2   Column: a

Kettle Falls Generation Station undergound fuel leak. Continuing remediation liability is recorded.

Schedule Page: 269   Line No.: 7   Column: a

The Washington Energy Recovery Mechanism (ERM) allows Avista to periodically increase or decrease electric rates. This accounting method tracks differences between actual power supply costs, net of wholesale sales and sales of fuel, and the amount included in base rates.

Schedule Page: 269   Line No.: 9   Column: a

Washington Decoupling for electric and natural gas for a 5 year period beginning January 1, 2015. Idaho approved for an initial term of 3 years beginning January 1, 2016, but extended thru March 31, 2025. Oregon approved similar to Washington and Idaho beginning March 1, 2016.

Decoupling revenue deferrals are recognized during the period they occur, subject to certain limitations. Revenue is expected to be collected within 24 months of the deferral.

Schedule Page: 269   Line No.: 10   Column: a

Washington Docket# UE-170485, 2 year plan

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2020	Year/Period of Report End of 2019/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	327,565,981	6,320,794	
3	Gas	79,958,638	2,688,056	
4	Other	90,350,945	-2,489,467	
5	TOTAL (Enter Total of lines 2 thru 4)	497,875,564	6,519,383	
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	497,875,564	6,519,383	
10	Classification of TOTAL			
11	Federal Income Tax	497,875,564	6,519,383	
12	State Income Tax			
13	Local Income Tax			

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
					5,322,775	339,209,550	2
					4,202,817	86,849,511	3
					949,468	88,810,946	4
					10,475,060	514,870,007	5
							6
							7
							8
					10,475,060	514,870,007	9
							10
					10,475,060	514,870,007	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	04/15/2020	End of 2019/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Electric	3,996,661	7,685,588	1,259,112
4				
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	3,996,661	7,685,588	1,259,112
10	Gas			
11	Gas	-6,680,910	9,126,454	
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	-6,680,910	9,126,454	
18	Other	172,893,400	831,706	
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	170,209,151	17,643,748	1,259,112
20	Classification of TOTAL			
21	Federal Income Tax	170,209,151	17,643,748	1,259,112
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) 04/15/2020	Year/Period of Report End of 2019/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						
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
-40,538					3,010,503	13,393,102	3
							4
							5
							6
							7
							8
-40,538					3,010,503	13,393,102	9
							10
-55,684			4,764			2,385,096	11
							12
							13
							14
							15
							16
-55,684			4,764			2,385,096	17
74,125			9,992,220			163,807,011	18
-22,097			9,996,984		3,010,503	179,585,209	19
							20
-22,097			9,996,984		3,010,503	179,585,209	21
							22
							23

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2020	End of 2019/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	6,245,251	190	1,396,668	342,447	5,191,030
2	Oregon BETC Credit	1,111,427				1,111,427
3	Interest Rate Swaps	28,078,514	427, 175	10,990,229		17,088,285
4	Nez Perce	550,316	557	22,008		528,308
5	Idaho Earnings Test	773,984	191	87,014		686,970
6	Decoupling Rebate	8,609,963	182	9,136,730	628,138	101,371
7	WA ERM	24,748,354			1,054,440	25,802,794
8	ID PCA - 1 year	7,559,909	182, 557	7,833,916	274,007	
9	Deferred Federal ITC - Varies	8,105,848	190	141,936		7,963,912
10	Plant Excess Deferred	410,749,394	410	12,378,938		398,370,456
11	Non Plant Excess Deferred	18,538,128	410	7,448,495		11,089,633
12	Reg Liability MDM System	305,126			284,603	589,729
13	AFUDC Equity Tax Deferral	1,692,177			571,460	2,263,637
14	Exist Meters/ERTS Excess Depr Deferred	188,620			763,783	952,403
15	DSM Tariff Rider	284,139			10,394	294,533
16	Low Income Energy Assistance	1,343,384	242, 908	9,249,947	10,308,427	2,401,864
17	Deferred CS2 & Colstrip O&M	658,833	182	261,474		397,359
18	Reg Liability - Tax Reform Amortization - 1 year	6,449,651	407	11,930,324	9,829,408	4,348,735
19	Reg Liability - Energy Efficiency Assistance				1,532,183	1,532,183
20	Other Regulatory Liabilities - Varies	1,447,796	190	955,292		492,504
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	527,440,814		71,832,971	25,599,290	481,207,133

Schedule Page: 278 Line No.: 1 Column: a

Not amortized

Schedule Page: 278 Line No.: 2 Column: a

Not amortized

Schedule Page: 278 Line No.: 3 Column: a

Mark-to-Market gains and losses for interest rate swap derivatives. Upon settlement, amortization of Regulatory Assets and Liabilities as a component of interest expense over the term of the associated debt.

Schedule Page: 278 Line No.: 6 Column: a

Decoupling rebates are recognized during the period they occur, subject to certain limitations. Rebates are returned to customers within 24 months of the deferral.

Schedule Page: 278 Line No.: 7 Column: a

The Washington Energy Recovery Mechanism allows Avista to periodically increase or decrease electric rates. This accounting method tracks differences between actual power supply costs, net of wholesale sales and sales of fuel, and the amount included in base rates. Avista files yearly on or before April 1 for prudence review by the commission.

Schedule Page: 278 Line No.: 8 Column: a

Avista defers 90 percent of the difference between actual net power supply expenses and the amount included in base retail rates for Idaho customers. Rate adjustments for rebate or surcharge are effective October 1.

Schedule Page: 278 Line No.: 9 Column: a

Noxon ITC - 65 year amortization, ends 2077
Community Solar ITC - 20 year amortization, ends 2035
Nine Mile ITC - 65 year amortization, ends 2080

Schedule Page: 278 Line No.: 10 Column: a

Amortized over remaining book life of plant, estimated 36 years.

Schedule Page: 278 Line No.: 11 Column: a

Washington Gas and Oregon Gas costs are amortized over 1 year. Idaho Electric was offset against Colstrip excess depreciation impacts from Docket# AVU-E-18-03 Order No. 34276.

Schedule Page: 278 Line No.: 13 Column: a

Amortization period not yet determined in all jurisdictions. Idaho Electric Settlement AVU-E-19-04 ordered a transfer to account 254320 for Idaho portion.

Schedule Page: 278 Line No.: 14 Column: a

Washington Docket#s UE-180418 and UG-180419

Schedule Page: 278 Line No.: 16 Column: a

Washington Docket# UE-190912, UG-190920
Idaho Docket# AVU-E-18-12, AVU-G-18-08
Oregon RG 81, Docket No. ADV 1063 (Advice No. 19-10-G)

Schedule Page: 278 Line No.: 18 Column: a

Washington Docket#s UE-170485, UG-170486
Oregon Advice# ADV 923/19-01-G (Schedule 474)
Idaho Case# GNR-U-18-01

Schedule Page: 278 Line No.: 19 Column: a

Avista's contribution in the Energy Assistance Fund as per Idaho Settlement Stipulation Case# AVU-E-19-04 (Page 10, #16 a.ii).

Schedule Page: 278 Line No.: 20 Column: a

FAS 109 ITC - 18 year amortization, ends 2020

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	369,101,530	368,752,670
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	317,589,170	314,532,129
5	Large (or Ind.) (See Instr. 4)	114,530,530	109,846,315
6	(444) Public Street and Highway Lighting	7,447,635	7,538,909
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales	1,502,287	1,385,654
10	TOTAL Sales to Ultimate Consumers	810,171,152	802,055,677
11	(447) Sales for Resale	81,398,279	91,775,470
12	TOTAL Sales of Electricity	891,569,431	893,831,147
13	(Less) (449.1) Provision for Rate Refunds	-2,908,847	10,290,335
14	TOTAL Revenues Net of Prov. for Refunds	894,478,278	883,540,812
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	342,546	299,355
18	(453) Sales of Water and Water Power	344,332	506,000
19	(454) Rent from Electric Property	2,797,207	2,982,930
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	69,178,898	83,116,369
22	(456.1) Revenues from Transmission of Electricity of Others	16,342,483	15,959,856
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	89,005,466	102,864,510
27	TOTAL Electric Operating Revenues	983,483,744	986,405,322

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2020	End of 2019/Q4

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
3,766,048	3,626,870	345,064	340,308	2
				3
3,170,031	3,156,248	42,930	42,618	4
2,047,228	1,772,281	1,305	1,318	5
17,973	18,423	612	594	6
				7
				8
14,708	13,717	148	138	9
9,015,988	8,587,539	390,059	384,976	10
2,942,248	3,777,497			11
11,958,236	12,365,036	390,059	384,976	12
				13
11,958,236	12,365,036	390,059	384,976	14

Line 12, column (b) includes $ -363,995 of unbilled revenues.

Line 12, column (d) includes 22,368 MWH relating to unbilled revenues

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	3,628,426	340,019,212	327,516	11,079	0.0937
3	2 Residential Service	4,502	278,564	348	12,937	0.0619
4	3 Residential Service					
5	12 Res. & Farm Gen. Service	89,352	13,067,088	15,390	5,806	0.1462
6	15 MOPS II Residential					
7	22 Res. & Farm Lg. Gen. Service	40,322	3,705,526	65	620,338	0.0919
8	30 Pumping-Special	11	1,647	3	3,667	0.1497
9	32 Res. & Farm Pumping Service	9,002	1,171,896	1,742	5,168	0.1302
10	48 Res. & Farm Area Lighting	3,526	1,182,765			0.3354
11	49 Area Lighting-High-Press.		-110			
12	56 Centralia Refund					
13	95 Wind Power		149,073			
14	72 Residential Service					
15	73 Residential Service					
16	74 Residential Service					
17	76 Residential Service					
18	77 Residential Service					
19	58A Tax Adjustment		-30,671			
20	58 Tax Adjustment		10,088,369			
21	SubTotal	3,775,141	369,633,359	345,064	10,940	0.0979
22	Residential-Unbilled	-9,093	-531,830			0.0585
23	Total Residential Sales	3,766,048	369,101,529	345,064	10,914	0.0980
24						
25	COMMERCIAL SALES (442)					
26	2 General Service					
27	3 General Service					
28	11 General Service	912,672	105,894,002	38,925	23,447	0.1160
29	12 Res. & Farm Gen. Service					
30	16 MOPS II Commercial					
31	19 Contract-General Service					
32	21 Large General Service	1,798,057	165,813,643	2,753	653,126	0.0922
33	25 Extra Lg. Gen. Service	355,813	23,347,419	13	27,370,231	0.0656
34	28 Contract-Extra Large Serv					
35	31 Pumping Service	103,943	9,219,861	1,239	83,893	0.0887
36	47 Area Lighting-Sod. Vap	4,958	1,476,500			0.2978
37	49 Area Lighting-High-Press.	2,276	663,245			0.2914
38	56 Centralia Refune					
39	95 Wind Power		62,161			
40	74 Large General Service					
41	TOTAL Billed	11,935,867	891,205,435	390,059	30,600	0.0747
42	Total Unbilled Rev.(See Instr. 6)	22,370	363,995	0	0	0.0163
43	TOTAL	11,958,237	891,569,430	390,059	30,658	0.0746

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2020	End of 2019/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		-42,146			
5	58 Tax Adjustment		11,246,682			
6	SubTotal	3,177,719	317,681,367	42,930	74,021	0.1000
7	Commercial-Unbilled	-7,688	-92,198			0.0120
8	Total Commercial	3,170,031	317,589,169	42,930	73,842	0.1002
9						
10	INDUSTRIAL SALES (442)					
11	2 General Service					
12	3 General Service					
13	8 Lg Gen Time of Use					
14	11 General Service	11,445	1,327,097	246	46,524	0.1160
15	12 Res. & Farm Gen. Service					
16	21 Large General Service	157,201	14,397,198	133	1,181,962	0.0916
17	25 Extra Lg. Gen. Service	1,753,119	89,491,163	21	83,481,857	0.0510
18	28 Contract - Extra Large Service					
19	29 Contract Lg. Gen. Service					
20	30 Pumping Service - Special	29,640	2,209,918	49	604,898	0.0746
21	31 Pumping Service	52,432	4,798,785	728	72,022	0.0915
22	32 Pumping Svc Res & Firm	4,043	377,184	128	31,586	0.0933
23	47 Area Lighting-Sod. Vap.	140	35,734			0.2552
24	49 Area Lighting - High-Press	57	15,975			0.2803
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		-1,404			
33	58 Tax Adjustment		890,017			
34	SubTotal	2,008,077	113,542,507	1,305	1,538,756	0.0565
35	Industrial-Unbilled	39,151	988,023			0.0252
36	Total Industrial	2,047,228	114,530,530	1,305	1,568,757	0.0559
37						
38	STREET AND HWY LIGHTING (444)					
39	6 Mercury Vapor St. Ltg.					
40	7 HP Sodium Vap. St. Ltg					
41	TOTAL Billed	11,935,867	891,205,435	390,059	30,600	0.0747
42	Total Unbilled Rev.(See Instr. 6)	22,370	363,995	0	0	0.0163
43	TOTAL	11,958,237	891,569,430	390,059	30,658	0.0746

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	11 General Service					
2	41 Co-Owned St. Lt. Service	50	11,523	6	8,333	0.2305
3	42 Co-Owned St. Lt. Service	14,769	6,839,291	505	29,246	0.4631
4	High-Press. Sod. Vap.					
5	43 Cust-Owned St. Lt. Energy					
6	and Maint. Service					
7	44 Cust-Owned St. Lt. Energy	384	64,030	25	15,360	0.1667
8	and Maint. Svce - High-Pres					
9	Sodium Vapor					
10	45 Cust. Owned St. Lt. Energy Svc	778	64,245	14	55,571	0.0826
11	46 Cust. Owned St. Lt. Energy Svc	1,992	209,797	62	32,129	0.1053
12	58A Tax Adjustment		-718			
13	58 Tax Adjustment		259,468			
14	SubTotal	17,973	7,447,636	612	29,368	0.4144
15	Street & Hwy Lighting-Unbilled					
16	Total Street & Hwy Lighting	17,973	7,447,636	612	29,368	0.4144
17						
18	OTHER SALES TO PUBLIC					
19	(445)					
20	None					
21						
22	INTERDEPARTMENTAL SALES	14,708	1,501,430	148	99,378	0.1021
23	58 Tax Adjustment		857			
24	Total Interdepartmental	14,708	1,502,287	148	99,378	0.1021
25						
26	SALES FOR RESALE (447)					
27	61 Sales to Other Utilities (NDA)	2,942,248	81,398,279			0.0277
28						
29						
30	Total Sales for Resale	2,942,248	81,398,279			0.0277
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	11,935,867	891,205,435	390,059	30,600	0.0747
42	Total Unbilled Rev.(See Instr. 6)	22,370	363,995	0	0	0.0163
43	TOTAL	11,958,237	891,569,430	390,059	30,658	0.0746

