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)

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 2020/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 2020/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 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	04/15/2021

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 Krasselt	Ryan L. Krasselt	
02 Title		
VP, Controller, Prin. Acctg	Ryan Krasselt	04/15/2021

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.

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".

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/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".

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/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	04/15/2021	End of 2020/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	Avista Edge, Inc.	Investment in Internet Tech.	100	3
4	Pentzer Corporation	Parent of Bay Area Mfg and	100	4
5		Penture Venture Holdings		
6	Pentzer Venture Holdings II, Inc.	Holding Company-Inactive	100	5
7	Bay Area Manufacturing, Inc.	Holding Company	100	6
8	Avista Capital II	Affiliated business trust	100	7
9		issued pref trust Securities		
10	Avista Northwest Resources, LLC	Owns an interest in a venture	100	8
11		fund investment		
12	Steam Plant Square, LLC	Office & Retail Leasing	100	9
13	Courtyard Office Center, LLC	Office & Retail Leasing	100	10
14	Steam Plant Brew Pub, LLC	Restaurant Operations	100	11
15	Salix, Inc.	Liquified Natural Gas Operati	100	12
16	Alaska Energy and Resources Company (AERC)	Parent Co of Alaska Opertions	100	13
17	Alaska Electric Light and Power Company	Utility Operations in Juneau	100	14
18	AJT Mining Properties, Inc.	Inactive mining Co holding	100	15
19		Certain Properties		
20	Snettisham Electric Company	Right to Purchase Snetti	100	16
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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.: 4 Column: d

Subsidiary of Avista Capital

Schedule Page: 103 Line No.: 6 Column: d

Subsidiary of Pentzer Coporation

Schedule Page: 103 Line No.: 7 Column: d

Subsidiary of Pentzer Corporation

Schedule Page: 103 Line No.: 8 Column: d

Subsidiary of Avista Corporation

Schedule Page: 103 Line No.: 10 Column: d

Subsidiary of Avista Capital

Schedule Page: 103 Line No.: 12 Column: d

Subsidiary of Avista Development

Schedule Page: 103 Line No.: 13 Column: d

Subsidiary of Avista Development

Schedule Page: 103 Line No.: 14 Column: d

Subsidiary of Steam Plant Square, LLC

Schedule Page: 103 Line No.: 15 Column: d

Subsidiary of Avista Capital

Schedule Page: 103 Line No.: 16 Column: d

Subsidiary of Avista Corporation

Schedule Page: 103 Line No.: 17 Column: d

Subsidiary of AERC

Schedule Page: 103 Line No.: 18 Column: d

Subsidiary of AERC

Schedule Page: 103 Line No.: 20 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	04/15/2021	End of 2020/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	737,693
2			
3	Executive Vice President, Chief Financial Officer	M. T. Thies	452,615
4	and Treasurer		
5			
6	Senior Vice President, External Affairs	K. J. Christie	333,462
7	and Chief Customer Officer		
8			
9	Sr Vice President	M. M. Durkin	237,539
10	(retired effective 8/1/2020)		
11			
12	Senior Vice President and Chief Human Resources Officer	K. S. Feltes	71,154
13	(retired effective 3/1/2020)		
14			
15	Senior Vice President, Energy Delivery	H. L. Rosentrater	329,385
16	and Shared Services		
17			
18	Senior Vice President, Energy Resources	J. R. Thackston	332,692
19	and Environmental Compliance Officer		
20			
21	Vice President, Safety and Human Resources	B. A. Cox	270,769
22			
23	Vice President, General Council, Corporate Secretary	G. C. Hessler	198,369
24	and Chief Ethics/ Compliance Officer		
25	(effective 1/1/2020)		
26			
27	Vice President Community & Economic Vitality	L. D. Hill	198,899
28	(effective 1/1/2020)		
29			
30	Vice President, Chief Information Officer, and	J. M. Kensok	290,077
31	Chief Security Officer		
32			
33	Vice President, Controller, and	R. L. Krasselt	251,308
34	Principal Accounting Officer		
35			
36	Vice President and Chief Counsel for Regulatory	D. J. Meyer	303,478
37	and Governmental Affairs		
38			
39	Vice President and Chief Strategy Officer	E. D. Schlect	272,231
40			
41	Executive Chairman of the Board of Directors	S. L. Morris	166,154
42	(retired effectitve 3/1/2020)		
43			
44			

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	Dennis P. Vermillion ***	1411 E. Mission Ave, Spokane, WA 99202
5	President and CEO	
6		
7	Kristianne Blake***	P.O. Box 3727, Spokane, WA 99220
8		
9	Donald C. Burke	16 Ivy Court, Langhorne, PA 19047
10		
11	Scott H. Maw	115 NW 78th St., Seattle, WA 98117
12		
13	Rebecca A. Klein	611 S. Congress Ave., Suite 125, Austin, TX 78704
14		
15	Jeffry L. Philipps	P.O. Box 9000, Spokane, WA 99209
16		
17	Marc F. Racicot	2234 Deerfield Ln., Helena, MT 59601
18		
19	Heidi B. Stanley***	P.O. Box 2884, Spokane, WA 99220
20		
21	R. John Taylor***	111 Main Street, Lewiston, ID 83501
22		
23	Janet D. Widmann	26 Sanford Ln., Lafayette, CA 94549
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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	04/15/2021	End of 2020/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 Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2021	Year/Period of Report End of 2020/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	04/15/2021	End of 2020/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. None
4. None
5. None
6. Reference is made to Notes 11, 12, 13 and 14 of the Notes to Financial Statements.
7. None
8. Average annual wage increases were 3.0% for non-exempt employees effective March 2, 2020. Average annual wage increases were 3.1% for exempt employees effective March 2, 2020. Officers received average increases of 5.5% effective February 22, 2020. Certain bargaining unit employees received increases of 3.0% effective March 26, 2020.
9. Reference is made to Note 17 of the Notes to Financial Statements.
10. None
11. Reserved
12. See page 123 of this report.

13. Effective March 1, 2020, Karen S. Feltes, Senior Vice President and Chief Human Resources Officer, retired.

Effective January 1, 2020, Marian Durkin moved from Chief Compliance Officer to Chief Legal Officer. She retained her role as the Corporate Secretary. Effective August 1, 2020, Marian Durkin retired.

Effective January 1, 2020, Greg Hesler has been promoted from Senior Counsel II to Vice President, General Counsel and Chief Compliance Officer. Effective May 11, 2020, Greg Hesler has been promoted from Chief Compliance Officer to Chief Ethics/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.

On March 10, 2021, the Company announced Sena Kwawu has been nominated to join the Avista Corp. board of directors. Mr. Kwawu will stand for election by the shareholders and, if elected, will join the baord effective May 11, 2021.

On March 10, 2021, the Company announced the upcoming retirement of board of directors member, Marc Racicot, who has reached the mandatory retirement age of 72 under the Company's bylaws.

14. Proprietary capital is not less than 30 percent.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/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	6,713,727,078	6,385,433,383
3	Construction Work in Progress (107)	200-201	172,073,892	157,909,990
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		6,885,800,970	6,543,343,373
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	2,294,362,603	2,121,893,905
6	Net Utility Plant (Enter Total of line 4 less 5)		4,591,438,367	4,421,449,468
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)		4,591,438,367	4,421,449,468
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)		5,311,287	4,340,610
19	(Less) Accum. Prov. for Depr. and Amort. (122)		212,107	176,234
20	Investments in Associated Companies (123)		11,547,000	11,547,000
21	Investment in Subsidiary Companies (123.1)	224-225	207,410,331	207,105,954
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)		77,890	77,973
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		24,673,077	22,034,002
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		596,015	922,948
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		249,403,493	245,852,253
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		7,363,358	3,067,240
36	Special Deposits (132-134)		4,335,989	4,434,090
37	Working Fund (135)		1,116,351	730,965
38	Temporary Cash Investments (136)		152,774	155,890
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		161,513,344	153,814,552
41	Other Accounts Receivable (143)		56,664,630	15,726,829
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		11,336,140	2,373,469
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		719,507	222,671
45	Fuel Stock (151)	227	4,088,628	4,148,891
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	51,854,056	46,558,819
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	0	0
55	Gas Stored Underground - Current (164.1)		9,535,324	14,305,397
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		26,280,659	24,682,259
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		24,973	129,823
60	Rents Receivable (172)		2,934,797	3,609,147
61	Accrued Utility Revenues (173)		0	0
62	Miscellaneous Current and Accrued Assets (174)		236,392	193,803
63	Derivative Instrument Assets (175)		1,523,219	1,780,327
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		596,015	922,948
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)		316,411,846	270,264,286
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		15,341,337	13,795,819
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	717,281,643	643,207,368
73	Prelim. Survey and Investigation Charges (Electric) (183)		0	0
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)		152,201	131,978
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	29,826,563	18,484,386
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)		7,512,371	8,883,821
82	Accumulated Deferred Income Taxes (190)	234	216,728,536	177,056,526
83	Unrecovered Purchased Gas Costs (191)		1,433,580	-3,189,401
84	Total Deferred Debits (lines 69 through 83)		988,276,231	858,370,497
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		6,152,522,013	5,802,928,580

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	end of 2020/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	1,249,688,206	1,176,498,977
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	-47,076,877	-44,938,398
11	Retained Earnings (215, 215.1, 216)	118-119	771,613,505	747,158,701
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-13,577,380	-13,386,701
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)	-14,378,164	-10,258,024
16	Total Proprietary Capital (lines 2 through 15)		2,029,726,333	1,934,254,640
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	2,017,200,000	1,904,200,000
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)		133,250	142,133
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		843,651	930,270
24	Total Long-Term Debt (lines 18 through 23)		1,984,336,599	1,871,258,863
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		67,716,314	65,565,105
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		395,000	245,000
29	Accumulated Provision for Pensions and Benefits (228.3)		211,880,117	212,005,607
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		3,820,594	11,767,158
32	Long-Term Portion of Derivative Instrument Liabilities		37,427,278	19,684,476
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		17,194,050	20,338,053
35	Total Other Noncurrent Liabilities (lines 26 through 34)		338,433,353	329,605,399
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		202,000,000	182,300,000
38	Accounts Payable (232)		104,217,591	107,406,813
39	Notes Payable to Associated Companies (233)		8,742,915	14,722,348
40	Accounts Payable to Associated Companies (234)		0	0
41	Customer Deposits (235)		3,028,142	4,745,573
42	Taxes Accrued (236)	262-263	45,266,874	38,022,918
43	Interest Accrued (237)		15,884,942	15,282,041
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)		111,813	168,034
48	Miscellaneous Current and Accrued Liabilities (242)		60,781,094	50,808,479
49	Obligations Under Capital Leases-Current (243)		4,249,213	4,127,561
50	Derivative Instrument Liabilities (244)		51,435,582	30,612,670
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		37,427,277	19,684,476
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)		458,290,889	428,511,961
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		2,444,383	2,083,490
57	Accumulated Deferred Investment Tax Credits (255)	266-267	29,866,627	30,443,961
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	31,450,029	29,659,558
60	Other Regulatory Liabilities (254)	278	473,121,377	481,207,133
61	Unamortized Gain on Reaquired Debt (257)		1,318,822	1,448,359
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		603,415,433	514,870,007
64	Accum. Deferred Income Taxes-Other (283)		200,118,168	179,585,209
65	Total Deferred Credits (lines 56 through 64)		1,341,734,839	1,239,297,717
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		6,152,522,013	5,802,928,580

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/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	1,379,875,645	1,428,099,066		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	762,581,592	818,533,678		
5	Maintenance Expenses (402)	320-323	74,568,922	70,160,821		
6	Depreciation Expense (403)	336-337	181,300,837	163,503,287		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	44,668,607	40,625,925		
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)		12,453,020	7,343,186		
13	(Less) Regulatory Credits (407.4)		57,223,861	24,373,462		
14	Taxes Other Than Income Taxes (408.1)	262-263	114,634,576	104,229,614		
15	Income Taxes - Federal (409.1)	262-263	-41,194,492	1,016,853		
16	- Other (409.1)	262-263	654,441	-512,990		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	134,834,319	16,095,155		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	82,145,804	3,735,815		
19	Investment Tax Credit Adj. - Net (411.4)	266	-577,334	718,518		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,144,653,870	1,193,703,817		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		235,221,775	234,395,249		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/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
942,731,364	983,483,744	437,144,281	444,615,322			2
						3
479,296,895	515,395,521	283,284,697	303,138,157			4
58,433,891	54,542,409	16,135,031	15,618,412			5
142,059,284	126,679,057	39,241,553	36,824,230			6
						7
32,861,811	30,546,857	11,806,796	10,079,068			8
99,047	99,047					9
						10
						11
8,161,579	5,890,125	4,291,441	1,453,061			12
47,876,238	20,930,818	9,347,623	3,442,644			13
86,303,016	79,246,048	28,331,560	24,983,566			14
-21,919,271	7,445,054	-19,275,221	-6,428,201			15
-214,113	-504,880	868,554	-8,110			16
83,467,206	5,035,837	51,367,113	11,059,318			17
61,963,304	2,388,896	20,182,500	1,346,919			18
-562,691	546,262	-14,643	172,256			19
						20
						21
						22
						23
						24
758,147,112	801,601,623	386,506,758	392,102,194			25
184,584,252	181,882,121	50,637,523	52,513,128			26

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2021	Year/Period of Report End of 2020/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)		235,221,775	234,395,249		
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)		108,256			
34	(Less) Expenses of Nonutility Operations (417.1)		5,439,625	14,612,589		
35	Nonoperating Rental Income (418)		-31,838	-31,291		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	5,304,376	13,582,269		
37	Interest and Dividend Income (419)		3,448,647	4,401,265		
38	Allowance for Other Funds Used During Construction (419.1)		338,811	-104,311		
39	Miscellaneous Nonoperating Income (421)					
40	Gain on Disposition of Property (421.1)		289,281	109,159		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		4,017,908	3,344,502		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)		-815,484	-33,721		
45	Donations (426.1)		2,999,603	11,332,979		
46	Life Insurance (426.2)		3,072,596	2,640,044		
47	Penalties (426.3)		-17,039	21,180		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,773,265	1,718,553		
49	Other Deductions (426.5)		3,494,855	27,317,212		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		10,507,796	42,996,247		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	923,792	311,708		
53	Income Taxes-Federal (409.2)	262-263	-60,470	-8,257,303		
54	Income Taxes-Other (409.2)	262-263	800	-350,985		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	218,831	-1,887,439		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	3,167,528	196,940		
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)		-2,084,575	-10,380,959		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		-4,405,313	-29,270,786		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		88,943,779	86,591,405		
63	Amort. of Debt Disc. and Expense (428)		937,453	321,206		
64	Amortization of Loss on Reaquired Debt (428.1)		2,222,423	2,266,506		
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)		186,289	489,554		
68	Other Interest Expense (431)		6,170,081	8,205,985		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		2,152,002	4,169,530		
70	Net Interest Charges (Total of lines 62 thru 69)		96,299,140	93,696,243		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		134,517,322	111,428,220		
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)		134,517,322	191,949,607		

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STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		705,980,176	623,531,170
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		129,212,946	178,367,338
17	Appropriations of Retained Earnings (Acct. 436)			
18			-4,274,423	(3,725,554)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-4,274,423	(3,725,554)
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			-110,253,196	(102,772,642)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-110,253,196	(102,772,642)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		5,495,054	10,579,864
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		726,160,557	705,980,176
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39			45,452,948	41,178,525
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	04/15/2021	End of 2020/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)		45,452,948	41,178,525
	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)		45,452,948	41,178,525
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		771,613,505	747,158,701
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-13,386,701	(16,389,107)
50	Equity in Earnings for Year (Credit) (Account 418.1)		5,304,376	13,582,269
51	(Less) Dividends Received (Debit)		5,000,000	10,000,000
52	Corporate Costs Allocated to Subsidiaries		-495,055	(579,863)
53	Balance-End of Year (Total lines 49 thru 52)		-13,577,380	(13,386,701)

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2021	Year/Period of Report End of 2020/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)	134,517,322	191,949,607
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	225,969,444	202,496,251
5	Amortization of Deferred Power and Natural Gas Costs	-9,923,228	-45,916,643
6	Amortization of Debt Expense	3,150,992	2,578,830
7	Amortization of Investment in Exchange Power		1,632,961
8	Deferred Income Taxes (Net)	49,739,817	10,274,962
9	Investment Tax Credit Adjustment (Net)	-577,334	718,518
10	Net (Increase) Decrease in Receivables	-51,466,229	-9,860,829
11	Net (Increase) Decrease in Inventory	-464,901	-6,255,653
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	6,150,782	1,823,471
14	Net (Increase) Decrease in Other Regulatory Assets	-9,597,307	-6,065,721
15	Net Increase (Decrease) in Other Regulatory Liabilities	-4,626,804	-5,135,361
16	(Less) Allowance for Other Funds Used During Construction	6,711,875	6,434,430
17	(Less) Undistributed Earnings from Subsidiary Companies	5,304,376	13,582,269
18	Other (provide details in footnote):	7,562,554	74,394,412
19	Allowance for Doubtful Accounts	4,149,939	400,000
20	Changes in Other Non-Current Assets and Liabilities	8,520,219	10,396,693
21	Cash Paid for Settlement of Interest Rate Swaps	-33,499,271	-13,325,137
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	317,589,743	390,089,662
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-399,504,892	-439,249,001
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)	-399,504,892	-439,249,001
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	570,225	882,641
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	-6,476,269	-3,693,898
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
54	Other	-1,362,792	-1,750,738
55	Dividends Received from Subsidiaries	5,000,000	10,000,000
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-401,773,728	-433,810,996
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	165,000,000	180,000,000
62	Preferred Stock		
63	Common Stock	72,200,592	64,572,145
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)	19,700,000	
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	256,900,592	244,572,145
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-52,000,000	-90,000,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):	-2,408,161	-891,513
77	Debt Issuance Costs	-3,376,862	-1,115,527
78	Net Decrease in Short-Term Debt (c)		-7,700,000
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-110,253,196	-102,772,642
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	88,862,373	42,092,463
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	4,678,388	-1,628,871
87			
88	Cash and Cash Equivalents at Beginning of Period	3,954,095	5,582,966
89			
90	Cash and Cash Equivalents at End of period	8,632,483	3,954,095

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

Power and natural gas deferrals	1,092,888
Change in special deposits	1,579,362
Change in other current assets	(861,790)
Non-cash stock compensation	5,846,058
Gain on sale of property and equipment	(289,281)
Other	195,317

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

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.: 76 Column: b

Payment of minimum tax withholdings for share-based payment awards	(2,408,161)

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

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

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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:

	2020	2019
Avista Corp.		
Ratio of depreciation to average depreciable property	3.43%	3.28%

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

	Avista Corp.
Electric thermal/other production	27
Hydroelectric production	81
Electric transmission	49
Electric distribution	39
Natural gas distribution property	44
Other shorter-lived general plant	8

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 Statements 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. 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.'s 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 effective AFUDC rate was the following for the years ended December 31:

	2020	2019
Avista Corp.		
Effective state AFUDC rate	7.25%	7.39%

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.

The Company did not incur any penalties on income tax positions in 2020 or 2019. The Company would recognize interest accrued related to income tax positions as interest expense and any penalties incurred as other operating expense.

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):

	2020	2019
Stock-based compensation expense	$ 5,846	$ 11,353
Income tax benefits	1,228	2,384
Excess tax benefits (expenses) on settled share-based employee payments	(165)	(612)

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:

	2020	2019
Restricted Shares		
Shares granted during the year	45,540	50,061
Shares vested during the year	56,203	48,228
Unvested shares at end of year	71,706	93,351
Unrecognized compensation expense at end of year (in thousands)	$ 2,003	$ 2,054
TSR Awards		
TSR shares granted during the year	47,848	99,214
TSR shares vested during the year (1)	71,299	106,858
Unvested TSR shares at end of year	122,133	178,035
Unrecognized compensation expense (in thousands)	$ 2,296	$ 3,377
CEPS Awards		
CEPS shares granted during the year	47,848	49,609
CEPS shares vested during the year	35,622	53,454
CEPS shares earned based on market metrics	63,763	106,908
Unvested CEPS shares at end of year	83,464	88,990
Unrecognized compensation expense (in thousands)	$ 1,090	$ 2,401

(1) The market metrics were not met during 2020 and 2019 and no TRS shares were earned during these periods.

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, 2020 and 2019, the Company had recognized cumulative compensation expense and a liability of $0.8 million and $0.9 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).

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 15 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. See Note 3 for discussion on decoupling revenue deferrals.

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 Debt Repurchase Costs

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 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):

	2020	2019
Appropriated retained earnings	$ 45,453	$ 41,179

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, 2020, the Company has not recorded any significant amounts related to unresolved contingencies. See Note 17 for further discussion of the Company's commitments and contingencies.

COVID-19

In 2020, the WUTC, IPUC, and OPUC approved accounting orders that allow the Company to defer certain net COVID-19 related costs and benefits. As such, as of December 31, 2020, the Company has deferred a net benefit to customers of $2.8 million for all jurisdictions.

The respective regulatory authorities will determine the appropriateness and prudency of any deferred expenses when the Company seeks recovery. See “Regulatory Deferred Charges and Credits”.

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):

	2020	2019
Avista Capital	$ (2,491)	$ 6,404
AERC	7,795	7,178
Total equity in earnings of subsidiary companies	$ 5,304	$ 13,582

Subsequent Events

Management has evaluated the impact of events occurring after December 31, 2020 up to February 23, 2021, the date that Avista Corp.’s U.S. GAAP financial statements were issued and has updated such evaluation for disclosure purposes through the date of this filing. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

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 Sheets through recognition of right-of-use (ROU) assets and lease liabilities for the Company's operating leases. Accounting for finance leases (formerly capital leases) remained substantially unchanged. See Note 4 for further information on the Company's leases.

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 became effective on January 1, 2020 and the requirements of this ASU did not have a material impact on the Company's fair value disclosures. See Note 15 for the Company's fair value disclosures.

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 became effective for periods ending after December 15, 2020 and the requirements of this ASU did not have a material impact on the Company’s disclosures upon adoption.

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):

	2020	2019
Unbilled accounts receivable	$ 68,545	$ 60,560

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 specifies 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 Statements 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 Statements 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 Tax Cuts and Jobs Act, 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):

	2020	2019
Utility-related taxes	$ 59,319	$ 59,528

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, 2020, the Company estimates it had unsatisfied capacity performance obligations of $23.8 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):

	2020	2019

Avista Corp.		
Revenue from contracts with customers	$ 1,168,207	$ 1,160,853
Derivative revenues	203,099	246,355
Alternative revenue programs	(3,814)	9,614
Deferrals and amortizations for rate refunds to customers	4,795	1,093
Other utility revenues	7,589	10,184
Total Avista Corp.	1,379,876	1,428,099

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):

	2020	2019
ELECTRIC OPERATIONS		
Revenue from contracts with customers		
Residential	$ 377,785	$ 369,102
Commercial and governmental	303,972	317,589
Industrial	113,563	114,530
Public street and highway lighting	7,304	7,448
Total retail revenue	802,624	808,669
Transmission	18,236	18,180
Other revenue from contracts with customers	19,252	26,969
Total revenue from contracts with customers	$ 840,112	$ 853,818

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):

	2020 Avista Corp.	2019 Avista Corp.
NATURAL GAS OPERATIONS		
Revenue from contracts with customers		
Residential	$ 213,612	$ 196,430
Commercial	94,937	92,168
Industrial and interruptible	7,128	5,263
Total retail revenue	315,677	293,861
Transportation	7,917	8,674
Other revenue from contracts with customers	4,501	4,500
Total revenue from contracts with customers	$ 328,095	$ 307,035

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 73 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 Sheets. Total short-term lease costs for the year ended December 31, 2020 are immaterial.

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

	2020	2019

Operating lease cost:		
Fixed lease cost	$ 4,746	$ 4,425
Variable lease cost	1,099	988
Total operating lease cost	$ 5,845	$ 5,413

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

	2020	2019
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash outflows:		
Operating lease payments	$ 4,612	$ 4,375

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

	December 31, 2020	December 31, 2019
Operating Leases		
Operating lease ROU assets (Utility Plant)	$ 71,891	$ 69,746
Obligations under capital lease - current	$ 4,249	$ 4,128
Obligations under capital lease - noncurrent	67,716	65,565
Total operating lease liabilities	$ 71,965	$ 69,693
Weighted Average Remaining Lease Term		
Operating leases	25.20 years	26.60 years
Weighted Average Discount Rate		
Operating leases	4.28%	3.82%

Maturities of lease liabilities (including principal and interest) were as follows as of December 31, 2020 (dollars in thousands):

	Operating Leases
2021	$ 4,779
2022	4,799
2023	4,827
2024	4,852
2025	4,865
Thereafter	96,734
Total lease payments	$ 120,856
Less: imputed interest	(48,891)
Total	$ 71,965

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

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, 2020 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

2021	1	224	10,353	65,188	17	451	5,448	39,273
2022	—	—	450	25,525	—	—	1,360	12,030
2023	—	—	—	4,950	—	—	1,360	900
2024	—	—	—	—	—	—	1,370	—
2025	—	—	—	—	—	—	1,115	—

As of December 31, 2020, there are no expected deliveries of energy commodity derivatives after 2025.

The following table presents the underlying energy commodity derivative volumes as of December 31, 2019 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
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 were no expected deliveries of energy commodity derivatives after 2022.

(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):

	2020	2019
Number of contracts	22	20
Notional amount (in United States dollars)	$ 3,860	$ 5,932
Notional amount (in Canadian dollars)	4,949	7,828

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, 2020	4	45,000	2021
	11	120,000	2022
	1	10,000	2023
December 31, 2019	7	70,000	2020
	3	35,000	2021
	10	110,000	2022

See Note 13 for discussion of the bond purchase agreement and the related settlement of interest rate swaps in connection with the pricing of the bonds in June 2020.

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 Sheets as of December 31, 2020 and December 31, 2019 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 Sheets as of December 31, 2020 (in thousands):

	Fair Value			
Derivative and Balance Sheet Location	Gross Asset	Gross Liability	Collateral Netting	Net Asset (Liability) on Balance Sheet
Foreign currency exchange derivatives				
Derivative instrument assets current	$ 30	$ —	$ —	$ 30
Interest rate swap derivatives				
Derivative instrument liabilities current	—	(19,575)	8,050	(11,525)
Long-term portion of derivative liabilities	952	(32,190)	—	(31,238)
Energy commodity derivatives				
Derivative instrument assets current	9,203	(8,306)	—	897
Long-term portion of derivative assets	1,755	(1,159)	—	596
Derivative instrument liabilities current	11,037	(14,007)	487	(2,483)
Long-term portion of derivative liabilities	1,725	(8,043)	129	(6,189)
Total derivative instruments recorded on the balance sheet	$ 24,702	$ (83,280)	$ 8,666	$ (49,912)

The following table presents the fair values and locations of derivative instruments recorded on the Balance Sheets as of December 31, 2019 (in thousands):

	Fair Value			
Derivative and Balance Sheet Location	Gross Asset	Gross Liability	Collateral Netting	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	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)

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):

	2020	2019
Energy commodity derivatives		
Cash collateral posted	$ 4,953	$ 7,812
Letters of credit outstanding	23,500	17,400
Balance sheet offsetting (cash collateral against net derivative positions)	616	3,378
Interest rate swap derivatives		
Cash collateral posted (offset by net derivative positions)	8,050	6,770

There were no letters of credit outstanding related to interest rate swap derivatives as of December 31, 2020 and December 31, 2019.

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):

	2020	2019
Interest rate swap derivatives		
Liabilities with credit-risk-related contingent features	$ 50,813	$ 34,056
Additional collateral to post	42,763	26,912

NOTE 6. JOINTLY OWNED ELECTRIC FACILITIES

The Company has a 15 percent ownership interest in Units 3 & 4 of the Colstrip generating station, a coal-fired plant located in southeastern Montana, and provides financing for its ownership interest in the project. Pursuant to the ownership and operating agreements among the co-owners, 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):

	2020	2019
Utility plant in service	$ 391,922	$ 387,860
Accumulated depreciation	(284,282)	(268,637)

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):

	2020	2019
Asset retirement obligation at beginning of year	$ 20,338	$ 18,266
Liabilities incurred	(2,315)	2,699
Liabilities settled	(1,645)	(1,503)
Accretion expense	816	876
Asset retirement obligation at end of year	$ 17,194	$ 20,338

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. Union employees hired on or after January 1, 2014 are still covered under the 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 2020 and 2019. The Company expects to contribute $42.0 million in cash to the pension plan in 2021.

