THIS FILING IS
Item 1: ☑ An Initial (Original) Submission OR ☐ Resubmission No.

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: 2021/ Q4

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. **Purpose**

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q) is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. **Who Must Submit**

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities, Licensees, and Others Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

1. one million megawatt hours of total annual sales,
2. 100 megawatt hours of annual sales for resale,
3. 500 megawatt hours of annual power exchanges delivered, or
4. 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. **What and Where to Submit**

a. Submit FERC Form Nos. 1 and 3-Q electronically through the eCollection portal at https://eCollection.ferc.gov, and according to the specifications in the Form 1 and 3-Q taxonomies.
b. The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.
c. Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:
Secretary
Federal Energy Regulatory Commission 888 First Street, NE
Washington, DC 20426
d. For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

   The CPA Certification Statement should:

   a. Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and
   b. Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

e. The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

   "In connection with our regular examination of the financial statements of [COMPANY NAME] for the year ended on which we have reported separately under date of [DATE], we have also reviewed schedules [NAME OF SCHEDULES] of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

   Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases." The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.
f. Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. Further instructions are found on the Commission's website at https://www.ferc.gov/ferc-online/ferc-online/frequently-asked-questions-faqs-efilingferc-online.
g. Federal, State, and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from https://www.ferc.gov/general-information-0/electric-industry-forms.

IV. **When to Submit**

FERC Forms 1 and 3-Q must be filed by the following schedule:

a. FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and
b. FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. **Where to Send Comments on Public Reporting Burden.**

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 168 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III. Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. The "Date of Report" included in the header of each page is to be completed only for resubmissions (see VII. below).

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII. For any resubmissions, please explain the reason for the resubmission in a footnote to the data field.

VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

X. Schedule specific instructions are found in the applicable taxonomy and on the applicable blank rendered form.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and" firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

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.

DEFINITIONS

I. Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

3. 'Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;
4. 'Person' means an individual or a corporation;
5. 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;
7. 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; ......
11. "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

a. 'To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304.

a. Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may by rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports shall be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309.

The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

GENERAL PENALTIES

The Commission may assess up to $1 million per day per violation of its rules and regulations. See FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

FERC FORM NO. 1
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent Avista Corporation	02 Year/ Period of Report End of: 2021/ Q4
03 Previous Name and Date of Change (If name changed during year) /	
04 Address of Principal Office at End of Period (Street, City, State, Zip Code) 1411 East Mission Avenue, Spokane, WA 99207	
05 Name of Contact Person Ryan L. Krasselt	06 Title of Contact Person VP, Controller, Prin. Acctg
07 Address of Contact Person (Street, City, State, Zip Code) 1411 East Mission Avenue, Spokane, WA 99207	

08 Telephone of Contact Person, Including Area Code (509) 495-2273	09 This Report is An Original / A Resubmission (1) ☑ An Original (2) ☐ A Resubmission	10 Date of Report (Mo, Da, Yr) 04/15/2022

Annual Corporate Officer Certification

The undersigned officer certifies that:

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

01 Name Ryan L. Krasselt	03 Signature Ryan L Krasselt	04 Date Signed (Mo, Da, Yr) 04/15/2022
02 Title VP, Controller, Prin Acctg Officer		

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

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

LIST OF SCHEDULES (Electric Utility)

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

57	**Amounts included in ISO/RTO Settlement Statements**	397	
58	**Purchase and Sale of Ancillary Services**	398	
59	**Monthly Transmission System Peak Load**	400	
60	**Monthly ISO/RTO Transmission System Peak Load**	400a	NA
61	**Electric Energy Account**	401a	
62	**Monthly Peaks and Output**	401b	
63	**Steam Electric Generating Plant Statistics**	402	
64	**Hydroelectric Generating Plant Statistics**	406	
65	**Pumped Storage Generating Plant Statistics**	408	NA
66	**Generating Plant Statistics Pages**	410	
0	**Energy Storage Operations (Large Plants)**	414	NA
67	**Transmission Line Statistics Pages**	422	
68	**Transmission Lines Added During Year**	424	
69	**Substations**	426	
70	**Transactions with Associated (Affiliated) Companies**	429	
71	**Footnote Data**	450	
	Stockholders' Reports (check appropriate box)		
	Stockholders' Reports Check appropriate box: ☐ Two copies will be submitted ☐ No annual report to stockholders is prepared		

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.

Avista Corporation

Ryan L. Krasselt

VP, Controller, Prin Acctg 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

State of Incorporation: WA

Date of Incorporation: 1889-03-15

Incorporated Under Special Law:

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.