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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	04/15/2020	End of 2019/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	SF	Tariff 9			
	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.
243,539		8,676,272		8,676,272	1
	694,290			694,290	2
41		1,187		1,187	3
4,000		276,400		276,400	4
1,565		28,083		28,083	5
24,213		986,706		986,706	6
2,596		97,288		97,288	7
80,740		3,425,000		3,425,000	8
56		1,979		1,979	9
5		178		178	10
20,030		624,514		624,514	11
272,928		10,524,687		10,524,687	12
46,700		1,370,132		1,370,132	13
400		70,000		70,000	14
0	0	0	0	0	
2,942,248	2,842,023	90,106,545	-11,550,289	81,398,279	
2,942,248	**2,842,023**	**90,106,545**	**-11,550,289**	**81,398,279**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2020	Year/Period of Report End of 2019/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	Chelan County PUD No. 1	LF	Tariff 12			
2	Citigroup Energy, Inc.	SF	Tariff 9			
3	Clatskanie Peoples PUD	SF	Tariff 9			
4	ConocoPhillips	SF	Tariff 9			
5	Direct Energy Business Marketing, LLC	LF	Tariff 9			
6	Douglas County PUD No. 1	SF	Tariff 9			
7	Douglas County PUD No. 1	LF	Tariff 12			
8	EDF Trading North America, LLC	SF	Tariff 9			
9	Energy Keepers, Inc.	SF	Tariff 9			
10	Eugene Water & Electric Board	SF	Tariff 9			
11	Evergy Kansas Central, Inc	SF	Tariff 9			
12	Exelon Generation Company, LLC	SF	Tariff 9			
13	Grant County PUD No. 2	LF	Tariff 12			
14	Gridforce Energy Management, LLC	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 ($) (h)	REVENUE: Energy Charges ($) (i)	REVENUE: Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
5		132		132	1
19,552		1,679,401		1,679,401	2
2,051		66,639		66,639	3
67,740		1,996,682		1,996,682	4
183,998		7,076,862		7,076,862	5
26,790		1,225,885		1,225,885	6
4		12		12	7
137,664		4,227,794		4,227,794	8
27,554		662,950		662,950	9
17,110		792,463		792,463	10
2,200		55,450		55,450	11
26,105		1,378,170		1,378,170	12
2		21		21	13
364		12,455		12,455	14
0	0	0	0	0	
2,942,248	2,842,023	90,106,545	-11,550,289	81,398,279	
2,942,248	**2,842,023**	**90,106,545**	**-11,550,289**	**81,398,279**	

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	Idaho Power Company	SF	Tariff 9			
2	Idaho Power Company	LF	Tariff 12			
3	Idaho Power Company Balancing	SF	Tariff 9			
4	Idaho Power Company Balancing	IF	Tariff 9			
5	Kootenai Electric Cooperative	LF	Tariff 8			
6	Macquarie Energy, LLC	SF	Tariff 9			
7	Macquarie Energy, LLC	IF	Tariff 9			
8	Mizuho Securities USA, Inc.	OS	NA			
9	Morgan Stanley Capital Group, Inc.	SF	Tariff 9			
10	Morgan Stanley Capital Group, Inc.	IF	Tariff 9			
11	Morgan Stanley Capital Group, Inc.	IF	Tariff 9			
12	Morgan Stanley Capital Group, Inc.	SF	Tariff 9			
13	Morgan Stanley Capital Group, Inc.	SF	Tariff 9			
14	Morgan Stanley Capital Group, Inc.	SF	Tariff 9			
	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 ($) (h)	REVENUE: Energy Charges ($) (i)	REVENUE: Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
600		11,950		11,950	1
18		497		497	2
7,317		174,535		174,535	3
3,171		97,079		97,079	4
1,266		60,881		60,881	5
111,063		3,254,199		3,254,199	6
56		1,745		1,745	7
			-13,487,622	-13,487,622	8
71,087		2,239,421		2,239,421	9
4,551		447,735		447,735	10
342,443		9,305,371		9,305,371	11
	275,940			275,940	12
	633,481			633,481	13
	364,896			364,896	14
0	0	0	0	0	
2,942,248	2,842,023	90,106,545	-11,550,289	81,398,279	
2,942,248	**2,842,023**	**90,106,545**	**-11,550,289**	**81,398,279**	

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	NaturEner Power Watch, LLC	LF	Tariff 9			
2	NaturEner Power Watch, LLC	LF	Tariff 9			
3	NaturEner Power Watch, LLC	LF	Tariff 12			
4	NaturEner Power Watch, LLC	SF	Tariff 9			
5	Nevada Power Company	SF	Tariff 9			
6	NorthWestern Energy LLC	SF	Tariff 9			
7	Northwestern Energy LLC	IF	Tariff 9			
8	NorthWestern Energy LLC	LF	Tariff 12			
9	NorthWestern Energy LLC	SF	Tariff 9			
10	NorthWestern Energy LLC	LF	Tariff 9			
11	Okanogan County PUD	SF	Tariff 9			
12	PacifiCorp	SF	Tariff 9			
13	PacifiCorp	LF	Tariff 12			
14	PacifiCorp	LF	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.
5		373		373	1
173		8,111		8,111	2
121		3,148		3,148	3
	45,602			45,602	4
2,085		214,120		214,120	5
88,646		3,022,208		3,022,208	6
353		16,140		16,140	7
40		1,194		1,194	8
	2,360			2,360	9
7,067		252,854		252,854	10
12,045		482,300		482,300	11
138,095		5,284,535		5,284,535	12
199		6,724		6,724	13
4,500		160,907		160,907	14
0	0	0	0	0	
2,942,248	2,842,023	90,106,545	-11,550,289	81,398,279	
2,942,248	**2,842,023**	**90,106,545**	**-11,550,289**	**81,398,279**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2020	Year/Period of Report End of 2019/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	IF	Tariff 9			
2	Pend Oreille Public Utility District	IF	Tariff 9			
3	Pend Oreille Public Utility District	IF	Tariff 9			
4	Pend Oreille Public Utility District	SF	Tariff 9			
5	Portland General Electric Company	SF	Tariff 9			
6	Portland General Electric Company	LF	Tariff 12			
7	Powerex	SF	Tariff 9			
8	Powerex	IF	Tariff 9			
9	Puget Sound Energy	LF	Tariff 9			
10	Puget Sound Energy	SF	Tariff 9			
11	Puget Sound Energy	LF	Tariff 12			
12	Rainbow Energy Marketing	SF	Tariff 9			
13	Rainbow Energy Marketing	IF	Tariff 9			
14	Sacramento Municipal Utility District	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.
	665,451			665,451	1
229		9,561		9,561	2
17,975		587,710		587,710	3
64,469		2,505,153		2,505,153	4
98,505		3,461,422		3,461,422	5
91		3,112		3,112	6
100,365		3,636,844		3,636,844	7
166		1,871		1,871	8
20,562		735,574		735,574	9
146,470		6,311,973		6,311,973	10
16		694		694	11
200		19,600		19,600	12
189		37,514		37,514	13
15		463		463	14
0	0	0	0	0	
2,942,248	2,842,023	90,106,545	-11,550,289	81,398,279	
2,942,248	**2,842,023**	**90,106,545**	**-11,550,289**	**81,398,279**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2020	End of 2019/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	Seattle City Light	SF	Tariff 9			
2	Seattle City Light	LF	Tariff 9			
3	Seattle City Light	LF	Tariff 12			
4	Shell Energy N.A.	SF	Tariff 9			
5	Shell Energy N.A.	SF	Tariff 9			
6	Sierra Pacific Power Company	LF	Tariff 12			
7	Snohomish County PUD	SF	Tariff 9			
8	Sovereign Power	LF	Tariff 9			
9	Sovereign Power	LF	Tariff 9			
10	Tacoma Power	SF	Tariff 9			
11	Tacoma Power	LF	Tariff 9			
12	Tacoma Power	LF	Tariff 12			
13	Talen Energy Montana, LLC	LF	Tariff 9			
14	Tenaska Power Services Co.	SF	Tariff 9			
	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.
12,020		408,165		408,165	1
445		9,302		9,302	2
3		54		54	3
122,961		3,443,327		3,443,327	4
	10,935			10,935	5
5		117		117	6
36,063		2,674,320		2,674,320	7
	149,068			149,068	8
13,629		438,066		438,066	9
10,998		286,293		286,293	10
1,287		29,440		29,440	11
4		153		153	12
16,063		574,667		574,667	13
228		10,275		10,275	14
0	0	0	0	0	
2,942,248	2,842,023	90,106,545	-11,550,289	81,398,279	
2,942,248	**2,842,023**	**90,106,545**	**-11,550,289**	**81,398,279**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2020	Year/Period of Report End of 2019/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	The Energy Authority	SF	Tariff 9			
2	The Energy Authority	IF	Tariff 9			
3	TransAlta Energy Marketing	SF	Tariff 9			
4	TransAlta Energy Marketing	IF	Tariff 9			
5	Turlock Irrigation Dist	SF	Tariff 9			
6	Vitol, Inc.	SF	Tariff 9			
7	Wells Fargo securities, LLC	OS	NA			
8	Western Area Power Admin	LF	Tariff 12			
9	IntraCompany Wheeling	LF				
10	IntraCompany Generation	LF				
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	04/15/2020	End of 2019/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.
35,152		1,619,283		1,619,283	1
32		1,270		1,270	2
233,284		7,740,556		7,740,556	3
122		6,405		6,405	4
45		885		885	5
7,800		289,550		289,550	6
			-15,619,811	-15,619,811	7
2		44		44	8
		-15,040,487	15,040,487		9
			2,516,657	2,516,657	10
					11
					12
					13
					14
0	0	0	0	0	
2,942,248	2,842,023	90,106,545	-11,550,289	81,398,279	
2,942,248	**2,842,023**	**90,106,545**	**-11,550,289**	**81,398,279**	

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: 310.1 Line No.: 1 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.1 Line No.: 5 Column: b
Contract terminates December 31, 2019.

Schedule Page: 310.1 Line No.: 7 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.1 Line No.: 11 Column: a
Formerly Westar Energy, Inc. Name changed to Evergy Kansas Central, Inc. on 10/09/2019.

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

Schedule Page: 310.1 Line No.: 14 Column: b
NWPP Reserve Sharing Sales

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

Schedule Page: 310.2 Line No.: 4 Column: b
Financially Settled Transmission Losses

Schedule Page: 310.2 Line No.: 5 Column: b
Kootenai Contract Terminates March 31,2024

Schedule Page: 310.2 Line No.: 7 Column: b
Financially Settled Transmission Losses

Schedule Page: 310.2 Line No.: 8 Column: b
Financial SWAP

Schedule Page: 310.2 Line No.: 10 Column: b
Financially Settled Transmission Losses

Schedule Page: 310.2 Line No.: 11 Column: b
Resource Contingent Bundled REC - Energy and Green Attributes 03/01/2019-12/31/2023.

Schedule Page: 310.2 Line No.: 12 Column: b
Capacity

Schedule Page: 310.2 Line No.: 13 Column: b
Capacity

Schedule Page: 310.2 Line No.: 14 Column: b
Reserves

Schedule Page: 310.3 Line No.: 1 Column: b
Financially Settled Transmission Losses

Schedule Page: 310.3 Line No.: 2 Column: b
Energy Associated with Dynamic Capacity and Energy Service Agreement

Schedule Page: 310.3 Line No.: 3 Column: b
NWPP Reserve Sharing Sales

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

Schedule Page: 310.3 Line No.: 7 Column: b
Financially Settled Transmission Losses

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

Schedule Page: 310.3 Line No.: 9 Column: b
Reserves

Schedule Page: 310.3 Line No.: 10 Column: b
NorthWestern Energy LLC sale expires October 31, 2023.

Schedule Page: 310.3 Line No.: 13 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.3 Line No.: 14 Column: b
PacifiCorp sale terminates October 31, 2023.

Schedule Page: 310.4 Line No.: 1 Column: b
Contract expires 9/30/2021.

Schedule Page: 310.4 Line No.: 2 Column: b
Contract expires 9/30/2021.

Schedule Page: 310.4 Line No.: 6 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.4 Line No.: 8 Column: b
Financially Settled Transmission Losses

Schedule Page: 310.4 Line No.: 9 Column: b
Puget Sound Energy sale terminates October 31, 2023.

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
Financially Settled Transmission Losses

Schedule Page: 310.5 Line No.: 3 Column: b
NWPP Reserve Sharing Sales

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

Schedule Page: 310.5 Line No.: 6 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.5 Line No.: 8 Column: b
Sovereign Power contract terminates 9-30-2021

Schedule Page: 310.5 Line No.: 9 Column: b
Sovereign Power Contract terminates 9-30-2021

Schedule Page: 310.5 Line No.: 11 Column: b
Financially Settled Transmission Losses

Schedule Page: 310.5 Line No.: 12 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.5 Line No.: 13 Column: b
Talen Energy sale terminates October 31,2023.

Schedule Page: 310.6 Line No.: 2 Column: b
Financially Settled Transmission Losses

Schedule Page: 310.6 Line No.: 4 Column: b
Financially Settled Transmission Losses

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

Schedule Page: 310.6 Line No.: 8 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.6 Line No.: 9 Column: b

IntraCompany Wheeling terminates 09/30/2023.

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

IntraCompany Generation - Sale of Ancillary Services.