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):

	2021	2022	2023	2024	2025	Total 2026-2030
Expected benefit payments	$ 42,390	$ 42,673	$ 42,478	$ 43,149	$ 43,752	$ 223,788

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):

	2021	2022	2023	2024	2025	Total 2026-2030
Expected benefit payments	$ 6,610	$ 6,800	$ 6,891	$ 7,021	$ 7,164	$ 37,156

The Company expects to contribute $6.8 million to other postretirement benefit plans in 2021, 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, 2020 and 2019 and the components of net periodic benefit costs for the years ended December 31, 2020 and 2019 (dollars in thousands):

	Pension Benefits		Other Post-retirement Benefits	
	2020	2019	2020	2019
Change in benefit obligation:				
Benefit obligation as of beginning of year	$ 742,382	$ 671,629	$ 159,296	$ 134,053
Service cost	22,392	19,755	3,902	3,006
Interest cost	27,853	28,417	6,042	5,598
Actuarial (gain)/loss	74,688	57,829	(2,589)	23,344
Benefits paid	(40,400)	(35,248)	(5,418)	(6,705)
Benefit obligation as of end of year	$ 826,915	$ 742,382	$ 161,233	$ 159,296
Change in plan assets:				
Fair value of plan assets as of beginning of year	$ 642,063	$ 544,051	$ 44,853	$ 36,852
Actual return on plan assets	96,591	109,942	7,320	8,001
Employer contributions	22,000	22,000	—	—
Benefits paid	(38,630)	(33,930)	—	—
Fair value of plan assets as of end of year	$ 722,024	$ 642,063	$ 52,173	$ 44,853
Funded status	$ (104,891)	$ (100,319)	$ (109,060)	$ (114,443)
Amounts recognized in the Balance Sheets:				
Current liabilities	$ (1,943)	$ (1,602)	$ (669)	$ (640)

Non-current liabilities	(102,948)	(98,717)	(108,391)	(113,803)
Net amount recognized	$ (104,891)	$ (100,319)	$ (109,060)	$ (114,443)
Accumulated pension benefit obligation	$ 710,023	$ 644,004		
Accumulated postretirement benefit obligation:				
For retirees			$ 75,876	$ 72,816
For fully eligible employees			$ 32,097	$ 34,545
For other participants			$ 53,260	$ 51,935
Included in accumulated other comprehensive loss (income) (net of tax):				
Unrecognized prior service cost	$ 1,902	$ 2,105	$ (3,570)	$ (4,400)
Unrecognized net actuarial loss	119,318	114,368	53,737	63,101
Total	121,220	116,473	50,167	58,701
Less regulatory asset	(108,301)	(107,395)	(48,708)	(57,520)
Accumulated other comprehensive loss for unfunded benefit obligation for pensions and other postretirement benefit plans	$ 12,919	$ 9,078	$ 1,459	$ 1,181

	Pension Benefits		Other Post-retirement Benefits	
	2020	2019	2020	2019
Weighted-average assumptions as of December 31:				
Discount rate for benefit obligation	3.25%	3.85%	3.27%	3.89%
Discount rate for annual expense	3.85%	4.31%	3.89%	4.32%
Expected long-term return on plan assets	5.50%	5.90%	5.30%	5.70%
Rate of compensation increase	4.74%	4.66%		
Medical cost trend pre-age 65 – initial			6.25%	5.75%
Medical cost trend pre-age 65 – ultimate			5.00%	5.00%
Ultimate medical cost trend year pre-age 65			2026	2023
Medical cost trend post-age 65 – initial			6.25%	6.50%
Medical cost trend post-age 65 – ultimate			5.00%	5.00%
Ultimate medical cost trend year post-age 65			2026	2026

	Pension Benefits		Other Post-retirement Benefits	
	2020	2019	2020	2019
Components of net periodic benefit cost:				
Service cost (a)	$ 22,392	$ 19,755	$ 3,902	$ 3,006
Interest cost	27,853	28,417	6,042	5,598
Expected return on plan assets	(34,886)	(31,763)	(2,377)	(2,101)
Amortization of prior service cost	257	257	(958)	(981)
Net loss recognition	6,717	10,216	4,871	4,013
Net periodic benefit cost	$ 22,333	$ 26,882	$ 11,480	$ 9,535

(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.

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, and absolute return. 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:

	2020	2019
Equity securities	35%	35%
Debt securities	49%	49%
Real estate	7%	7%
Absolute return	9%	9%

The target investment allocation percentages were revised in the first quarter of 2021 and the pension plan assets are being reinvested to move toward the new target investment allocation percentages of 55 percent equity securities, 40 percent debt securities, 5 percent real estate and 0 percent absolute return. The target asset allocation percentages were modified to better align the asset allocations with the funded status of the pension plan.

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.

The Company's investments in common/collective trusts have redemption limitations that permit quarterly redemptions following notice requirements of 45 to 60 days. 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 following table discloses by level within the fair value hierarchy (see Note 15 for a description of the fair value hierarchy) of the pension plan's assets measured and reported as of December 31, 2020 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ —	$ 3,309	$ —	$ 3,309
Fixed income securities:				
U.S. government issues	—	10,990	—	10,990
Corporate issues	—	279,857	—	279,857
International issues	—	39,634	—	39,634
Municipal issues	—	22,431	—	22,431

Mutual funds:				
U.S. equity securities	146,375	—	—	146,375
International equity securities	96,311	—	—	96,311
Absolute return (1)	11,640	—	—	11,640
Plan assets measured at NAV (not subject to hierarchy disclosure)				
Common/collective trusts:				
Real estate	—	—	—	29,532
Partnership/closely held investments:				
Absolute return (1)	—	—	—	47,188
International equity securities	—	—	—	26,760
Real estate	—	—	—	7,997
Total	$ 254,326	$ 356,221	$ —	$ 722,024

The following table discloses by level within the fair value hierarchy (see Note 15 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

(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 2020 and 2019.

The fair value of other postretirement plan assets was determined as of December 31, 2020 and 2019.

The following table discloses by level within the fair value hierarchy (see Note 15 for a description of the fair value hierarchy) of other postretirement plan assets measured and reported as of December 31, 2020 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Balanced index mutual fund (1)	$ 52,173	$ —	$ —	$ 52,173

The following table discloses by level within the fair value hierarchy (see Note 15 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 fund (1)	$ 44,853	$ —	$ —	$ 44,853

(1) The balanced index fund for 2020 and 2019 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):

	2020	2019
Employer 401(k) matching contributions	$ 11,742	$ 10,412

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):

	2020	2019
Deferred compensation assets and liabilities	$ 9,174	$ 8,948

NOTE 9. ACCOUNTING FOR INCOME TAXES

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, 2020, the Company had $18.3 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 $8.6 million of the state tax credits. As such, the Company has recorded a valuation allowance of $9.7 million against the state tax credit carryforwards and reflected the net amount of $8.6 million as an asset as of December 31, 2020. State tax credits expire from 2021 to 2034.

Status of Internal Revenue Service (IRS) and State Examinations

The Company and its eligible subsidiaries file federal income tax returns. All tax years after 2016 are open for an IRS tax examination.

The Company also files state income tax returns in certain jurisdictions, including Idaho, Oregon, and Montana. Subsidiaries are charged or credited with the tax effects of their operations on a stand-alone basis.

The Idaho State Tax Commission is currently reviewing tax years 2014 through 2017. All tax years after 2016 are open for examination in Montana and Oregon, and all tax years after 2017 are open for examination in Idaho.

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):

	2020	2019
Utility power resources	$ 324,297	$ 376,769

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

	2021	2022	2023	2024	2025	Thereafter	Total
Power resources	$ 181,872	$ 177,786	$ 173,536	$ 157,221	$ 157,887	$ 849,444	$ 1,697,746
Natural gas resources	67,717	52,158	42,499	35,598	32,473	241,145	471,590
Total	$ 249,589	$ 229,944	$ 216,035	$ 192,819	$ 190,360	$ 1,090,589	$ 2,169,336

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

The above future contractual commitments for power resources include fixed contractual amounts related to the Company's contracts with certain Public Utility Districts (PUD) to purchase portions of the output of certain generating facilities. Although Avista Corp. has no investment in the PUD generating facilities, the fixed contracts obligate Avista Corp. to pay certain minimum amounts whether or not the facilities are operating. The cost of power obtained under the contracts, including payments made when a facility is not operating, is included in utility resource costs in the Statements of Income. The contractual amounts included above consist of Avista Corp.'s share of existing debt service cost and its proportionate share of the variable operating expenses of these projects. The minimum amounts payable under these contracts are based in part on the proportionate share of the debt service requirements of the PUD's revenue bonds for which the Company is indirectly responsible. The Company's total future debt service obligation associated with the revenue bonds outstanding at December 31, 2020 (principal and interest) was $63.7 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):

	2021	2022	2023	2024	2025	Thereafter	Total
Contractual obligations	$ 33,885	$ 31,339	$ 32,083	$ 35,682	$ 33,706	$ 208,526	$ 375,221

NOTE 11. NOTES PAYABLE

Avista Corp. has a committed line of credit with various financial institutions in the total amount of $400.0 million. During 2020, the Company amended and extended, for one additional year, the revolving line of credit agreement for a revised expiration date of April 2022, with the option to extend for an additional one year period. The committed line of credit is secured by non-transferable first mortgage bonds of the Company issued to the agent bank that would only become due and payable in the event, and then only to the extent, that the Company defaults on its obligations under the committed 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, 2020, 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):

	2020	2019
Balance outstanding at end of period	$ 102,000	$ 182,300
Letters of credit outstanding at end of period	$ 27,618	$ 21,473
Average interest rate at end of period	1.22%	2.64%

As of December 31, 2020 and 2019, the borrowings outstanding under Avista Corp.'s committed line of credit were classified as short-term borrowings on the Balance Sheets.

NOTE 12. CREDIT AGREEMENT

In April 2020, the Company entered into a Credit Agreement with various financial institutions, in the amount of $100 million with an expiration date of April 2021. Indebtedness under this agreement is unsecured.

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 borrowed the entire $100 million available under this agreement.

NOTE 13. BONDS

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

Maturity Year	Description	Interest Rate	2020	2019
Avista Corp. Secured Long-Term Debt				
2020	First Mortgage Bonds	3.89%	—	52,000
2022	First Mortgage Bonds	5.13%	250,000	250,000

2023	Secured Medium-Term Notes	7.18%-7.54%	13,500	13,500
2028	Secured Medium-Term Notes	6.37%	25,000	25,000
2032	Secured Pollution Control Bonds (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	3.43%	180,000	180,000
2050	First Mortgage Bonds (2)	3.07%	165,000	—
2051	First Mortgage Bonds	3.54%	175,000	175,000
	Total Avista Corp. secured long-term bonds		2,017,200	1,904,200
	Secured Pollution Control Bonds held by Avista Corporation (1)		(83,700)	(83,700)
	Total long-term bonds		$ 1,933,500	$ 1,820,500

(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 September 2020, the Company issued and sold $165.0 million of 3.07 percent first mortgage bonds due in 2050 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 $52.0 million and repay a portion of the outstanding balance under Avista Corp.'s $400.0 million committed line of credit. In connection with the pricing of the first mortgage bonds in June 2020, the Company cash settled seven interest rate swap derivatives (notional aggregate amount of $70.0 million) and paid a net amount of $33.5 million. See Note 5 for a discussion of interest rate swap derivatives.

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

	2021	2022	2023	2024	2025	Thereafter	Total
Debt maturities	$ —	$ 250,000	$ 13,500	$ —	$ —	$ 1,721,547	$ 1,985,047

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, 2020, property additions and retired bonds would have allowed, and the net earnings test would not have prohibited, the issuance of $1.7 billion in an aggregate principal amount of additional first mortgage bonds at Avista Corp.

NOTE 14. ADVANCES FROM ASSOCIATED COMPANIES

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

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

	2020	2019
Low distribution rate	1.10%	2.79%
High distribution rate	2.79%	3.61%
Distribution rate at the end of the year	1.10%	2.79%

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 15. 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):

	2020		2019	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Bonds (Level 2)	$ 963,500	$ 1,189,824	$ 963,500	$ 1,124,649
Bonds (Level 3)	970,000	1,125,618	857,000	946,674
Advances from associated companies (Level 3)	51,547	43,815	51,547	41,238

These estimates of fair value of bonds and advances from associated 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 85.0 to 144.9, where a par value of 100.00 represents the carrying value recorded on the Balance Sheets. Level 2 bonds represent 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 bonds with similar risk and terms if there is no trading activity near a period end. Level 3 bonds consist of private placement bonds and advances from affiliated companies, 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 bonds 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, 2020 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, 2020					
Assets:					
Energy commodity derivatives	$ —	$ 23,645	$ —	$ (22,152)	$ 1,493
Level 3 energy commodity derivatives:					

Natural gas exchange agreements	—	—	75	(75)	—
Foreign currency exchange derivatives	—	30	—	—	30
Interest rate swap derivatives	—	952	—	(952)	—
Deferred compensation assets:					
Mutual Funds:					
Fixed income securities	2,471	—	—	—	2,471
Equity securities	6,228	—	—	—	6,228
Total	$ 8,699	$ 24,627	$ 75	$ (23,179)	$ 10,222
Liabilities:					
Energy commodity derivatives	$ —	$ 23,030	$ —	$ (22,768)	$ 262
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	8,485	(75)	8,410
Interest rate swap derivatives	—	51,765	—	(9,002)	42,763
Total	$ —	$ 74,795	$ 8,485	$ (31,845)	$ 51,435

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 agreement	—	—	27	(27)	—
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

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

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

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

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

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

Deferred compensation assets and liabilities represent funds held by the Company in a Rabbi Trust for an executive deferral plan. These funds consist of actively traded equity and bond funds with quoted prices in active markets. The balance disclosed in the table above excludes cash and cash equivalents of $0.5 million as of December 31, 2020 and $0.4 million as of December 31, 2019.

Level 3 Fair Value

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, 2020 (dollars in thousands):

	Fair Value (Net) at December 31, 2020	Valuation Technique	Unobservable Input	Range
Natural gas exchange	(8,410)	Internally derived weighted average cost of gas	Forward purchase prices	$1.71 - $2.54/mmBTU $2.01 Weighted Average
			Forward sales prices	$1.76 - $4.16/mmBTU $3.22 Weighted Average
			Purchase volumes	130,000 - 310,000 mmBTUs
			Sales volumes	75,000 - 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, 2020:			
Balance as of January 1, 2020	$ (2,976)	$ —	$ (2,976)
Total losses (realized/unrealized):			
Included in regulatory assets (1)	(4,311)	—	(4,311)
Settlements	(1,123)	—	(1,123)
Ending balance as of December 31, 2020 (2)	$ (8,410)	$ —	$ (8,410)
Year ended December 31, 2019:			
Balance as of January 1, 2019	$ (2,774)	$ (2,488)	$ (5,262)
Total losses (realized/unrealized):			
Included in regulatory assets (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)

(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 16. 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, 2020 was $311.8 million.

The Company has 10 million authorized shares of preferred stock. The Company did not have any preferred stock outstanding as of December 31, 2020 and 2019.

Equity Issuances

The Company issued equity in 2020 for total net proceeds of $72.2 million. Most of these issuances came through the Company's sales agency agreements under which the sales agents may offer and sell new shares of common stock from time to time. The Company has board and regulatory authority to issue a maximum of 3.2 million shares under these agreements, of which 1.3 million remain unissued as of December 31, 2020. In 2020, 1.9 million shares were issued under these agreements resulting in total net proceeds of $70.6 million.

NOTE 17. 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 agreement with the IBEW represents approximately 40 percent of all of Avista Corp.'s employees. Avista's largest represented group, representing approximately 90 percent of Avista Corp.'s bargaining unit employees in Washington and Idaho, are currently covered under a three-year agreement which expires in March 2021.

The Company is in the process of negotiating a new agreement with the IBEW. However, there is a risk that if the collective bargaining agreement expired and a new agreement was not reached, employees subject to that agreement could strike. Given the number of employees that are covered by the collective bargaining agreement, a strike could result in disruptions to our operations. However, the Company believes that the possibility of this occurring is remote.

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 and Order 06 described above. In April 2016, this matter was certified for review directly by the Court of Appeals, an intermediate appellate court in the State of Washington.

In August 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.

In March 2020, the Company received an order from the WUTC that requires 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, which is being refunded over a twelve-month period that began on April 1, 2020. The Company previously recorded a customer refund liability of $8.5 million in 2019.

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

In August 2019, the Company was served with a complaint, captioned "State of Washington Department of Natural Resources v. Avista Corporation," seeking recovery up to $4.4 million for fire suppression and investigation 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 the tree before it 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. Additional lawsuits have subsequently been filed by private landowners seeking property damages, and holders of insurance subrogation claims seeking recovery of insurance proceeds paid.

The lawsuits were filed in the Superior Court of Ferry County, Washington. The Company intends to vigorously defend itself in the litigation. However, the Company cannot predict the outcome of these matters.

Labor Day Windstorm

In September 2020, a severe windstorm occurred in eastern Washington and northern Idaho. The extreme weather event resulted in customer outages and the cause of multiple wildfires in the region. With respect to wildfires, the Company's investigation determined that the primary cause of the fires was extreme high winds. To date, the Company has not found any evidence that the fires were caused by any deficiencies in its equipment, maintenance activities or vegetation management practices.

The Company has become aware of instances where, during the course of the storm, otherwise healthy trees and limbs, located in areas outside its maintenance right-of-way, broke under the extraordinary wind conditions and caused damage to its energy delivery system at or near what is believed to be the potential area of origin of a wildfire. Those instances include what has been referred to as: the Babb Road fire (near Malden and Pine City, Washington); the Christensen Road fire (near Airway Heights, Washington); and the Mile Marker 49 fire (near Orofino, Idaho). These wildfires covered, in total, approximately 22,000 acres. The Company currently estimates approximately 230 residential, commercial and other structures were impacted. Parallel investigations by applicable state agencies, including the Washington Department of Natural Resources, are ongoing, and the Company is cooperating with those efforts.

In addition to the instances identified above, the Company is aware of a 5-acre fire that occurred in Colfax, Washington, which damaged several residential structures. The Company's investigation determined that the Company's facilities were not involved in the ignition of this fire in any way.

The Company's investigation has found no evidence of negligence with respect to any of the fires, and the Company intends to vigorously defend any claims for damages that may be asserted against it with respect to the wildfires arising out of the extreme wind event.

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.'s operations, the Company seeks, to the extent appropriate, recovery of incurred costs through the ratemaking process.

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

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

NOTE 18. 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 2020, the Company recognized a pre-tax benefit of $6.2 million under the ERM in Washington compared to a benefit of $4.4 million for 2019. Total net deferred power costs under the ERM were a liability of $37.9 million as of December 31, 2020 and a liability of $40.0 million as of December 31, 2019. 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. As the cumulative rebate balance exceeded $30 million, the Company's 2019 filing contained a proposed rate refund. The ERM proceeding was considered with the Company's 2019 general rate case proceeding and a refund was approved and is being returned to customers over a two-year period that began on April 1, 2020. 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.

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 $2.5 million as of December 31, 2020 and $0.3 million as of December 31, 2019. 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 were an asset of $1.4 million as of December 31, 2020 and a liability of $3.2 million as of December 31, 2019. Asset balances represent amounts due from customers and liabilities represent amounts due to customers.

Decoupling and Earnings Sharing Mechanisms

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

Washington Decoupling and Earnings Sharing

In Washington, the WUTC approved the Company's decoupling mechanisms for electric and natural gas for a five-year period beginning January 1, 2015. In 2019, the WUTC approved an extension of the mechanisms for an additional five-year term through March 31, 2025, with one modification in that new customers added after any test period would not be decoupled until included in a future test period.

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. In 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. 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, 2020 and December 31, 2019, the Company had the following cumulative balances outstanding related to decoupling and earnings sharing mechanisms in its various jurisdictions (dollars in thousands):

	December 31, 2020	December 31, 2019
Washington		
Decoupling surcharge	$ 21,340	$ 22,440
Idaho		
Decoupling surcharge	$ 1,202	$ 2,549
Provision for earnings sharing rebate	(686)	(686)
Oregon		
Decoupling rebate	$ (1,262)	$ (739)

There were no earnings sharing rebates associated with Washington and Oregon as of December 31, 2020 and December 31, 2019.

NOTE 19. TERMINATION OF PROPOSED ACQUISITION BY HYDRO ONE

In July 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, in January 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 in January 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 were $19.7 million pre-tax and included financial advisers' fees, legal fees, consulting fees and employee time.

NOTE 20. 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 in April 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 21. SUPPLEMENTAL CASH FLOW INFORMATION

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

	2020	2019
Cash paid for interest	$ 91,188	$ 92,681
Cash paid for income taxes	701	26,164
Cash received for income tax refunds	(984)	(589)

NOTE 22. SUBSEQUENT EVENTS

The Company has evaluated its subsequent events and noted no subsequent events have occurred.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/Q4

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

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

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year		(7,866,070)		
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value		(2,391,954)		
4	Total (lines 2 and 3)		(2,391,954)		
5	Balance of Account 219 at End of Preceding Quarter/Year		(10,258,024)		
6	Balance of Account 219 at Beginning of Current Year		(10,258,024)		
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value		(4,120,140)		
9	Total (lines 7 and 8)		(4,120,140)		
10	Balance of Account 219 at End of Current Quarter/Year		(14,378,164)		

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Insert Footnote at Line 1 to specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1			(7,866,070)	[redacted]	[redacted]
2				[redacted]	[redacted]
3			(2,391,954)	[redacted]	[redacted]
4			(2,391,954)	196,979,195	194,587,241
5			(10,258,024)	[redacted]	[redacted]
6			(10,258,024)	[redacted]	[redacted]
7				[redacted]	[redacted]
8			(4,120,140)	[redacted]	[redacted]
9			(4,120,140)	134,517,321	130,397,181
10			(14,378,164)	[redacted]	[redacted]

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/Q4

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

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

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	6,627,834,919	4,525,328,898
4	Property Under Capital Leases	71,890,863	
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	6,699,725,782	4,525,328,898
9	Leased to Others		
10	Held for Future Use	13,727,648	12,822,127
11	Construction Work in Progress	172,073,892	150,751,249
12	Acquisition Adjustments	273,648	273,648
13	Total Utility Plant (8 thru 12)	6,885,800,970	4,689,175,922
14	Accum Prov for Depr, Amort, & Depl	2,294,362,603	1,635,742,935
15	Net Utility Plant (13 less 14)	4,591,438,367	3,053,432,987
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	2,132,757,425	1,607,056,988
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	161,605,178	28,685,947
22	Total In Service (18 thru 21)	2,294,362,603	1,635,742,935
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)	2,294,362,603	1,635,742,935

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/Q4

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
1,410,775,568				691,730,453	3
				71,890,863	4
					5
					6
					7
1,410,775,568				763,621,316	8
					9
190,585				714,936	10
3,747,095				17,575,548	11
					12
1,414,713,248				781,911,800	13
421,698,079				236,921,589	14
993,015,169				544,990,211	15
					16
					17
421,097,745				104,602,692	18
					19
					20
600,334				132,318,897	21
421,698,079				236,921,589	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
421,698,079				236,921,589	33

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) X An Original (2) __ A Resubmission	04/15/2021	2020/Q4

FOOTNOTE DATA

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

ROU Asset - $71,890,863

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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	04/15/2021	End of 2020/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	44,373,854	2,317,727
4	(303) Miscellaneous Intangible Plant	25,423,701	7,421,846
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	69,797,555	9,739,573
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	3,578,472	284,864
9	(311) Structures and Improvements	139,674,955	1,221,499
10	(312) Boiler Plant Equipment	192,656,435	1,450,206
11	(313) Engines and Engine-Driven Generators	8,179	1,072,700
12	(314) Turbogenerator Units	57,238,023	1,219,106
13	(315) Accessory Electric Equipment	29,561,074	1,559,557
14	(316) Misc. Power Plant Equipment	16,624,409	1,044,743
15	(317) Asset Retirement Costs for Steam Production	17,026,651	-2,315,577
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	456,368,198	5,537,098
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	64,014,211	885,138
28	(331) Structures and Improvements	97,019,506	1,675,216
29	(332) Reservoirs, Dams, and Waterways	192,430,218	1,546,822
30	(333) Water Wheels, Turbines, and Generators	234,559,681	-111,730
31	(334) Accessory Electric Equipment	69,727,335	6,562,094
32	(335) Misc. Power PLant Equipment	15,179,096	-2,133,230
33	(336) Roads, Railroads, and Bridges	3,649,100	
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	676,579,147	8,424,310
36	D. Other Production Plant		
37	(340) Land and Land Rights	905,167	
38	(341) Structures and Improvements	17,169,217	288,072
39	(342) Fuel Holders, Products, and Accessories	21,390,353	-318,631
40	(343) Prime Movers	23,507,372	
41	(344) Generators	219,321,048	1,863,789
42	(345) Accessory Electric Equipment	22,350,892	195,712
43	(346) Misc. Power Plant Equipment	1,702,679	-61,293
44	(347) Asset Retirement Costs for Other Production	351,683	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	306,698,411	1,967,649
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,439,645,756	15,929,057

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/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
			46,691,581		3
964,551		53,919	31,934,915		4
964,551		53,919	78,626,496		5
					6
					7
			3,863,336		8
177,410			140,719,044		9
467,210			193,639,431		10
			1,080,879		11
268,049			58,189,080		12
280,472			30,840,159		13
29,078			17,640,074		14
			14,711,074		15
1,222,219			460,683,077		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			64,899,349		27
436,439		-62,582	98,195,701		28
			193,977,040		29
93,974			234,353,977		30
915,127			75,374,302		31
3,850			13,042,016		32
			3,649,100		33
					34
1,449,390		-62,582	683,491,485		35
					36
			905,167		37
17,878			17,439,411		38
2,516			21,069,206		39
			23,507,372		40
62,086			221,122,751		41
5,153			22,541,451		42
			1,641,386		43
			351,683		44
87,633			308,578,427		45
2,759,242		-62,582	1,452,752,989		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	04/15/2021	End of 2020/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	29,647,248	1,317,287
49	(352) Structures and Improvements	25,358,219	3,346,156
50	(353) Station Equipment	287,013,636	28,710,707
51	(354) Towers and Fixtures	17,160,699	92,604
52	(355) Poles and Fixtures	278,634,026	21,441,701
53	(356) Overhead Conductors and Devices	158,589,765	7,464,344
54	(357) Underground Conduit	3,253,240	577,382
55	(358) Underground Conductors and Devices	2,602,442	576,099
56	(359) Roads and Trails	2,107,559	46,426
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	804,366,834	63,572,706
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	11,814,980	7,576,606
61	(361) Structures and Improvements	33,532,067	1,302,968
62	(362) Station Equipment	146,876,585	9,910,815
63	(363) Storage Battery Equipment	2,428,752	
64	(364) Poles, Towers, and Fixtures	436,264,125	26,250,177
65	(365) Overhead Conductors and Devices	280,528,350	18,365,903
66	(366) Underground Conduit	123,584,467	10,412,009
67	(367) Underground Conductors and Devices	219,816,148	12,701,847
68	(368) Line Transformers	280,684,915	13,237,158
69	(369) Services	180,415,605	9,836,373
70	(370) Meters	72,884,062	21,619,348
71	(371) Installations on Customer Premises	2,114,606	1,011,018
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	65,814,671	4,693,076
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,856,759,333	136,917,298
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	507,277	
87	(390) Structures and Improvements	8,475,394	2,179,421
88	(391) Office Furniture and Equipment	1,438,878	1,691,400
89	(392) Transportation Equipment	49,928,658	3,711,321
90	(393) Stores Equipment	391,830	
91	(394) Tools, Shop and Garage Equipment	6,162,650	1,033,327
92	(395) Laboratory Equipment	1,801,512	205,954
93	(396) Power Operated Equipment	31,797,569	136,180
94	(397) Communication Equipment	48,785,141	4,783,859
95	(398) Miscellaneous Equipment	193,350	85,133
96	SUBTOTAL (Enter Total of lines 86 thru 95)	149,482,259	13,826,595
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)	149,482,259	13,826,595
100	TOTAL (Accounts 101 and 106)	4,320,051,737	239,985,229
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	4,320,051,737	239,985,229