(a) Name of Receiver or Trustee Holding Property of the Respondent: None

(b) Date Receiver took Possession of Respondent Property:

(c) Authority by which the Receivership or Trusteeship was created:

(d) Date when possession by receiver or trustee ceased:

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

(2) ☑ No

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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

Definitions

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Avista Capital, Inc.	Parent to the Co's Subsidiary	100%	[a] 1
2	Avista Development, Inc.	Investment in Real Estate	100%	[b] 2
3	Avista Edge, Inc.	Investment in Internet Tech.	100%	[c] 3
4	Pentzer Corporation	Parent of Bay Area Mfg and Penture Venture Holdings	100%	[d] 4
5	Pentzer Venture Holdings II, Inc.	Holding Company-Inactive	100%	[e] 5
6	Bay Area Manufacturing, Inc.	Holding Company	100%	[f] 6
7	Avista Capital II	Affiliated business trust issued preferred trust Securities	100%	[g] 7
8	Avista Northwest Resources, LLC	Owns an interest in a venture fund investment	100%	[h] 8
9	Courtyard Office Center, LLC	Office & Retail Leasing	100%	[i] 9
10	Salix, Inc.	Liquified Natural Gas Operations	100%	[j] 10
11	Alaska Energy and Resources Company (AERC)	Parent Co of Alaska Opertions	100%	[k] 11
12	Alaska Electric Light and Power Company	Utility Operations in Juneau	100%	[l] 12
13	AJT Mining Properties, Inc.	Inactive mining Co holding certain properties	100%	[m] 13
14	Snettisham Electric Company	Right to Purchase Snettisham	100%	[n] 14

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FOOTNOTE DATA

(a) Concept: FootnoteReferences
(b) Concept: FootnoteReferences
(c) Concept: FootnoteReferences
(d) Concept: FootnoteReferences
(e) Concept: FootnoteReferences
(f) Concept: FootnoteReferences
(g) Concept: FootnoteReferences
(h) Concept: FootnoteReferences
(i) Concept: FootnoteReferences
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(k) Concept: FootnoteReferences
(l) Concept: FootnoteReferences
(m) Concept: FootnoteReferences
(n) Concept: FootnoteReferences

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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)	Date Started in Period (d)	Date Ended in Period (e)
1	President and Chief Executive Officer	D. P. Vermillion	757,327	2022-01-01	2022-12-31
2	Executive Vice President, Chief Financial Officer and Treasurer	M. T. Thies	454,562	2022-01-01	2022-12-31
3	Senior Vice President, External Affairs and Chief Customer Officer	K. J. Christie	338,269	2022-01-01	2022-12-31
4	Senior Vice President, Energy Delivery and Shared Services	H. L. Rosentrater	338,231	2022-01-01	2022-12-31
5	Senior Vice President, Energy Resources and Environmental Compliance Officer	J. R. Thackston	338,309	2022-01-01	2022-12-31
6	Vice President, Safety and Human Resources	B. A. Cox	285,990	2022-01-01	2022-12-31
7	Vice President, General Council, Corporate Secretary and Chief Ethics/ Compliance Officer	G. C. Hessler	260,867	2022-01-01	2022-12-31
8	Vice President Community & Economic Vitality	L. D. Hill	228,078	2022-01-01	2022-12-31
9	Vice President, Chief Information Officer, and Chief Security Officer	J. M. Kensok	297,423	2022-01-01	2022-12-31
10	Vice President, Controller, and Principal Accounting Officer	R. L. Krasselt	253,349	2022-01-01	2022-12-31
11	Vice President and Chief Counsel for Regulatory and Governmental Affairs	D. J. Meyer	310,843	2022-01-01	2022-12-31
12	Vice President and Chief Strategy Officer	E. D. Schlect	273,378	2022-01-01	2022-12-31

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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), name and abbreviated titles of the directors who are officers of the respondent.
2. Provide the principle place of business in column (b), designate members of the Executive Committee in column (c), and the Chairman of the Executive Committee in column (d).