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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) 04/15/2020	Year/Period of Report End of 2019/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	355,496	345,980
5	(501) Fuel	30,554,741	27,775,865
6	(502) Steam Expenses	3,760,759	4,055,476
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	888,160	934,119
10	(506) Miscellaneous Steam Power Expenses	3,107,546	3,306,135
11	(507) Rents	15,079	34,621
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	38,681,781	36,452,196
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	506,378	479,496
16	(511) Maintenance of Structures	759,694	529,070
17	(512) Maintenance of Boiler Plant	5,794,165	5,335,916
18	(513) Maintenance of Electric Plant	638,851	1,458,737
19	(514) Maintenance of Miscellaneous Steam Plant	1,222,605	466,688
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	8,921,693	8,269,907
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	47,603,474	44,722,103
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	2,754,616	2,619,276
45	(536) Water for Power	930,038	1,156,275
46	(537) Hydraulic Expenses	9,607,953	8,434,948
47	(538) Electric Expenses	5,884,654	5,741,274
48	(539) Miscellaneous Hydraulic Power Generation Expenses	1,070,877	1,148,251
49	(540) Rents	6,428,232	6,344,885
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	26,676,370	25,444,909
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	792,626	1,152,932
54	(542) Maintenance of Structures	657,326	406,234
55	(543) Maintenance of Reservoirs, Dams, and Waterways	1,636,470	2,130,811
56	(544) Maintenance of Electric Plant	2,824,428	3,020,296
57	(545) Maintenance of Miscellaneous Hydraulic Plant	947,013	1,154,554
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	6,857,863	7,864,827
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	33,534,233	33,309,736

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	228,562	344,393
63	(547) Fuel	71,500,955	63,237,753
64	(548) Generation Expenses	2,231,850	2,286,764
65	(549) Miscellaneous Other Power Generation Expenses	1,254,645	350,643
66	(550) Rents	47,044	-33,822
67	TOTAL Operation (Enter Total of lines 62 thru 66)	75,263,056	66,185,731
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	651,663	585,982
70	(552) Maintenance of Structures	133,426	68,190
71	(553) Maintenance of Generating and Electric Plant	7,094,951	3,927,388
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	426,816	358,281
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	8,306,856	4,939,841
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	83,569,912	71,125,572
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	144,313,775	136,263,902
77	(556) System Control and Load Dispatching	660,144	598,799
78	(557) Other Expenses	48,105,794	75,953,261
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	193,079,713	212,815,962
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	357,787,332	361,973,373
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	1,931,225	1,868,255
84			
85	(561.1) Load Dispatch-Reliability	60,658	39,842
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,227,913	1,045,793
87	(561.3) Load Dispatch-Transmission Service and Scheduling	1,002,020	1,017,880
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	663,145	506,799
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	499,947	460,703
94	(563) Overhead Lines Expenses	370,882	438,645
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	17,252,820	17,529,488
97	(566) Miscellaneous Transmission Expenses	2,805,371	2,414,323
98	(567) Rents	170,983	189,784
99	TOTAL Operation (Enter Total of lines 83 thru 98)	25,984,964	25,511,512
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	499,807	538,347
102	(569) Maintenance of Structures	570,168	632,439
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	823,646	697,405
108	(571) Maintenance of Overhead Lines	1,002,431	1,346,716
109	(572) Maintenance of Underground Lines	47	188
110	(573) Maintenance of Miscellaneous Transmission Plant	73,382	91,275
111	TOTAL Maintenance (Total of lines 101 thru 110)	2,969,481	3,306,370
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	28,954,445	28,817,882

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2020	End of 2019/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	3,341,232	2,922,781
135	(581) Load Dispatching		
136	(582) Station Expenses	768,839	688,490
137	(583) Overhead Line Expenses	2,206,002	2,245,066
138	(584) Underground Line Expenses	1,618,684	1,470,722
139	(585) Street Lighting and Signal System Expenses	5,265	4,104
140	(586) Meter Expenses	1,744,750	1,559,238
141	(587) Customer Installations Expenses	829,754	709,280
142	(588) Miscellaneous Expenses	7,149,060	6,977,162
143	(589) Rents	353,727	364,153
144	TOTAL Operation (Enter Total of lines 134 thru 143)	18,017,313	16,940,996
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	1,230,289	1,099,667
147	(591) Maintenance of Structures	532,672	384,683
148	(592) Maintenance of Station Equipment	769,884	721,467
149	(593) Maintenance of Overhead Lines	10,873,805	9,778,342
150	(594) Maintenance of Underground Lines	804,137	802,329
151	(595) Maintenance of Line Transformers	359,548	333,165
152	(596) Maintenance of Street Lighting and Signal Systems	158,130	181,548
153	(597) Maintenance of Meters	39,048	25,312
154	(598) Maintenance of Miscellaneous Distribution Plant	536,940	185,260
155	TOTAL Maintenance (Total of lines 146 thru 154)	15,304,453	13,511,773
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	33,321,766	30,452,769
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	114,406	119,601
160	(902) Meter Reading Expenses	2,042,787	2,228,677
161	(903) Customer Records and Collection Expenses	7,885,571	7,653,010
162	(904) Uncollectible Accounts	208,808	2,043,405
163	(905) Miscellaneous Customer Accounts Expenses	159,633	225,469
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	10,411,205	12,270,162

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2020	End of 2019/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	37,686,359	36,541,837
169	(909) Informational and Instructional Expenses	1,153,181	898,729
170	(910) Miscellaneous Customer Service and Informational Expenses	250,163	340,964
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	39,089,703	37,781,530
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	25,372,504	25,654,940
182	(921) Office Supplies and Expenses	4,732,387	4,547,185
183	(Less) (922) Administrative Expenses Transferred-Credit	102,345	121,108
184	(923) Outside Services Employed	10,107,690	9,023,010
185	(924) Property Insurance	1,451,884	1,281,469
186	(925) Injuries and Damages	4,177,429	4,285,035
187	(926) Employee Pensions and Benefits	30,761,884	28,396,015
188	(927) Franchise Requirements	1,200	1,200
189	(928) Regulatory Commission Expenses	6,380,843	5,724,225
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses		
192	(930.2) Miscellaneous General Expenses	4,995,151	4,027,640
193	(931) Rents	312,788	417,575
194	TOTAL Operation (Enter Total of lines 181 thru 193)	88,191,415	83,237,186
195	Maintenance		
196	(935) Maintenance of General Plant	12,182,064	11,842,584
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	100,373,479	95,079,770
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	569,937,930	566,434,201

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	Avangrid Renewables, LLC	LF	NWPP			
4	Avangrid Renewables, LLC	OS	Tariff 9			
5	BP Energy	SF	Tariff 9			
6	Bonneville Power Administration	LF	WNP#3 Agr.			
7	Bonneville Power Administration	SF	Tariff 9			
8	Bonneville Power Administration	LF	NWPP			
9	Bonneville Power Administration	LF	Tariff 8			
10	Bonneville Power Administration	LF	Tariff 8			
11	Bonneville Power Administration	OS	BPA OATT			
12	Brookfield Energy Marketing LP	SF	Tariff 9			
13	CP Energy Marketing (US) Inc.	SF	Tariff 9			
14	California Independent System Operator	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.
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	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
(g)	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
42,346				1,644,997		1,644,997	1
107,344				2,102,503		2,102,503	2
2				50		50	3
					7,500	7,500	4
48				36,000		36,000	5
173,447				7,910,918		7,910,918	6
159,197				3,426,240		3,426,240	7
131				3,750		3,750	8
24,264				938,351		938,351	9
1,657				35,417		35,417	10
					36,322	36,322	11
2,776				158,324		158,324	12
366				27,515		27,515	13
21,707				960,967		960,967	14
5,344,702	9,046	429,475	27,343,304	126,812,614	-9,842,143	144,313,775	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2020	End of 2019/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	Calpine Energy Services LP	SF	Tariff 9			
2	City of Spokane	LU	PURPA			
3	City of Spokane	IU	PURPA			
4	Chelan County PUD	IU	Rocky Reach			
5	Chelan County PUD	IU	Rocky Reach			
6	Chelan County PUD	SF	Tariff 9			
7	Chelan County PUD	LF	NWPP			
8	Chelan County PUD	IU	Chelan Sys			
9	Clark Fork Hydro	LU	PURPA			
10	Clatskanie PUD	SF	Tariff 9			
11	Clearwater Paper Company	IU	PURPA			
12	Clearwater Power Company	RQ	NA			
13	Community Solar	LU	PURPA			
14	ConocoPhillips 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.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
13,452				448,093		448,093	1
37,550				2,141,849		2,141,849	2
121,032				5,574,934		5,574,934	3
2,603							4
-23,972							5
24,216				686,900		686,900	6
2				50		50	7
380,706			15,276,675			15,276,675	8
868				50,030		50,030	9
704				8,796		8,796	10
356,248				8,728,076		8,728,076	11
147				13,888		13,888	12
561				27,282		27,282	13
15,600				506,200		506,200	14
5,344,702	9,046	429,475	27,343,304	126,812,614	-9,842,143	144,313,775	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2020	Year/Period of Report End of 2019/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	Deep Creek Energy, LLC	IU	PURPA			
2	Direct Energy Business Marketing, LLC	SF	Tariff 9			
3	Douglas County PUD No. 1	LU	Wells			
4	Douglas County PUD No. 1	SF	Tariff 9			
5	Douglas County PUD No. 1	SF	Tariff9			
6	Douglas County PUD No. 1	LF	NWPP			
7	Douglas County PUD No. 1	EX	Tariff 9			
8	EDF Trading No America	SF	Tariff 9			
9	Enel X North America, Inc.	LU	PURPA			
10	Energy Keepers, Inc.	SF	Tariff 9			
11	Eugene Water & Electric Board	SF	Tariff 9			
12	Exelon Generation Company, LLC	SF	Tariff 9			
13	Exelon Generation Company, LLC	OS	Tariff 9			
14	Ford Hydro Limited Partnership	LU	PURPA			
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
163				5,579		5,579	1
960				168,000		168,000	2
366,833			2,629,006			2,629,006	3
44,293				1,202,991		1,202,991	4
				38,166		38,166	5
2				50		50	6
		420,480			281,629	281,629	7
12,565				453,006		453,006	8
1							9
90				1,980		1,980	10
1,217				24,427		24,427	11
26,826				576,155		576,155	12
					125	125	13
3,805				222,047		222,047	14
5,344,702	9,046	429,475	27,343,304	126,812,614	-9,842,143	144,313,775	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2020	Year/Period of Report End of 2019/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	Grant County PUD No. 2	LU	Priest Rapids			
2	Grant County PUD No. 2	LF	NWPP			
3	Grant County PUD No. 2	EX	FERC #104			
4	Gridforce Energy Management, LLC	LF	NWPP			
5	Hydro Technology Systems	IU	PURPA			
6	Idaho County Power & Light	LU	PURPA			
7	Idaho Power Company	SF	Tariff 9			
8	Idaho Power Company	IF	Tariff 9			
9	Idaho Power Company Balancing	SF	Tariff 9			
10	Inland Power & Light Company	RQ	208			
11	Kootenai Electric Cooperative	LF	Tariff 8			
12	Macquarie Energy LLC	SF	Tariff 9			
13	Mizuho Securities USA, Inc.	OS	NA			
14	Morgan Stanley Capital Group	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.
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)	
279,934			9,437,623			9,437,623	1
7				177		177	2
					-27,255	-27,255	3
5				154		154	4
8,903				484,804		484,804	5
2,752				141,730		141,730	6
170,895				10,099,644		10,099,644	7
85				10,496		10,496	8
5,862				70,122		70,122	9
139				10,153		10,153	10
1,235				46,732		46,732	11
39,822				1,701,134		1,701,134	12
					-4,240,268	-4,240,268	13
37,315				1,430,945		1,430,945	14
5,344,702	9,046	429,475	27,343,304	126,812,614	-9,842,143	144,313,775	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2020	End of 2019/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	Nevada Power Company	SF	Tariff 9			
2	Nevada Power Company	IF	Tariff 9			
3	NextEra Energy Power Marketing LLC	SF	Tariff 9			
4	NorthWestern Energy LLC	SF	Tariff 9			
5	NorthWestern Energy LLC	LF	NWPP			
6	NorthWestern Energy LLC	IF	Tariff 9			
7	Okanogan County PUD No. 1	SF	Tariff 9			
8	PacifiCorp	SF	Tariff 9			
9	PacifiCorp	LF	NWPP			
10	PacifiCorp	IF	Tariff 9			
11	Palouse Wind LLC	LU	PPA			
12	Pend Oreille County PUD No. 1	SF	Pend O'			
13	Pend Oreille County PUD No. 1	IF	Pend O'			
14	Pend Oreille County PUD No. 1	IF	Pend O'			
	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.
				2,012		2,012	1
1				58		58	2
2,600				77,200		77,200	3
19,769				638,867		638,867	4
18				488		488	5
433				13,765		13,765	6
9,170				227,687		227,687	7
48,980				1,670,097		1,670,097	8
35				990		990	9
947				28,839		28,839	10
302,136				18,596,471		18,596,471	11
116,842				3,404,731		3,404,731	12
16,380				441,253		441,253	13
6,712				204,627		204,627	14
5,344,702	9,046	429,475	27,343,304	126,812,614	-9,842,143	144,313,775	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2020	Year/Period of Report End of 2019/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	Phillips Ranch	LU	PURPA			
2	Portland General Electric Company	EX	Tariff 9			
3	Portland General Electric Company	SF	Tariff 9			
4	Portland General Electric Company	LF	NWPP			
5	Portland General Electric Company	IF	Tariff 9			
6	Powerex Corp	SF	Tariff 9			
7	Puget Sound Energy	SF	Tariff 9			
8	Puget Sound Energy	LF	NWPP			
9	Puget Sound Energy	IF	Tariff 9			
10	Rathdrum Power LLC	LU	Lancaster			
11	Seattle City Light	SF	Tariff 9			
12	Seattle City Light	LF	NWPP			
13	Sheep Creek Hydro	LU	PURPA			
14	Shell Energy	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.
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)	
25				689		689	1
	8,996	8,995					2
56,060				2,798,915		2,798,915	3
30				818		818	4
9,016				272,044		272,044	5
101,729				4,919,827		4,919,827	6
72,572				3,064,624		3,064,624	7
31				839		839	8
56				2,013		2,013	9
1,798,402				28,176,399		28,176,399	10
13,435				309,515		309,515	11
13				358		358	12
6,436				284,579		284,579	13
97,508				2,661,302		2,661,302	14
5,344,702	9,046	429,475	27,343,304	126,812,614	-9,842,143	144,313,775	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2020	End of 2019/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	Snohomish County PUD No. 1	SF	Tariff 9			
2	Sovereign Power	LF	Sovereign			
3	Spokane County	LU	PURPA			
4	Stimson Lumber	IU	PURPA			
5	Tacoma Power	SF	Tariff 9			
6	Tacoma Power	LF	NWPP			
7	Talen Energy Marketing	SF	Tariff 9			
8	Temp Diesel	IU	PURPA			
9	The City of Cove	LU	PURPA			
10	The Energy Authority	SF	Tariff 9			
11	TransAlta Energy Marketing	SF	Tariff 9			
12	Turlock Irrigation District	SF	Tariff 9			
13	Vitol Inc.	SF	Tariff 9			
14	Wells Fargo Securities, LLC	OS	NA			
	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)	
18,540				397,755		397,755	1
7,539				204,372		204,372	2
1,283				57,203		57,203	3
37,288				1,940,817		1,940,817	4
8,255				227,820		227,820	5
3				80		80	6
-80				-3,200		-3,200	7
103							8
2,716				115,739		115,739	9
14,585				382,209		382,209	10
94,122				3,220,607		3,220,607	11
4,901				40,933		40,933	12
8,600				253,650		253,650	13
					-8,416,853	-8,416,853	14
5,344,702	9,046	429,475	27,343,304	126,812,614	-9,842,143	144,313,775	