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2021	Year/Period of Report End of 2020/Q4

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
			30,964,535		48
49,043			28,655,332		49
4,232,393		-27,918	311,464,032		50
			17,253,303		51
751,245			299,324,482		52
276,819			165,777,290		53
			3,830,622		54
			3,178,541		55
			2,153,985		56
					57
5,309,500		-27,918	862,602,122		58
					59
		-1,251,620	18,139,966		60
4,429			34,830,606		61
297,345		27,918	156,517,973		62
			2,428,752		63
1,270,839			461,243,463		64
96,581			298,797,672		65
35,999			133,960,477		66
272,308			232,245,687		67
157,661			293,764,412		68
63,421			190,188,557		69
12,365,355			82,138,055		70
			3,125,624		71
					72
703,381			69,804,366		73
					74
15,267,319		-1,223,702	1,977,185,610		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			507,277		86
21,359			10,633,456		87
1,009,878		-135,335	1,985,065		88
780,794			52,859,185		89
4,430			387,400		90
389,760			6,806,217		91
109,389			1,898,077		92
949,882			30,983,867		93
5,418,468		-327,878	47,822,654		94
			278,483		95
8,683,960		-463,213	154,161,681		96
					97
					98
8,683,960		-463,213	154,161,681		99
32,984,572		-1,723,496	4,525,328,898		100
					101
					102
					103
32,984,572		-1,723,496	4,525,328,898		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	04/15/2021	End of 2020/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	2,869,904
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	Distribution Plant Land, Coeur d'Alene, Idaho	Nov 2020	2022-2026	775,530
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
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			12,822,127

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Cabinet Gorge Fish Passage	40,181,572
2	KF Fuel Yard Equipment Replacement	12,954,239
3	Irvin Sub - New Construction	8,516,252
4	Energy Imbalance Market	7,123,281
5	CS2 Single Phase Transformer	6,835,301
6	Westside 230 kV Substation - Rebuild	6,758,685
7	Lolo-Oxbow 230kV Transmission Line Rebuild Project	5,693,321
8	Substation Rebuilds	5,440,111
9	Protection System Upgrades for PRC-002	4,466,211
10	Electric Transmission Plant-Storm	3,454,702
11	Metro-Post St 115kV Underground Tx Line Rebuild	2,931,066
12	Long Lake Plant Upgrades	2,620,433
13	Transportation Equip	2,423,155
14	LL HED Stability Enhancement	2,253,797
15	Saddle Mountain Integration Phase 2	2,230,440
16	Cabinet Gorge Unit 3 Protection & Control Upgrade	2,169,487
17	Clark Fork Implement PME Agreement	1,798,996
18	Substation Asset Mgmt Capital Maintenance	1,551,470
19	CG HED Station Service Replacement	1,532,661
20	New Substations	1,506,950
21	Saddle Mountain Integration	1,489,741
22	Transmission Minor Rebuild	1,298,904
23	Colstrip Capital Additions	1,167,846
24	Regulating Hydro	1,073,010
25	Minor projects <$1M	15,308,523
26	R&D/Strategic Initiatives	7,971,095
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	150,751,249

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/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	1,503,624,342	1,503,624,342		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	123,386,421	123,386,421		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	4,616,453	4,616,453		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	128,002,874	128,002,874		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	32,020,020	32,020,020		
13	Cost of Removal	9,725,603	9,725,603		
14	Salvage (Credit)	348,299	348,299		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	41,397,324	41,397,324		
16	Other Debit or Cr. Items (Describe, details in footnote):	16,827,096	16,827,096		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	1,607,056,988	1,607,056,988		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	346,616,483	346,616,483		
21	Nuclear Production				
22	Hydraulic Production-Conventional	158,689,393	158,689,393		
23	Hydraulic Production-Pumped Storage				
24	Other Production	147,254,839	147,254,839		
25	Transmission	241,331,580	241,331,580		
26	Distribution	644,634,303	644,634,303		
27	Regional Transmission and Market Operation				
28	General	68,530,390	68,530,390		
29	TOTAL (Enter Total of lines 20 thru 28)	1,607,056,988	1,607,056,988		

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

Includes:

Depreciation offset for non-recoverable plant for Boulder Park ($112,280)
AMI/MDM Deferral $10,213,392
ARO Depreciation $748,048
Change in Removal Work in Progress ($6,008,426)
Other Credits ($27,490)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1				
2	Investment in Avista Capital	01/01/1997		256,138,971
3	Avista Capital - Equity in Earnings			-152,844,453
4	Investment in AERC	07/01/2014		89,816,380
5	AERC - Equity in Earnings			13,995,056
6				
7				
8				
9				
10				
11				
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41				
42	Total Cost of Account 123.1 $ 0		TOTAL	207,105,954

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/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
		256,138,971		2
-2,490,851		-155,335,303		3
		89,816,380		4
7,795,227	5,000,000	16,790,283		5
				6
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				41
5,304,376	5,000,000	207,410,331		42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/Q4

MATERIALS AND SUPPLIES

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

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	4,148,891	4,088,628	(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)	29,944,453	36,162,860	(1)
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	3,443,631	3,661,588	(1)
8	Transmission Plant (Estimated)	-4,267	170,727	(1)
9	Distribution Plant (Estimated)	585,679	727,662	(1)
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	12,589,323	11,131,219	(1),(2)
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	46,558,819	51,854,056	
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)	50,707,710	55,942,684	

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

Transmission Service and Generation Interconnection Study Costs

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

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	Gordon Butte Project 50	6,936	186200		
23	Aurora Solar Project 59	74,477	186200		
24	Clarkston Hts Solar Project 60	142,508	186200		
25	Rattlesnake II Wind Project 62	108,776	186200		
26	Post Falls HED Project 63	29,556	186200		
27	Kettle Falls Upgrade Project 66	46,251	186200		
28	Old Milwaukee Solar Project 67	5,738	186200		
29	Clearwater Wind II Project 68	5,750	186200		
30	Clearwater Wind III Project 69	4,975	186200		
31	EnerNOC Battery Storage Project 70	6,611	186200		
32	Geronimo Solar Project 71	14,462	186200		
33	Geronimo Solar Project 72	4,886	186200		
34	Sprague Solar Project 73	5,577	186200		
35	Royal City Solar Project 76	4,358	186200		
36	Elf II Solar Project 79	45,841	186200		
37	Elf 1 Solar Project 80	33,886	186200		
38	Ralston Solar Project 81	3,767	186200		
39	Haymaker Wind Project 82	3,740	186200		
40	Martinsdale Wind Project 83	2,187	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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8					
9					
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11					
12					
13					
14					
15					
16					
17					
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19					
20					
21	**Generation Studies**				
22	Rainier Solar Project 85	840	186200		
23	Acadia Solar Project 84	26,254	186200		
24	Geronimo6 Solar Project 94	205	186200		
25	Geronimo2 Solar Project 90	325	186200		
26	Jane Wind 2 Project 96	1,098	186200		
27	Jane Wind Project 95	1,248	186200		
28	Lolo Solar Project 97	17,313	186200		
29	Rattlesnake Optional Study	73,425	186200		
30	Wahatis Solar Project 99	4,128	186200		
31	Stringtown Solar Project 100	4,314	186200		
32	North Cheyenne Project 101	2,693	186200		
33	Harrington Solar Project 103	1,831	186200		
34	Colville Solar Project 105	1,849	186200		
35	Latah Wind Project 104	1,985	186200		
36	Big Sky Connector Line Project	1,509	186200		
37	Bench Solar Project 106	2,252	186200		
38	Broadview IV Project 107	834	186200		
39	Ursus Wind Project 108	1,752	186200		
40	Rathdrum CT 109	237	186200		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/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**				
2					
3					
4					
5					
6					
7					
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9					
10					
11					
12					
13					
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15					
16					
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20					
21	**Generation Studies**				
22	Bafus Solar Project 77	14,862	186200	14,862	186210
23					
24					
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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
Total Life to Date Costs

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Total Life to Date Costs

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Total Life to Date Costs

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

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

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

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

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Total Life to Date Costs

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Schedule Page: 231.1 Line No.: 22 Column: b
Total Life to Date Costs

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

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

Total Life to Date Costs

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

Total Life to Date Costs

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

Total Life to Date Costs

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 Q4 2020.

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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	04/15/2021	End of 2020/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	10,344,716	1,321,185	407	3,068,230	8,597,671
2	Reg Asset Post Ret Liab	210,801,207	4,159,538	228	12,639,368	202,321,377
3	Regulatory Asset FAS109 Utility Plant	83,355,934	11,703,947	283	1,351,599	93,708,282
4	Regulatory Asset FAS109 DSIT Non Plant	3,023,201	1,293,066	283	1,971,362	2,344,905
5	Regulatory Asset- Spokane River Relicense	133,911		407	133,911	
6	Regulatory Asset- Lake CDA Settlement - Varies	41,309,157		407	1,266,390	40,042,767
7	Reg Assets- Decouplings Surcharge - 2 years	19,326,621	9,292,164	456, 495	18,525,668	10,093,117
8	Reg Asset - Colstrip	4,945,687	4,765,647	407	1,820,200	7,891,134
9	Commodity MTM ST & LT Regulatory Asset	6,573,588	8,596,118	244, 175	7,374,854	7,794,852
10	Regulatory Asset FAS143 Asset Retirement Obligation	1,800,206	116,094			1,916,300
11	Regulatory Asset Workers Comp	1,126,296	98,214	242	206,551	1,017,959
12	Interest Rate Swap Asset	168,594,071	84,321,626	Various	38,064,531	214,851,166
13	DSM Asset	12,170,199	25,399,919	Various	33,756,305	3,813,813
14	Deferred ITC	3,981,955		283, 410	70,968	3,910,987
15	Regulatory Asset MDM System	13,394,821	13,052,758	407,419	68,655	26,378,924
16	Regulatory Asset BPA Residential Exchange	1,326,885	2,004,379	407	1,846,303	1,484,961
17	Regulatory Asset FISERV - 3 years	3,594,035	452,238	407,419	1,326,173	2,720,100
18	Regulatory Asset - AFUDC (PIS,WIP) & Equity DFIT	44,093,659	35,928,791	Various	27,652,017	52,370,433
19	Regulatory Asset ID PCA Deferral - 1 year	256,594	5,095,887	557,419	2,805,313	2,547,168
20	Existing Meters/ERTS Retirement Def	13,052,304	17,039,161	108	4,177,507	25,913,958
21	Regulatory Asset- Colstip Community Fund		1,500,000			1,500,000
22	Regulatory Asset- COVID-19		11,380,742	Various	8,520,795	2,859,947
23	Regulatory Asset- Energy Imbalance Market		253,023	407	58,098	194,925
24	Regulatory Assset- Oregon CAT Tax		916,223	407, 419	86,636	829,587
25	Deferred Regulatory Fees		72,652	407, 419	13,133	59,519
26	Regulatory Asset- Wildfire Resiliency		1,006,452	407		1,006,452
27	Deferral for CS2 & Colstrip (O&M, Excess Depr)		2,210,829	407	1,101,894	1,108,935
28	Other Regulatory Assets	2,321	83			2,404
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	**TOTAL :**	643,207,368	241,980,736		167,906,461	717,281,643

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
Deferred tax flow through balance on utility plant. Amortization occurs over book life of respective utility plant assets.

Schedule Page: 232 Line No.: 5 Column: a
Amortization for TDG Idaho ended on December 2019. Spokane River relicensing amortization costs ended on 11/30/2020.

Schedule Page: 232 Line No.: 6 Column: a
WA Docket UE-080416 & ID Order AVU-E-08-01. Amortization thru 2059.

Schedule Page: 232 Line No.: 7 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.: 8 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.: 9 Column: a
Washington Docket# UE-002066 and Idaho Order# 28648

Schedule Page: 232 Line No.: 10 Column: a
Regulatory Assets related to deferred ARO expenses for Kettle Falls and Coyote Springs thermal plants. The expenses will not be collected from Customers until actual work is performed.

Schedule Page: 232 Line No.: 11 Column: a
Quarterly adjustments to workers comp reserve for current unpaid claims.

Schedule Page: 232 Line No.: 12 Column: a
Settled swaps are amortized over the life of the associated debt.

Schedule Page: 232 Line No.: 13 Column: a
Amortization period varies depending on timing of transactions.

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

Schedule Page: 232 Line No.: 15 Column: a
Washington Docket#s UE-180418, UG-180419

Schedule Page: 232 Line No.: 16 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.: 17 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.: 18 Column: a
Deferring the difference between FERC formula and State approved AFUDC rates from 2010 to present.

Schedule Page: 232 Line No.: 20 Column: a
Washington Docket#s UE-180418 and UG-180419. Amortization period to be determined.

Schedule Page: 232 Line No.: 21 Column: a
WA Order 09 in Dockets UE-190334, UE-190222. Deferral of customer portion for future rate

recovery. The funds are set aside to helping the Colstrip community transition away from economic activity related to coal-fired generation.

Schedule Page: 232 Line No.: 22 Column: a

Deferral of COVID-19 costs as per Idaho PUC Order No. 34718, Oregon PUC Order No. 20-401, Docket UM 2069 and WA UTC Order No. 01, Dockets UE-200407 and UG-200408.

Schedule Page: 232 Line No.: 23 Column: a

Idaho PUC Order No. 34606. Deferral of costs related to Avista's entry in the Energy Imbalance Market in March 2022.

Schedule Page: 232 Line No.: 24 Column: a

Oregon PUC Order No. 20-398, Docket UM-2042.

Schedule Page: 232 Line No.: 25 Column: a

Oregon Order # 20-354. Deferral of cost of variance in annual regulatory fee rate and the amount collected in rates.

Schedule Page: 232 Line No.: 26 Column: a

Idaho PUC Order 34883

Schedule Page: 232 Line No.: 27 Column: a

WA Order 09, Docket Nos. UE-190334, UG-190335, UE-190222.

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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	04/15/2021	End of 2020/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	4,815,987		VAR	851,006	3,964,981
5	Gas Supply Transactions	496,981	20,224			517,205
6	WA REC Deferral	540,265		557	145,434	394,831
7	Reg Asset - Decoupling Deferred	8,551,769	6,825,184			15,376,953
8	Reg Asset - COVID 19 Deferral		5,305,694			5,305,694
9	Nez Perce Settlement	124,313		VAR	5,188	119,125
10	Clarkston Hts Solar Project#60	110,267	32,241			142,508
11	Timber Harvest Revenue	-226,818				-226,818
12	Rattlesnake II Wind Proj #62	32,101	76,675			108,776
13	Misc. Deferred Debits <$100,000	572,880	83,787			656,667
14						
15						
16						
17						
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45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	18,484,386				29,826,563

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/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		20,510,338	102,475,097
3			
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	20,510,338	102,475,097
9	Gas		
10		3,791,114	21,374,121
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15	3,791,114	21,374,121
17	Other	152,755,074	92,879,318
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	177,056,526	216,728,536

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	04/15/2021	End of 2020/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		
14				
15				
16				
17				
18				
19				
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42				

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2021	Year/Period of Report End of 2020/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
69,238,901	1,249,688,206					2
				71,706	3,667,762	3
69,238,901	1,249,688,206			71,706	3,667,762	4
						5
						6
						7
						8
						9
						10
						11
						12
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						42

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. Restricted stock is valued at the close of market of the Company’s common stock on the grant date.

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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
2		
3		
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36		
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39		
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	04/15/2021	End of 2020/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	-47,076,877
2		
3		
4		
5		
6		
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8		
9		
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21		
22	TOTAL	-47,076,877

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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	04/15/2021	End of 2020/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 - 6.25% SERIES	150,000,000	1,812,935
7	Discount- FMBS - 6.25% SERIES		367,500
8	FMBS - 5.70% SERIES	150,000,000	4,702,304
9	Discount- FMBS - 5.70% SERIES		222,000
10	FMBS - 5.125% SERIES	250,000,000	2,284,788
11	Discount- FMBS - 5.125% SERIES		575,000
12	COLSTRIP 2010A PCRBs DUE 2032	66,700,000	
13	COLSTRIP 2010B PCRBs DUE 2034	17,000,000	
14	FMBS - 3.89% SERIES	52,000,000	385,129
15	FMBS - 5.55% SERIES	35,000,000	258,834
16	4.45% SERIES DUE 12-14-2041	85,000,000	692,833
17	4.23% SERIES DUE 11-29-2047	80,000,000	730,833
18	FMBS- 4.11% SERIES	60,000,000	428,205
19	FMBS- 4.37% SERIES	100,000,000	590,761
20	FMBS- 3.54% SERIES	175,000,000	1,042,569
21	FMBS 3.91% SERIES	90,000,000	552,539
22	FMBS 4.35% SERIES	375,000,000	4,246,448
23	Discount- FMBS - 4.350% SERIES		378,750
24	FMBS 3.43% SERIES	180,000,000	1,108,340
25	FMBS 3.07% SERIES	165,000,000	1,071,782
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	2,120,747,000	23,010,782

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	712,864	4
06-19-1998	06-19-2028	06-19-1998	06-19-2028	25,000,000	1,592,500	5
11-17-2005	12-01-2035	11-17-2005	12-01-2035	150,000,000	9,375,000	6
						7
12-15-2006	07-01-2037	12-15-2006	07-01-2037	150,000,000	8,550,000	8
						9
09-22-2009	04-01-2022	09-22-2009	04-01-2022	250,000,000	12,812,500	10
						11
12-15-2010	10-1-2032	12-15-2010	10-1-2032	66,700,000	475,775	12
12-15-2010	3-1-2034	12-15-2010	3-1-2034	17,000,000	121,425	13
12-20-2010	12-20-2020	12-20-2010	12-20-2020		1,960,992	14
12-20-2010	12-20-2040	12-20-2010	12-20-2040	35,000,000	1,942,500	15
12-14-2011	12-14-2041	12-14-2011	12-14-2041	85,000,000	3,782,500	16
11-30-2012	11-29-2047	11-30-2012	11-29-2047	80,000,000	3,384,000	17
12-18-2014	12-1-2044	12-18-2014	12-1-2044	60,000,000	2,466,000	18
12-16-2015	12-1-2045	12-16-2015	12-1-2045	100,000,000	4,370,000	19
12-15-2016	12-1-2051	12-15-2016	12-1-2051	175,000,000	6,195,000	20
12-14-2017	12-1-2047	12-14-2017	12-1/2047	90,000,000	3,519,000	21
05-22-2018	06-01-2048	06-1-2018	06-1-2048	375,000,000	16,312,500	22
						23
11-26-2019	12-01-2049	12-01-2019	12-01-2049	180,000,000	6,174,000	24
09-30-2020	09-30-2050	09-30-2020	09-30-2050	165,000,000	5,065,500	25
						26
						27
						28
						29
						30
						31
						32
				2,068,747,000	89,804,206	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.: 12 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.: 12 Column: c

The Company reacquired these bonds in 2010.

Schedule Page: 256 Line No.: 13 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.: 13 Column: c

The Company reacquired these bonds in 2010.

Schedule Page: 256 Line No.: 25 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. 171210 entered into January 11, 2018 and Order of the Washington Utilities and Transporation Commission in Docket No. 190554 entered into September 12, 2019;

2. Order of the Idaho Public Utilities Commission, Order No. 33978 entered January 30, 2018 and Order of the Idaho Public Utilities Commission, Order No. 34386 entered July 31, 2019;

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

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

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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)	134,517,322
2		
3		
4	Taxable Income Not Reported on Books	
5		8,180,842
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		301,465,914
11	Federal Income Tax Expense	7,957,636
12	State Income Tax Expense Adj	-534,566
13		
14	Income Recorded on Books Not Included in Return	
15		-39,821,309
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		-413,202,637
21		
22		
23		
24	Equity in Subs Earnings	-5,304,376
25	Corporate Overhead Unallocated Subs	626,652
26		
27	Federal Tax Net Income	-6,114,523
28	Show Computation of Tax:	
29		
30	Federal Tax at 21%	-1,284,050
31		
32	Prior Year True Ups	-39,280,403
33		
34	Customer refunds related to prior years at 35 percent	-690,508
35		
36	Total Federal Current Tax Expense	-41,254,961
37		
38		
39		
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41		
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43		
44		

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2021	Year/Period of Report End of 2020/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)	BALANCE AT BEGINNING OF YEAR 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	-5,428,255	-315,720	
3	Income Tax 2015			-4,279,292	-202,821	
4	Income Tax 2016		-520,411	520,410		
5	Income Tax 2017		-104,399	333,945	-104,399	
6	Income Tax 2018		-1,252,305	-17,125,557		
7	Income Tax 2019		-6,543,388	-15,456,612		
8	Income Tax (Current)			-65,559		
9	Total Federal		-8,172,855	-41,500,920	-622,940	
10						
11	STATE OF WASHINGTON:					
12	Payroll Taxes 2020				235,053	
13	Property Tax 2018	5,584		-5,585		
14	Property Tax 2019	18,740,467		-905,401	17,835,066	
15	Property Tax 2020			18,090,306	493	
16	Excise Tax 2016	892,951				
17	Excise Tax 2019	2,915,002		66,765	2,981,767	
18	Excise Tax 2020			27,059,961	24,129,961	
19	Natural Gas Use Tax	490		1,849	1,859	
20	Municipal Occupation Tax	3,130,051		23,928,191	23,992,990	
21	Community Solar	-31,729		-301,505	-333,921	
22	Sales & Use Tax 2018	2,669				-2,669
23	Sales & Use Tax 2019	286,528			160,363	-126,166
24	Sales & Use Tax 2020			1,048,091	1,061,712	128,835
25	Total Washington	25,942,013		68,982,672	70,065,343	
26						
27	STATE OF IDAHO:					
28	Income Tax 2019		-319,616	-10,224		
29	Income Tax 2020					
30	Payroll Taxes 2020				16,105	
31	Property Tax 2019	3,817,356		58	3,817,414	
32	Property Tax 2020			7,887,651	3,954,640	
33	Hydro Relicensing			27,134	27,134	
34	Sales & Use Tax 2019	9,341			11,381	2,040
35	Sales & Use Tax 2020			216,900	187,358	-2,040
36	Irrigation Credits 2020					
37	KWH Tax 2019	26,277		-1,296	24,981	
38	KWH Tax 2020			369,390	341,275	
39	Franchise Tax 2018	21				-21
40	Franchise Tax 2019	1,103,281			1,103,288	21
41	TOTAL	38,022,918	-12,378,042	78,385,117	112,191,434	-1

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
	-4,864,887		-154,443		-908,767	2
	-4,076,471		194,476		-420,342	3
			701,981		341,317	4
	333,945					5
	-18,377,863		-12,282		689	6
	-22,000,000		-22,547,949		-18,630,041	7
	-65,559		-101,054		35,495	8
	-49,050,835		-21,919,271		-19,581,649	9
						10
						11
-235,053		2,772,402			-2,772,402	12
		-5,525			-60	13
		-676,035			-229,366	14
18,089,813		14,382,815			3,707,491	15
892,951						16
		66,842			-77	17
2,930,000		21,013,190			6,046,771	18
480		1,849				19
3,065,253		18,449,768			5,478,423	20
688					-301,505	21
						22
-1						23
115,214					1,048,091	24
24,859,345		56,005,306			12,977,366	25
						26
						27
	-329,840	-8,691			-1,533	28
						29
-16,105		495,425			-495,425	30
		50			8	31
3,933,011		6,128,579			1,759,072	32
		27,134				33
						34
27,502					216,900	35
		3,558			-3,558	36
		-1,296				37
28,115		369,390				38
						39
14		3,224			-3,224	40
45,266,874	-53,428,314	82,646,398	-21,919,271		17,657,990	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	04/15/2021	End of 2020/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	Franchise Tax 2020			4,625,749	3,535,443	
2	Total Idaho	4,956,276	-319,616	13,115,362	13,019,019	
3						
4	STATE OF MONTANA:					
5	Income Tax 2019		-124,334	-235,616	-359,950	
6	Income Tax 2020			-2	50	
7	Payroll Taxes 2020				4,910	
8	Property Tax 2019	5,767,811		-14,367	5,753,442	-1
9	Property Tax 2020			11,822,356	5,924,294	
10	Colstrip Generation Tax			1,837	1,837	
11	KWH Tax 2019	226,610			226,610	
12	KWH Tax 2020			962,699	760,983	
13	Consumer Council Fee	15		109	66	
14	Public Commission Fee	51		218	227	
15	Total Montana	5,994,487	-124,334	12,537,234	12,312,469	-1
16						
17	STATE OF OREGON:					
18	Income Tax 2019					
19	Income Tax 2020			100,000	100,000	
20	Corp Activities Tax-CAT 2020			800,004	600,000	
21	Payroll Taxes 2020				9,574	
22	Property Tax 2019		-3,759,647	3,759,648		
23	Property Tax 2020			4,047,330	8,094,817	
24	Franchise Tax 2018	43,414			43,414	
25	Franchise Tax 2019	1,046,390			1,046,389	
26	Franchise Tax 2020			3,796,632	2,758,478	
27	Total Oregon	1,089,804	-3,759,647	12,503,614	12,652,672	
28						
29	STATE OF CALIFORNIA:					
30	Income Tax 2020			800	800	
31	Total California			800	800	
32						
33	MISCELLANEOUS STATES:					
34	Income Tax (Current)		-1,590	279	-1,211	
35	Payroll Taxes 2020				402	
36	Total Misc States		-1,590	279	-809	
37						
38	MISCELLANEOUS OTHER					
39	Payroll Taxes 2020			14,683,386	6,664,088	
40	Timber Excise Tax (2017)					
41	TOTAL	38,022,918	-12,378,042	78,385,117	112,191,434	-1

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
1,090,306		3,505,313			1,120,436	1
5,062,843	-329,840	10,522,686			2,592,676	2
						3
						4
		-235,616				5
	-52	-2				6
-4,910		132,045			-132,045	7
		-14,367				8
5,898,062		11,822,356				9
		-230			2,067	10
						11
201,716		962,699				12
58		109				13
42		218				14
6,094,968	-52	12,667,212			-129,978	15
						16
						17
						18
		30,000			70,000	19
200,004					800,004	20
-9,574		9,053			-9,053	21
		1,646,769			2,112,879	22
	-4,047,487	1,765,176			2,282,154	23
						24
						25
1,038,154					3,796,632	26
1,228,584	-4,047,487	3,450,998			9,052,616	27
						28
						29
					800	30
					800	31
						32
						33
	-100	196			83	34
-402						35
-402	-100	196			83	36
						37
						38
8,019,298					14,683,386	39
						40
45,266,874	-53,428,314	82,646,398	-21,919,271		17,657,990	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	04/15/2021	End of 2020/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)	BALANCE AT BEGINNING OF YEAR Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust- ments (f)
1	WA Renewable Energy			-1,933,932	-1,933,932	
2	Misc Distribution	33,158		-32,834		
3	Thermal Fuel Tax	7,180		29,456	34,724	
4	Total Other	40,338		12,746,076	4,764,880	
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
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27						
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31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	38,022,918	-12,378,042	78,385,117	112,191,434	-1

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2021	Year/Period of Report End of 2020/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)	
					-1,933,932	1
326					-32,834	2
1,912					29,456	3
8,021,536					12,746,076	4
						5
						6
						7
						8
						9
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45,266,874	-53,428,314	82,646,398	-21,919,271		17,657,990	41

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2021	Year/Period of Report End of 2020/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 Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%						
6	Fed ITC	29,182,023			411	520,104	
7	Idaho ITC	1,066,366	411	-12,205	411	30,382	
8	TOTAL	30,248,389		-12,205		550,486	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Gas Property (100%	7,116			411	7,116	
11	Idaho ITC	188,456	411	-2,154	411	5,373	
12	TOTAL PROPERTY	195,572		-2,154		12,489	
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	04/15/2021	End of 2020/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
28,661,919			6
1,023,779			7
29,685,698			8
			9
			10
180,929			11
180,929			12
			13
			14
			15
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			48

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2021	Year/Period of Report End of 2020/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	1,125,000				1,125,000
2	Kettle Falls Diesel Leak	297,078	514, 545	254,006		43,072
3	Bills Pole Rentals	193,105	172	465,598	918,828	646,335
4	Defer Comp Active Execs	8,947,679	128	1,888,925	2,115,126	9,173,880
5	Executive Incent Plan	140,000				140,000
6	Unbilled Revenue	1,243,970	908	19,767,661	18,629,136	105,445
7	WA Energy Recovery Mechanism	14,154,482	Various	18,632,775	15,861,541	11,383,248
8	Decoupling Deferred Credits	3,526,878	456, 495	11,589,552	9,917,842	1,855,168
9	Reg Liability-COVID-19 Deferral				6,660,724	6,660,724
10	Misc Deferred Credits	31,366	186, 550	56,125	341,916	317,157
11						
12						
13						
14						
15						
16						
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45						
46						
47	TOTAL	29,659,558		52,654,642	54,445,113	31,450,029

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 2025.

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.: 8 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.: 9 Column: a

Deferral of COVID-19 costs as per Idaho PUC Order No. 34718, Oregon PUC Order No. 20-401, Docket UM 2069 and WA UTC Order No. 01, Dockets UE-200407 and UG-200408.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/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	339,209,550	44,688,310	
3	Gas	86,849,511	32,594,670	
4	Other	88,810,946	-1,572,234	
5	TOTAL (Enter Total of lines 2 thru 4)	514,870,007	75,710,746	
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	514,870,007	75,710,746	
10	Classification of TOTAL			
11	Federal Income Tax	514,870,007	75,710,746	
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					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
					14,346,260	398,244,120	2
					24,466,166	143,910,347	3
			25,977,746			61,260,966	4
			25,977,746		38,812,426	603,415,433	5
							6
							7
							8
			25,977,746		38,812,426	603,415,433	9
							10
			25,977,746		38,812,426	603,415,433	11
							12
							13

NOTES (Continued)

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2021	Year/Period of Report End of 2020/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	13,393,102	1,968,358	745,973
4				
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	13,393,102	1,968,358	745,973
10	Gas			
11	Gas	2,385,096	1,762,139	362,272
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	2,385,096	1,762,139	362,272
18	Other	163,807,011	5,921,872	
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	179,585,209	9,652,369	1,108,245
20	Classification of TOTAL			
21	Federal Income Tax	179,585,209	9,652,369	1,108,245
22	State Income Tax			
23	Local Income Tax			

NOTES

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

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

CHANGES DURING YEAR		ADJUSTMENTS					
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
275,061	899,441		1,063,055			12,928,052	3
							4
							5
							6
							7
							8
275,061	899,441		1,063,055			12,928,052	9
							10
-27,961			714,455			3,042,547	11
							12
							13
							14
							15
							16
-27,961			714,455			3,042,547	17
102,944					14,315,742	184,147,569	18
350,044	899,441		1,777,510		14,315,742	200,118,168	19
							20
350,044	899,441		1,777,510		14,315,742	200,118,168	21
							22
							23

NOTES (Continued)

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2021	Year/Period of Report End of 2020/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	5,191,030	190	1,072,903	4,756,652	8,874,779
2	Oregon BETC Credit	1,111,427	190, 283	1,099,869		11,558
3	Interest Rate Swaps	17,088,285	427, 175	2,042,533		15,045,752
4	Nez Perce	528,308	557	22,008		506,300
5	Idaho Earnings Test	686,970				686,970
6	Decoupling Rebate	101,371	495, 182	1,081,410	3,315,785	2,335,746
7	WA ERM	25,802,794	182, 557	53,679,690	54,363,026	26,486,130
8	Deferred Federal ITC - Varies	7,963,912	190	141,936		7,821,976
9	Plant Excess Deferred	398,370,456	190, 282	15,431,659		382,938,797
10	Non Plant Excess Deferred	11,089,633	108, 411	11,015,304		74,329
11	Reg Liability MDM System	589,729			307,687	897,416
12	AFUDC Equity Tax Deferral	2,263,637			342,811	2,606,448
13	Exist Meters/ERTS Excess Depr Deferred	952,403	407	13,254	940,093	1,879,242
14	DSM Tariff Rider	294,533	182,431,908	12,389,437	12,635,179	540,275
15	Low Income Energy Assistance	2,401,864	242, 908	12,954,756	14,336,849	3,783,957
16	Deferred CS2 & Colstrip O&M	397,359	407	397,359		
17	Reg Liability - Tax Reform Amortization - 1 year	4,348,735	407, 431	6,385,196	3,030,529	994,068
18	Reg Liability - Energy Efficiency Assistance	1,532,183				1,532,183
19	Reg Liability - Colstrip Community Fund		407, 431	1,071,334	4,428,445	3,357,111
20	Reg Liability - COVID-19 Deferral				4,288,655	4,288,655
21	Other Regulatory Liabilities - Varies	492,504	143,190,407	30,122	7,997,303	8,459,685
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
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38						
39						
40						
41	TOTAL	481,207,133		118,828,770	110,743,014	473,121,377

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

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.: 9 Column: a

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

Schedule Page: 278 Line No.: 10 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.: 12 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.: 13 Column: a

Washington Docket#s UE-180418 and UG-180419

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

Washington Orders Dockets UE-190912 and UG-190920, Idaho Docket AVU-E-18-12 and AVU-G-18-08, Oregon Order No. 19-424

Schedule Page: 278 Line No.: 15 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.: 17 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.: 18 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.: 19 Column: a

Washington Order 09 in Dockets UE-190334, UE-190222. Deferral of funds from shareholders and customers set aside to helping the Colstrip community transition away from economic activity related to coal-fired generation.

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

Deferral of COVID-19 costs as per Idaho PUC Order No. 34718, Oregon PUC Order No. 20-401, Docket UM 2069 and WA UTC Order No. 01, Dockets UE-200407 and UG-200408.

Schedule Page: 278 Line No.: 21 Column: a

FAS 109 ITC - 18 year amortization, ends 2020.

State income tax net operating loss carryforward of $7.5M recorded during the year and will reverse over the period in which we are able to utilize the loss to offset taxable income on the Idaho, Montana, and Oregon tax returns.
Deferral of depreciation expense of $0.5M per Idaho Order No. 34276, Case Nos. AVU-E-18-03 and AVU-G-18-02.

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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	04/15/2021	End of 2020/Q4

ELECTRIC OPERATING REVENUES (Account 400)

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

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	377,785,465	369,101,530
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	303,971,920	317,589,170
5	Large (or Ind.) (See Instr. 4)	113,563,149	114,530,530
6	(444) Public Street and Highway Lighting	7,303,244	7,447,635
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales	1,422,102	1,502,287
10	TOTAL Sales to Ultimate Consumers	804,045,880	810,171,152
11	(447) Sales for Resale	82,055,793	81,398,279
12	TOTAL Sales of Electricity	886,101,673	891,569,431
13	(Less) (449.1) Provision for Rate Refunds	-1,601,776	-2,908,847
14	TOTAL Revenues Net of Prov. for Refunds	887,703,449	894,478,278
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	150,458	342,546
18	(453) Sales of Water and Water Power	515,996	344,332
19	(454) Rent from Electric Property	2,028,311	2,797,207
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	35,962,624	69,178,898
22	(456.1) Revenues from Transmission of Electricity of Others	16,370,526	16,342,483
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	55,027,915	89,005,466
27	TOTAL Electric Operating Revenues	942,731,364	983,483,744

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/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
3,807,041	3,766,048	349,890	345,064	2
				3
2,994,648	3,170,031	43,399	42,930	4
2,042,265	2,047,228	1,297	1,305	5
17,654	17,973	639	612	6
				7
				8
13,435	14,708	152	148	9
8,875,043	9,015,988	395,377	390,059	10
2,796,393	2,942,248			11
11,671,436	11,958,236	395,377	390,059	12
				13
11,671,436	11,958,236	395,377	390,059	14

Line 12, column (b) includes $ 2,416,764 of unbilled revenues.

Line 12, column (d) includes 23,712 MWH relating to unbilled revenues

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	RESIDENTIAL SALES (440)					
2	1 Residential Service	3,639,357	346,016,498	332,474	10,946	0.0951
3	2 Residential Service	5,537	352,592	438	12,642	0.0637
4	3 Residential Service					
5	12 Res. & Farm Gen. Service	88,207	12,770,530	15,904	5,546	0.1448
6	15 MOPS II Residential					
7	22 Res. & Farm Lg. Gen. Service	38,095	3,511,536	65	586,077	0.0922
8	30 Pumping-Special	12	1,829	4	3,000	0.1524
9	32 Res. & Farm Pumping Service	8,805	1,161,801	1,785	4,933	0.1319
10	48 Res. & Farm Area Lighting	3,316	1,161,570			0.3503
11	49 Area Lighting-High-Press.					
12	56 Centralia Refund					
13	95 Wind Power		146,268			
14	72 Residential Service					
15	73 Residential Service					
16	74 Residential Service					
17	76 Residential Service					
18	77 Residential Service					
19	58A Tax Adjustment		-29,996			
20	58 Tax Adjustment		10,173,345			
21	SubTotal	3,783,329	375,265,973	350,670	10,789	0.0992
22	Residential-Unbilled	23,714	2,519,493			0.1062
23	Total Residential Sales	3,807,043	377,785,466	350,670	10,856	0.0992
24						
25	COMMERCIAL SALES (442)					
26	2 General Service					
27	3 General Service					
28	11 General Service	891,911	102,700,293	39,581	22,534	0.1151
29	12 Res. & Farm Gen. Service					
30	16 MOPS II Commercial					
31	19 Contract-General Service					
32	21 Large General Service	1,659,809	157,071,759	2,630	631,106	0.0946
33	25 Extra Lg. Gen. Service	332,268	21,894,391	13	25,559,077	0.0659
34	28 Contract-Extra Large Serv					
35	31 Pumping Service	101,070	9,287,613	1,274	79,333	0.0919
36	47 Area Lighting-Sod. Vap	4,532	1,421,609			0.3137
37	49 Area Lighting-High-Press.	2,209	683,514			0.3094
38	56 Centralia Refune					
39	95 Wind Power		77,872			
40	74 Large General Service					
41	TOTAL Billed	11,649,485	883,684,904	396,236	29,400	0.0759
42	Total Unbilled Rev.(See Instr. 6)	21,951	2,416,764	0	0	0.1101
43	TOTAL	11,671,436	886,101,668	396,236	29,456	0.0759

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2021	Year/Period of Report End of 2020/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		-39,273			
5	58 Tax Adjustment		10,655,764			
6	SubTotal	2,991,799	303,753,542	43,498	68,780	0.1015
7	Commercial-Unbilled	2,849	218,378			0.0767
8	Total Commercial	2,994,648	303,971,920	43,498	68,846	0.1015
9						
10	INDUSTRIAL SALES (442)					
11	2 General Service					
12	3 General Service					
13	8 Lg Gen Time of Use					
14	11 General Service	10,928	1,271,634	239	45,724	0.1164
15	12 Res. & Farm Gen. Service					
16	21 Large General Service	145,579	13,757,416	126	1,155,389	0.0945
17	25 Extra Lg. Gen. Service	1,797,372	89,793,336	22	81,698,727	0.0500
18	28 Contract - Extra Large Service					
19	29 Contract Lg. Gen. Service					
20	30 Pumping Service - Special	32,837	2,510,581	50	656,740	0.0765
21	31 Pumping Service	56,223	5,257,367	714	78,744	0.0935
22	32 Pumping Svc Res & Firm	3,749	352,880	126	29,754	0.0941
23	47 Area Lighting-Sod. Vap.	132	33,103			0.2508
24	49 Area Lighting - High-Press	55	15,911			0.2893
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		-1,397			
33	58 Tax Adjustment		892,584			
34	SubTotal	2,046,875	113,884,255	1,277	1,602,878	0.0556
35	Industrial-Unbilled	-4,610	-321,107			0.0697
36	Total Industrial	2,042,265	113,563,148	1,277	1,599,268	0.0556
37						
38	STREET AND HWY LIGHTING (444)					
39	6 Mercury Vapor St. Ltg.					
40	7 HP Sodium Vap. St. Ltg					
41	TOTAL Billed	11,649,485	883,684,904	396,236	29,400	0.0759
42	Total Unbilled Rev.(See Instr. 6)	21,951	2,416,764	0	0	0.1101
43	TOTAL	11,671,436	886,101,668	396,236	29,456	0.0759

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	11 General Service					
2	41 Co-Owned St. Lt. Service	35	6,391	5	7,000	0.1826
3	42 Co-Owned St. Lt. Service	14,592	6,717,797	536	27,224	0.4604
4	High-Press. Sod. Vap.					
5	43 Cust-Owned St. Lt. Energy					
6	and Maint. Service					
7	44 Cust-Owned St. Lt. Energy	435	69,831	25	17,400	0.1605
8	and Maint. Svce - High-Pres					
9	Sodium Vapor					
10	45 Cust. Owned St. Lt. Energy Svc	777	65,400	13	59,769	0.0842
11	46 Cust. Owned St. Lt. Energy Svc	1,815	195,510	60	30,250	0.1077
12	58A Tax Adjustment		-681			
13	58 Tax Adjustment		248,995			
14	SubTotal	17,654	7,303,243	639	27,628	0.4137
15	Street & Hwy Lighting-Unbilled					
16	Total Street & Hwy Lighting	17,654	7,303,243	639	27,628	0.4137
17						
18	OTHER SALES TO PUBLIC					
19	(445)					
20	None					
21						
22	INTERDEPARTMENTAL SALES	13,435	1,421,459	152	88,388	0.1058
23	58 Tax Adjustment		643			
24	Total Interdepartmental	13,435	1,422,102	152	88,388	0.1059
25						
26	SALES FOR RESALE (447)					
27	61 Sales to Other Utilities (NDA)	2,796,393	82,055,790			0.0293
28						
29						
30	Total Sales for Resale	2,796,393	82,055,790			0.0293
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	11,649,485	883,684,904	396,236	29,400	0.0759
42	Total Unbilled Rev.(See Instr. 6)	21,951	2,416,764	0	0	0.1101
43	TOTAL	11,671,436	886,101,668	396,236	29,456	0.0759

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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) 04/15/2021	Year/Period of Report End of 2020/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	Avangrid Renewables, LLC	SF	Tariff 9			
2	Avangrid Renewables, LLC	SF	Tariff 9			
3	Avangrid Renewables, LLC	LF	Tariff 12			
4	BP Energy Company	SF	Tariff 9			
5	Black Hills Power, Inc.	SF	Tariff 9			
6	Bonneville Power Administration	LF	Tariff 8			
7	Bonneville Power Administration	LF	Tariff 8			
8	Bonneville Power Administration	SF	Tariff 9			
9	Bonneville Power Administration	LF	Tariff 12			
10	British Columbia Hydro and Power Author	LF	Tariff 12			
11	Brookfield Energy Marketing, LP	SF	Tariff 9			
12	California Independent System Operator	SF	Tariff 9			
13	Calpine Energy Services LP	SF	Tariff 9			
14	Chelan County PUD No. 1	LF	Tariff 12			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
113,430		2,379,350		2,379,350	1
	522,490			522,490	2
53		640		640	3
146,071		4,262,180		4,262,180	4
6,415		114,045		114,045	5
33,739		1,294,161		1,294,161	6
2,380		52,458		52,458	7
58,785		1,278,945		1,278,945	8
66		1,024		1,024	9
26		615		615	10
408		53,225		53,225	11
378,009		10,509,328		10,509,328	12
6,805		265,080		265,080	13
6		47		47	14
0	0	0	0	0	
2,796,393	2,201,012	49,664,905	30,189,876	82,055,793	
2,796,393	**2,201,012**	**49,664,905**	**30,189,876**	**82,055,793**	

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	Citigroup Energy, Inc.	SF	Tariff 9			
2	Clatskanie Peoples PUD	SF	Tariff 9			
3	ConocoPhillips	SF	Tariff 9			
4	Douglas County PUD No. 1	SF	Tariff 9			
5	Douglas County PUD No. 1	LF	Tariff 12			
6	EDF Trading North America, LLC	SF	Tariff 9			
7	EDF Trading North America, LLC	SF	Tariff 9			
8	Energy Keepers, Inc.	SF	Tariff 9			
9	Eugene Water & Electric Board	SF	Tariff 9			
10	Exelon Generation Company, LLC	SF	Tariff 9			
11	Grant County PUD No. 2	LF	Tariff 12			
12	Gridforce Energy Management, LLC	LF	Tariff 12			
13	Idaho Power Company	IF	Tariff 9			
14	Idaho Power Company	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.
2,400		229,800		229,800	1
1,340		36,203		36,203	2
15,076		281,687		281,687	3
2,735		80,205		80,205	4
2		6		6	5
74,341		1,628,524		1,628,524	6
	185,925			185,925	7
2,931		80,324		80,324	8
5,552		151,109		151,109	9
19,302		490,985		490,985	10
5		20		20	11
174		3,852		3,852	12
71		1,538		1,538	13
6		158		158	14
0	0	0	0	0	
2,796,393	2,201,012	49,664,905	30,189,876	82,055,793	
2,796,393	**2,201,012**	**49,664,905**	**30,189,876**	**82,055,793**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/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	Idaho Power Company Balancing	SF	Tariff 9			
2	Idaho Power Company Balancing	IF	Tariff 9			
3	Kootenai Electric Cooperative	LF	Tariff 8			
4	Macquarie Energy, LLC	SF	Tariff 9			
5	Macquarie Energy, LLC	IF	Tariff 9			
6	Mizuho Securities USA, Inc.	OS	NA			
7	Modesto Irrigation District	SF	Tariff 9			
8	Morgan Stanley Capital Group, Inc.	SF	Tariff 9			
9	Morgan Stanley Capital Group, Inc.	IF	Tariff 9			
10	Morgan Stanley Capital Group, Inc.	IF	Tariff 9			
11	Morgan Stanley Capital Group, Inc.	SF	Tariff 9			
12	Morgan Stanley Capital Group, Inc.	SF	Tariff 9			
13	NaturEner Power Watch, LLC	LF	Tariff 12			
14	Nevada Power Company	SF	Tariff 9			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
4,917		77,727		77,727	1
7,808		196,054		196,054	2
2,122		44,297		44,297	3
113,558		2,360,730		2,360,730	4
146		994		994	5
			5,703,092	5,703,092	6
330		19,800		19,800	7
514,331		9,653,776		9,653,776	8
11,690		255,998		255,998	9
410,702		8,298,785		8,298,785	10
	276,696			276,696	11
	645,624			645,624	12
139		2,399		2,399	13
675		21,250		21,250	14
0	0	0	0	0	
2,796,393	2,201,012	49,664,905	30,189,876	82,055,793	
2,796,393	**2,201,012**	**49,664,905**	**30,189,876**	**82,055,793**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2021	Year/Period of Report End of 2020/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	NextEra Energy Marketing, LLC	SF	Tariff 9			
2	NorthWestern Energy LLC	SF	Tariff 9			
3	Northwestern Energy LLC	IF	Tariff 9			
4	NorthWestern Energy LLC	LF	Tariff 12			
5	NorthWestern Energy LLC	LF	Tariff 9			
6	Okanogan County PUD	SF	Tariff 9			
7	PacifiCorp	SF	Tariff 9			
8	PacifiCorp	LF	Tariff 12			
9	PacifiCorp	LF	Tariff 9			
10	Pend Oreille Public Utility District	IF	Tariff 9			
11	Pend Oreille Public Utility District	IF	Tariff 9			
12	Pend Oreille Public Utility District	IF	Tariff 9			
13	Pend Oreille Public Utility District	SF	Tariff 9			
14	Portland General Electric Company	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.
378		8,694		8,694	1
79,538		2,702,572		2,702,572	2
363		7,792		7,792	3
55		1,724		1,724	4
6,389		133,891		133,891	5
5,720		143,180		143,180	6
98,619		3,287,363		3,287,363	7
99		2,114		2,114	8
4,067		85,203		85,203	9
	434,368			434,368	10
9,322		120,713		120,713	11
26,410		584,981		584,981	12
59,354		1,068,206		1,068,206	13
76,157		1,631,934		1,631,934	14
0	0	0	0	0	
2,796,393	2,201,012	49,664,905	30,189,876	82,055,793	
2,796,393	**2,201,012**	**49,664,905**	**30,189,876**	**82,055,793**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/Q4

SALES FOR RESALE (Account 447)

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

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

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
26		902		902	1
37,539		575,854		575,854	2
2,224		80,103		80,103	3
18,588		389,500		389,500	4
64,797		1,576,045		1,576,045	5
4		124		124	6
9,457		382,461		382,461	7
699		24,317		24,317	8
841		80,902		80,902	9
10		278		278	10
10,305		188,185		188,185	11
605		10,186		10,186	12
66		1,993		1,993	13
184,467		4,071,244		4,071,244	14
0	0	0	0	0	
2,796,393	2,201,012	49,664,905	30,189,876	82,055,793	
2,796,393	**2,201,012**	**49,664,905**	**30,189,876**	**82,055,793**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2021	Year/Period of Report End of 2020/Q4

SALES FOR RESALE (Account 447)

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

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

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
	3,810			3,810	1
11,065		273,120		273,120	2
1,191		415,950		415,950	3
	132,099			132,099	4
11,241		276,595		276,595	5
4,440		53,340		53,340	6
1,559		29,608		29,608	7
2		38		38	8
14,521		304,297		304,297	9
3,600		74,442		74,442	10
33,542		958,915		958,915	11
9		244		244	12
75,620		1,946,836		1,946,836	13
158		3,317		3,317	14
0	0	0	0	0	
2,796,393	2,201,012	49,664,905	30,189,876	82,055,793	
2,796,393	**2,201,012**	**49,664,905**	**30,189,876**	**82,055,793**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2021	Year/Period of Report End of 2020/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Turlock Irrigation Dist	SF	Tariff 9			
2	Vitol, Inc.	SF	Tariff 9			
3	Wells Fargo securities, LLC	OS	NA			
4	IntraCompany Wheeling	LF				
5	IntraCompany Generation	LF				
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2021	Year/Period of Report End of 2020/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 ($) (h)	REVENUE: Energy Charges ($) (i)	REVENUE: Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
4,800		454,400		454,400	1
2,000		47,200		47,200	2
			5,433,304	5,433,304	3
		-16,461,177	16,461,177		4
			2,592,303	2,592,303	5
					6
					7
					8
					9
					10
					11
					12
					13
					14
0	0	0	0	0	
2,796,393	2,201,012	49,664,905	30,189,876	82,055,793	
2,796,393	**2,201,012**	**49,664,905**	**30,189,876**	**82,055,793**	

Schedule Page: 310 Line No.: 2 Column: b
Capacity

Schedule Page: 310 Line No.: 3 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310 Line No.: 6 Column: b
BPA Contract Terminates September 30, 2028.

Schedule Page: 310 Line No.: 7 Column: b
Effective October 1, 2018 - This Scheduling Agreement shall remain in effect until such time as BPA is no longer the designated scheduling agent for any Federal Load.

Schedule Page: 310 Line No.: 9 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310 Line No.: 10 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310 Line No.: 14 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.1 Line No.: 5 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.1 Line No.: 7 Column: b
Reserves

Schedule Page: 310.1 Line No.: 11 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.1 Line No.: 12 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.1 Line No.: 13 Column: b
Financially Settled Transmission Losses

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

Schedule Page: 310.2 Line No.: 2 Column: b
Financially Settled Transmission Losses

Schedule Page: 310.2 Line No.: 3 Column: b
Kootenai Contract Terminates March 31,2024

Schedule Page: 310.2 Line No.: 5 Column: b
Financially Settled Transmission Losses

Schedule Page: 310.2 Line No.: 6 Column: b
Financial SWAP

Schedule Page: 310.2 Line No.: 9 Column: b
Financially Settled Transmission Losses

Schedule Page: 310.2 Line No.: 10 Column: b
Resource Contingent Bundled REC - Energy and Green Attributes 03/01/2019-12/31/2023.

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

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

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

Schedule Page: 310.3 Line No.: 3 Column: b
Financially Settled Transmission Losses

Schedule Page: 310.3 Line No.: 4 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.3 Line No.: 5 Column: b
NorthWestern Energy LLC sale expires October 31, 2023.

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

Schedule Page: 310.3 Line No.: 9 Column: b
PacifiCorp sale terminates October 31, 2023.

Schedule Page: 310.3 Line No.: 10 Column: b
Contract expires 9/30/2021.

Schedule Page: 310.3 Line No.: 11 Column: b
Contract expires 9/30/2021.

Schedule Page: 310.3 Line No.: 12 Column: b
Deviation Energy

Schedule Page: 310.4 Line No.: 1 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.4 Line No.: 3 Column: b
Financially Settled Transmission Losses

Schedule Page: 310.4 Line No.: 4 Column: b
Puget Sound Energy sale terminates October 31, 2023.

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.: 10 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.4 Line No.: 12 Column: b
Financially Settled Transmission Losses

Schedule Page: 310.4 Line No.: 13 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.5 Line No.: 1 Column: b
Reserves

Schedule Page: 310.5 Line No.: 4 Column: b
Sovereign Power contract terminates 9-30-2021

Schedule Page: 310.5 Line No.: 5 Column: b
Sovereign Power Contract terminates 9-30-2021

Schedule Page: 310.5 Line No.: 7 Column: b
Financially Settled Transmission Losses

Schedule Page: 310.5 Line No.: 8 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.5 Line No.: 9 Column: b
Talen Energy sale terminates October 31,2023.

Schedule Page: 310.5 Line No.: 12 Column: b
Financially Settled Transmission Losses

Schedule Page: 310.5 Line No.: 14 Column: b
Financially Settled Transmission Losses

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

Schedule Page: 310.6 Line No.: 4 Column: b
IntraCompany Wheeling terminates 09/30/2023.

Schedule Page: 310.6 Line No.: 5 Column: b
IntraCompany Generation - Sale of Ancillary Services.