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	Western Area Power Admin-Sierra Nev Re	SF	Tariff 9			
2	IntraCompany Generation Services	OS	OATT			
3	Other - Inadvertent Interchange	EX				
4						
5						
6						
7						
8						
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		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)	
800				56,000		56,000	1
					2,516,657	2,516,657	2
	50						3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
5,344,702	9,046	429,475	27,343,304	126,812,614	-9,842,143	144,313,775	

Schedule Page: 326 Line No.: 3 Column: a
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
Schedule Page: 326 Line No.: 4 Column: a
Pondage
Schedule Page: 326 Line No.: 6 Column: a
BPA Contract Terminates June 30, 2019
Schedule Page: 326 Line No.: 8 Column: a
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
Schedule Page: 326 Line No.: 9 Column: a
BPA Contract Terminates September 30, 2028
Schedule Page: 326 Line No.: 10 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.: 11 Column: a
Ancillary Services - Spinning & Supplemental
Schedule Page: 326.1 Line No.: 7 Column: a
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
Schedule Page: 326.1 Line No.: 12 Column: a
Service to Ahsahka, Idaho from Clearwater Power Company. No demand charges associated with the agreement.
Schedule Page: 326.2 Line No.: 5 Column: a
Dutch Henry Energy Imbalance
Schedule Page: 326.2 Line No.: 6 Column: a
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
Schedule Page: 326.2 Line No.: 7 Column: a
Exchange
Schedule Page: 326.2 Line No.: 13 Column: a
Pondage
Schedule Page: 326.3 Line No.: 2 Column: a
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
Schedule Page: 326.3 Line No.: 4 Column: a
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
Schedule Page: 326.3 Line No.: 8 Column: a
Financially Settled Transmission Losses
Schedule Page: 326.3 Line No.: 10 Column: a
Service to Deer Lake from Inland Power and Light. No demand charges associated with the agreement.
Schedule Page: 326.3 Line No.: 11 Column: a
Kootenai Contract Terminates March 31, 2024
Schedule Page: 326.3 Line No.: 13 Column: a
Financial SWAP
Schedule Page: 326.4 Line No.: 1 Column: a
Energy Imbalance Charges
Schedule Page: 326.4 Line No.: 2 Column: a
Financially Settled Transmission Losses
Schedule Page: 326.4 Line No.: 5 Column: a
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
Schedule Page: 326.4 Line No.: 6 Column: a
Financially Settled Transmission Losses
Schedule Page: 326.4 Line No.: 9 Column: a
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
Schedule Page: 326.4 Line No.: 10 Column: a
Financially Settled Transmission Losses

Schedule Page: 326.4 Line No.: 13 Column: a

Pend Oreille County PUD contract expires 09/30/2021. Deviation Energy.

Schedule Page: 326.5 Line No.: 4 Column: a

Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.

Schedule Page: 326.5 Line No.: 5 Column: a

Financially Settled Transmission Losses

Schedule Page: 326.5 Line No.: 8 Column: a

Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.

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

Financially Settled Transmission Losses

Schedule Page: 326.5 Line No.: 12 Column: a

Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.

Schedule Page: 326.6 Line No.: 2 Column: a

Sovereign Contract Terminates September 30, 2021. Deviation Energy.

Schedule Page: 326.6 Line No.: 6 Column: a

Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.

Schedule Page: 326.6 Line No.: 14 Column: a

Financial SWAP

Schedule Page: 326.7 Line No.: 2 Column: a

Ancillary Services

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2020	Year/Period of Report End of 2019/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	EDF Trading N.A. LLC	Avista Corporation	NorthWestern Energy	NF
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	EDF Trading N.A. LLC	NorthWestern Energy	Idaho Power Company	NF
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	Idaho Power Company	Grant County PUD	Idaho Power Company	NF
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	Idaho Power Company	Chelan County PUD	Idaho Power Company	NF
29	PacifiCorp	PacifiCorp	PacifiCorp	SFP
30	Idaho Power Company	Avista Corporation	Idaho Power Company	SFP
31	Idaho Power Company	Avista Corporation	Idaho Power Company	NF
32	Idaho Power Company	Bonneville Power Administration	Idaho Power Company	SFP
33	Macquarie Energy LLC	Grant County PUD	Idaho Power Company	NF
34	Idaho Power Company	PacifiCorp	Idaho Power Comany	SFP
	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 No. 182	Dry Gulch	Dry Gulch		58,319	58,319	1
FERC Trf No. 8	Chelan-Stratford	Stratford		205,669	205,669	2
FERC Trf No. 8	Chelan-Stratford	Stratford		205,654	205,654	3
FERC No. 104	Stratford	Coulee City/Wilson		90,110	90,110	4
FERC Trf No. 8	AVA.BPAT	AVA.SYS	3	2,809	2,809	5
FERC Trf No. 8	AVA.BPAT	AVA.SYS	3	3,702	3,702	6
FERC Trf No. 8	AVA.BPAT	AVA.SYS	4	6,370	6,370	7
FERC Trf No. 8	AVA.BPAT	AVA.SYS		2,029,368	2,029,368	8
						9
						10
						11
FERC Trf No. 8				15	15	12
						13
FERC Trf No. 8				563	563	14
FERC Trf No. 8				12,209	12,209	15
FERC Trf No. 8				25	25	16
FERC Trf No. 8				1,421	1,421	17
FERC Trf No. 8				12	12	18
FERC Trf No. 8				9,456	9,456	19
FERC Trf No. 8				258	258	20
FERC Trf No. 8				28,590	28,590	21
FERC Trf No. 8				38,171	38,171	22
FERC Trf No. 8				880	880	23
FERC Trf No. 8				8,421	8,421	24
FERC Trf No. 8				24	24	25
FERC Trf No. 8				5,291	5,291	26
FERC Trf No. 8				35	35	27
FERC Trf No. 8				200	200	28
FERC Trf No. 8				3,090	3,090	29
FERC Trf No. 8				1,060	1,060	30
FERC Trf No. 8				1,088	1,088	31
FERC Trf No. 8				69,420	69,420	32
FERC Trf No. 8				15	15	33
FERC Trf No. 8				800	800	34
			13	**3,689,993**	**3,689,993**	

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.
277,574			277,574	1
142,906		90,228	233,134	2
223,038		75,190	298,228	3
27,567			27,567	4
28,800		6,410	35,210	5
10,800		5,747	16,547	6
32,160		9,299	41,459	7
6,414,865		2,470,236	8,885,101	8
		27,973	27,973	9
		9,480	9,480	10
		6,120	6,120	11
144			144	12
		604	604	13
2,425			2,425	14
51,518			51,518	15
128			128	16
8,218			8,218	17
81			81	18
41,838			41,838	19
1,322			1,322	20
143,303			143,303	21
243,557			243,557	22
6,741			6,741	23
42,289			42,289	24
123			123	25
27,209			27,209	26
179			179	27
1,155			1,155	28
24,367			24,367	29
2,923			2,923	30
8,303			8,303	31
231,315			231,315	32
130			130	33
3,084			3,084	34
12,692,240	**0**	**3,650,242**	**16,342,482**	

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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) 04/15/2020	Year/Period of Report End of 2019/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	Douglas County PUD	Bonneville Power Administration	Avista Corporation	NF
3	EDF Trading N.A. LLC	Bonneville Power Administration	NorthWestern Energy	NF
4	EDF Trading N.A. LLC	Avista Corporation	Bonneville Power Administration	NF
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	Idaho Power Company	Chelan County PUD	NF
22	Morgan Stanley Capital Group	Idaho Power Company	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	Bonneville Power Administration	Bonneville Power Administration	Avista Corporation	SFP
30	Powerex	Bonneville Power Administration	Idaho Power Company	NF
31	Energy Keepers Inc.	NorthWestern Energy	Idaho Power Company	SFP
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				6,213	6,213	1
FERC Trf No. 8				2,242	2,242	2
FERC Trf No. 8				2,661	2,661	3
FERC Trf No. 8				31	31	4
FERC Trf No. 8				6,512	6,512	5
FERC Trf No. 8				24,064	24,064	6
FERC Trf No. 8				25	25	7
FERC Trf No. 8				55	55	8
FERC Trf No. 8				670	670	9
FERC Trf No. 8				7,617	7,617	10
FERC Trf No. 8	AVA.SYS	LOLO	3	14,682	14,682	11
FERC Trf No. 8				249	249	12
FERC Trf No. 8				7,960	7,960	13
FERC Trf No. 8				505	505	14
FERC Trf No. 8				11,811	11,811	15
FERC Trf No. 8				3,064	3,064	16
FERC Trf No. 8				15,330	15,330	17
FERC Trf No. 8				1,268	1,268	18
FERC Trf No. 8				13,329	13,329	19
FERC Trf No. 8				785	785	20
FERC Trf No. 8				77	77	21
FERC Trf No. 8				491	491	22
FERC Trf No. 8				2	2	23
FERC Trf No. 8				6,005	6,005	24
FERC Trf No. 8				1,581	1,581	25
FERC Trf No. 8				4,015	4,015	26
FERC Trf No. 8				1,386	1,386	27
FERC Trf No. 8				30	30	28
FERC Trf No. 8				20,923	20,923	29
FERC Trf No. 8				4,947	4,947	30
FERC Trf No. 8				496	496	31
FERC Trf No. 8				31,545	31,545	32
FERC Trf No. 8				3,355	3,355	33
FERC Trf No. 8				4,343	4,343	34
			13	**3,689,993**	**3,689,993**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2020	Year/Period of Report End of 2019/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.
23,542			23,542	1
13,017		2,406	15,423	2
16,552			16,552	3
209			209	4
40,237			40,237	5
157,385			157,385	6
146			146	7
317			317	8
5,092			5,092	9
53,345			53,345	10
72,000		22,549	94,549	11
1,683			1,683	12
30,967			30,967	13
1,928			1,928	14
73,592			73,592	15
18,916			18,916	16
107,534			107,534	17
8,652			8,652	18
84,954			84,954	19
5,702			5,702	20
526			526	21
3,353			3,353	22
12			12	23
37,707			37,707	24
9,821			9,821	25
24,754			24,754	26
8,855			8,855	27
180			180	28
106,791			106,791	29
28,562			28,562	30
2,861			2,861	31
268,753			268,753	32
36,588			36,588	33
37,527			37,527	34
12,692,240	**0**	**3,650,242**	**16,342,482**	

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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) 04/15/2020	Year/Period of Report End of 2019/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	Grant County PUD	NF
5	Shell Energy North America (US) LP	Grant County Public Utility	Idaho Power Company	NF
6	Transalta Energy Marketing	PacifiCorp	Idaho Power Company	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	Grant County PUD	NorthWestern Energy	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	Northwestern Energy	Bonneville Power Administration	NF
17	Morgan Stanley Capital Group	Grant County PUD	Bonneville Power Administration	NF
18	NorthWestern Energy	NorthWestern Energy	Bonneville Power Administration	NF
19	Transalta Energy Marketing	Idaho Power Company	PacifiCorp	NF
20	PacifiCorp	PacifiCorp	Bonneville Power Company	SFP
21	PacifiCorp	NorthWestern Energy	PacifiCorp	NF
22	PacifiCorp	PacifiCorp	PacifiCorp	NF
23	Portland General Electric	NorthWestern Energy	Portland General Electric	NF
24	PacifiCorp	Idaho Power Company	Bonneville Power Administration	SFP
25	Puget Sound Energy	NorthWestern Energy	Bonneville Power Administration	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	NorthWestern Energy	Bonneville Power Administration	SFP
31	Rainbow Energy Marketing Corp	NorthWestern Energy	Chelan County PUD	SFP
32	The Energy Authority	Bonneville Power Administration	NorthWestern Energy	NF
33	The Energy Authority	NorthWestern Energy	Bonneville Power Administration	NF
34	Rainbow Energy Marketing Corp	NorthWestern Energy	Puget Sound Energy	SFP
	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)	MegaWatt Hours Delivered (j)	Line No.
FERC Trf No. 8				8,555	8,555	1
T1110						2
FERC Trf No. 8				461	461	3
FERC Trf No. 8				10,613	10,613	4
FERC Trf No. 8				30,471	30,471	5
FERC Trf No. 8				775	775	6
FERC Trf No. 8				7,123	7,123	7
FERC Trf No. 8				2,465	2,465	8
FERC Trf No. 8				423	423	9
FERC Trf No. 8						10
FERC Trf No. 8				475	475	11
FERC Trf No, 8				2,210	2,210	12
FERC Trf No. 8				258	258	13
FERC Trf No. 8				400	400	14
FERC Trf No. 8				3,256	3,256	15
FERC Trf No. 8				1,426	1,426	16
FERC Trf No. 8				392	392	17
FERC Trf No. 8				4,646	4,646	18
FERC Trf No. 8				50	50	19
FERC Trf No. 8				3,561	3,561	20
FERC Trf No. 8				1,600	1,600	21
FERC Trf No. 8				10,939	10,939	22
FERC Trf No. 8				1,846	1,846	23
FERC Trf No. 8				14,685	14,685	24
FERC Trf No. 8				4,087	4,087	25
FERC Trf No. 8				12	12	26
FERC Trf No. 8				399	399	27
FERC Trf No. 8				68	68	28
FERC Trf No. 8				1,443	1,443	29
FERC Trf No. 8				837	837	30
FERC Trf No. 8				446	446	31
FERC Trf No. 8						32
FERC Trf No. 8				122	122	33
FERC Trf No. 8				394	394	34
			13	**3,689,993**	**3,689,993**	

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.
62,597			62,597	1
		924,000	924,000	2
4,416			4,416	3
61,609			61,609	4
181,668			181,668	5
4,472			4,472	6
44,559			44,559	7
14,253			14,253	8
3,000			3,000	9
231			231	10
3,464			3,464	11
12,779			12,779	12
1,506			1,506	13
2,308			2,308	14
22,882			22,882	15
5,919			5,919	16
2,677			2,677	17
40,681			40,681	18
289			289	19
27,690			27,690	20
9,232			9,232	21
104,645			104,645	22
10,667			10,667	23
54,658			54,658	24
20,898			20,898	25
69			69	26
2,629			2,629	27
457			457	28
19,501			19,501	29
3,225			3,225	30
1,718			1,718	31
58			58	32
704			704	33
1,518			1,518	34
12,692,240	**0**	**3,650,242**	**16,342,482**	

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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) 04/15/2020	Year/Period of Report End of 2019/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	Bonneville Power Administration	Idaho Power Company	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	Macquarie Energy LLC	Avista Corporation	Bonneville Power Administration	NF
8	NorthWestern Energy	Avista Corporation	NorthWestern Energy	NF
9	PacifiCorp	Idaho Power Company	Bonneville Power Administration	NF
10	PacifiCorp	Avista Corporation	Bonneville Power Administration	NF
11	Morgan Stanley Capital Group	Chelan County PUD	Bonneville Power Administration	NF
12	PacifiCorp	Avista Corporation	Idaho Power Company	NF
13	The Energy Authority	Idaho Power Company	Bonneville Power Company	NF
14	Morgan Stanley Capital Group	NorthWestern Energy	Avista Corporation	SFP
15	Morgan Stanley Capital Group	Idaho Power Company	Bonneville Power Administration	SFP
16	The Energy Authority	Bonneville Power Administration	Idaho Power Company	NF
17	PacifiCorp	NorthWestern Energy	PacifiCorp	SFP
18	PacifiCorp	Idaho Power Company	PacifiCorp	SFP
19	Powerex	Idaho Power Company	Bonneville Power Administration	NF
20	Powerex	Idaho Power Company	Chelan County PUD	NF
21	Powerex	Chelan County PUD	NorthWestern Energy	NF
22	The Energy Authority	Bonneville Power Administration	Avista Corporation	SFP
23	The Energy Authority	Idaho Power Company	Grant County PUD	SFP
24	The Energy Authority	Idaho Power Company	PacifiCorp	SFP
25	The Energy Authority	Idaho Power Company	Puget Sound Energy	SFP
26	The Energy Authority	Idaho Power Company	Douglas County PUD	SFP
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
FERC Trf No. 8				595	595	1
FERC Trf No. 8				2,620	2,620	2
FERC Trf No. 8				39,860	39,860	3
FERC Trf No. 8				137,751	137,751	4
FERC Trf No. 8				7,904	7,904	5
FERC Trf No. 8				6,352	6,352	6
FERC Trf No. 8				27	27	7
FERC Trf No. 8						8
FERC Trf No. 8				915	915	9
FERC Trf No. 8				25	25	10
FERC Trf No. 8				216	216	11
FERC Trf No. 8				350	350	12
FERC Trf No. 8				559	559	13
FERC Trf No. 8				487	487	14
FERC Trf No. 8				2	2	15
FERC Trf No. 8				376	376	16
FERC Trf No. 8				24,170	24,170	17
FERC Trf No. 8				367,732	367,732	18
FERC Trf No. 8				700	700	19
FERC Trf No. 8				19	19	20
FERC Trf No. 8				298	298	21
FERC Trf No. 8				102	102	22
FERC Trf No. 8				200	200	23
FERC Trf No. 8				1,200	1,200	24
FERC Trf No. 8				1,581	1,581	25
FERC Trf No. 8				200	200	26
						27
						28
						29
						30
						31
						32
						33
						34
			13	**3,689,993**	**3,689,993**	

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.
3,433			3,433	1
16,496			16,496	2
164,294			164,294	3
540,511			540,511	4
26,324			26,324	5
23,572			23,572	6
234			234	7
1,327			1,327	8
8,078			8,078	9
221			221	10
1,475			1,475	11
2,020			2,020	12
3,240			3,240	13
3,270			3,270	14
13			13	15
3,035			3,035	16
81,058			81,058	17
1,783,656			1,783,656	18
4,138			4,138	19
128			128	20
2,002			2,002	21
461			461	22
1,016			1,016	23
6,093			6,093	24
8,028			8,028	25
1,016			1,016	26
				27
				28
				29
				30
				31
				32
				33
				34
12,692,240	**0**	**3,650,242**	**16,342,482**	

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.: 2 Column: m

Ancillary Services

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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2020	End of 2019/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Magawatt-hours Received (c)	TRANSFER OF ENERGY Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Bonneville Power Admin	LFP			1,499,551			1,499,551
2	Bonneville Power Admin	LFP			10,135,988		2,186,232	12,322,220
3	Bonneville Power Admin	LFP			471,701			471,701
4	Bonneville Power Admin	OS					54,432	54,432
5	Bonneville Power Admin	FNS			1,171,717		239,990	1,411,707
6	Bonneville Power Admin	NF	45,868	45,868		236,983		236,983
7	Idaho Power Company	NF	3,965	3,965		25,297		25,297
8	Nevada Power Company	NF	50	50		339		339
9	Kootenai Electric Coop	LFP			47,538			47,538
10	Northern Lights	LFP			139,315			139,315
11	NorthWestern Energy	SFP			103,518		13,267	116,785
12	NorthWestern Energy	NF	39,047	39,047		200,063		200,063
13	Portland General Elec	LFP			628,000		14,989	642,989
14	Portland General Elec	NF	5,487	5,487		6,433		6,433
15	Snohomish County PUD	NF	24,417	24,417		33,594		33,594
16	Puget Sound Energy	NF	4,317	4,317		9,485	352	9,837
	TOTAL		135,887	135,887	14,197,328	546,230	2,509,262	17,252,820

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2020	End of 2019/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Arizona Public Service	NF	1	1		8		8
2	Seattle City Light	NF	9,915	9,915		12,517		12,517
3	PacifiCorp	NF	2,820	2,820		21,511		21,511
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		135,887	135,887	14,197,328	546,230	2,509,262	17,252,820

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.: 11 Column: g

Ancillary Services and Regulation & Frequency Response

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

Ancillary Services

Schedule Page: 332 Line No.: 16 Column: g

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	04/15/2020	End of 2019/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	828,888
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	360,042
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Community Relations	328,283
7	Director Expenses	422,468
8	Education & Information	25,843
9	Rating Agency Fees	149,978
10	Aircraft Operation and fees	514,340
11	Misc Vendors >5000	1,672,262
12	Misc Vendors < 5000	693,047
13		
14		
15		
16		
17		
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45		
46	TOTAL	4,995,151

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2020	End of 2019/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			4,164,422		4,164,422
2	Steam Production Plant	16,630,523				16,630,523
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	13,583,713				13,583,713
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	10,635,972			1,632,961	12,268,933
7	Transmission Plant	15,658,811				15,658,811
8	Distribution Plant	48,023,375				48,023,375
9	Regional Transmission and Market Operation					
10	General Plant	3,958,042		47,607		4,005,649
11	Common Plant-Electric	18,188,621		24,701,867		42,890,488
12	TOTAL	126,679,057		28,913,896	1,632,961	157,225,914

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	57,470	70.00	-6.00	1.99	S1.5	7.50
15	312	86,181	60.00	-6.00	2.67	R1	7.50
16	313	4		-6.00	9.22	R2.5	7.50
17	314	23,624	40.00	-6.00	8.34	R0.5	7.50
18	315	10,116	50.00	-6.00	2.97	R3	7.50
19	316	9,599	53.00	-6.00	3.96	R2	7.50
20	Subtotal	186,994					
21							
22	Colstrip No. 4						
23	311	53,633	70.00	-7.00	2.95	S1.5	7.50
24	312	59,933	60.00	-7.00	4.79	R1	7.50
25	313	4		-7.00	9.34	R2.5	7.50
26	314	15,050	40.00	-7.00	7.59	R0.5	7.50
27	315	7,218	50.00	-7.00	3.72	R3	7.50
28	316	4,521	53.00	-7.00	4.74	R2	7.50
29	Subtotal	140,359					
30							
31	Kettle Falls					0	
32	310	148			1.32	SQ	12.00
33	311	28,657	70.00	-4.00	2.49	S1.5	11.70
34	312	46,669	55.00	-4.00	3.18	R1	11.30
35	314	18,626	35.00	-4.00	2.25	R0.5	10.20
36	315	12,323	50.00	-4.00	4.06	R3	11.40
37	316	2,506	55.00	-4.00	2.97	R2	11.30
38	Subtotal	108,929					
39							
40	HYDRO PLANT						
41	Cabinet Gorge						
42	330	9,383	100.00		1.90	R4	38.10
43	331	25,349	55.00	-16.00	1.73	R2	42.45
44	332	44,406	60.00	-16.00	2.03	R1	45.53
45	333	47,050	65.00	-16.00	2.59	R1.5	40.80
46	334	8,245	40.00	-16.00	2.10	S1	29.40
47	335	5,600	50.00	-16.00	1.89	R1	41.38
48	336	1,671	55.00	-16.00	2.00	S2.5	29.30
49	Subtotal	141,704					
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	Noxon Rapids						
13	330	30,477	100.00		1.64	R4	52.50
14	331	23,592	55.00	-24.00	2.23	R2	44.50
15	332	37,009	60.00	-24.00	2.22	R1	47.23
16	333	88,683	65.00	-24.00	2.41	R1.5	44.90
17	334	17,278	40.00	-24.00	4.09	S1	27.40
18	335	4,275	50.00	-24.00	2.04	R1	41.68
19	336	260	55.00	-24.00	2.96	S2.5	26.20
20	Subtotal	201,574					
21							
22	Post Falls						
23	330	2,908	80.00		1.91	R4	24.25
24	331	4,171	55.00	-4.00	1.53	R2	38.10
25	332	25,503	60.00	-4.00	2.48	R1	36.90
26	333	2,234	65.00	-4.00	0.79	R1.5	33.60
27	334	1,760	40.00	-4.00	1.20	S1	23.20
28	335	787	60.00	-4.00	2.39	R1	36.90
29	336	578	55.00	-4.00	2.62	S2.5	26.20
30	Subtotal	37,941					
31							
32	Long Lake						
33	330	418	80.00		1.91	R4	25.70
34	331	9,789	55.00	-7.00	1.64	R2	33.70
35	332	36,755	60.00	-7.00	1.85	R1	34.00
36	333	8,738	65.00	-7.00	0.45	R1.5	33.70
37	334	3,347	40.00	-7.00	0.85	S1	29.20
38	335	850	60.00	-7.00	1.69	R1	32.60
39	336		55.00	-7.00	2.62	S2.5	26.20
40	Subtotal	59,897					
41							
42	Little Falls						
43	330	4,217	80.00		1.28	R4	19.60
44	331	3,958	110.00	-7.00	1.87	R2	41.60
45	332	6,717	100.00	-7.00	1.17	R1	39.80
46	333	38,925	65.00	-7.00	1.40	R1.5	39.10
47	334	13,813	40.00	-7.00	2.72	S1	32.30
48	335	549	60.00	-7.00	1.67	R1	36.30
49	Subtotal	68,179					
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	Upper Falls						
13	330	64	100.00		1.38	R4	18.60
14	331	975	50.00	-7.00	3.36	R2	30.80
15	332	7,789	110.00	-7.00	1.82	R1	40.70
16	333	1,166	65.00	-7.00	0.22	R1.5	38.00
17	334	4,269	40.00	-7.00	3.11	S1	29.90
18	335	104	60.00	-7.00	2.14	R1	34.70
19	336	508	55.00	-7.00	2.53	S2.5	26.20
20	Subtotal	14,875					
21							
22	Nine Mile						
23	330	11	100.00		1.50	R4	25.25
24	331	19,277	110.00	-4.00	2.41	R2	40.10
25	332	28,683	110.00	-4.00	2.10	R1	37.30
26	333	41,703	65.00	-4.00	2.58	R1.5	39.40
27	334	19,171	40.00	-4.00	2.92	S1	33.40
28	335	3,276	60.00	-4.00	2.68	R1	38.00
29	336	595	55.00	-4.00	2.70	S2.5	26.20
30	Subtotal	112,716					
31							
32	Monroe Street						
33	331	12,122	55.00	-7.00	2.39	R2	40.80
34	332	9,972	110.00	-7.00	1.91	R1	49.80
35	333	11,001	65.00	-7.00	2.22	R1.5	40.80
36	334	3,809	40.00	-7.00	3.66	S1	25.60
37	335	34	60.00	-7.00	2.30	R1	40.50
38	336	50	55.00	-7.00	2.89	R2.5	31.10
39	Subtotal	36,988					
40							
41	OTHER PRODUCTION						
42	Northeast Turbine						
43	341	751	55.00	-5.00	30.78	S4	2.00
44	342	39	55.00	-5.00		R3	
45	343	9,059	60.00	-5.00	2.51	S2.5	2.00
46	344	2,610	45.00	-5.00	2.56	R1	2.00
47	345	1,243	20.00	-5.00	16.94	S1	2.00
48	346	399	35.00	-5.00	23.28	R2.5	1.90
49	Subtotal	14,101					
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	3,580	55.00	-4.00	3.70	S4	16.00
14	342	1,696	55.00	-4.00	3.56	R3	17.60
15	343	5,722	60.00	-4.00	3.77	S2.5	17.60
16	344	49,716	45.00	-4.00	3.94	R1	16.40
17	345	3,462	20.00	-4.00	8.22	S1	11.90
18	346	249	35.00	-4.00	5.69	R2.5	17.40
19	Subtotal	64,425					
20							
21	Kettle Falls CT						
22	341	9	55.00	-1.00	1.36	S4	11.00
23	342	89	55.00	-1.00	3.33	R3	11.80
24	343	8,671	60.00	-1.00	3.45	S2.5	11.90
25	344	759	45.00	-1.00	4.11	R1	11.30
26	345	13	20.00	-1.00	8.00	S1	11.00
27	Subtotal	9,541					
28							
29	Boulder Park						
30	341	1,277	55.00	-2.00	2.56	S4	25.90
31	342	162	55.00	-2.00	2.62	R3	25.00
32	343	57	60.00	-2.00	2.38	S2.5	25.30
33	344	31,132	45.00	-2.00	2.43	R1	22.20
34	345	656	20.00	-2.00	6.42	S1	15.10
35	346	57	35.00	-2.00	3.99	R2.5	23.70
36	Subtotal	33,341					
37							
38	Coyote Springs 2						
39	341	11,560	55.00	-3.00	2.37	S4	26.80
40	342	19,318	55.00	-3.00	2.45	R3	25.60
41	344	137,143	45.00	-3.00	3.36	R1	23.40
42	345	16,933	20.00	-3.00	5.25	S1	11.70
43	346	1,003	35.00	-3.00	4.27	R2.5	22.10
44	Subtotal	185,957					
45							
46	Solar Power						
47	344 & 345	482	25.00	-3.00	7.46	S2.5	12.70
48	Subtotal	482					
49							
50	Lancaster						