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2021	Year/Period of Report End of 2020/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	354,806	355,496
5	(501) Fuel	29,506,761	30,554,741
6	(502) Steam Expenses	3,514,368	3,760,759
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	743,487	888,160
10	(506) Miscellaneous Steam Power Expenses	4,636,347	3,107,546
11	(507) Rents		15,079
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	38,755,769	38,681,781
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	660,566	506,378
16	(511) Maintenance of Structures	776,895	759,694
17	(512) Maintenance of Boiler Plant	7,796,381	5,794,165
18	(513) Maintenance of Electric Plant	2,263,602	638,851
19	(514) Maintenance of Miscellaneous Steam Plant	1,186,306	1,222,605
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	12,683,750	8,921,693
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	51,439,519	47,603,474
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	1,909,402	2,754,616
45	(536) Water for Power	1,417,118	930,038
46	(537) Hydraulic Expenses	9,826,421	9,607,953
47	(538) Electric Expenses	5,782,034	5,884,654
48	(539) Miscellaneous Hydraulic Power Generation Expenses	1,089,381	1,070,877
49	(540) Rents	6,590,160	6,428,232
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	26,614,516	26,676,370
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	577,244	792,626
54	(542) Maintenance of Structures	2,148,575	657,326
55	(543) Maintenance of Reservoirs, Dams, and Waterways	347,512	1,636,470
56	(544) Maintenance of Electric Plant	3,116,588	2,824,428
57	(545) Maintenance of Miscellaneous Hydraulic Plant	672,199	947,013
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	6,862,118	6,857,863
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	33,476,634	33,534,233

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	387,513	228,562
63	(547) Fuel	53,865,752	71,500,955
64	(548) Generation Expenses	2,362,990	2,231,850
65	(549) Miscellaneous Other Power Generation Expenses	407,606	1,254,645
66	(550) Rents	84,304	47,044
67	TOTAL Operation (Enter Total of lines 62 thru 66)	57,108,165	75,263,056
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	681,138	651,663
70	(552) Maintenance of Structures	178,602	133,426
71	(553) Maintenance of Generating and Electric Plant	4,117,018	7,094,951
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	408,807	426,816
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	5,385,565	8,306,856
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	62,493,730	83,569,912
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	136,251,226	144,313,775
77	(556) System Control and Load Dispatching	708,451	660,144
78	(557) Other Expenses	33,286,543	48,105,794
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	170,246,220	193,079,713
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	317,656,103	357,787,332
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,195,597	1,931,225
84			
85	(561.1) Load Dispatch-Reliability	25,215	60,658
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,203,318	1,227,913
87	(561.3) Load Dispatch-Transmission Service and Scheduling	1,008,482	1,002,020
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	483,110	663,145
90	(561.6) Transmission Service Studies	655	
91	(561.7) Generation Interconnection Studies	4,366	
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	477,902	499,947
94	(563) Overhead Lines Expenses	423,608	370,882
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	16,539,039	17,252,820
97	(566) Miscellaneous Transmission Expenses	2,365,717	2,805,371
98	(567) Rents	185,537	170,983
99	TOTAL Operation (Enter Total of lines 83 thru 98)	24,912,546	25,984,964
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	426,853	499,807
102	(569) Maintenance of Structures	429,943	570,168
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	761,185	823,646
108	(571) Maintenance of Overhead Lines	1,346,772	1,002,431
109	(572) Maintenance of Underground Lines	3,651	47
110	(573) Maintenance of Miscellaneous Transmission Plant	35,220	73,382
111	TOTAL Maintenance (Total of lines 101 thru 110)	3,003,624	2,969,481
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	27,916,170	28,954,445

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/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	3,716,544	3,341,232
135	(581) Load Dispatching		
136	(582) Station Expenses	641,798	768,839
137	(583) Overhead Line Expenses	2,561,515	2,206,002
138	(584) Underground Line Expenses	1,747,358	1,618,684
139	(585) Street Lighting and Signal System Expenses	38,628	5,265
140	(586) Meter Expenses	1,634,878	1,744,750
141	(587) Customer Installations Expenses	689,416	829,754
142	(588) Miscellaneous Expenses	4,826,245	7,149,060
143	(589) Rents	275,841	353,727
144	TOTAL Operation (Enter Total of lines 134 thru 143)	16,132,223	18,017,313
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	1,374,983	1,230,289
147	(591) Maintenance of Structures	566,579	532,672
148	(592) Maintenance of Station Equipment	494,075	769,884
149	(593) Maintenance of Overhead Lines	13,734,825	10,873,805
150	(594) Maintenance of Underground Lines	676,586	804,137
151	(595) Maintenance of Line Transformers	430,900	359,548
152	(596) Maintenance of Street Lighting and Signal Systems	141,014	158,130
153	(597) Maintenance of Meters	50,253	39,048
154	(598) Maintenance of Miscellaneous Distribution Plant	553,027	536,940
155	TOTAL Maintenance (Total of lines 146 thru 154)	18,022,242	15,304,453
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	34,154,465	33,321,766
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	149,519	114,406
160	(902) Meter Reading Expenses	1,204,370	2,042,787
161	(903) Customer Records and Collection Expenses	7,480,445	7,885,571
162	(904) Uncollectible Accounts	7,961,674	208,808
163	(905) Miscellaneous Customer Accounts Expenses	145,713	159,633
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	16,941,721	10,411,205

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/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	33,716,712	37,686,359
169	(909) Informational and Instructional Expenses	1,029,735	1,153,181
170	(910) Miscellaneous Customer Service and Informational Expenses	320,788	250,163
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	35,067,235	39,089,703
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses		
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)		
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	27,858,120	25,372,504
182	(921) Office Supplies and Expenses	4,275,810	4,732,387
183	(Less) (922) Administrative Expenses Transferred-Credit	103,030	102,345
184	(923) Outside Services Employed	10,580,489	10,107,690
185	(924) Property Insurance	1,673,027	1,451,884
186	(925) Injuries and Damages	4,251,143	4,177,429
187	(926) Employee Pensions and Benefits	31,925,253	30,761,884
188	(927) Franchise Requirements	1,200	1,200
189	(928) Regulatory Commission Expenses	6,021,061	6,380,843
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses		
192	(930.2) Miscellaneous General Expenses	6,469,003	4,995,151
193	(931) Rents	566,423	312,788
194	TOTAL Operation (Enter Total of lines 181 thru 193)	93,518,499	88,191,415
195	Maintenance		
196	(935) Maintenance of General Plant	12,476,593	12,182,064
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	105,995,092	100,373,479
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	537,730,786	569,937,930

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Adams Nielson Solar, LLC	LU	PURPA			
2	Avangrid Renewables, LLC	SF	Tariff 9			
3	Avangrid Renewables, LLC	LF	NWPP			
4	Avangrid Renewables, LLC	OS	Tariff 9			
5	BP Energy	SF	Tariff 9			
6	Black Hills Power, Inc.	SF	Tariff 9			
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	California Independent System Operator	SF	Tariff 9			
14	Calpine Energy Services LP	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 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.
45,281				1,796,750		1,796,750	1
156,203				1,852,515		1,852,515	2
8				193		193	3
					3,500	3,500	4
5,800				17,950		17,950	5
425				12,650		12,650	6
143,686				2,084,017		2,084,017	7
227				5,494		5,494	8
17,908				394,640		394,640	9
1,783				30,531		30,531	10
					29,843	29,843	11
7,444				228,662		228,662	12
5,391				108,747		108,747	13
7,828				174,000		174,000	14
5,465,161	9,313	429,763	30,688,728	99,167,441	6,395,057	136,251,226	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2021	Year/Period of Report End of 2020/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	City of Spokane	LU	PURPA			
2	City of Spokane	IU	PURPA			
3	Chelan County PUD	IU	Rocky Reach			
4	Chelan County PUD	IU	Rocky Reach			
5	Chelan County PUD	SF	Tariff 9			
6	Chelan County PUD	LF	NWPP			
7	Chelan County PUD	IU	Chelan Sys			
8	Clark Fork Hydro	LU	PURPA			
9	Clatskanie PUD	SF	Tariff 9			
10	Clearwater Paper Company	IU	PURPA			
11	Clearwater Power Company	RQ	NA			
12	Community Solar	LU	PURPA			
13	ConocoPhillips Company	SF	Tariff 9			
14	Deep Creek Energy, LLC	IU	PURPA			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
51,202				1,896,628		1,896,628	1
125,281				5,841,923		5,841,923	2
21,097							3
-23,893							4
18,600				273,450		273,450	5
11				268		268	6
422,794			16,793,744			16,793,744	7
1,034				64,064		64,064	8
732				8,090		8,090	9
426,954				10,460,373		10,460,373	10
180				14,451		14,451	11
534				13,252		13,252	12
28,095				841,235		841,235	13
331				14,125		14,125	14
5,465,161	9,313	429,763	30,688,728	99,167,441	6,395,057	136,251,226	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2021	Year/Period of Report End of 2020/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Douglas County PUD No. 1	LU	Wells			
2	Douglas County PUD No. 1	SF	Tariff 9			
3	Douglas County PUD No. 1	LF	NWPP			
4	Douglas County PUD No. 1	OS	Wells			
5	Douglas County PUD No. 1	EX	Tariff 9			
6	EDF Trading No America	SF	Tariff 9			
7	Enel X North America, Inc.	LU	PURPA			
8	Energy Keepers, Inc.	SF	Tariff 9			
9	Eugene Water & Electric Board	SF	Tariff 9			
10	Exelon Generation Company, LLC	SF	Tariff 9			
11	Ford Hydro Limited Partnership	LU	PURPA			
12	Grant County PUD No. 2	LU	Priest Rapids			
13	Grant County PUD No. 2	LF	NWPP			
14	Grant County PUD No. 2	EX	FERC #104			
	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)	
500,828			3,915,081			3,915,081	1
9,650				123,487		123,487	2
4				103		103	3
					493,806	493,806	4
		421,632					5
857				11,530		11,530	6
44							7
584				5,189		5,189	8
2,934				46,139		46,139	9
19,721				276,876		276,876	10
3,990				258,149		258,149	11
351,771			9,979,903			9,979,903	12
18				451		451	13
					29,508	29,508	14
5,465,161	9,313	429,763	30,688,728	99,167,441	6,395,057	136,251,226	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2021	Year/Period of Report End of 2020/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Gridforce Energy Management, LLC	LF	NWPP			
2	Hydro Technology Systems	IU	PURPA			
3	Idaho County Power & Light	LU	PURPA			
4	Idaho Power Company	SF	Tariff 9			
5	Idaho Power Company	IF	Tariff 9			
6	Inland Power & Light Company	RQ	208			
7	Kootenai Electric Cooperative	LF	Tariff 8			
8	Macquarie Energy LLC	SF	Tariff 9			
9	Mizuho Securities USA, Inc.	OS	NA			
10	Morgan Stanley Capital Group	SF	Tariff 9			
11	Nevada Power Company	SF	Tariff 9			
12	NextEra Energy Power Marketing LLC	SF	Tariff 9			
13	NorthWestern Energy LLC	SF	Tariff 9			
14	NorthWestern Energy LLC	LF	NWPP			
	Total					

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2021	Year/Period of Report End of 2020/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
17				445		445	1
11,549				602,547		602,547	2
2,161				114,447		114,447	3
25,779				353,902		353,902	4
29				349		349	5
165				12,077		12,077	6
2,063				41,159		41,159	7
30,787				616,450		616,450	8
					1,137,096	1,137,096	9
49,499				719,098		719,098	10
				-10		-10	11
7,850				116,110		116,110	12
26,760				419,565		419,565	13
30				730		730	14
5,465,161	9,313	429,763	30,688,728	99,167,441	6,395,057	136,251,226	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2021	Year/Period of Report End of 2020/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	NorthWestern Energy LLC	IF	Tariff 9			
2	Okanogan County PUD No. 1	SF	Tariff 9			
3	PacifiCorp	SF	Tariff 9			
4	PacifiCorp	LF	NWPP			
5	Palouse Wind LLC	LU	PPA			
6	Pend Oreille County PUD No. 1	SF	Pend O'			
7	Pend Oreille County PUD No. 1	IF	Pend O'			
8	Pend Oreille County PUD No. 1	IF	Pend O'			
9	Phillips Ranch	LU	PURPA			
10	Portland General Electric Company	EX	Tariff 9			
11	Portland General Electric Company	SF	Tariff 9			
12	Portland General Electric Company	LF	NWPP			
13	Portland General Electric Company	IF	Tariff 9			
14	Powerex Corp	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)	
848				26,966		26,966	1
7,050				75,980		75,980	2
31,552				624,493		624,493	3
63				1,559		1,559	4
370,142				23,352,036		23,352,036	5
200,192				3,662,630		3,662,630	6
11,086				164,063		164,063	7
39,005				451,205		451,205	8
26				797		797	9
	8,130	8,131					10
30,615				870,175		870,175	11
50				1,235		1,235	12
7,783				161,657		161,657	13
59,572				1,746,688		1,746,688	14
5,465,161	9,313	429,763	30,688,728	99,167,441	6,395,057	136,251,226	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/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	Puget Sound Energy	SF	Tariff 9			
2	Puget Sound Energy	LF	NWPP			
3	Puget Sound Energy	IF	Tariff 9			
4	Rathdrum Power LLC	LU	Lancaster			
5	Rattlesnake Flat, LLC	LU	PPA			
6	Seattle City Light	SF	Tariff 9			
7	Seattle City Light	LF	NWPP			
8	Sheep Creek Hydro	LU	PURPA			
9	Shell Energy	SF	Tariff 9			
10	Snohomish County PUD No. 1	SF	Tariff 9			
11	Sovereign Power	LF	Sovereign			
12	Spokane County	LU	PURPA			
13	Stimson Lumber	IU	PURPA			
14	Tacoma Power	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)	
76,800				1,637,168		1,637,168	1
56				1,414		1,414	2
3				55		55	3
1,685,079				28,069,627		28,069,627	4
37,157				807,070		807,070	5
14,375				236,225		236,225	6
25				617		617	7
8,697				277,164		277,164	8
110,522				1,391,825		1,391,825	9
15,310				222,490		222,490	10
13,777				192,255		192,255	11
1,055				52,908		52,908	12
36,523				1,694,707		1,694,707	13
16,357				382,474		382,474	14
5,465,161	9,313	429,763	30,688,728	99,167,441	6,395,057	136,251,226	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/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	Tacoma Power	LF	NWPP			
2	Tenaska Power Services Co	SF	Tariff 9			
3	The City of Cove	LU	PURPA			
4	The Energy Authority	SF	Tariff 9			
5	TransAlta Energy Marketing	SF	Tariff 9			
6	Turlock Irrigation District	SF	Tariff 9			
7	Vitol Inc.	SF	Tariff 9			
8	Wells Fargo Securities, LLC	OS	NA			
9	IntraCompany Generation Services	OS	OATT			
10	Other - Inadvertent Interchange	EX				
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)	
14				348		348	1
1,763				13,385		13,385	2
2,895				109,479		109,479	3
28,351				391,058		391,058	4
135,547				2,614,207		2,614,207	5
8,045				33,280		33,280	6
2,800				47,400		47,400	7
					2,109,002	2,109,002	8
					2,592,302	2,592,302	9
	1,183						10
							11
							12
							13
							14
5,465,161	9,313	429,763	30,688,728	99,167,441	6,395,057	136,251,226	

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.: 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.: 6 Column: a
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.

Schedule Page: 326.1 Line No.: 11 Column: a
Service to Ahsahka, Idaho from Clearwater Power Company. No demand charges associated with the agreement.

Schedule Page: 326.2 Line No.: 3 Column: a
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.

Schedule Page: 326.2 Line No.: 4 Column: a
Canadian Entitlement associated with Wells contract.

Schedule Page: 326.2 Line No.: 5 Column: a
Exchange

Schedule Page: 326.2 Line No.: 13 Column: a
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.

Schedule Page: 326.3 Line No.: 1 Column: a
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.

Schedule Page: 326.3 Line No.: 5 Column: a
Financially Settled Transmission Losses

Schedule Page: 326.3 Line No.: 6 Column: a
Service to Deer Lake from Inland Power and Light. No demand charges associated with the agreement.

Schedule Page: 326.3 Line No.: 7 Column: a
Kootenai Contract Terminates March 31, 2024

Schedule Page: 326.3 Line No.: 9 Column: a
Financial SWAP

Schedule Page: 326.3 Line No.: 11 Column: a
Energy Imbalance Charges

Schedule Page: 326.3 Line No.: 14 Column: a
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.

Schedule Page: 326.4 Line No.: 1 Column: a
Financially Settled Transmission Losses

Schedule Page: 326.4 Line No.: 4 Column: a
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.

Schedule Page: 326.4 Line No.: 7 Column: a
Pend Oreille County PUD contract expires 09/30/2021. Deviation Energy.

Schedule Page: 326.4 Line No.: 12 Column: a
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.

Schedule Page: 326.4 Line No.: 13 Column: a
Financially Settled Transmission Losses

Schedule Page: 326.5 Line No.: 2 Column: a
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.

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

Financially Settled Transmission Losses

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

Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.

Schedule Page: 326.5 Line No.: 11 Column: a

Sovereign Contract Terminates September 30, 2021. Deviation Energy.

Schedule Page: 326.6 Line No.: 1 Column: a

Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.

Schedule Page: 326.6 Line No.: 8 Column: a

Financial SWAP

Schedule Page: 326.6 Line No.: 9 Column: a

Ancillary Services

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/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	Shell Energy North America (US) LP	Bonneville Power Administration	NorthWestern Energy	SFP
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	Douglas County PUD	Chelan County PUD	Avista Corporation	NF
18	Morgan Stanley Capital Group	Avista Corporation	NorthWestern Energy	SFP
19	Shell Energy North America (US) LP	PacifiCorp	Bonneville Power Administration	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	PacifiCorp	Idaho Power Company	SFP
27	Shell Energy North America (US) LP	Chelan County PUD	NorthWestern Energy	SFP
28	EDR Trading North America LLC	Bonneville Power Administration	NorthWestern Energy	NF
29	PacifiCorp	PacifiCorp	PacifiCorp	SFP
30	Idaho Power Company	Avista Corporation	Idaho Power Company	SFP
31	EDR Trading North America LLC	NorthWestern Energy	Avista Corporation	NF
32	Idaho Power Company	Bonneville Power Administration	Idaho Power Company	SFP
33	EDR Trading North America LLC	Avista Corporation	NorthWestern Energy	NF
34	Idaho Power Company	PacifiCorp	Idaho Power Company	SFP
	TOTAL			

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2021	Year/Period of Report End of 2020/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
RS No. 182	Dry Gulch	Dry Gulch		22,384	22,384	1
FERC Trf No. 8	Chelan-Stratford	Stratford		126,003	126,003	2
FERC Trf No. 8	Chelan-Stratford	Stratford		125,983	125,983	3
RS No. 104	Stratford	Coulee City/Wilson		86,685	86,685	4
FERC Trf No. 8	AVA.BPAT	AVA.SYS	3	3,202	3,202	5
FERC Trf No. 8	AVA.BPAT	AVA.SYS	3	2,726	2,726	6
FERC Trf No. 8	AVA.BPAT	AVA.SYS	4	6,270	6,270	7
FERC Trf No. 8	AVA.BPAT	AVA.SYS		2,019,544	2,019,544	8
PURPA						9
PURPA						10
PURPA						11
FERC Trf No. 8				1,810	1,810	12
PURPA						13
FERC Trf No. 8				34,757	34,757	14
FERC Trf No. 8				84,841	84,841	15
FERC Trf No. 8				1,200	1,200	16
FERC Trf No. 8				48	48	17
FERC Trf No. 8				964	964	18
FERC Trf No. 8				188	188	19
FERC Trf No. 8				7,994	7,994	20
FERC Trf No. 8				23,723	23,723	21
FERC Trf No. 8				19,784	19,784	22
FERC Trf No. 8				75	75	23
FERC Trf No. 8				21,809	21,809	24
FERC Trf No. 8				419	419	25
FERC Trf No. 8				34,979	34,979	26
FERC Trf No. 8				37	37	27
FERC Trf No. 8				2,553	2,553	28
FERC Trf No. 8				216	216	29
FERC Trf No. 8				1,624	1,624	30
FERC Trf No. 8				36	36	31
FERC Trf No. 8				184,050	184,050	32
FERC Trf No. 8				50	50	33
FERC Trf No. 8				3,336	3,336	34
			13	**3,510,201**	**3,510,201**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2021	Year/Period of Report End of 2020/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.
301,661			301,661	1
154,228		90,228	244,456	2
208,000		90,228	298,228	3
28,479			28,479	4
18,000		7,113	25,113	5
10,800		5,544	16,344	6
32,160		9,332	41,492	7
6,612,430		2,550,162	9,162,592	8
		27,973	27,973	9
		8,448	8,448	10
		6,120	6,120	11
5,329			5,329	12
		603	603	13
209,586			209,586	14
291,128			291,128	15
4,333			4,333	16
2,354			2,354	17
3,350			3,350	18
1,186			1,186	19
25,472			25,472	20
92,324			92,324	21
102,389			102,389	22
433			433	23
85,929			85,929	24
2,108			2,108	25
126,094			126,094	26
233			233	27
15,893			15,893	28
1,355			1,355	29
7,072			7,072	30
209			209	31
876,203			876,203	32
319			319	33
17,282			17,282	34
12,628,226	**0**	**3,742,300**	**16,370,526**	

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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) 04/15/2021	Year/Period of Report End of 2020/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Idaho Power Company	Chelan County PUD	Idaho Power Company	SFP
2	Idaho Power Company	PacifiCorp	NorthWestern Energy	NF
3	Macquarie Energy LLC	Avista Corporation	NorthWestern Energy	NF
4	Avangrid Renewables	Bonneville Power Administration	NorthWestern Energy	NF
5	Powerex	Chelan County PUD	NorthWestern Energy	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	Grant County PUD	NorthWestern Energy	SFP
14	Energy Keepers Inc	Bonneville Power Administration	NorthWestern Energy	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	Rainbow Energy Marketing Corp	Bonneville Power Administration	Idaho Power Company	NF
19	Morgan Stanley Capital Group	NorthWestern Energy	Idaho Power Company	NF
20	Morgan Stanley Capital Group	NorthWestern Energy	Grant County PUD	NF
21	Rainbow Energy Marketing Corp	Bonneville Power Administration	NorthWestern Energy	NF
22	Rainbow Energy Marketing Corp	NorthWestern Energy	PacifiCorp	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	Idaho Power Company	Bonneville Power Administration	NorthWestern Energy	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)	MegaWatt Hours Delivered (j)	Line No.
FERC Trf No. 8				13,168	13,168	1
FERC Trf No. 8				2,176	2,176	2
FERC Trf No. 8				11	11	3
FERC Trf No. 8				75	75	4
FERC Trf No. 8				430	430	5
FERC Trf No. 8				23,523	23,523	6
FERC Trf No. 8				8,890	8,890	7
FERC Trf No. 8				234	234	8
FERC Trf No. 8				78	78	9
FERC Trf No. 8				67	67	10
FERC Trf No. 8	AVA.SYS	LOLO	3	15,278	15,278	11
FERC Trf No. 8				145	145	12
FERC Trf No. 8				3,174	3,174	13
FERC Trf No. 8				1,470	1,470	14
FERC Trf No. 8				13,802	13,802	15
FERC Trf No. 8				18,117	18,117	16
FERC Trf No. 8				2,484	2,484	17
FERC Trf No. 8				1,414	1,414	18
FERC Trf No. 8				12,116	12,116	19
FERC Trf No. 8				651	651	20
FERC Trf No. 8				274	274	21
FERC Trf No. 8				100	100	22
FERC Trf No. 8				10	10	23
FERC Trf No. 8				7,243	7,243	24
FERC Trf No. 8				1,330	1,330	25
FERC Trf No. 8				6,946	6,946	26
FERC Trf No. 8				702	702	27
FERC Trf No. 8				78	78	28
FERC Trf No. 8				11,969	11,969	29
FERC Trf No. 8				1,166	1,166	30
FERC Trf No. 8				34,679	34,679	31
FERC Trf No. 8				25,252	25,252	32
FERC Trf No. 8				5,573	5,573	33
FERC Trf No. 8				5,775	5,775	34
			13	**3,510,201**	**3,510,201**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/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.
57,446			57,446	1
16,629			16,629	2
63			63	3
433			433	4
2,513			2,513	5
138,625			138,625	6
40,279			40,279	7
1,344			1,344	8
935			935	9
803			803	10
72,000		22,549	94,549	11
948			948	12
13,128			13,128	13
7,384			7,384	14
91,751			91,751	15
120,617			120,617	16
15,802			15,802	17
11,311			11,311	18
79,719			79,719	19
4,111			4,111	20
2,176			2,176	21
606			606	22
59			59	23
45,996			45,996	24
8,432			8,432	25
45,195			45,195	26
4,637			4,637	27
535			535	28
				29
7,303			7,303	30
271,816			271,816	31
182,050			182,050	32
40,104			40,104	33
39,180			39,180	34
12,628,226	**0**	**3,742,300**	**16,370,526**	

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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) 04/15/2021	Year/Period of Report End of 2020/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	Rainbow Energy Marketing Corp	PacifiCorp	Idaho Power Company	NF
4	Rainbow Energy Marketing Corp	Avista Corporation	Idaho Power Company	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	The Energy Authority	Bonneville Power Administration	Avista Corporation	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	Transalta Energy Marketing	Puget Sound Energy	Idaho Power Company	NF
14	Macquarie Energy LLC	Bonneville Power Administration	NorthWestern Energy	NF
15	Idaho Power Company	PacifiCorp	Idaho Power Company	NF
16	Transalta Energy Marketing	Bonneville Power Administration	NorthWestern Energy	NF
17	Transalta Energy Marketing	Grant County PUD	Idaho Power Company	NF
18	NorthWestern Energy	NorthWestern Energy	Bonneville Power Administration	NF
19	Transalta Energy Marketing	Chelan County PUD	Idaho Power Company	NF
20	PacifiCorp	PacifiCorp	Bonneville Power Company	SFP
21	Transalta Energy Marketing	Avista Corporation	Bonneville Power Administration	NF
22	PacifiCorp	PacifiCorp	PacifiCorp	NF
23	Transalta Energy Marketing	Avista Corporation	Idaho Power Company	NF
24	Idaho Power Company	Bonneville Power Administration	PacifiCorp	SFP
25	Idaho Power Company	PacifiCorp	NorthWestern Energy	SFP
26	Powerex	Bonneville Power Administration	NorthWestern Energy	NF
27	Powerex	NorthWestern Energy	Bonneville Power Administration	NF
28	Idaho Power Company	Puget Sound Energy	NorthWestern Energy	SFP
29	Idaho Power Company	Grant County PUD	NorthWestern Energy	SFP
30	Idaho Power Company	Chelan County PUD	NorthWestern Energy	SFP
31	Idaho Power Company	Avista Corporation	NorthWestern Energy	SFP
32	The Energy Authority	Bonneville Power Administration	NorthWestern Energy	NF
33	Idaho Power Company	Idaho Power Company	Grant County PUD	SFP
34	Macquarie Energy LLC	Bonneville Power Administration	NorthWestern Energy	SFP
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
FERC Trf No. 8				6,271	6,271	1
RS No. T1110						2
FERC Trf No. 8				550	550	3
FERC Trf No. 8				931	931	4
FERC Trf No. 8				22,169	22,169	5
FERC Trf No. 8				1,547	1,547	6
FERC Trf No. 8				8,928	8,928	7
FERC Trf No. 8				7,528	7,528	8
FERC Trf No. 8				348	348	9
FERC Trf No. 8				62	62	10
FERC Trf No. 8				1,068	1,068	11
FERC Trf No, 8				1,662	1,662	12
FERC Trf No. 8				60	60	13
FERC Trf No. 8				2,902	2,902	14
FERC Trf No. 8				125	125	15
FERC Trf No. 8				1,575	1,575	16
FERC Trf No. 8				20	20	17
FERC Trf No. 8				3,148	3,148	18
FERC Trf No. 8				42	42	19
FERC Trf No. 8				28,805	28,805	20
FERC Trf No. 8				70	70	21
FERC Trf No. 8				668	668	22
FERC Trf No. 8				15	15	23
FERC Trf No. 8				2,000	2,000	24
FERC Trf No. 8				400	400	25
FERC Trf No. 8				3,627	3,627	26
FERC Trf No. 8				75	75	27
FERC Trf No. 8				2,000	2,000	28
FERC Trf No. 8				800	800	29
FERC Trf No. 8				1,800	1,800	30
FERC Trf No. 8				176	176	31
FERC Trf No. 8				110	110	32
FERC Trf No. 8				2,382	2,382	33
FERC Trf No. 8				1,971	1,971	34
			13	**3,510,201**	**3,510,201**	

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.
39,686			39,686	1
		924,000	924,000	2
3,331			3,331	3
9,574			9,574	4
130,864			130,864	5
9,602			9,602	6
53,618			53,618	7
44,873			44,873	8
3,727			3,727	9
653			653	10
5,511			5,511	11
10,259			10,259	12
400			400	13
16,889			16,889	14
721			721	15
20,309			20,309	16
115			115	17
19,845			19,845	18
280			280	19
180,666			180,666	20
466			466	21
6,249			6,249	22
87			87	23
8,707			8,707	24
9,277			9,277	25
21,740			21,740	26
490			490	27
16,243			16,243	28
3,483			3,483	29
7,598			7,598	30
766			766	31
866			866	32
9,230			9,230	33
11,722			11,722	34
12,628,226	**0**	**3,742,300**	**16,370,526**	