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2020	Year/Period of Report End of 2019/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	342	92	55.00	-5.00	3.07	R3	23.40
13	344	209	45.00	-5.00	3.52	R1	21.50
14	345	49	20.00	-5.00	6.19	S1	16.70
15	Subtotal	350					
16							
17	TRANSMISSION PLANT						
18	350	22,538	80.00		1.13	R4	55.85
19	352	25,868	65.00	-10.00	1.63	S1.5	52.90
20	353	290,493	44.00	-10.00	2.41	R2	32.60
21	354	17,161	75.00	-15.00	1.51	R4	41.90
22	355	280,744	63.00	-30.00	1.93	R2.5	51.70
23	356	159,395	70.00	-30.00	1.90	R3	45.90
24	357	3,253	60.00		1.64	R4	47.40
25	358	2,603	50.00		2.06	S3	29.30
26	359	2,113	70.00		1.41	R4	42.80
27	Subtotal	804,168					
28							
29	DISTRIBUTION PLANT						
30	360	4,071	75.00		1.34	R4	69.40
31	361	34,136	60.00	-10.00	1.72	S1.5	46.70
32	362	148,162	42.00	-10.00	2.68	R1.5	30.40
33	363	2,598	15.00		6.80	L3	13.50
34	364 - WA	284,700	67.00	-60.00	2.47	R2.5	51.70
35	364 - ID	151,962	65.00	-60.00	2.57	R2.5	51.70
36	365 - WA	180,173	68.00	-50.00	2.27	R3	44.40
37	365 - ID	101,008	65.00	-50.00	2.45	R3.5	44.40
38	366 - WA	80,584	60.00	-30.00	1.56	R1.5	46.50
39	366 - ID	43,161	60.00	-30.00	2.14	S2.5	46.50
40	367 - WA	146,018	35.00	-30.00	3.44	S1.5	24.70
41	367 - ID	74,117	35.00	-20.00	2.99	S1.5	24.70
42	368	280,772	47.00	-10.00	2.16	R2	35.50
43	369	180,434	65.00	-40.00	2.10	R4	50.40
44	370 - AN	157	35.00	-2.00	2.89	S0	
45	370.2 - ID	23,834	15.00		9.06	S2.5	7.70
46	370.3 - WA	48,954	35.00		2.89	S0	26.50
47	371	2,122	10.00		10.36	S1	9.50
48	373	23,886	37.00	-20.00	1.87	R2.5	27.90
49	373.4	26,675	37.00	-20.00	3.04	R2.5	29.20
50	373.5	15,256	37.00	-20.00	3.17	R2.5	36.10

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2020	End of 2019/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Subtotal	1,852,780					
13							
14	GENERAL PLANT						
15	390.1	8,504	50.00	-5.00	1.90	R2.5	42.20
16	391	8	15.00		6.67	SQ	15.00
17	391.1	1,891	5.00		20.00	SQ	1.70
18	393	392	25.00		4.00	SQ	14.60
19	394	6,165	20.00		5.00	SQ	11.00
20	395	1,811	15.00		6.67	SQ	7.40
21	397	49,696	15.00		6.67	SQ	8.50
22	398	194	10.00		10.00	SQ	6.60
23	Subtotal	68,661					
24							
25	MISC POWER						
26	392	7,838	16.00		5.48	L2.5	12.20
27	396	3,865	22.00		3.75	S1	14.80
28	Subtotal	11,703					
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39	TOTAL COMPANY	4,155,665					
40							
41							
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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	04/15/2020	End of 2019/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.	2,596,139	32,603	2,628,742	
5					
6					
7					
8					
9	Washington Utilities and Transportation				
10	Commission: includes annual fee and various				
11	other electric dockets	1,087,170	1,034,748	2,121,918	
12					
13	Includes annual fee and various other natural				
14	gas dockets	291,397	279,668	571,065	
15					
16	Idaho Public Utilities Commission				
17	Includes annual fee and various other electric				
18	dockets	663,458	448,538	1,111,996	
19					
20	Includes annual fee and various other natural				
21	gas dockets	154,795	89,959	244,754	
22					
23	Public Utility Commission of Oregon				
24	Includes annual fees and various other natural				
25	gas dockets	541,152	348,782	889,934	
26					
27	Not directly assigned electric		518,188	518,188	
28	Not directly assigned natural gas		253,712	253,712	
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	5,334,111	3,006,198	8,340,309	

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	2,628,742					4
							5
							6
							7
							8
							9
							10
Electric	928	2,121,918					11
							12
							13
Gas	928	571,065					14
							15
							16
							17
Electric	928	1,111,996					18
							19
							20
Gas	928	244,754					21
							22
							23
							24
Gas	928	889,934					25
							26
Electric	928	518,188					27
Gas	928	253,712					28
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							30
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							32
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							45
		8,340,309					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	04/15/2020	End of 2019/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. Electric (3) Distribution	Battery Storage and Electric Vehicle Supply Equip
2		
3		
4		
5		
6		
7		
8	A. Electric (6) Other - Testing Lab & Facility	HUB-Morris Center Lab Test Facility
9		
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Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2020	Year/Period of Report End of 2019/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		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
579,917	1,507,094	107	2,087,011		1
639	16,275	557	16,914		2
	99,239	587	99,239		3
43,224	8,016	598	51,240		4
87,105		920	87,105		5
	2,000	930	2,000		6
					7
142,164	177,179	107	319,343		8
					9
					10
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2020	End of 2019/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	13,119,472		
4	Transmission	4,128,801		
5	Regional Market			
6	Distribution	9,754,373		
7	Customer Accounts	7,471,488		
8	Customer Service and Informational	599,173		
9	Sales			
10	Administrative and General	22,278,296		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	57,351,603		
12	Maintenance			
13	Production	5,163,196		
14	Transmission	1,020,436		
15	Regional Market			
16	Distribution	3,999,308		
17	Administrative and General			
18	TOTAL Maintenance (Total of lines 13 thru 17)	10,182,940		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	18,282,668		
21	Transmission (Enter Total of lines 4 and 14)	5,149,237		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	13,753,681		
24	Customer Accounts (Transcribe from line 7)	7,471,488		
25	Customer Service and Informational (Transcribe from line 8)	599,173		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	22,278,296		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	67,534,543	-2,061,080	65,473,463
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply	895,589		
34	Storage, LNG Terminaling and Processing	9,947		
35	Transmission			
36	Distribution	6,249,270		
37	Customer Accounts	3,259,054		
38	Customer Service and Informational	342,792		
39	Sales			
40	Administrative and General	8,958,668		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	19,715,320		
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	1,787,888		

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution	3,242,057		
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	5,029,945		
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)	895,589		
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru 47)	9,947		
56	Transmission (Lines 35 and 47)	1,787,888		
57	Distribution (Lines 36 and 48)	9,491,327		
58	Customer Accounts (Line 37)	3,259,054		
59	Customer Service and Informational (Line 38)	342,792		
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)	8,958,668		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	24,745,265	7,060,487	31,805,752
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	92,279,808	4,999,407	97,279,215
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	43,013,400	13,479,982	56,493,382
69	Gas Plant	11,563,912	4,571,235	16,135,147
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	54,577,312	18,051,217	72,628,529
72	Plant Removal (By Utility Departments)			
73	Electric Plant	1,960,333	504,622	2,464,955
74	Gas Plant	473,307	121,837	595,144
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	2,433,640	626,459	3,060,099
77	Other Accounts (Specify, provide details in footnote):			
78	Stores Expense (163)	2,499,877	-2,499,877	
79	Small Tool Expense (184)	4,601,566	-4,601,566	
80	Miscellaneous Deferred Debits (186)	1,056,805		1,056,805
81	Non-Operating Expenses (417)	1,058,754		1,058,754
82	Retirement/Bonus/Serp/HRA Settlement (228)	18,856		18,856
83	Activities (426)	1,229,448		1,229,448
84	Employee Incentive Plan (232380)	14,549,409	-14,549,409	
85	DSM Tariff Rider	2,026,689	-2,026,689	
86	Incentive/Stock Compensation (238000)	133,376		133,376
87	Payroll Equilization Liability	21,702,073	458	21,702,531
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	48,876,853	-23,677,083	25,199,770
96	TOTAL SALARIES AND WAGES	198,167,613		198,167,613

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	274,339,398
389	Land and Land Rights	13,815,624
390	Structures and Improvements	156,177,554
391	Office Furniture and Equipment	92,161,863
392	Transportation Equipment	14,287,313
393	Stores Equipment	4,910,772
394	Tools, Shop & Garage Equipment	14,532,607
395	Laboratory Equipment	1,568,515
396	Power Operated Equipment	2,026,723
397	Communications Equipment	77,551,368
398	Miscellaneous Equipment	626,313
399	Asset Retirement Cost	0
	Total Common Plant	651,998,050
	Const. Work in Progress	24,865,214
	Total Utility Plant	676,863,264
	Acc. Prov. for Dep. & Amort.	197,862,807
	Net Utility Plant	479,000,457

3. Common Expenses allocated to Electric and Gas departments:

Acct. No. & Description	Total	Allocation to Electric Dept	Allocated to Gas Dept	Basis of Allocation
901 Cust acct/collect supervision	252,054	131,577	120,477	#of cust @ yr end
902 Meter reading expenses	3,669,156	2,224,022	1,445,134	#of cust @ yr end
903 Cust rec & collectn expenses	15,374,892	8,333,675	7,041,217	#of cust @ yr end
903.90-99 A/R misc fees	0	0	0	net direct plant
904 Uncollectible accounts	400,000	208,808	191,192	#of cust @ yr end
905 Misc cust acct expenses	333,642	174,168	159,474	#of cust @ yr end
907 Cust svce & Info exp supervision	0	0	0	#of cust @ yr end
908 Cust assistance expenses	671,316	401,616	269,700	#of cust @ yr end
909 Info & instruct advert expenses	1,940,938	1,176,474	764,464	#of cust @ yr end
910 Misc cust serv & info expenses	491,416	256,529	234,887	#of cust @ yr end
911 Sales expense -supervision	0	0	0	#of cust @ yr end

COMMON UTILITY PLANT AND EXPENSES

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

912 Demo and selling expenses	0	0	0	#of cust @ yr end
913 Advertising expenses	0	0	0	#of cust @ yr end
916 Misc sales expenses	0	0	0	#of cust @ yr end
920 Admin & gen salaries	33,498,958	23,719,038	9,779,920	four factor
921 Office supplies & expenses	6,286,833	4,441,305	1,845,528	four factor
922 Admin expenses tranf-credit	0	0	0	four factor
923 Outside services employed	12,951,952	9,147,448	3,804,504	four factor
924 Property insurance	1,618,025	1,141,970	476,055	four factor
925 Injuries and damages	6,707,709	4,890,538	1,817,171	four factor
926 Employee pensions&benefits	90,337,343	63,760,016	26,577,327	four factor
927 Franchise requirement	0	0	0	four factor
928 Regulatory commission expenses	2,053,656	1,524,134	529,522	four factor
929 Duplicate charges-credit	0	0	0	four factor
930.1 General advertising expenses	0	0	0	four factor
930.2 Misc general expenses	5,402,940	3,835,817	1,567,123	four factor
931 Rents	433,782	308,077	125,705	four factor
935 Maint of general plant	15,592,094	11,136,091	4,456,003	four factor
403 Depreciation	25,450,157	18,188,621	7,261,536	four factor
404 Amort of LTD term plant	34,603,854	24,701,866	9,901,988	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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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2020	End of 2019/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

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

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	856,734	849,655	938,050	957,925
3	Net Sales (Account 447)	(3,917,453)	(5,324,792)	(8,398,930)	(10,561,206)
4	Transmission Rights				
5	Ancillary Services	(11,605)	(22,438)	(34,198)	(40,673)
6	Other Items (list separately)				
7	Access Charge	71,505	182,292	183,990	185,123
8	Cost Recovery	10,526	9,572	(7,474)	(8,902)
9	Day Ahead Energy-Congestion Losses	(29,412)	(42,441)	(42,764)	(40,505)
10	FERC Fees	489	1,223	1,233	1,240
11	GMC	34,943	62,313	99,042	123,102
12	Hour Ahead Scheduling Process-RT	(1,021)	(1,300)	(994)	(2,818)
13	Other	(95)	(767)	(307)	1,883
14					
15					
16					
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46	TOTAL	(2,985,389)	(4,286,683)	(7,262,352)	(9,384,831)