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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	04/15/2021	End of 2020/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	Morgan Stanley Capital Group	Idaho Power Company	Bonneville Power Administration	SFP
4	Morgan Stanley Capital Group	NorthWestern Energy	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	Morgan Stanley Capital Group	Idaho Power Company	Chelan County PUD	SFP
8	Morgan Stanley Capital Group	Avista Corporation	Bonneville Power Administration	SFP
9	PacifiCorp	PacifiCorp	Idaho Power Company	SFP
10	Avangrid Renewables	Bonneville Power Administration	NorthWestern Energy	SFP
11	Powerex	Bonneville Power Administration	Idaho Power Company	SFP
12	Powerex	Bonneville Power Administration	NorthWestern Energy	SFP
13	Powerex	Chelan County PUD	Idaho Power Company	SFP
14	Rainbow Energy Marketing Corp	Bonneville Power Administration	Idaho Power Company	SFP
15	Rainbow Energy Marketing Corp	Bonneville Power Administration	NorthWestern Energy	SFP
16	The Energy Authority	Bonneville Power Administration	Idaho Power Company	NF
17	Rainbow Energy Marketing Corp	PacifiCorp	Idaho Power Company	SFP
18	PacifiCorp	Idaho Power Company	PacifiCorp	SFP
19	Rainbow Energy Marketing Corp	Puget Sound Energy	Idaho Power Company	SFP
20	Rainbow Energy Marketing Corp	Grant County PUD	Idaho Power Company	SFP
21	Rainbow Energy Marketing Corp	Avista Corporation	Bonneville Power Administration	SFP
22	The Energy Authority	Bonneville Power Administration	Avista Corporation	SFP
23				
24				
25				
26				
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				60	60	1
FERC Trf No. 8				1,880	1,880	2
FERC Trf No. 8				213,207	213,207	3
FERC Trf No. 8				196	196	4
FERC Trf No. 8				5,183	5,183	5
FERC Trf No. 8				1,607	1,607	6
FERC Trf No. 8				19	19	7
FERC Trf No. 8				1,200	1,200	8
FERC Trf No. 8				44,220	44,220	9
FERC Trf No. 8				1,602	1,602	10
FERC Trf No. 8				61,746	61,746	11
FERC Trf No. 8				4,400	4,400	12
FERC Trf No. 8				2,676	2,676	13
FERC Trf No. 8				7,528	7,528	14
FERC Trf No. 8				8,659	8,659	15
FERC Trf No. 8				205	205	16
FERC Trf No. 8				200	200	17
FERC Trf No. 8				12,410	12,410	18
FERC Trf No. 8				2,654	2,654	19
FERC Trf No. 8				600	600	20
FERC Trf No. 8				400	400	21
FERC Trf No. 8				24	24	22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			13	**3,510,201**	**3,510,201**	

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.
379			379	1
13,703			13,703	2
700,165			700,165	3
1,198			1,198	4
24,431			24,431	5
7,208			7,208	6
73			73	7
3,713			3,713	8
202,599			202,599	9
6,184			6,184	10
268,226			268,226	11
15,481			15,481	12
9,503			9,503	13
42,610			42,610	14
48,347			48,347	15
1,200			1,200	16
1,430			1,430	17
50,765			50,765	18
18,262			18,262	19
2,308			2,308	20
2,233			2,233	21
92			92	22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
12,628,226	**0**	**3,742,300**	**16,370,526**	

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/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			1,505,764			1,505,764
2	Bonneville Power Admin	LFP			10,448,928		2,160,672	12,609,600
3	Bonneville Power Admin	OS					54,432	54,432
4	Bonneville Power Admin	FNS			1,115,693		228,515	1,344,208
5	Bonneville Power Admin	NF	7,258	7,258		38,612		38,612
6	Idaho Power Company	NF	1,397	1,397		5,815		5,815
7	Kootenai Electric Coop	LFP			47,538			47,538
8	Northern Lights	LFP			137,268			137,268
9	NorthWestern Energy	SFP			80,388		3,111	83,499
10	NorthWestern Energy	NF	12,036	12,036		43,725		43,725
11	Portland General Elec	LFP			628,000		14,989	642,989
12	Portland General Elec	NF	3,047	3,047		3,453		3,453
13	Snohomish County PUD	NF	4,302	4,302		5,011		5,011
14	Puget Sound Energy	NF	240	240		535	-139	396
15	Energy Keepers, Inc	NF	2,664	2,664		11,322		11,322
16	Seattle City Light	NF	3,781	3,781		5,278		5,278
	TOTAL		34,828	34,828	13,963,579	113,880	2,461,580	16,539,039

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	The Energy Authority	NF	103	103		129		129
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		34,828	34,828	13,963,579	113,880	2,461,580	16,539,039

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

Ancillary Services

Schedule Page: 332   Line No.: 3   Column: g

Use of Facilities

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

Ancillary Services

Schedule Page: 332   Line No.: 9   Column: g

Ancillary Services and Regulation & Frequency Response

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

Ancillary Services

Schedule Page: 332   Line No.: 14   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	04/15/2021	End of 2020/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	1,156,732
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	787,388
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Community Relations	481,418
7	Board of Director Activities	1,468,746
8	Education, Information & Training	92,686
9	Emergency Operating Procedure Events	2,031,738
10	Misc Employee Expenses	41,782
11	Misc Labor	5,135
12	Misc Legal, Professional, and General Services	181,490
13	Misc Transportation	196,414
14	Other Misc Expenses <$5,000	25,474
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
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35		
36		
37		
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41		
42		
43		
44		
45		
46	TOTAL	6,469,003

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/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			4,734,362		4,734,362
2	Steam Production Plant	26,466,230				26,466,230
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	14,525,512				14,525,512
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	10,583,010				10,583,010
7	Transmission Plant	17,309,358				17,309,358
8	Distribution Plant	50,168,069				50,168,069
9	Regional Transmission and Market Operation					
10	General Plant	4,334,242		127,473		4,461,715
11	Common Plant-Electric	18,672,863		27,999,976		46,672,839
12	TOTAL	142,059,284		32,861,811		174,921,095

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	57,709	70.00	-6.00	1.99	S1.5	7.50
15	312	86,478	60.00	-6.00	2.67	R1	7.50
16	313	343		-6.00	9.22	R2.5	7.50
17	314	23,854	40.00	-6.00	8.34	R0.5	7.50
18	315	10,548	50.00	-6.00	2.97	R3	7.50
19	316	9,916	53.00	-6.00	3.96	R2	7.50
20	Subtotal	188,848					
21							
22	Colstrip No. 4						
23	311	54,319	70.00	-7.00	2.95	S1.5	7.50
24	312	60,447	60.00	-7.00	4.79	R1	7.50
25	313	738		-7.00	9.34	R2.5	7.50
26	314	15,766	40.00	-7.00	7.59	R0.5	7.50
27	315	8,014	50.00	-7.00	3.72	R3	7.50
28	316	5,249	53.00	-7.00	4.74	R2	7.50
29	Subtotal	144,533					
30							
31	Kettle Falls						
32	310	433			1.32	SQ	12.00
33	311	28,776	70.00	-4.00	2.49	S1.5	11.70
34	312	46,845	55.00	-4.00	3.18	R1	11.30
35	314	18,632	35.00	-4.00	2.25	R0.5	10.20
36	315	12,389	50.00	-4.00	4.06	R3	11.40
37	316	2,477	55.00	-4.00	2.97	R2	11.30
38	Subtotal	109,552					
39							
40	HYDRO PLANT						
41	Cabinet Gorge						
42	330	9,383	100.00		1.90	R4	38.10
43	331	24,010	55.00	-16.00	1.73	R2	42.45
44	332	44,638	60.00	-16.00	2.03	R1	45.53
45	333	46,085	65.00	-16.00	2.59	R1.5	40.80
46	334	13,685	40.00	-16.00	2.10	S1	29.40
47	335	5,578	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	145,050					
50							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Noxon Rapids						
13	330	30,477	100.00		1.64	R4	52.50
14	331	24,705	55.00	-24.00	2.23	R2	44.50
15	332	36,033	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	18,642	40.00	-24.00	4.09	S1	27.40
18	335	4,371	50.00	-24.00	2.04	R1	41.68
19	336	260	55.00	-24.00	2.96	S2.5	26.20
20	Subtotal	203,171					
21							
22	Post Falls						
23	330	2,908	80.00		1.91	R4	24.25
24	331	4,403	55.00	-4.00	1.53	R2	38.10
25	332	25,932	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	1,977	40.00	-4.00	1.20	S1	23.20
28	335	804	60.00	-4.00	2.39	R1	36.90
29	336	578	55.00	-4.00	2.62	S2.5	26.20
30	Subtotal	38,836					
31							
32	Long Lake						
33	330	418	80.00		1.91	R4	25.70
34	331	9,459	55.00	-7.00	1.64	R2	33.70
35	332	36,757	60.00	-7.00	1.85	R1	34.00
36	333	8,736	65.00	-7.00	0.45	R1.5	33.70
37	334	3,926	40.00	-7.00	0.85	S1	29.20
38	335	826	60.00	-7.00	1.69	R1	32.60
39	336		55.00	-7.00	2.62	S2.5	26.20
40	Subtotal	60,122					
41							
42	Little Falls						
43	330	4,217	80.00		1.28	R4	19.60
44	331	4,242	110.00	-7.00	1.87	R2	41.60
45	332	6,434	100.00	-7.00	1.17	R1	39.80
46	333	39,074	65.00	-7.00	1.40	R1.5	39.10
47	334	13,895	40.00	-7.00	2.72	S1	32.30
48	335	549	60.00	-7.00	1.67	R1	36.30
49	Subtotal	68,411					
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	1,082	50.00	-7.00	3.36	R2	30.80
15	332	7,729	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	4,299	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	14,952					
21							
22	Nine Mile						
23	330	11	100.00		1.50	R4	25.25
24	331	20,419	110.00	-4.00	2.41	R2	40.10
25	332	30,904	110.00	-4.00	2.10	R1	37.30
26	333	41,757	65.00	-4.00	2.58	R1.5	39.40
27	334	17,923	40.00	-4.00	2.92	S1	33.40
28	335	1,071	60.00	-4.00	2.68	R1	38.00
29	336	595	55.00	-4.00	2.70	S2.5	26.20
30	Subtotal	112,680					
31							
32	Monroe Street						
33	331	12,128	55.00	-7.00	2.39	R2	40.80
34	332	9,972	110.00	-7.00	1.91	R1	49.80
35	333	11,575	65.00	-7.00	2.22	R1.5	40.80
36	334	3,178	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	36,937					
40							
41	OTHER PRODUCTION						
42	Northeast Turbine						
43	341	751	55.00	-5.00	30.78	S4	2.00
44	342	37	55.00	-5.00		R3	
45	343	9,058	60.00	-5.00	2.51	S2.5	2.00
46	344	2,609	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	14,097					
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	3,565	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	50,500	45.00	-4.00	3.94	R1	16.40
17	345	3,457	20.00	-4.00	8.22	S1	11.90
18	346	249	35.00	-4.00	5.69	R2.5	17.40
19	Subtotal	65,189					
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	8,670	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	9,540					
28							
29	Boulder Park						
30	341	1,274	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	31,285	45.00	-2.00	2.43	R1	22.20
34	345	662	20.00	-2.00	6.42	S1	15.10
35	346	65	35.00	-2.00	3.99	R2.5	23.70
36	Subtotal	33,505					
37							
38	Coyote Springs 2						
39	341	11,849	55.00	-3.00	2.37	S4	26.80
40	342	19,000	55.00	-3.00	2.45	R3	25.60
41	344	138,025	45.00	-3.00	3.36	R1	23.40
42	345	17,123	20.00	-3.00	5.25	S1	11.70
43	346	935	35.00	-3.00	4.27	R2.5	22.10
44	Subtotal	186,932					
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) 04/15/2021	Year/Period of Report End of 2020/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	22,799	80.00		1.13	R4	55.85
19	352	29,270	65.00	-10.00	1.63	S1.5	52.90
20	353	316,164	44.00	-10.00	2.41	R2	32.60
21	354	17,254	75.00	-15.00	1.51	R4	41.90
22	355	301,952	63.00	-30.00	1.93	R2.5	51.70
23	356	166,779	70.00	-30.00	1.90	R3	45.90
24	357	3,831	60.00		1.64	R4	47.40
25	358	3,179	50.00		2.06	S3	29.30
26	359	2,161	70.00		1.41	R4	42.80
27	Subtotal	863,389					
28							
29	DISTRIBUTION PLANT						
30	360	4,139	75.00		1.34	R4	69.40
31	361	35,477	60.00	-10.00	1.72	S1.5	46.70
32	362	158,013	42.00	-10.00	2.68	R1.5	30.40
33	363	2,598	15.00		6.80	L3	13.50
34	364 - WA	302,630	67.00	-60.00	2.47	R2.5	51.70
35	364 - ID	159,053	65.00	-60.00	2.57	R2.5	51.70
36	365 - WA	191,455	68.00	-50.00	2.27	R3	44.40
37	365 - ID	108,031	65.00	-50.00	2.45	R3.5	44.40
38	366 - WA	88,440	60.00	-30.00	1.56	R1.5	46.50
39	366 - ID	45,790	60.00	-30.00	2.14	S2.5	46.50
40	367 - WA	154,626	35.00	-30.00	3.44	S1.5	24.70
41	367 - ID	77,996	35.00	-20.00	2.99	S1.5	24.70
42	368	293,857	47.00	-10.00	2.16	R2	35.50
43	369	190,214	65.00	-40.00	2.10	R4	50.40
44	370 - AN	157	35.00	-2.00	2.89	S0	
45	370.2 - ID	23,750	15.00		9.06	S2.5	7.70
46	370.3 - WA	58,292	35.00		2.89	S0	26.50
47	371	3,152	10.00		10.36	S1	9.50
48	373	25,497	37.00	-20.00	1.87	R2.5	27.90
49	373.4	27,769	37.00	-20.00	3.04	R2.5	29.20
50	373.5	16,552	37.00	-20.00	3.17	R2.5	36.10

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	1,967,488					
13							
14	GENERAL PLANT						
15	390.1	10,676	50.00	-5.00	1.90	R2.5	42.20
16	391	8	15.00		6.67	SQ	15.00
17	391.1	2,514	5.00		20.00	SQ	1.70
18	393	387	25.00		4.00	SQ	14.60
19	394	6,813	20.00		5.00	SQ	11.00
20	395	1,908	15.00		6.67	SQ	7.40
21	397	48,895	15.00		6.67	SQ	8.50
22	398	279	10.00		10.00	SQ	6.60
23	Subtotal	71,480					
24							
25	MISC POWER						
26	392	8,508	16.00		5.48	L2.5	12.20
27	396	4,001	22.00		3.75	S1	14.80
28	Subtotal	12,509					
29							
30							
31							
32							
33							
34							
35							
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38							
39	TOTAL COMPANY	4,348,053					
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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	04/15/2021	End of 2020/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.	2,629,180	34,224	2,663,404	
5					
6					
7					
8					
9	Washington Utilities and Transportation				
10	Commission: includes annual fee and various				
11	other electric dockets	1,099,656	687,609	1,787,265	
12					
13	Includes annual fee and various other natural				
14	gas dockets	295,440	153,301	448,741	
15					
16	Idaho Public Utilities Commission				
17	Includes annual fee and various other electric				
18	dockets	684,318	160,523	844,841	
19					
20	Includes annual fee and various other natural				
21	gas dockets	163,671	46,147	209,818	
22					
23	Public Utility Commission of Oregon				
24	Includes annual fees and various other natural				
25	gas dockets	611,398	351,510	962,908	
26					
27	Not directly assigned electric		725,551	725,551	
28	Not directly assigned natural gas		311,991	311,991	
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	5,483,663	2,470,856	7,954,519	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2021	Year/Period of Report End of 2020/Q4

REGULATORY COMMISSION EXPENSES (Continued)

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

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
							2
							3
Electric	928	2,663,404					4
							5
							6
							7
							8
							9
							10
Electric	928	1,787,265					11
							12
							13
Gas	928	448,741					14
							15
							16
							17
Electric	928	844,841					18
							19
							20
Gas	928	209,818					21
							22
							23
							24
Gas	928	962,908	72,367	407.4	13,133	59,519	25
							26
Electric	928	725,551					27
Gas	928	311,991					28
							29
							30
							31
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							45
		7,954,519	72,367		13,133	59,519	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	04/15/2021	End of 2020/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		
9		
10		
11	A. Electric (6) Other - Testing Lab & Facility	HUB-Morris Center Lab Test Facility
12		
13		
14		
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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) 04/15/2021	Year/Period of Report End of 2020/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

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

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

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
1,992,325	609,473	107	2,601,798		1
	1,422	108	1,422		2
	248,828	182	248,828		3
	17,989	557	17,989		4
173,909	27,987	580	201,896		5
1,954		587	1,954		6
67,886	9,768	598	77,654		7
200,595	-1,350	920	199,245		8
	16,858	930	16,858		9
					10
453,374	3,965,780	107	4,419,154		11
58,348		182	58,348		12
					13
					14
					15
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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	04/15/2021	End of 2020/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	13,667,061		
4	Transmission	4,359,748		
5	Regional Market			
6	Distribution	9,555,026		
7	Customer Accounts	6,615,674		
8	Customer Service and Informational	473,347		
9	Sales			
10	Administrative and General	27,189,564		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	61,860,420		
12	Maintenance			
13	Production	4,612,103		
14	Transmission	907,722		
15	Regional Market			
16	Distribution	5,236,480		
17	Administrative and General			
18	TOTAL Maintenance (Total of lines 13 thru 17)	10,756,305		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	18,279,164		
21	Transmission (Enter Total of lines 4 and 14)	5,267,470		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	14,791,506		
24	Customer Accounts (Transcribe from line 7)	6,615,674		
25	Customer Service and Informational (Transcribe from line 8)	473,347		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	27,189,564		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	72,616,725	9,141,941	81,758,666
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply	1,104,381		
34	Storage, LNG Terminaling and Processing	6,045		
35	Transmission			
36	Distribution	5,936,287		
37	Customer Accounts	2,930,182		
38	Customer Service and Informational	294,694		
39	Sales			
40	Administrative and General	11,457,871		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	21,729,460		
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	1,955,158		

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DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution	3,487,785		
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	5,442,943		
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)	1,104,381		
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru 47)	6,045		
56	Transmission (Lines 35 and 47)	1,955,158		
57	Distribution (Lines 36 and 48)	9,424,072		
58	Customer Accounts (Line 37)	2,930,182		
59	Customer Service and Informational (Line 38)	294,694		
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)	11,457,871		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	27,172,403	3,204,941	30,377,344
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	99,789,128	12,346,882	112,136,010
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	44,889,619	6,589,540	51,479,159
69	Gas Plant	11,755,963	2,383,819	14,139,782
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	56,645,582	8,973,359	65,618,941
72	Plant Removal (By Utility Departments)			
73	Electric Plant	1,830,775	166,241	1,997,016
74	Gas Plant	610,391	55,425	665,816
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	2,441,166	221,666	2,662,832
77	Other Accounts (Specify, provide details in footnote):			
78	Stores Expense (163)	2,463,257	-2,463,257	
79				
80	Small Tool Expense (184)	4,652,116	-4,652,116	
81	Miscellaneous Deferred Debits (186)	1,269,599		1,269,599
82	Non-operating Expenses (417)	407,078		407,078
83	RetirementBonus/SERP/HRA Settlement (228)	135,681		135,681
84	Activities (426)	864,971		864,971
85	Employee Incentive Plan (232380)	12,199,466	-12,199,466	
86	DSM Tarrif Rider and (242600)	2,227,068	-2,227,068	
87	Incentive / Stock Compensation (238000)	152,034		152,034
88	Payroll Equalization Liability(242700)	19,670,743		19,670,743
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	44,042,013	-21,541,907	22,500,106
96	TOTAL SALARIES AND WAGES	202,917,889		202,917,889

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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/Q4

COMMON UTILITY PLANT AND EXPENSES

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

1 & 2. Common Plant in service and accumulated provision for depreciation

Acct. No.	Description	
303	Intangible	304,344,902
389	Land and Land Rights	13,914,952
390	Structures and Improvements	159,691,791
391	Office Furniture and Equipment	85,031,246
392	Transportation Equipment	14,561,590
393	Stores Equipment	5,027,374
394	Tools, Shop & Garage Equipment	14,641,292
395	Laboratory Equipment	1,610,417
396	Power Operated Equipment	1,953,262
397	Communications Equipment	90,260,645
398	Miscellaneous Equipment	692,982
399	Asset Retirement Cost	0
	Total Common Plant	691,730,453
	Const. Work in Progress	17,575,548
	Total Utility Plant	709,306,001
	Acc. Prov. for Dep. & Amort.	236,921,589
	Net Utility Plant	472,384,412

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	285,636	149,519	136,117	# of Customers
902	Meter reading expenses	1,991,082	1,203,191	787,891	# of Customers
903	Cust rec & collectn expenses	13,992,504	7,415,685	6,576,819	# of Customers
904	Uncollectible accounts	0	0	0	# of Customers
905	Misc cust acct expenses	279,808	145,713	134,095	# of Customers
907	Cust svce & Info exp supervision	0	0	0	# of Customers
908	Cust assistance expenses	534,483	322,119	212,364	# of Customers
909	Info & instruct advert expenses	1,704,434	1,029,972	674,462	# of Customers
910	Misc cust serv & info expenses	616,000	320,788	295,212	# of Customers
911	Sales expense -supervision	0	0	0	# of Customers
912	Demo and selling expenses	0	0	0	# of Customers

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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.

913	Advertising expenses	0	0	0	# of Customers
916	Misc sales expenses	0	0	0	# of Customers
920	Admin & gen salaries	37,468,341	26,233,828	11,234,513	Four Factor
921	Office supplies & expenses	5,940,261	4,150,086	1,790,175	Four Factor
922	Admin expenses tranf-credit	0	0	0	Four Factor
923	Outside services employed	14,294,431	9,998,838	4,295,593	Four Factor
924	Property insurance	1,895,653	1,323,583	572,070	Four Factor
925	Injuries and damages	6,913,181	4,948,673	1,964,508	Four Factor
926	Employee pensions&benefits	94,320,328	65,999,683	28,320,645	Four Factor
927	Franchise requirement	0	0	0	Four Factor
928	Regulatory commission expenses	1,722,828	1,255,660	467,168	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	7,786,009	5,450,509	2,335,500	Four Factor
931	Rents	532,877	373,300	159,577	Four Factor
935	Maint of general plant	15,771,036	11,175,850	4,595,186	Four Factor
403	Depreciation	26,398,612	18,672,863	7,725,749	Four Factor
404	Amort of LTD term plant	39,682,805	27,999,976	11,682,829	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
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AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

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

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	5,639	48,058	109,281	112,077
3	Net Sales (Account 447)	(3,822,515)	(5,962,090)	(7,757,268)	(10,567,487)
4	Transmission Rights				
5	Ancillary Services	(7,297)	(14,142)	(24,226)	(37,898)
6	Other Items (list separately)				
7	Access Charge			1,582	16,454
8	Cost Recovery	(7,654)	(11,596)	(11,243)	(11,292)
9	Day Ahead Energy-Congestion Losses	(3)	(5)	(3,528)	(3,975)
10	FERC Fees			146	235
11	GMC	51,416	96,584	126,745	157,048
12	Hour Ahead Scheduling Process-RT	254	427	(1,980)	(2,105)
13	Other	32	(1,055)	(1,186)	(2,568)
14					
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45					
46	TOTAL	(3,780,128)	(5,843,819)	(7,561,677)	(10,339,511)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/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				82	MW	1,062,984
4	Energy Imbalance	21,754	MWh	466,330	38,240	MWh	1,390,916
5	Operating Reserve - Spinning				61	MW	797,238
6	Operating Reserve - Supplement				61	MW	734,478
7	Other	836	MW	10,475,077	836	MW	10,475,077
8	Total (Lines 1 thru 7)	22,590		10,941,407	39,280		14,460,693

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 Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2021	Year/Period of Report End of 2020/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	2,268	14	1900	1,536	355	282	11	95	130
2	February	2,189	6	1800	1,316	286	282	12	305	377
3	March	1,981	10	800	1,311	299	286	15	85	485
4	Total for Quarter 1				4,163	940	850	38	485	992
5	April	1,846	1	1000	1,190	274	297	5	85	393
6	May	1,908	29	1800	1,258	253	302	15	95	300
7	June	2,302	24	1800	1,362	273	298	15	369	806
8	Total for Quarter 2				3,810	800	897	35	549	1,499
9	July	2,746	31	1700	1,650	343	296	15	457	545
10	August	2,901	19	1600	1,553	316	297	21	736	353
11	September	2,492	4	1800	1,416	298	290	22	488	275
12	Total for Quarter 3				4,619	957	883	58	1,681	1,173
13	October	2,511	26	900	1,350	334	288	10	539	284
14	November	2,059	30	1800	1,364	295	282	9	118	67
15	December	2,133	7	1800	1,418	309	282	17	124	76
16	Total for Quarter 4				4,132	938	852	36	781	427
17	Total Year to Date/Year				16,724	3,635	3,482	167	3,496	4,091

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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/Q4

ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY	
2	Generation (Excluding Station Use):	
3	Steam	1,485,162
4	Nuclear	
5	Hydro-Conventional	3,650,548
6	Hydro-Pumped Storage	
7	Other	1,988,395
8	Less Energy for Pumping	
9	Net Generation (Enter Total of lines 3 through 8)	7,124,105
10	Purchases	5,465,161
11	Power Exchanges:	
12	Received	9,313
13	Delivered	429,763
14	Net Exchanges (Line 12 minus line 13)	-420,450
15	Transmission For Other (Wheeling)	
16	Received	3,510,201
17	Delivered	3,510,201
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)	12,168,816

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	8,875,043
23	Requirements Sales for Resale (See instruction 4, page 311.)	
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	2,796,393
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	44,593
27	Total Energy Losses	452,787
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	12,168,816

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/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	1,152,209	248,892	1,613	14	1900
30	February	1,049,271	231,269	1,512	4	1800
31	March	1,060,578	246,047	1,362	10	0800
32	April	1,107,339	406,733	1,262	1	1000
33	May	987,788	308,891	1,303	29	1800
34	June	896,267	222,362	1,445	23	1700
35	July	1,038,492	246,947	1,708	31	1600
36	August	1,002,989	189,422	1,721	17	1600
37	September	847,969	156,712	1,473	4	1700
38	October	922,806	170,737	1,416	26	1000
39	November	997,749	180,789	1,423	30	1300
40	December	1,105,359	187,592	1,479	7	1800
41	TOTAL	12,168,816	2,796,393			

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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/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)	282			44		
7	Plant Hours Connected to Load	6736			21		
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	1767332000			666000		
13	Cost of Plant: Land and Land Rights	0			138753		
14	Structures and Improvements	11848521			751025		
15	Equipment Costs	175083507			13343648		
16	Asset Retirement Costs	351682			0		
17	Total Cost	187283710			14233426		
18	Cost per KW of Installed Capacity (line 17/5) Including	634.8600			230.3143		
19	Production Expenses: Oper, Supv, & Engr	126688			4225		
20	Fuel	25388467			16307		
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	1784704			41760		
26	Misc Steam (or Nuclear) Power Expenses	130027			4394		
27	Rents	87122			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	174095			21053		
30	Maintenance of Structures	174581			1617		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	3612570			43240		
33	Maintenance of Misc Steam (or Nuclear) Plant	202092			21963		
34	Total Production Expenses	31680346			154559		
35	Expenses per Net KWh	0.0179			0.2321		
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	11629411	0	0	8062	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	2.183	0.000	0.000	2.023	0.000	0.000
41	Average Cost of Fuel per Unit Burned	2.183	0.000	0.000	2.023	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	2.140	0.000	0.000	1.983	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.014	0.000	0.000	0.024	0.000	0.000
44	Average BTU per KWh Net Generation	6712.000	0.000	0.000	12347.000	0.000	0.000

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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/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
98	235	161	6
3759	6916	1284	7
54	222	167	8
54	222	0	9
54	222	0	10
28	249	1	11
264851000	1220311000	171022000	12
2573941	1289395	621682	13
28775717	112028649	3565118	14
80342935	221351503	61624330	15
323787	14387288	0	16
112016380	349056835	65811130	17
2209.3961	1495.5306	395.2620	18
205292	149532	13258	19
7093295	22413469	3223334	20
0	0	0	21
537501	2976867	0	22
0	0	0	23
0	0	0	24
709798	33359	242375	25
387759	4121891	19942	26
0	0	0	27
0	0	0	28
105987	549910	41274	29
140959	635889	0	30
1657292	6138583	0	31
308156	1958141	62878	32
213320	973011	68289	33
11359359	39950652	3671350	34
0.0429	0.0327	0.0215	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
Wood	Gas		Coal	Oil		Gas			36
Ton	MCF		Ton	BBL		MCF			37
462472	4743	0	762615	2755	0	2016263	0	0	38
8600000	1020000	0	16970000	5880000	0	1020000	0	0	39
15.314	2.364	0.000	29.096	81.344	0.000	1.599	0.000	0.000	40
15.314	2.364	0.000	29.096	81.344	0.000	1.599	0.000	0.000	41
1.781	2.317	0.000	1.715	13.834	0.000	1.567	0.000	0.000	42
0.027	0.035	0.000	0.018	0.000	0.000	0.019	0.000	0.000	43
15035.000	0.000	0.000	10618.000	0.000	0.000	12025.000	0.000	0.000	44

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2021	Year/Period of Report End of 2020/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)	35			0		
7	Plant Hours Connected to Load	2289			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	48140000			0		
13	Cost of Plant: Land and Land Rights	185629			0		
14	Structures and Improvements	1273892			0		
15	Equipment Costs	32230931			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	33690452			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	1369.5306			0		
19	Production Expenses: Oper, Supv, & Engr	9512			0		
20	Fuel	840291			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	228328			0		
26	Misc Steam (or Nuclear) Power Expenses	21332			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	58062			0		
30	Maintenance of Structures	400			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	388157			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	108042			0		
34	Total Production Expenses	1654124			0		
35	Expenses per Net KWh	0.0344			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas					
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF					
38	Quantity (Units) of Fuel Burned	432653	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	1.942	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	1.942	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	1.904	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.017	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	9167.000	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	04/15/2021	End of 2020/Q4

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

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

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/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

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
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

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

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Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/Q4

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

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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	04/15/2021	End of 2020/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

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	04/15/2021	End of 2020/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)	15	11
7	Plant Hours Connect to Load	7,440	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	83,100,000	58,141,000
13	Cost of Plant		
14	Land and Land Rights	51,600	1,081,854
15	Structures and Improvements	12,114,919	1,082,308
16	Reservoirs, Dams, and Waterways	9,972,020	7,728,573
17	Equipment Costs	14,506,197	5,569,698
18	Roads, Railroads, and Bridges	50,448	508,242
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	36,695,184	15,970,675
21	Cost per KW of Installed Capacity (line 20 / 5)	2,479.4043	1,597.0675
22	Production Expenses		
23	Operation Supervision and Engineering	4,943	2,343
24	Water for Power	0	0
25	Hydraulic Expenses	991	975
26	Electric Expenses	513,228	486,287
27	Misc Hydraulic Power Generation Expenses	15,259	18,629
28	Rents	0	0
29	Maintenance Supervision and Engineering	17,377	5,228
30	Maintenance of Structures	1,861	51,218
31	Maintenance of Reservoirs, Dams, and Waterways	22,638	6,701
32	Maintenance of Electric Plant	97,440	43,109
33	Maintenance of Misc Hydraulic Plant	4,446	20,223
34	Total Production Expenses (total 23 thru 33)	678,183	634,713
35	Expenses per net KWh	0.0082	0.0109

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/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	258	6
6,863	7,203	5,952	7
			8
38	18	255	9
38	18	295	10
5	5	2	11
117,927,000	77,008,000	1,002,706,000	12
			13
33,429	4,161,522	16,380,178	14
20,040,785	4,403,016	24,009,674	15
30,903,663	25,932,396	44,638,421	16
60,751,179	5,014,893	65,347,796	17
594,870	577,944	1,671,013	18
0	0	0	19
112,323,926	40,089,771	152,047,082	20
2,987.3385	2,708.7683	573.7626	21
			22
8,322	20,391	62,415	23
0	0	9	24
428	3,309	3,932	25
671,901	638,156	1,127,312	26
192,719	78,666	194,050	27
0	0	0	28
4,188	12,693	26,707	29
28,757	30,389	1,376,774	30
10,028	55,167	58,358	31
180,660	152,085	995,943	32
5,962	16,807	41,303	33
1,102,965	1,007,663	3,886,803	34
0.0094	0.0131	0.0039	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 2058 Plant Name: Noxon Rapids (b)	FERC Licensed Project No. 2545 Plant Name: Long Lake (c)
1	Kind of Plant (Run-of-River or Storage)	Storage	Storage
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional
3	Year Originally Constructed	1959	1915
4	Year Last Unit was Installed	1977	1924
5	Total installed cap (Gen name plate Rating in MW)	487.80	71.10
6	Net Peak Demand on Plant-Megawatts (60 minutes)	541	92
7	Plant Hours Connect to Load	4,901	6,566
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	581	90
10	(b) Under the Most Adverse Oper Conditions	623	90
11	Average Number of Employees	11	1
12	Net Generation, Exclusive of Plant Use - Kwh	1,596,412,000	502,673,000
13	Cost of Plant		
14	Land and Land Rights	36,130,081	2,500,473
15	Structures and Improvements	24,705,239	9,378,027
16	Reservoirs, Dams, and Waterways	36,033,151	36,757,010
17	Equipment Costs	111,695,555	13,487,799
18	Roads, Railroads, and Bridges	259,750	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	208,823,776	62,123,309
21	Cost per KW of Installed Capacity (line 20 / 5)	428.0930	873.7456
22	Production Expenses		
23	Operation Supervision and Engineering	137,155	8,645
24	Water for Power	0	0
25	Hydraulic Expenses	68,375	6,219
26	Electric Expenses	930,495	691,502
27	Misc Hydraulic Power Generation Expenses	197,349	146,203
28	Rents	0	0
29	Maintenance Supervision and Engineering	16,726	3,543
30	Maintenance of Structures	135,807	120,318
31	Maintenance of Reservoirs, Dams, and Waterways	116,773	10,777
32	Maintenance of Electric Plant	482,523	301,786
33	Maintenance of Misc Hydraulic Plant	89,721	26,684
34	Total Production Expenses (total 23 thru 33)	2,174,924	1,315,677
35	Expenses per net KWh	0.0014	0.0026

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

FERC Licensed Project No. 2545 Plant Name: Little Falls (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
Run-of-River			1
Conventional			2
1910			3
1911			4
43.20	0.00	0.00	5
44	0	0	6
6,566	0	0	7
			8
43	0	0	9
43	0	0	10
1	0	0	11
212,533,000	0	0	12
			13
4,325,371	0	0	14
4,242,067	0	0	15
6,434,060	0	0	16
53,518,018	0	0	17
0	0	0	18
0	0	0	19
68,519,516	0	0	20
1,586.0999	0.0000	0.0000	21
			22
2,978	0	0	23
0	0	0	24
6,173	0	0	25
580,733	0	0	26
76,190	0	0	27
1,035,399	0	0	28
11,228	0	0	29
136,724	0	0	30
37,630	0	0	31
207,812	0	0	32
40,152	0	0	33
2,135,019	0	0	34
0.0100	0.0000	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/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	10.0	1,235,000	9,567,500
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3						
4						
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7						
8						
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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	90,581	27,210	9,434	Nat Gas	199	1
						2
						3
						4
						5
						6
						7
						8
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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	04/15/2021	End of 2020/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Group Sum		60.00	60.00		1.00		
2								
3	Group Sum		115.00	115.00		1,564.00		
4								
5	Beacon Sub #4	BPA Bell Sub	230.00	230.00	Steel Pole	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 Tower	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	37.00		2
14	Beacon Sub	Lolo Sub	230.00	230.00	H Type	62.00		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	230.00	230.00	Steel Pole	2.00		1
35	BPA/Hot Springs #2	Noxon Plant	230.00	230.00	H Type	68.00		1
36					TOTAL	2,253.00	1.00	39

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2021	Year/Period of Report End of 2020/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
	136,038	636,193	772,231					1
								2
	12,361,257	274,811,363	287,172,620	721,451	693,722		1,415,173	3
								4
1272 ACSS								5
1272 ACSS	17,912	1,429,421	1,447,333		5,634		5,634	6
1272 ACSS								7
1272 ACSS	30,323	3,275,357	3,305,680	9,257	888		10,145	8
1590 ACSS								9
1590 ACSS								10
1590 ACSR	1,156,196	41,780,782	42,936,978	9,002	17,540		26,542	11
1590 ACSS								12
1590 ACSS								13
1272 AAC								14
1272 ACSS	456,162	22,973,670	23,429,832	25,125	6,105		31,230	15
1622 ACSS								16
1590 ACSS	570,207	48,748,733	49,318,940	633	2,740		3,373	17
1272 ACSR								18
1590 ACSS								19
954 AAC	1,097,679	19,150,574	20,248,253	21,156	244,468		265,624	20
795 ACSR								21
954 AAC	184,211	1,923,078	2,107,289	22,932	55,732		78,664	22
954 AAC	387,459	5,222,681	5,610,140		17,441		17,441	23
1272 AAC	165,333	7,091,503	7,256,836	2,099	46,745		48,844	24
1272 AAC								25
1272 ACSR								26
1272 ACSR	623,984	6,730,559	7,354,543					27
1272 ACSR								28
1272 ACSR	872,150	10,043,381	10,915,531					29
1590 ACSS								30
1272 AAC	249,136	14,004,803	14,253,939					31
1272 ACSR								32
1272 ACSR		19,521	19,521		9,650		9,650	33
1272 ACSR								34
1272 AAC	3,603,324	10,069,035	13,672,359	31,023	24,864		55,887	35
	22,912,609	510,288,801	533,201,410	943,470	1,243,798	87,681	2,274,949	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	04/15/2021	End of 2020/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	Coulee	West Side Sub	230.00	230.00	Steel Pole	2.00		2
2	BPA Line	West Side Sub	230.00	230.00	Steel Pole	2.00		2
3	Hatwai	N. Lewiston Sub	230.00	230.00	H Type	7.00		1
4	Divide Creek	Imnaha	230.00	230.00	H Type	20.00		1
5	Colstrip Plant	Broadview	500.00	500.00				
6								
7								
8								
9								
10								
11								
12								
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22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	2,253.00	1.00	39

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1272 ACSR	8,482		8,482					1
1272 ACSR	36,461	594,132	630,593					2
1590 ACSR	155,244	2,616,153	2,771,397	2,713	159		2,872	3
1272 AAC	205,262	1,312,224	1,517,486		16,588		16,588	4
	595,789	37,855,638	38,451,427	98,079	101,522	87,681	287,282	5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	22,912,609	510,288,801	533,201,410	943,470	1,243,798	87,681	2,274,949	36

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2021	Year/Period of Report End of 2020/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							
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL						

TRANSMISSION LINES ADDED DURING YEAR (Continued)

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

CONDUCTORS			Voltage	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
									1
									2
									3
									4
									5
									6
									7
									8
									9
									10
									11
									12
									13
									14
									15
									16
									17
									18
									19
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									37
									38
									39
									40
									41
									42
									43
									44

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2021	Year/Period of Report End of 2020/Q4

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	STATE OF WASHINGTON				
2	Airway Heights	Distr. Unattended	115.00	13.80	
3	Barker Road	Distr. Unattended	115.00	13.80	
4	Beacon	Trnsm. & Distr Unatt	230.00	115.00	13.80
5	Boulder	Trnsm. & 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) 04/15/2021	Year/Period of Report End of 2020/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/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	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	Saddle Mountain	Trans. Unattended	230.00	115.00	13.80
6	Shawnee	Trans. Unattended	230.00	115.00	13.80
7	Silver Lake	Distr. Unattended	115.00	13.80	
8	Southeast	Distr. Unattended	115.00	13.80	
9	South Othello	Distr. Unattended	115.00	13.80	
10	South Pullman	Distr. Unattended	115.00	13.80	
11	Sunset	Distr. Unattended	115.00	13.80	
12	Terre View	Distr. Unattended	115.00	13.80	
13	Third & Hatch	Distr. Unattended	115.00	13.80	
14	Turner	Distr. Unattended	115.00	13.80	
15	Waikiki	Distr. Unattended	115.00	13.80	
16	West Side	Trans. Unattended	230.00	115.00	13.80
17	Other: 27 substations less than 10MVA	Distr. Unattended			
18					
19	STATE OF IDAHO				
20	Appleway	Dist. Unattended	115.00	13.80	
21	Avondale	Dist. Unattended	115.00	13.80	
22	Benewah	Trans. Unattended	230.00	115.00	13.80
23	Big Creek	Distr. Unattended	115.00	13.80	
24	Blue Creek	Distr. Unattended	115.00	13.80	
25	Bunker Hill Limited	Distr. Unattended	115.00	13.80	
26	Cabinet Gorge (Switchyard)	Trans. Unattended	230.00	115.00	13.80
27	Clark Fork	Distr. Unattended	115.00	21.80	
28	Coeur d'Alene 15th Ave	Distr. Unattended	115.00	13.80	
29	Cottonwood	Distr. Unattended	115.00	24.90	
30	Dalton	Distr. Unattended	115.00	13.80	
31	Grangeville	Distr. Unattended	115.00	13.80	
32	Holbrook	Distr. Unattended	115.00	13.80	
33	Huetter	Distr. Unattended	115.00	13.80	
34	Idaho Road	Distr Unattended	115.00	13.80	
35	Juliaetta	Distr. Unattended	115.00	13.80	
36	Kamiah	Dist. Unattended	115.00	13.80	
37	Kooskia	Distr. Unattended	115.00	13.80	
38	Lewiston Mill Rd	Distr. Unattended	115.00	13.20	
39	Lolo	Tran & Dist Unattnd	230.00	115.00	13.80
40	Moscow	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) 04/15/2021	Year/Period of Report End of 2020/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
36	2		Frcd Oil	2	60	1
24	2		Two Stage Fan	2	40	2
33	2		Two Stage Fan	2	57	3
24	2		Two Stage Fan	2	40	4
150	1		Two Stage Fan	1	250	5
150	1		Two Stage Fan	1	250	6
12	1		Two Stage Fan	1	20	7
36	2		Two Stage Fan	2	60	8
12	1		Two Stage Fan	1	20	9
30	2		Two Stage Fan	2	50	10
33	2		Two Stage Fan & Caps	50	55	11
12	1		Two Stage Fan	1	20	12
54	3		Two Stg Fan & Cap	103	90	13
36	2		Two Stg Fan	2	60	14
24	2		Two Stage Fan	2	40	15
300	2		Two Stage Fan	2	500	16
164	28					17
						18
						19
36	2		Two Stage Fan	2	60	20
12	1		Two Stage Fan	1	20	21
75	1		Two Stage Fan & Caps	223	125	22
18	2		Portable Fan	2	22	23
12	1		Two Stage Fan	1	20	24
12	1		Frcd Air Fan	1	16	25
75	1		Two Stage Fan	1	125	26
10	1		Frcd Air Fan	1	13	27
36	2		Two Stage Fan	2	60	28
12	1		Two Stage Fan	1	20	29
36	2		Two Stage Fan	2	60	30
25	4		FrcdOil/Air/Pt Fan&C	17	34	31
12	1		Two Stage Fan	1	20	32
12	1		Two Stage Fan	1	20	33
12	1		Two Stage Fan	1	20	34
12	1		Frcd Oil & Air Fan	1	20	35
12	1		Two Stage Fan	1	20	36
15	3		Frcd Air Fan	3	20	37
18	1		Two Stage Fan	1	30	38
262	3		Frcd Oil/Air/Two Stg	1	270	39
24	2		FrOil/Air/2Stg Fan	2	40	40

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2021	Year/Period of Report End of 2020/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	Moscow 230Kv	Tran & Dist Unattnd	230.00	115.00	13.80
2	North Lewiston 230kV	Tran & Dist Unattnd	230.00	115.00	13.80
3	North Moscow	Distr. Unattended	115.00	13.80	
4	Oden	Distr. Unattended	115.00	21.80	
5	Oldtown	Distr. Unattended	115.00	21.80	
6	Orofino	Distr. Unattended	115.00	24.00	
7	Osburn	Distr. Unattended	115.00	13.80	
8	Pine Creek	Tran & Dist Unattnd	230.00	115.00	13.80
9	Pleasant View	Distr. Unattended	115.00	13.80	
10	Plummer	Dist Unattended	115.00	13.80	
11	Post Falls	Distr. Unattended	115.00	13.80	
12	Potlatch	Distr. Unattended	115.00	24.90	
13	Prarie	Distr. Unattended	115.00	13.80	
14	Priest River	Distr. Unattended	115.00	20.80	
15	Rathdrum	Trans & Distr Unattd	230.00	115.00	13.80
16	Sagle	Dist. Unattended	115.00	21.80	
17	Sandpoint	Distr. Unattended	115.00	20.80	
18	South Lewiston	Distr. Unattended	115.00	13.80	
19	Sweetwater	Distr. Unattended	115.00	24.90	
20	St. Maries	Distr. Unattended	115.00	23.90	
21	Tenth & Stewart	Distr. Unattended	115.00	13.80	
22					
23	Other: 13 substations less than 10 MVA	Distr. Unattended			
24					
25	STATE OF MONTANA				
26	Other: 1 substation less than 10 MVA	Distr. Unattended			
27					
28	SUBSTA. @ GENERATING PLANTS				
29	STATE OF WASHINGTON				
30	Boulder Park	Trans. Attended	115.00	13.80	
31	Kettle Falls	Trans. Attended	115.00	13.80	
32	Long Lake	Trans. Attended	115.00	4.00	
33	Nine Mile	Trans. Attended	115.00	13.80	
34	Little Falls	Trans. Attended	115.00	4.00	
35	Northeast	Trans. Attended	115.00	13.80	
36	Post Street	Trans. Attended	13.80	4.00	
37					
38	STATE OF IDAHO				
39	Cabinet Gorge (HED)	Trans. Attended	230.00	13.80	
40	Post Falls	Trans. Attended	115.00	2.30	

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.
162	2		Frcd Air Fan & Caps	76	270	1
258	2		Frcd Air Fan & Caps	48	260	2
12	1		Two Stage Fan	1	20	3
10	1		Frcd Air Fan	1	13	4
18	2		Frcd Air Fan	2	22	5
20	2		Frcd Oil & Air Fan	1	28	6
12	1		Portable Fan	1	15	7
212	3		Two Stg Fan/Capacito	45	270	8
12	1		Two Stage Fan	1	20	9
12	1		Two Stage Fan	1	20	10
18	1		Two Stage Fan	1	30	11
15	2		Portable Fan	2	19	12
12	1		Frcd Oil & Air Fan	1	20	13
10	1		Frcd Air Fan	1	13	14
474	4		Frcd Oil & Air Fan	50	490	15
12	1		Two Stage Fan	1	20	16
30	3		Frcd Air Fan	3	38	17
27	4		Port Fan/FrcdOil/Air	4	39	18
12	1		Frcd Oil & Air Fan	1	20	19
24	2		Two Stage Fan	2	40	20
30	2		Frcd Oil/Air/Two Stg	2	50	21
						22
73	13					23
						24
						25
5	1					26
						27
						28
						29
36	1		Two Stage Fan	1	60	30
34	1	1	Two Stage Fan	1	62	31
80	4	1				32
42	2		Two Stage Fan	1	56	33
24	2		Frcd Oil & Air Fan	2	40	34
36	1		Two Stage Fan	1	60	35
35	2					36
						37
						38
300	6	1				39
16	2		Frcd Air/Oil/Air Fan	2	21	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	04/15/2021	End of 2020/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	Rathdrum	Trans. Attended	115.00	13.80	
2					
3	STATE OF MONTANA				
4	Noxon	Trans. Attended	230.00	13.80	
5					
6	STATE OF OREGON				
7	Coyote Springs II	Trans. Attended	500.00	13.80	18.00
8					
9	SUMMARY:				
10	Washington: 4 subs	Trans. Unattended			
11	76 subs	Distr. Unattended			
12	2 subs	Tran & Dist Unattnd			
13	7 subs	Trans. Attended			
14	Idaho 2 subs	Trans. Unattended			
15	48 subs	Distr. Unattended			
16	5 subs	Tran & Dist Unattnd			
17	3 subs	Trans. Attended			
18	Montana: 1 sub	Trans. Attended			
19	1 sub	Distr. Unattended			
20	Oregon: 1 sub	Trans. Unattended			
21	Total System: 150 subs		14543.80	2927.90	197.40
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2021	Year/Period of Report End of 2020/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
114	2	1	Two Stage Fan	2	190	1
						2
						3
435	9	1	Two Stage Fan	6	635	4
						5
						6
213	1		Two Stage fan	1	355	7
						8
						9
750						10
1274						11
854						12
287						13
150						14
683						15
1368						16
430						17
435						18
5						19
213						20
12900	238	5		1050	8,389	21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/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	Other	Steam Plant Square	931000	155,496
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	243,657
22	Corporate Support	Avista Development	146000	157,414
23	Corporate Support	Avista Capital	146000	75,581
24	Corporate Support	AELP	146000	23,967
25	Corporate Support	AJT Mining	146000	2,753
26	Corporate Support	Steam Plant Square	146000	155,000
27	Corporate Support	Avista Edge	146000	350,426
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

Avista Corp.

2020

IDAHO

State Electric Annual Report

(IC 61-405)

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Name of Respondent	This Report is:	Date of Report	Year / Period of Report
Avista Corporation	[X] An Original [ ] A Resubmission	*mm/dd/yyyy* 04/15/2021	End of 2020 / Q4

STATEMENT OF UTILITY OPERATING INCOME - IDAHO

Instructions

1. For each account below, report the amount attributable to the state of Idaho based on Idaho jurisdictional Results of Operations.
2. Provide any necessary important notes regarding this statement of utility operating income in a footnote in the available space at the bottom of this

Line No.	Account (a)	*Refer to Form 1 Page* (b)	TOTAL SYSTEM - IDAHO Current Year (c)	 Prior Year (d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)	300-301	401,474,827	410,666,937
3	Operating Expenses			
4	Operation Expenses (401)	320-323	222,680,326	229,746,234
5	Maintenance Expenses (402)	320-323	22,558,272	22,442,747
6	Depreciation Expense (403)	336-337	52,013,390	50,071,177
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	-	-
8	Amortization & Depletion of Utility Plant (404-405)	336-337	11,408,775	9,690,048
9	Amortization of Utility Plant Acquisition Adjustment (406)	336-337	67,304	(333,312)
10	Amort. of Property Losses, Unrecov Plant and Regulatory Study Costs (407)		-	-
11	Amortization of Conversion Expenses (407)		-	-
12	Regulatory Debits (407.3)		3,230,497	2,803,455
13	(Less) Regulatory Credits (407.4)		(12,771,604)	(8,396,725)
14	Taxes Other Than Income Taxes (408.1)	262-263	21,042,881	18,930,820
15	Income Taxes - Federal (409.1)	262-263	1,579,230	4,413,421
16	- Other (409.1)	262-263	-	-
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	6,241,945	6,046,073
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	-	-
19	Investment Tax Credit Adjustment - Net (411.4)	266	(168,096)	(170,725)
20	(Less) Gains from Disposition of Utility Plant (411.6)		-	-
21	Losses from Disposition Of Utility Plant (411.7)		-	-
22	(Less) Gains from Disposition of Allowances (411.8)		-	-
23	Losses from Disposition of Allowances (411.9)		-	-
24	Accretion Expense (411.10)		-	-
25	TOTAL Utility Operating Expenses (Total of line 4 through 24)		327,882,920	335,243,213
26	Net Utility Operating Income (Total line 2 less 25)		73,591,907	75,423,724

Name of Respondent	This Report is:	Date of Report	Year / Period of Report
Avista Corporation	[X] An Original [ ] A Resubmission	*mm/dd/yyyy* 04/15/2021	End of 2020 / Q4

STATEMENT OF UTILITY OPERATING INCOME - IDAHO

Instructions

page or in a separate schedule.

3. Explain in a footnote if the previous year's figures are different from those reported in prior reports.

ELECTRIC UTILITY Current Year (e)	ELECTRIC UTILITY Prior Year (f)	GAS UTILITY Current Year (g)	GAS UTILITY Prior Year (h)	OTHER UTILITY Current Year (i)	OTHER UTILITY Prior Year (j)	Line No.
						1
313,156,038	318,857,908	88,318,789	91,809,029			2
						3
166,966,029	170,366,040	55,714,297	59,380,194			4
19,681,401	18,972,892	2,876,871	3,469,855			5
44,066,079	42,426,949	7,947,311	7,644,228			6
	-		-			7
9,360,286	7,924,496	2,048,489	1,765,552			8
67,304	(333,312)	-	-			9
	-		-			10
	-		-			11
2,425,018	2,409,720	805,479	393,735			12
(12,327,802)	(8,174,293)	(443,802)	(222,432)			13
17,626,332	15,896,443	3,416,549	3,034,377			14
2,402,917	4,776,202	(823,687)	(362,781)			15
	-		-			16
3,743,523	3,617,921	2,498,422	2,428,152			17
	-	-	-			18
(167,058)	(166,573)	(1,038)	(4,152)			19
	-		-			20
	-		-			21
	-		-			22
	-		-			23
	-		-			24
253,844,029	257,716,485	74,038,891	77,526,728	-	-	25
59,312,009	61,141,423	14,279,898	14,282,301	-	-	26

Name of Respondent	This Report is:	Date of Report	Year / Period of Report
Avista Corporation	[X] An Original [ ] A Resubmission	mm/dd/yyyy 04/15/2021	End of 2020 / Q4

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

Instructions

1. Report below the original cost of utility plant in service necessary to furnish utility service to customers in the state of Idaho, and the accumulated provisions for depreciation, amortization, and depletion attributable to that plant in service.
2. Report in column (c) the amount for electric function, in column (d) the amount for gas function, in columns (e), (f), and (g) report other (specify),

Line No.	Account (a)	Total Company End of Current Year (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	2,013,413,723	1,530,217,343
4	Property Under Capital Leases	24,173,936	
5	Plant Purchased or Sold	-	
6	Completed Construction not Classified	-	
7	Experimental Plant Unclassified	-	
8	Total (Total lines 3 through 7)	2,037,587,659	1,530,217,343
9	Leased to Others	-	
10	Held for Future Use	1,614,766	1,424,181
11	Construction Work in Progress	55,129,303	49,431,352
12	Acquisition Adjustments	-	
13	Total Utility Plant (Total lines 8 through 12)	2,094,331,728	1,581,072,876
14	Accumulated Provision for Depreciation, Amortization, and Depletion	748,745,320	582,560,104
15	Net Utility Plant (Line 13 less line 14)	1,345,586,408	998,512,772
16	Detail of Accumulated Provision for Depreciation, Amortization, and Depletion		
17	In Service		
18	Depreciation	706,169,782	574,330,139
19	Amortization and Depletion of Producing Natural Gas Lands / Land Rights	-	
20	Amortization of Underground Storage Lands / Land Rights	-	
21	Amortization of Other Utility Plant	42,575,538	8,229,965
22	Total (Total lines 18 through 21)	748,745,320	582,560,104
23	Leased to Others		
24	Depreciation	-	-
25	Amortization and Depletion	-	-
26	Total Leased to Others	-	-
27	Held for Future Use		
28	Depreciation	-	-
29	Amortization	-	-
30	Total Held for Future Use	-	-
31	Abandonment of Leases (Natural Gas)	-	-
32	Amortization of Plant Acquisition Adjustment	-	-
33	Total Accumulated Provision (Total lines 22, 26, 30, 31, 32)	748,745,320	582,560,104

(1) A small portion of the Company's electric distribution plant is located in Montana. For jurisdictional reporting purposes, those amounts are included as Idaho plant.

(2) Common Property Under Capital Lease is comprised of ROU Assets

Name of Respondent	This Report is:	Date of Report	Year / Period of Report
Avista Corporation	[X] An Original [ ] A Resubmission	mm/dd/yyyy 04/15/2021	End of 2020 / Q4

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

Instructions

and in column (h) common function.