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2020	Year/Period of Report End of 2019/Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch						
2	Reactive Supply and Voltage						
3	Regulation and Frequency Response				80	MW	1,031,012
4	Energy Imbalance	27,157	MWh	1,020,502	28,074	MWh	1,144,875
5	Operating Reserve - Spinning				60	MW	773,259
6	Operating Reserve - Supplement				60	MW	712,386
7	Other	847	MW	10,604,106	847	MW	10,604,106
8	Total (Lines 1 thru 7)	28,004		11,624,608	29,121		14,265,638

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	04/15/2020	End of 2019/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	2,232	15	800	1,424	337	288	18	183	288
2	February	2,639	7	800	1,543	400	288	16	408	258
3	March	2,983	4	800	1,494	388	292	21	809	375
4	Total for Quarter 1				4,461	1,125	868	55	1,400	921
5	April	2,024	10	800	1,146	244	300	9	334	38
6	May	1,899	30	1700	1,276	245	303	29	75	74
7	June	2,086	13	1600	1,427	280	305	26	74	460
8	Total for Quarter 2				3,849	769	908	64	483	572
9	July	2,276	23	1700	1,546	304	301	32	124	67
10	August	2,499	7	1700	1,615	315	295	27	274	260
11	September	1,963	4	1800	1,340	257	292	31	74	588
12	Total for Quarter 3				4,501	876	888	90	472	915
13	October	2,244	30	800	1,492	349	288	39	114	99
14	November	2,287	21	800	1,270	296	282	17	439	167
15	December	2,471	11	1800	1,357	295	282	13	536	120
16	Total for Quarter 4				4,119	940	852	69	1,089	386
17	Total Year to Date/Year				16,930	3,710	3,516	278	3,444	2,794

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ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY	
2	Generation (Excluding Station Use):	
3	Steam	1,898,160
4	Nuclear	
5	Hydro-Conventional	3,519,884
6	Hydro-Pumped Storage	
7	Other	2,155,469
8	Less Energy for Pumping	
9	Net Generation (Enter Total of lines 3 through 8)	7,573,513
10	Purchases	5,344,702
11	Power Exchanges:	
12	Received	9,046
13	Delivered	429,475
14	Net Exchanges (Line 12 minus line 13)	-420,429
15	Transmission For Other (Wheeling)	
16	Received	3,689,993
17	Delivered	3,689,993
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)	12,497,786

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	9,015,988
23	Requirements Sales for Resale (See instruction 4, page 311.)	
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	2,942,248
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	86,149
27	Total Energy Losses	453,401
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	12,497,786

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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2020	End of 2019/Q4

MONTHLY PEAKS AND OUTPUT

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

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	1,088,872	217,189	1,475	15	0800
30	February	1,064,342	212,065	1,577	7	0800
31	March	1,166,712	310,411	1,527	1	0800
32	April	1,091,759	380,311	1,224	11	0800
33	May	1,095,475	386,851	1,309	30	1700
34	June	1,009,485	284,634	1,470	13	1600
35	July	1,019,952	226,577	1,590	23	1700
36	August	1,007,778	181,821	1,656	7	1700
37	September	922,575	222,870	1,385	4	1800
38	October	955,260	165,475	1,504	30	0800
39	November	1,000,441	174,636	1,418	1	0800
40	December	1,075,135	179,408	1,474	16	1800
41	TOTAL	12,497,786	2,942,248			

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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2020	End of 2019/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)	284	63
7	Plant Hours Connected to Load	7409	63
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	1890646000	3459000
13	Cost of Plant: Land and Land Rights	0	138753
14	Structures and Improvements	11559743	751025
15	Equipment Costs	174396811	13347298
16	Asset Retirement Costs	351682	0
17	Total Cost	186308236	14237076
18	Cost per KW of Installed Capacity (line 17/5) Including	631.5533	230.3734
19	Production Expenses: Oper, Supv, & Engr	144560	6
20	Fuel	32967512	70677
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	1624751	107378
26	Misc Steam (or Nuclear) Power Expenses	281900	7999
27	Rents	80866	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	183191	14104
30	Maintenance of Structures	114321	1945
31	Maintenance of Boiler (or reactor) Plant	0	0
32	Maintenance of Electric Plant	6556222	86380
33	Maintenance of Misc Steam (or Nuclear) Plant	194870	20127
34	Total Production Expenses	42148193	308616
35	Expenses per Net KWh	0.0223	0.0892

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
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	12440725	0	0	41880	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	2.650	0.000	0.000	1.688	0.000	0.000
41	Average Cost of Fuel per Unit Burned	2.650	0.000	0.000	1.688	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	2.598	0.000	0.000	1.655	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.017	0.000	0.000	0.020	0.000	0.000
44	Average BTU per KWh Net Generation	6712.000	0.000	0.000	12350.000	0.000	0.000

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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2020	End of 2019/Q4

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

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Kettle Falls* (d)			Plant Name: *Colstrip* (e)			Plant Name: *Rathdrum* (f)			Line No.
Steam			Steam			Gas Turbine			1
Conventional			Conventional			Not Applicable			2
1983			1984			1995			3
1983			1985			1995			4
50.70			233.40			166.50			5
100			235			156			6
6887			7923			1663			7
54			222			167			8
54			222			0			9
54			222			0			10
29			306			1			11
316112000			1582048000			176180000			12
2289077			1321965			621682			13
28656948			111103126			3580204			14
80124261			216249590			60844532			15
323787			16702865			0			16
111394073			345377546			65046418			17
2197.1218			1479.7667			390.6692			18
154779			200708			920			19
7834090			23017352			4409644			20
0			0			0			21
592550			3168489			0			22
0			0			0			23
0			0			0			24
794284			83229			231050			25
440623			2461320			29647			26
0			15079			0			27
0			0			0			28
99292			398065			28756			29
146467			614683			12679			30
1657964			4147938			0			31
431938			205474			88017			32
747243			476576			103039			33
12899230			34788913			4903752			34
0.0408			0.0220			0.0278			35
WOOD	GAS		COAL	OIL		GAS			36
TON	MCF		TON	BBL		MCF			37
499986	8854	0	970451	2075	0	2087852	0	0	38
8600000	1020000	0	16970000	5880000	0	1020000	0	0	39
15.632	2.082	0.000	23.512	96.412	0.000	2.112	0.000	0.000	40
15.632	2.082	0.000	23.512	96.412	0.000	2.112	0.000	0.000	41
1.818	2.041	0.000	1.386	16.397	0.000	2.071	0.000	0.000	42
0.025	0.025	0.000	0.014	0.000	0.000	0.025	0.000	0.000	43
13634.000	0.000	0.000	10417.000	0.000	0.000	12088.000	0.000	0.000	44

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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2020	End of 2019/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	2978	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	66910000	0
13	Cost of Plant: Land and Land Rights	185629	0
14	Structures and Improvements	1276684	0
15	Equipment Costs	32064610	0
16	Asset Retirement Costs	0	0
17	Total Cost	33526923	0
18	Cost per KW of Installed Capacity (line 17/5) Including	1362.8830	0
19	Production Expenses: Oper, Supv, & Engr	4080	0
20	Fuel	1472415	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	206063	0
26	Misc Steam (or Nuclear) Power Expenses	33826	0
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	96739	0
30	Maintenance of Structures	4177	0
31	Maintenance of Boiler (or reactor) Plant	0	0
32	Maintenance of Electric Plant	310098	0
33	Maintenance of Misc Steam (or Nuclear) Plant	96704	0
34	Total Production Expenses	2224102	0
35	Expenses per Net KWh	0.0332	0.0000

Line No.	Item (a)	(b)			(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	594300	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	2.478	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	2.478	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	2.429	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.022	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	9060.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2020	Year/Period of Report End of 2019/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
									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	04/15/2020	End of 2019/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	04/15/2020	End of 2019/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
									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	04/15/2020	End of 2019/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	04/15/2020	End of 2019/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

									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	04/15/2020	End of 2019/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)	23	17
7	Plant Hours Connect to Load	8,476	8,760
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	98,076,000	66,538,000
13	Cost of Plant		
14	Land and Land Rights	51,600	1,081,854
15	Structures and Improvements	12,113,194	974,617
16	Reservoirs, Dams, and Waterways	9,972,020	7,789,435
17	Equipment Costs	14,563,523	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)	36,750,785	15,893,670
21	Cost per KW of Installed Capacity (line 20 / 5)	2,483.1611	1,589.3670
22	Production Expenses		
23	Operation Supervision and Engineering	4,513	3,845
24	Water for Power	0	0
25	Hydraulic Expenses	3,108	3,528
26	Electric Expenses	513,064	521,003
27	Misc Hydraulic Power Generation Expenses	13,197	21,731
28	Rents	0	0
29	Maintenance Supervision and Engineering	54,484	11,145
30	Maintenance of Structures	9,607	4,651
31	Maintenance of Reservoirs, Dams, and Waterways	213,682	63,164
32	Maintenance of Electric Plant	58,647	28,663
33	Maintenance of Misc Hydraulic Plant	7,077	3,288
34	Total Production Expenses (total 23 thru 33)	877,379	661,018
35	Expenses per net KWh	0.0089	0.0099

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2020	End of 2019/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
28	16	266	6
6,960	7,162	8,603	7
			8
38	18	255	9
38	18	295	10
5	5	11	11
119,575,000	68,660,000	991,068,000	12
			13
33,429	3,672,815	16,380,178	14
18,899,291	4,171,447	25,349,240	15
28,683,217	25,503,438	44,405,805	16
64,150,086	4,780,903	60,700,087	17
594,870	577,944	1,671,013	18
0	0	0	19
112,360,893	38,706,547	148,506,323	20
2,988.3216	2,615.3072	560.4012	21
			22
14,382	12,524	41,417	23
0	0	0	24
285	5,650	2,011	25
672,182	667,334	1,079,998	26
91,857	73,590	183,102	27
0	0	0	28
20,682	3,069	26,416	29
46,107	37,162	71,275	30
46,341	96,002	180,360	31
228,798	50,211	685,211	32
34,722	26,889	16,016	33
1,155,356	972,431	2,285,806	34
0.0097	0.0142	0.0023	35

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)	556	91
7	Plant Hours Connect to Load	4,301	6,780
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	12	6
12	Net Generation, Exclusive of Plant Use - Kwh	1,573,513,000	438,456,000
13	Cost of Plant		
14	Land and Land Rights	35,968,495	2,500,473
15	Structures and Improvements	22,764,035	9,789,347
16	Reservoirs, Dams, and Waterways	37,009,326	36,754,005
17	Equipment Costs	109,657,885	12,896,877
18	Roads, Railroads, and Bridges	259,750	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	205,659,491	61,940,702
21	Cost per KW of Installed Capacity (line 20 / 5)	421.6062	884.8672
22	Production Expenses		
23	Operation Supervision and Engineering	244,753	9,428
24	Water for Power	0	0
25	Hydraulic Expenses	54,594	8,652
26	Electric Expenses	984,913	678,477
27	Misc Hydraulic Power Generation Expenses	226,901	137,262
28	Rents	0	0
29	Maintenance Supervision and Engineering	87,860	53,239
30	Maintenance of Structures	205,593	150,447
31	Maintenance of Reservoirs, Dams, and Waterways	412,407	525,692
32	Maintenance of Electric Plant	890,157	87,061
33	Maintenance of Misc Hydraulic Plant	73,197	24,909
34	Total Production Expenses (total 23 thru 33)	3,180,375	1,675,167
35	Expenses per net KWh	0.0020	0.0038

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
37	0	0	6
6,780	0	0	7
			8
88	0	0	9
88	0	0	10
5	0	0	11
163,998,000	0	0	12
			13
4,325,371	0	0	14
3,958,492	0	0	15
6,716,892	0	0	16
53,286,645	0	0	17
0	0	0	18
0	0	0	19
68,287,400	0	0	20
1,690.2822	0.0000	0.0000	21
			22
998	0	0	23
0	0	0	24
7,895	0	0	25
607,205	0	0	26
34,006	0	0	27
979,249	0	0	28
269	0	0	29
57,636	0	0	30
48,262	0	0	31
106,489	0	0	32
10,203	0	0	33
1,852,212	0	0	34
0.0113	0.0000	0.0000	35

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2020	Year/Period of Report End of 2019/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	16.0	18,274,000	9,567,500
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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	04/15/2020	End of 2019/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.
1,323,903	83,249	494,465	54,669	Nat Gas	242	1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
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						25
						26
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						42
						43
						44
						45
						46

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2020	Year/Period of Report End of 2019/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 (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	Group Sum		60.00	60.00		1.00		
2								
3	Group Sum		115.00	115.00		1,551.00		
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	Saddle Mtn-Walla Walla	Wanapum	230.00	230.00	Steel Pole	2.00		1
31	Saddle Mtn-Walla Walla	Wanapum	230.00	230.00	H Type	79.00		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	2,240.00	3.00	40

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
	136,038	636,193	772,231					1
								2
	12,223,201	250,346,744	262,569,945	129,685	346,228		475,913	3
								4
1272 ACSS								5
1272 ACSS	17,912	1,429,560	1,447,472	2,272	3,298		5,570	6
1272 ACSS								7
1272 ACSS	30,323	3,275,357	3,305,680		644		644	8
1590 ACSS								9
1590 ACSS								10
1590 ACSR	1,156,196	41,777,661	42,933,857		112,744		112,744	11
1590 ACSS								12
1590 ACSS								13
1272 AAC								14
1272 ACSS	456,162	23,167,785	23,623,947	380	33,579		33,959	15
1622 ACSS								16
1590 ACSS	570,207	48,748,733	49,318,940					17
1272 ACSR								18
1590 ACSS								19
954 AAC	1,097,679	19,137,055	20,234,734	4,703	131,763		136,466	20
795 ACSR								21
954 AAC	184,211	1,924,829	2,109,040		60,878		60,878	22
954 AAC	387,459	5,268,081	5,655,540		14,063		14,063	23
1272 AAC	86,228	7,065,037	7,151,265	5,371	24,372		29,743	24
1272 AAC								25
1272 ACSR								26
1272 ACSR	623,984	7,779,351	8,403,335		12,735		12,735	27
1272 ACSR								28
1272 ACSR	872,150	10,043,831	10,915,981					29
1590 ACSS								30
1272 AAC	205,347	10,350,488	10,555,835	32	16,887		16,919	31
1272 ACSR								32
1272 ACSR		19,521	19,521	4,269	10,073		14,342	33
1272 McMAL								34
1272 ACSR								35
	22,651,659	483,043,010	505,694,669	244,378	956,232	88,581	1,289,191	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	04/15/2020	End of 2019/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	BPA/Hot Springs #2	Noxon Plant	230.00	230.00	H Type	68.00		1
2	Coulee	West Side Sub	230.00	230.00	Steel Pole	2.00		2
3	BPA Line	West Side Sub	230.00	230.00	Steel Pole	2.00		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								
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23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	2,240.00	3.00	40

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)	
1272 AAC	3,603,324	10,069,035	13,672,359		43,315		43,315	1
1272 ACSR	8,482		8,482					2
1272 ACSR	36,461	594,543	631,004					3
1590 ACSR	155,244	2,605,651	2,760,895		2,265		2,265	4
1272 AAC	205,262	1,312,224	1,517,486		5,704		5,704	5
	595,789	37,491,331	38,087,120	97,666	137,684	88,581	323,931	6
								7
								8
								9
								10
								11
								12
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								14
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								31
								32
								33
								34
								35
	22,651,659	483,043,010	505,694,669	244,378	956,232	88,581	1,289,191	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	04/15/2020	End of 2019/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	N/A						
2							
3							
4							
5							
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41							
42							
43							
44	TOTAL						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2020	End of 2019/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).

3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage KV (Operating)	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)	
									1
									2
									3
									4
									5
									6
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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. & Distr Unatt	230.00	115.00	13.80
6	Chester	Distr. Unattended	115.00	13.80	
7	Chewelah 115Kv	Distr. Unattended	115.00	13.20	
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	Greenacres	Distr. Unattended	115.00	13.80	
22	Greenwood	Distr. Unattended	115.00	13.80	
23	Hallett & White	Distr. Unattended	115.00	13.80	
24	Indian Trail	Dist. Unattended	115.00	13.80	
25	Industrial Park	Dist. Unattended	115.00	13.80	
26	Kettle Falls	Distr. Unattended	115.00	13.80	
27	Lee & Reynolds	Distr. Unattended	115.00	13.80	
28	Liberty Lake	Distr. Unattended	115.00	13.80	
29	Lind	Dist. Unattended	115.00	13.80	
30	Little Falls 115/34Kv	Distr. Unattended	115.00	34.00	
31	Lyons & Standard	Distr. Unattended	115.00	13.80	
32	Mead	Distr. Unattended	115.00	13.80	
33	Metro	Distr. Unattended	115.00	13.80	
34	Milan	Distr. Unattended	115.00	13.80	
35	Millwood	Dist. Unattended	115.00	13.80	
36	Ninth & Central	Dist. Unattended	115.00	13.80	
37	Northeast	Distr. Unattended	115.00	13.80	
38	Northwest	Distr. Unattended	115.00	13.80	
39	Opportunity	Dist. Unattended	115.00	13.80	
40	Othello	Distr. Unattended	115.00	13.80	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2020	Year/Period of Report End of 2019/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Number of Units (j)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Total Capacity (In MVa) (k)	Line No.
						1
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
318	3		Two Stage Fan	3	530	5
24	2		Frcd Oil & Air Fan	2	40	6
12	1		Two Stage Fan	1	20	7
12	1		Frcd Oil&Air Fan&Cap	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
12	1		Frcd Oil & Air Fan	1	20	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
16	2		One Stage Fan	1	17	19
12	1		Frcd Oil & Air Fan	1	20	20
18	1		Two Stage Fan	1	30	21
12	1		Two Stage Fan	1	20	22
36	2		Two Stage Fan	2	60	23
12	1		Two Stage Fan	1	20	24
24	2		Two Stg/Frcd Oil&Cap	14	40	25
12	1		Frcd Oil & Air Fan	1	20	26
36	2		Two Stage Fan	2	60	27
24	2		Two Stage Fan	2	40	28
12	1		Two Stage Fan	1	20	29
12	1					30
36	2		Two Stage Fan	2	60	31
18	1		Two Stage Fan	1	30	32
24	2		Two Stage Fan	2	40	33
24	2		Frcd Oil & Air Fan	2	40	34
24	2		Two Stage Fan	2	40	35
36	2		Two Stage Fan	2	60	36
24	2		Two Stage Fan	2	40	37
24	2		Two Stage Fan	2	40	38
12	1		Two Stage Fan	1	20	39
24	2		FrOil/AirFan/2StgFn	2	40	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 (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Post Street	Distr. Unattended	115.00	13.80	
2	Pound Lane	Distr. Unattended	115.00	13.80	
3	Ross Park	Distr. Unattended	115.00	13.80	
4	Roxboro	Distr. Unattended	115.00	24.00	
5	Shawnee	Trans. Unattended	230.00	115.00	13.80
6	Silver Lake	Distr. Unattended	115.00	13.80	
7	Southeast	Distr. Unattended	115.00	13.80	
8	South Othello	Distr. Unattended	115.00	13.80	
9	South Pullman	Distr. Unattended	115.00	13.80	
10	Sunset	Distr. Unattended	115.00	13.80	
11	Terre View	Dist. Unattended	115.00	13.80	
12	Third & Hatch	Distr. Unattended	115.00	13.80	
13	Turner	Dist. Unattended	115.00	13.80	
14	Waikiki	Distr. Unattended	115.00	13.80	
15	West Side	Trans. Unattended	230.00	115.00	13.80
16	Other: 27 substa less than 10MVA	Distr. Unattended			
17					
18	STATE OF IDAHO				
19	Appleway	Dist. Unattended	115.00	13.80	
20	Avondale	Dist. Unattended	115.00	13.80	
21	Benewah	Trans. Unattended	230.00	115.00	13.80
22	Big Creek	Distr. Unattended	115.00	13.80	
23	Blue Creek	Distr. Unattended	115.00	13.80	
24	Bunker Hill Limited	Distr. Unattended	115.00	13.80	
25	Cabinet Gorge (Switchyard)	Trans. Unattended	230.00	115.00	13.80
26	Clark Fork	Distr. Unattended	115.00	21.80	
27	Coeur d'Alene 15th Ave	Distr. Unattended	115.00	13.80	
28	Cottonwood	Distr. Unattended	115.00	24.90	
29	Dalton	Distr. Unattended	115.00	13.80	
30	Grangeville	Distr. Unattended	115.00	13.80	
31	Holbrook	Distr. Unattended	115.00	13.80	
32	Huetter	Distr. Unattended	115.00	13.80	
33	Idaho Road	Distr Unattended	115.00	13.80	
34	Juliaetta	Distr. Unattended	115.00	13.80	
35	Kamiah	Dist. Unattended	115.00	13.80	
36	Kooskia	Distr. Unattended	115.00	13.80	
37	Lewiston Mill Rd	Distr. Unattended	115.00	13.20	
38	Lolo	Tran & Dist Unattnd	230.00	115.00	13.80
39	Moscow	Distr. Unattended	115.00	13.80	
40	Moscow 230Kv	Tran & Dist Unattnd	230.00	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)	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)	
36	2		Frcd Oil	2	60	1
24	2		Two Stage Fan	2	40	2
30	2		Two Stage Fan	2	54	3
24	2		Two Stage Fan	2	40	4
150	1		Two Stage Fan	1	250	5
12	1		Two Stage Fan	1	20	6
36	2		Two Stage Fan	2	60	7
12	1		Two Stage Fan	1	20	8
30	2		Two Stage Fan	2	50	9
33	2		Two Stage Fan & Caps	50	55	10
12	1		Two Stage Fan	1	20	11
54	3		Two Stg Fan & Cap	103	90	12
36	2		Two Stg Fan	2	60	13
24	2		Two Stage Fan	2	40	14
275	2		Two Stage Fan	1	375	15
164	28					16
						17
						18
36	2		Two Stage Fan	2	60	19
12	1		Two Stage Fan	1	20	20
75	1		Two Stage Fan & Caps	223	125	21
18	2		Portable Fan	2	22	22
12	1		Two Stage Fan	1	20	23
12	1		Frcd Air Fan	1	16	24
75	1		Two Stage Fan	1	125	25
10	1		Frcd Air Fan	1	13	26
36	2		Two Stage Fan	2	60	27
12	1		Two Stage Fan	1	20	28
12	1		Two Stage Fan	1	20	29
25	4		FrcdOil/Air/Pt Fan&C	17	34	30
12	1		Two Stage Fan	1	20	31
12	1		Two Stage Fan	1	20	32
12	1		Two Stage Fan	1	20	33
12	1		Frcd Oil & Air Fan	1	20	34
12	1		Two Stage Fan	1	20	35
15	3		Frcd Air Fan	3	20	36
18	1		Two Stage Fan	1	30	37
262	3		Frcd Oil/Air/Two Stg	1	270	38
24	2		FrOil/Air/2Stg Fan	2	40	39
162	2		Frcd Air Fan & Caps	76	270	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	04/15/2020	End of 2019/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	North Moscow	Distr. Unattended	115.00	13.80	
3	Oden	Distr. Unattended	115.00	21.80	
4	Oldtown	Distr. Unattended	115.00	21.80	
5	Orofino	Distr. Unattended	115.00	24.00	
6	Osburn	Distr. Unattended	115.00	13.80	
7	Pine Creek	Tran & Dist Unattnd	230.00	115.00	13.80
8	Pleasant View	Distr. Unattended	115.00	13.80	
9	Plummer	Dist Unattended	115.00	13.80	
10	Post Falls	Distr. Unattended	115.00	13.80	
11	Potlatch	Distr. Unattended	115.00	24.90	
12	Prarie	Distr. Unattended	115.00	13.80	
13	Priest River	Distr. Unattended	115.00	20.80	
14	Rathdrum	Trans & Distr Unattd	230.00	115.00	13.80
15	Sagle	Dist. Unattended	115.00	21.80	
16	Sandpoint	Distr. Unattended	115.00	20.80	
17	South Lewiston	Distr. Unattended	115.00	13.80	
18	Sweetwater	Distr. Unattended	115.00	24.90	
19	St. Maries	Distr. Unattended	115.00	23.90	
20	Tenth & Stewart	Distr. Unattended	115.00	13.80	
21					
22	Other: 13 substa less than 10 MVA	Distr. Unattended			
23					
24	STATE OF MONTANA				
25	1 substation less than 10 MVA	Distr. Unattended			
26					
27	SUBSTA. @ GENERATING PLANTS				
28	STATE OF WASHINGTON				
29	Boulder Park	Trans. Attended	115.00	13.80	
30	Kettle Falls	Trans. Attended	115.00	13.80	
31	Long Lake	Trans. Attended	115.00	4.00	
32	Nine Mile	Trans. Attended	115.00	13.80	
33	Little Falls	Trans. Attended	115.00	4.00	
34	Northeast	Trans. Attended	115.00	13.80	
35	Post Street	Trans. Attended	13.80	4.00	
36					
37	STATE OF IDAHO				
38	Cabinet Gorge (HED)	Trans. Attended	230.00	13.80	
39	Post Falls	Trans. Attended	115.00	2.30	
40	Rathdrum	Trans. Attended	115.00	13.80	

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
12	1		Two Stage Fan	1	20	2
10	1		Frcd Air Fan	1	13	3
18	2		Frcd Air Fan	2	22	4
20	2		Frcd Oil & Air Fan	1	28	5
12	1		Portable Fan	1	15	6
212	3		Two Stg Fan/Capacito	45	270	7
12	1		Two Stage Fan	1	20	8
12	1		Two Stage Fan	1	20	9
18	1		Two Stage Fan	1	30	10
15	2		Portable Fan	2	19	11
12	1		Frcd Oil & Air Fan	1	20	12
10	1		Frcd Air Fan	1	13	13
474	4		Frcd Oil & Air Fan	50	490	14
12	1		Two Stage Fan	1	20	15
30	3		Frcd Air Fan	3	38	16
27	4		Port Fan/FrcdOil/Air	4	39	17
12	1		Frcd Oil & Air Fan	1	20	18
24	2		Two Stage Fan	2	40	19
30	2		Frcd Oil/Air/Two Stg	2	50	20
						21
73	13					22
						23
						24
5	1					25
						26
						27
						28
36	1		Two Stage Fan	1	60	29
34	1	1	Two Stage Fan	1	62	30
80	4	1				31
42	2		Two Stage Fan	1	56	32
24	2		Frcd Oil & Air Fan	2	40	33
36	1		Two Stage Fan	1	60	34
35	2					35
						36
						37
300	6	1				38
16	2		Frcd Air/Oil/Air Fan	2	21	39
114	2	1	Two Stage Fan	2	190	40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2020	End of 2019/Q4

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1					
2	STATE OF MONTANA				
3	Noxon	Trans. Attended	230.00	13.80	
4					
5	STATE OF OREGON				
6	Coyote Springs II	Trans. Attended	500.00	13.80	18.00
7					
8	SUMMARY:				
9	Washington: 3 subs	Trans. Unattended			
10	76 subs	Distr. Unattended			
11	2 subs	Tran & Dist Unattnd			
12	7 subs	Trans. Attended			
13	Idaho 2 subs	Trans. Unattended			
14	48 subs	Distr. Unattended			
15	5 subs	Tran & Dist Unattnd			
16	3 subs	Trans. Attended			
17	Montana: 1 sub	Trans. Attended			
18	1 sub	Distr. Unattended			
19	Oregon: 1 sub	Trans. Unattended			
20	System: 149 subs				
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
						2
435	9	1	Two Stage Fan	6	635	3
						4
						5
213	1		Two Stage fan	1	355	6
						7
						8
575						9
1271						10
854						11
287						12
150						13
661						14
1368						15
430						16
435						17
5						18
213						19
6249						20
						21
						22
						23
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						40

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2020	Year/Period of Report End of 2019/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Corporate Support	Salix Inc.	146000	261,360
22	Corporate Support	Avista Development Inc	146000	281,610
23				
24				
25				
26				
27				
28				
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