3. In order to accurately reflect utility plant in service necessary to furnish utility service to customers in the state of Idaho, electric and gas plant not directly assigned is allocated to the state of Idaho as appropriate and included in column (c) and (d).

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
294,219,534				188,976,846	3
				24,173,936	4
					5
					6
					7
294,219,534	-	-	-	213,150,782	8
					9
190,585					10
683,990				5,013,961	11
					12
295,094,109	-	-	-	218,164,743	13
99,683,748	-	-	-	66,501,468	14
195,410,361	-	-	-	151,663,275	15
					16
					17
99,537,687				32,301,956	18
					19
					20
146,061				34,199,512	21
99,683,748	-	-	-	66,501,468	22
					23
					24
					25
-	-	-	-	-	26
					27
					28
					29
-	-	-	-	-	30
					31
					32
99,683,748	-	-	-	66,501,468	33

Name of Respondent	This Report is:	Date of Report	Year / Period of Report
Avista Corporation	[X] An Original [ ] A Resubmission	mm/dd/yyyy 04/15/2021	End of 2020 / Q4

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

Instructions

1. Report below the original cost of electric plant in service necessary to furnish electric utility service to customers in the state of Idaho. Include electric plant not directly assigned as allocated to the state of Idaho.
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, include 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 amounts.
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 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) distributions of

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	301 Organization	-	
3	302 Franchises and Consents	15,135,311	
4	303 Miscellaneous Intangible Plant	7,891,973	1,659,924
5	TOTAL Intangible Plant (Total of lines 2, 3, and 4)	23,027,284	1,659,924
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	310 Land and Land Rights	1,229,563	-
9	311 Structures and Improvements	48,313,933	374,213
10	312 Boiler Plant Equipment	66,622,238	363,757
11	313 Engines and Engine-Driven Generators	2,931	369,652
12	314 Turbogenerator Units	19,784,168	329,217
13	315 Accessory Electric Equipment	10,207,540	423,988
14	316 Miscellaneous Power Plant Equipment	5,753,102	360,018
15	317 Asset Retirement Costs for Steam Production	-	
16	TOTAL Steam Production Plant (Total of lines 8 through 15)	151,913,475	2,220,845
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 Miscellaneous Power Plant Equipment	-	
24	326 Asset Retirement Costs for Nuclear Production	-	
25	TOTAL Nuclear Production Plant (Total of lines 18 through 24)	-	-
26	C. Hydraulic Production Plant		
27	330 Land and Land Rights	21,995,285	544,390
28	331 Structures and Improvements	33,350,642	(323,528)
29	332 Reservoirs, Dams, and Waterways	66,210,000	304,002
30	333 Water Wheels, Turbines, and Generators	80,457,288	(886,419)
31	334 Accessory Electric Equipment	23,979,923	6,102,872
32	335 Miscellaneous Power Plant Equipment	5,217,390	29,970
33	336 Roads, Railroads, and Bridges	1,254,114	
34	337 Asset Retirement Costs for Hydraulic Production	-	
35	TOTAL Hydraulic Production Plant (Total of lines 27 through 34)	232,464,642	5,771,287
36	D. Other Production Plant		
37	340 Land and Land Rights	311,016	
38	341 Structures and Improvements	5,899,409	99,270
39	342 Fuel Holders, Products, and Accessories	7,349,726	(109,800)
40	343 Prime Movers	8,077,133	-
41	344 Generators	76,150,660	1,082,497
42	345 Accessory Electric Equipment	7,679,903	65,519
43	346 Miscellaneous Power Plant Equipment	585,123	(23,494)
44	347 Asset Retirement Costs for Other Production	-	
45	TOTAL Other Production Plant (Total of lines 37 through 44)	106,052,970	1,113,992
46	TOTAL Production Plant (Total of lines 16, 25, 35, and 45)	490,431,087	9,106,124

(1) A small portion of the Company's electric distribution plant is located in Montana. For jurisdictional reporting purposes, those amounts are included as Idaho plant.

Name of Respondent	This Report is:	Date of Report	Year / Period of Report
Avista Corporation	[X] An Original [ ] A Resubmission	mm/dd/yyyy 04/15/2021	End of 2020 / Q4

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

Instructions

these tentative classifications in columns (c) and (d), including the reversals of the prior year's tentative account distributions of these amounts. Careful observance of these 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 account 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 as required by the Uniform System of Accounts, give also the date of such filing.

Retirements (d)	Adjustments (e)	Transfers (f)	Balance End of Year (g)		Line No.
					1
			-		2
		44,050	15,179,361		3
298,864		151,029	9,404,062		4
298,864	-	195,079	24,583,423		5
					6
					7
-		101,742	1,331,305		8
55,278		68,527	48,701,395		9
84,233		108,484	67,010,246		10
-		(1,237)	371,346		11
3,132		13,822	20,124,075		12
1,148		29,502	10,659,882		13
		(8,641)	6,104,479		14
			-		15
143,791	-	312,199	154,302,728		16
					17
			-		18
			-		19
			-		20
			-		21
			-		22
			-		23
			-		24
-	-	-	-		25
					26
		(175,357)	22,364,318		27
420,002		1,245,910	33,853,022		28
-		421,727	66,935,729		29
91,761		1,141,454	80,620,562		30
134,462		(3,952,675)	25,995,658		31
1,327		(749,896)	4,496,137		32
		3,650	1,257,764		33
			-		34
647,552	-	(2,065,187)	235,523,190		35
					36
		905	311,921		37
15,086		26,095	6,009,688		38
-		20,523	7,260,449		39
-		23,507	8,100,640		40
5,711		(234,293)	76,993,153		41
5,153		27,652	7,767,921		42
		4,076	565,705		43
			-		44
25,950	-	(131,535)	107,009,477		45
817,293	-	(1,884,523)	496,835,395		46

Name of Respondent	This Report is:	Date of Report	Year / Period of Report
Avista Corporation	[X] An Original [ ] A Resubmission	mm/dd/yyyy 04/15/2021	End of 2020 / Q4

ELECTRIC PLANT IN SERVICE - IDAHO (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	10,212,156	81,676
49	352 Structures and Improvements	8,724,011	1,277,325
50	353 Station Equipment	98,548,745	1,911,462
51	354 Towers and Fixtures	5,942,873	31,911
52	355 Poles and Fixtures	95,799,428	2,798,010
53	356 Overhead Conductors and Devices	54,547,530	594,735
54	357 Underground Conduit	1,117,813	(37,662)
55	358 Underground Conductors and Devices	894,454	(37,662)
56	359 Roads and Trails	724,401	
57	359.1 Asset Retirement Costs for Transmission Plant	-	
58	TOTAL Transmission Plant (Total of lines 48 through 57)	276,511,411	6,619,795
59	4. DISTRIBUTION PLANT		
60	360 Land and Land Rights	4,322,033	-
61	361 Structures and Improvements	6,794,686	325,931
62	362 Station Equipment	46,111,264	6,440,944
63	363 Storage Battery Equipment	-	-
64	364 Poles, Towers, and Fixtures	151,844,143	7,400,567
65	365 Overhead Conductors and Devices	100,818,443	7,023,647
66	366 Underground Conduit	43,170,873	2,660,023
67	367 Underground Conductors and Devices	74,090,735	3,994,386
68	368 Line Transformers	86,895,646	4,221,941
69	369 Services	61,726,743	3,376,424
70	370 Meters	23,988,831	226,967
71	371 Installations on Customer Premises	-	-
72	372 Leased Property on Customer Premises	-	-
73	373 Street Lighting and Signal Systems	23,246,128	1,490,182
74	374 Asset Retirement Costs for Distribution Plant	-	
75	TOTAL Distribution Plant (Total of lines 60 through 74)	623,009,525	37,161,012
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 Operation Plant	-	
84	TOTAL Transmission and Market Operation Plant (Total lines 77 through 83)	-	-
85	6. GENERAL PLANT		
86	389 Land and Land Rights	369,296	
87	390 Structures and Improvements	4,141,640	678,414
88	391 Office Furniture and Equipment	513,754	427,558
89	392 Transportation Equipment	14,981,654	1,296,313
90	393 Stores Equipment	121,356	-
91	394 Tools, Shop and Garage Equipment	1,824,214	335,831
92	395 Laboratory Equipment	437,804	54,490
93	396 Power Operated Equipment	12,093,902	43,215
94	397 Communication Equipment	15,988,082	734,367
95	398 Miscellaneous Equipment	64,311	-
96	SUBTOTAL (Total of lines 86 through 95)	50,536,013	3,570,188
97	399 Other Tangible Property	-	
98	399.1 Asset Retirement Costs for General Plant	-	
99	TOTAL General Plant (Total of lines 96, 97 and 98)	50,536,013	3,570,188
100	TOTAL (Accounts 101 and 106)	1,463,515,320	58,117,043
101	102 Electric Plant Purchased		
102	102 (Less) Electric Plant Sold	-	
103	103 Experimental Plant Unclassified	-	
104	TOTAL Electric Plant in Service (Total of lines 100 through 103)	1,463,515,320	58,117,043

Name of Respondent	This Report is:	Date of Report	Year / Period of Report
Avista Corporation	[X] An Original [ ] A Resubmission	mm/dd/yyyy 04/15/2021	End of 2020 / Q4

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance End of Year (g)		Line No.
					47
		401,348	10,695,180		48
16,834		(99,048)	9,885,454		49
1,475,208		8,263,874	107,248,873		50
-		1,078	5,975,862		51
74,724		4,685,451	103,208,165		52
37,422		2,065,551	57,170,394		53
		239,881	1,320,032		54
		238,789	1,095,581		55
		18,027	742,428		56
			-		57
1,604,188	-	15,814,951	297,341,969		58
					59
		-	4,322,033		60
		(1)	7,120,616		61
31,797		138,133	52,658,544		62
-		-	-		63
314,813		-	158,929,897		64
27,227		15,972	107,830,835		65
34,365		(1)	45,796,530		66
123,033		-	77,962,088		67
44,114		1	91,073,474		68
26,832			65,076,335		69
310,723			23,905,075		70
-			-		71
-			-		72
254,002			24,482,308		73
			-		74
1,166,906	-	154,104	659,157,735		75
					76
			-		77
			-		78
			-		79
			-		80
			-		81
			-		82
			-		83
-	-	-	-		84
					85
		210	369,506		86
4,428		42,793	4,858,419		87
320,475		(14,451)	606,386		88
154,371		276,638	16,400,234		89
2,014		3,595	122,937		90
115,173		2,116	2,046,988		91
-		12,708	505,002		92
649,257		28,680	11,516,540		93
1,848,276		905,589	15,779,762		94
-		28,736	93,047		95
3,093,994	-	1,286,614	52,298,821		96
			-		97
			-		98
3,093,994	-	1,286,614	52,298,821		99
6,981,245	-	15,566,225	1,530,217,343		100
			-		101
			-		102
			-		103
6,981,245	-	15,566,225	1,530,217,343		104

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ELECTRIC OPERATING REVENUES - IDAHO

Instructions

1. Report below operating revenues attributable to the state of Idaho for each prescribed account in accordance with jurisdictional Results of Operations. Report the portion of total operating revenue and megawatt hours which pertains to unbilled revenue and MWH pertaining unbilled revenue in the lines provided.
2. Report number of customers (columns (f) and (g)) on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
3. If increases or decreases from previous period (columns (c), (e), and (g)) are not derived from previously reported figures, explain any inconsistencies in a footnote in the available space at the bottom of the page, or in a separate schedule.

Line No.	Account (a)	ELECTRIC OPERATING REVENUE Current Year (b)	 Prior Year (c)
1	Sales of Electricity		
2	440 Residential Sales	124,037,662	119,154,126
3	442 Commercial and Industrial Sales (3)		
4	Small (or Commercial)	85,688,459	89,886,994
5	Large (or Industrial)	53,578,621	50,408,829
6	444 Public Street and Highway Lighting	2,723,779	2,669,672
7	445 Other Sales to Public Authorities		-
8	446 Sales to Railroads and Railways		-
9	448 Interdepartmental Sales	248,741	274,645
10	TOTAL Sales to Ultimate Customers	(1) 266,277,262	262,394,266
11	447 Sales for Resale	28,276,426	27,968,449
12	TOTAL Sales of Electricity	294,553,688	290,362,715
13	449.1 (Less) Provision for Rate Refunds		(78,338)
14	TOTAL Revenues Net of Provision for Refunds	294,553,688	290,284,377
15	Other Operating Revenues		
16	450 Forfeited Discounts		-
17	451 Miscellaneous Service Revenues	47,984	128,342
18	453 Sales of Water and Water Power	177,812	118,312
19	454 Rent from Electric Property	421,424	1,268,815
20	455 Interdepartmental Rents		-
21	456 Other Electric Revenues	(4) 17,949,115	21,442,785
22	456.1 Revenues from Transmission of Electricity for Others	6,015	5,615,277
23	457.1 Regional Control Service Revenues		-
24	457.2 Miscellaneous Revenues		-
25			
26	TOTAL Other Operating Revenues	18,602,350	28,573,531
27	TOTAL Electric Operating Revenues	313,156,038	318,857,908

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ELECTRIC OPERATING REVENUES - IDAHO

Instructions

4. Disclose amounts of $250,000 or greater in a footnote at the bottom of the page or in a separate schedule for accounts 451, 456, and 457.2.
5. Commercial and Industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
6. See pages 108-109 in the FERC Form 1, Important Changes During Period, for important new territory added and important rate increases or decreases.
7. Include unmetered sales. Provide details of such Sales in a footnote in the available space at the bottom of this page or in a separate schedule.

MEGAWATT HOURS SOLD		AVG. NO. OF CUSTOMERS PER MONTH			Line No.
Current Year (d)	Previous Year (e)	Current Year (f)	Previous Year (g)		
					1
1,258,168	1,231,818	118,386	116,121		2
					3
973,813	1,005,069	17,989	17,751		4
1,171,472	1,095,960	413	428		5
7,146	7,243	177	169		6
	-		-		7
	-		-		8
2,754	3,022	45	41		9
(2) 3,413,353	3,343,112	137,010	134,510		10
964	955		-		11
3,414,317	3,344,067	137,010	134,510		12
-	-		-		13
3,414,317	3,344,067	137,010	134,510		14

(1) Includes $222,931 of unbilled revenues.

(2) Includes 6,464 MWH relating to unbilled revenues.

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

(4) Includes $ 62,791 associated with a special contract for wheeling over the distribution system on file with the IPUC, recorded in sub-account 456700.

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES - IDAHO

Instructions

1. For each prescribed account below, report operation and maintenance expenses as allocated by the Results of Operations model to the state of Idaho.
2. If the amount for previous year is not derived from previously reported figures, explain in a 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	122,266	155,977
5	501 Fuel	10,168,030	10,600,529
6	502 Steam Expenses	1,211,051	1,347,668
7	503 Steam from Other Sources		-
8	504 (Less) Steam Transferred-Cr.		-
9	505 Electric Expenses	256,206	365,797
10	506 Miscellaneous Steam Power Expenses	1,597,685	1,098,074
11	507 Rents	-	5,181
12	509 Allowances		-
13	TOTAL Operation (Total of lines 4 through 12)	13,355,238	13,573,226
14	Maintenance		
15	510 Maintenance Supervision and Engineering	227,631	186,640
16	511 Maintenance of Structures	267,718	263,702
17	512 Maintenance of Boiler Plant	2,686,633	2,094,794
18	513 Maintenance of Electric Plant	780,037	236,673
19	514 Maintenance of Miscellaneous Steam Plant	408,801	432,104
20	TOTAL Maintenance (Total of Lines 15 through 19)	4,370,820	3,213,913
21	TOTAL Steam Power Generation Expenses (Total lines 13 & 20)	17,726,058	16,787,139
22	B. Nuclear Power Generation		
23	Operation		
24	517 Operation Supervision and Engineering	-	-
25	518 Fuel	-	-
26	519 Coolants and Water	-	-
27	520 Steam Expenses	-	-
28	521 Steam from Other Sources	-	-
29	522 (Less) Steam Transferred-Cr.	-	-
30	523 Electric Expenses	-	-
31	524 Miscellaneous Nuclear Power Expenses	-	-
32	525 Rents	-	-
33	TOTAL Operation (Total of lines 24 through 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 (Total of lines 35 through 39)	-	-
41	TOTAL Nuclear Power Generation Expenses (Total lines 33 & 40)	-	-
42	C. Hydraulic Power Generation		
43	Operation		
44	535 Operation Supervision and Engineering	657,980	1,176,128
45	536 Water for Power	488,339	321,374
46	537 Hydraulic Expenses	3,379,990	3,378,832
47	538 Electric Expenses	1,992,489	2,641,294
48	539 Miscellaneous Hydraulic Power Generation Expenses	381,517	386,393
49	540 Rents	2,265,857	2,221,232
50	TOTAL Operation (Total of lines 44 through 49)	9,166,172	10,125,253
51	Maintenance		
52	541 Maintenance Supervision and Engineering	198,918	346,581
53	542 Maintenance of Structures	740,399	254,176
54	543 Maintenance of Reservoirs, Dams, and Waterways	119,753	632,319
55	544 Maintenance of Electric Plant	1,073,976	1,216,322
56	545 Maintenance of Miscellaneous Hydraulic Plant	231,640	392,282
57	TOTAL Maintenance (Total of lines 53 through 57)	2,364,686	2,841,680
58	TOTAL Hydraulic Power Generation Expenses (Total of lines 50 & 58)	11,530,858	12,966,933
59			

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES - IDAHO

Instructions

1. For each prescribed account below, report operation and maintenance expenses as allocated by the Results of Operations model to the state of Idaho.
2. If the amount for previous year is not derived from previously reported figures, explain in a 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	133,537	95,408
63	547 Fuel	18,562,138	24,567,728
64	548 Generation Expenses	814,286	814,456
65	549 Miscellaneous Other Power Generation Expenses	140,461	462,470
66	550 Rents	29,051	16,164
67	TOTAL Operation (Total of lines 62 through 66)	19,679,473	25,956,226
68	Maintenance		
69	551 Maintenance Supervision and Engineering	234,720	273,791
70	552 Maintenance of Structures	61,546	46,230
71	553 Maintenance of Generating and Electric Plant	1,418,724	2,484,593
72	554 Maintenance of Miscellaneous Other Power Generation Plant	140,875	163,115
73	TOTAL Maintenance (Total of lines 69 through 72)	1,855,865	2,967,729
74	TOTAL Other Power Generation Expenses	21,535,338	28,923,955
75	E. Other Power Supply Expenses		
76	555 Purchased Power	53,807,902	55,230,889
77	556 System Control and Load Dispatching	244,132	264,267
78	557 Other Expenses	11,439,196	12,382,127
79	TOTAL Other Power Supply Expenses (Total of lines 76 through 78)	65,491,230	67,877,283
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74, & 79)	116,283,484	126,555,310
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	560 Operation Supervision and Engineering	756,603	864,248
84	561 Load Dispatching	939,085	1,299,328
85	561.1 Load Dispatch-Reliability		-
86	561.2 Load Dispatch-Monitor and Operation Transmission System		-
87	561.3 Load Dispatch-Transmission Service and Scheduling		-
88	561.4 Scheduling, System Control and Dispatch Services		-
89	561.5 Reliability, Planning and Standards Development		-
90	561.6 Transmission Service Studies		-
91	561.7 Generation Interconnection Studies		-
92	561.8 Reliability, Planning and Standards Development Services		-
93	562 Station Expenses	164,685	198,400
94	563 Overhead Lines Expenses	145,975	132,400
95	564 Underground Lines Expenses		-
96	565 Transmission of Electricity by Others	5,699,353	5,928,069
97	566 Miscellaneous Transmission Expenses	815,226	1,102,308
98	567 Rents	63,936	61,081
99	TOTAL Operation (Total of lines 83 through 98)	8,584,863	9,585,834
100	Maintenance		
101	568 Maintenance Supervision and Engineering	148,557	224,815
102	569 Maintenance of Structures	150,905	239,771
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	262,433	339,863
108	571 Maintenance of Overhead Lines	474,027	357,120
109	572 Maintenance of Underground Lines	1	-
110	573 Maintenance of Miscellaneous Transmission Plant	12,414	26,985
111	TOTAL Maintenance (Total of lines 101 through 110)	1,048,337	1,188,554
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	9,633,200	10,774,388

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES - IDAHO

Instructions

1. For each prescribed account below, report operation and maintenance expenses as allocated by the Results of Operations model to the state of Idaho.
2. If the amount for previous year is not derived from previously reported figures, explain in a 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 (Total lines 115 through 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 (Total lines 125 through 129)	-	-
131	TOTAL Regional Market Expenses (Total lines 123 & 130)	-	-
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	580 Operation Supervision and Engineering	1,245,865	1,388,741
135	581 Load Dispatching		-
136	582 Station Expenses	262,930	378,600
137	583 Overhead Line Expenses	863,135	939,045
138	584 Underground Line Expenses	792,348	765,754
139	585 Street Lighting and Signal System Expenses	1,959	322
140	586 Meter Expenses	239,569	345,023
141	587 Customer Installations Expenses	268,566	300,719
142	588 Miscellaneous Expenses	1,573,466	2,860,794
143	589 Rents	92,756	110,870
144	TOTAL Operation (Total of lines 134 through 143)	5,340,594	7,089,868
145	Maintenance		
146	590 Maintenance Supervision and Engineering	519,053	381,056
147	591 Maintenance of Structures	299,884	212,521
148	592 Maintenance of Station Equipment	118,583	239,823
149	593 Maintenance of Overhead Lines	4,695,989	3,278,398
150	594 Maintenance of Underground Lines	252,055	286,046
151	595 Maintenance of Line Transformers	81,056	84,468
152	596 Maintenance of Street Lighting and Signal Systems	20,777	28,298
153	597 Maintenance of Meters	7,854	7,240
154	598 Maintenance of Miscellaneous Distribution Plant	157,537	195,605
155	TOTAL Maintenance (Total lines 146 through 154)	6,152,788	4,713,455
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	11,493,382	11,803,323
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	901 Supervision	51,837	62,228
160	902 Meter Reading Expenses	223,403	311,145
161	903 Customer Records and Collection Expenses	2,590,200	3,597,494
162	904 Uncollectable Accounts	2,122,968	72,045
163	905 Miscellaneous Customer Accounts Expenses	50,517	74,340
164	TOTAL Customer Accounts Expenses (Total of line 159 through 163)	5,038,925	4,117,252

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES - IDAHO

Instructions

1. For each prescribed account below, report operation and maintenance expenses as allocated by the Results of Operations model to the state of Idaho.
2. If the amount for previous year is not derived from previously reported figures, explain in a 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	10,444,842	10,463,125
169	909 Informational and Instructional Expenses	286,981	413,169
170	910 Miscellaneous Customer Service and Informational Expenses	111,214	94,750
171	TOTAL Customer Service and Informational Expenses (Total lines 167 through 170)	10,843,037	10,971,044
172	7. SALES EXPENSES		
173	Operation		
174	911 Supervision		-
175	912 Demonstrating and Selling Expenses		-
176	913 Advertising Expenses		-
177	916 Miscellaneous Sales Expenses		-
178	TOTAL Sales Expenses (Total of lines 174 through 177)	-	-
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	920 Administrative and General Salaries	8,771,462	10,507,028
182	921 Office Supplies and Expenses	1,355,737	1,506,359
183	922 (Less) Administrative Expenses Transferred-Credit	(32,696)	(31,533)
184	923 Outside Services Employed	3,242,940	3,017,109
185	924 Property Insurance	530,918	447,340
186	925 Injuries and Damages	1,347,538	982,231
187	926 Employee Pensions and Benefits	10,016,680	527,264
188	927 Franchise Requirements	1,200	1,200
189	928 Regulatory Commission Expenses	2,012,674	2,429,023
190	929 (Less) Duplicate Charges-Cr.	-	-
191	930.1 General Advertising Expenses		-
192	930.2 Miscellaneous General Expenses	2,037,189	1,584,398
193	931 Rents	182,855	99,635
194	TOTAL Operation (Total of lines 181 through 193)	29,466,497	21,070,054
195	Maintenance		
196	935 Maintenance of General Plant	3,888,905	4,047,561
197	TOTAL Administrative and General Expenses (Total of lines 194 and 196)	33,355,402	25,117,615
198	TOTAL Elec Op and Maint Expns (Total lines 80, 112, 131, 156, 164, 171, 178, 197)	186,647,430	189,338,932

Name of Respondent	This Report is:	Date of Report	Year / Period of Report
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TRANSMISSION LINE STATISTICS - IDAHO

Instructions

1. Report information concerning transmission lines physically located in the state of Idaho, including the cost of lines, and expenses for the year. List each transmission line having nominal voltage of 132 kilovolts or greater. Transmission lines below this voltage should be grouped and totals reported for each group.
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 the 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 in the available space at the bottom of this page or in a separate

Line No.	DESIGNATION		VOLTAGE (KV) *Indicate where other than 60 cycle, 3 phase*		Type of Supporting Structure	LENGTH (Pole Miles) *For underground lines, report circuit miles*		Number of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Group Sum - 115kV		115.00	115.00		593.00		
2								
3								
4	Beacon	Cabinet Gorge Plant			Steel Pole	20.00		2
5	Beacon	Cabinet Gorge Plant			H Type	53.00		1
6								
7	Divide Creek	Lolo Sub	230.00	230.00	H Type	43.00		1
8	Noxon Plant	Pine Creek Sub	230.00	230.00	Steel Pole	15.00		1
9	Noxon Plant	Pine Creek Sub	230.00	230.00	H Type	1.00		1
10	Noxon Plant	Pine Creek Sub	230.00	230.00	H Type	14.00		1
11	Cabinet Gorge Plant	Noxon	230.00	230.00	H Type	2.00		1
12								
13	Benewah Sw. Station	Pine Creek Sub	230.00	230.00	H Type	43.00		1
14	Beacon Sub	Lolo Sub	230.00	230.00	Steel Pole	37.00		2
15	Beacon Sub	Lolo Sub	230.00	230.00	H Type	35.00		1
16	Beacon Sub	Lolo Sub	230.00	230.00	H Type	8.00		1
17	North Lewiston	Walla Walla	230.00	230.00	H Type	8.00		1
18	North Lewiston	Shawnee	230.00	230.00	H Type	1.00		1
19	Hatwai	N. Lewiston Sub	230.00	230.00	H Type	7.00		1
20								
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TRANSMISSION LINE STATISTICS - IDAHO

Instructions

schedule, explain the basis of such occupancy and state whether these expenses with respect to such structures are included in the expenses reported for the line designated.

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 have 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 details of such matters as percent ownership by respondent in the line, name of c-owner, basis of sharing expenses of the line, and and how expenses borne by the respondent are accounts 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) through (l) on the book cost at end of year associated with the physical lines reported.

Size of Conductor and Material (i)	COST OF LINE *Include in column (j) land, land rights, and clearing right-of-way* Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
	5,205,472	110,641,734	115,847,206	149,720	213,016		362,736	1
			-				-	2
			-				-	3
1590 ACSS			-				-	4
1590 ACSR	1,042,786	26,150,464	27,193,250	9,002	8,800		17,802	5
			-				-	6
1272 AAC	165,333	7,091,503	7,256,836	2,099	46,745		48,844	7
1272 ACSR			-				-	8
1590 ACSS			-				-	9
954 AAC	692,847	11,293,114	11,985,961		224,985		224,985	10
954 AAC	138,010	451,945	589,955	22,932	4,813		27,745	11
			-				-	12
954 AAC	387,459	5,222,681	5,610,140		17,441		17,441	13
1590 ACSS			-				-	14
1272 AAC			-				-	15
1272 ACSS	363,604	20,607,585	20,971,189				-	16
1272 AAC	25,818	1,132,628	1,158,446		-		-	17
1272 ACSR	10,015	319,300	329,315				-	18
1590 ACSR	155,244	2,616,153	2,771,397	2,713	159		2,872	19
			-				-	20
			-				-	21
			-				-	22
			-				-	23
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			-				-	30
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			-				-	32
			-				-	33
			-				-	34
			-				-	35
			-				-	36