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)	Member of the Executive Committee (c)	Chairman of the Executive Committee (d)
1	Scott L. Morris** (Chairman of the Board)	1411 E. Mission Ave, Spokane, WA 99202	true	true
2	Dennis P. Vermillion *** President and CEO	1411 E. Mission Ave, Spokane, WA 99202	true	false
3	Kristianne Blake***	P.O. Box 3727, Spokane, WA 99220	true	false
4	Donald C. Burke	16 Ivy Court, Langhorne, PA 19047	false	false
5	Scott H. Maw	115 NW 78th St., Seattle, WA 98117	false	false
6	Rebecca A. Klein	611 S. Congress Ave., Suite 125, Austin, TX 78704	false	false
7	Jeffry L. Philipps	P.O. Box 9000, Spokane, WA 99209	false	false
8	Marc F. Racicot (Retired May 2021)	2234 Deerfield Ln., Helena, MT 59601	false	false
9	Heidi B. Stanley***	P.O. Box 2884, Spokane, WA 99220	true	false
10	R. John Taylor*** (Resigned June 2021)	111 Main Street, Lewiston, ID 83501	true	false
11	Janet D. Widmann	26 Sanford Ln., Lafayette, CA 94549	false	false
12	Julie A. Bentz (Joined November 2021)	38748 Lulay Rd, Scio, OR 97374	false	false
13	Sena M. Kwawu (Joined May 2021)	2507 101st Lane NE, Bellevue, WA 98004	false	false

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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 Pages 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.

None

None

None

None

None

Referenceis made to notes 11, 12, 13 and 14 of the Notes to the Financial Statements.

None

Average annual wage increases were 3.0% for non-exempt employees effective March 1, 2021. Average annual wage increases were 3.0% for exempt employees effective March 1, 2021. Officers received averaged increases of 5.2% effective February 15, 2021. Certain bargaining unit employees received increases of 2.0% effective April 1, 2021.

Referenceis made to Note 12 of the notes to Financial Statements.

None

Effective May11, 2021, Sena Kwawu was elected by the shareholders of the company to join theAvista Corp. board of directors.
Effective May11, 2021, Marc Racicot retired from the board of directors.
Effective June21, 2021, R. John Taylor resigned from the board of directors.
EffectiveAugust 11, 2021 Major General (Retired) Julie Bentz was appointed by the boardof directors and has joined the board effective November 1, 2021.

ProprietaryCapital is not less than 30 percent.

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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	7,072,675,570	6,713,727,078
3	Construction Work in Progress (107)	200	196,305,682	172,073,892
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		7,268,981,252	6,885,800,970
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	2,465,058,317	2,294,362,603
6	Net Utility Plant (Enter Total of line 4 less 5)		4,803,922,935	4,591,438,367
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202		
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)			
9	Nuclear Fuel Assemblies in Reactor (120.3)			
10	Spent Nuclear Fuel (120.4)			
11	Nuclear Fuel Under Capital Leases (120.6)			
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202		
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	
14	Net Utility Plant (Enter Total of lines 6 and 13)		4,803,922,935	4,591,438,367
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)		6,992,076	6,992,076
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		4,500,764	5,311,287
19	(Less) Accum. Prov. for Depr. and Amort. (122)		247,981	212,107
20	Investments in Associated Companies (123)		11,547,000	11,547,000
21	Investment in Subsidiary Companies (123.1)	224	225,965,713	207,410,331
23	Noncurrent Portion of Allowances	228		
24	Other Investments (124)		77,889	77,890
25	Sinking Funds (125)		0	
26	Depreciation Fund (126)		0	
27	Amortization Fund - Federal (127)		0	
28	Other Special Funds (128)		11,152,367	24,673,077
29	Special Funds (Non Major Only) (129)		0	
30	Long-Term Portion of Derivative Assets (175)		2,658,520	596,015
31	Long-Term Portion of Derivative Assets - Hedges (176)		0	
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		255,654,272	249,403,493
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	
35	Cash (131)		11,893,219	7,363,358
36	Special Deposits (132-134)		21,477,352	4,335,989
37	Working Fund (135)		1,227,292	1,116,351
38	Temporary Cash Investments (136)		153,241	152,774
39	Notes Receivable (141)		0	
40	Customer Accounts Receivable (142)		183,224,129	161,513,344
41	Other Accounts Receivable (143)		50,330,014	56,664,630
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		10,368,511	11,336,140
43	Notes Receivable from Associated Companies (145)		0	
44	Accounts Receivable from Assoc. Companies (146)		738,517	719,507
45	Fuel Stock (151)	227	4,388,454	4,088,628
46	Fuel Stock Expenses Undistributed (152)	227	0	
47	Residuals (Elec) and Extracted Products (153)	227	0	
48	Plant Materials and Operating Supplies (154)	227	60,277,408	51,854,056
49	Merchandise (155)	227	0	
50	Other Materials and Supplies (156)	227	0	
51	Nuclear Materials Held for Sale (157)	202/227	0	
52	Allowances (158.1 and 158.2)	228	0	
53	(Less) Noncurrent Portion of Allowances	228		
54	Stores Expense Undistributed (163)	227	0	
55	Gas Stored Underground - Current (164.1)		17,603,996	9,535,324
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	
57	Prepayments (165)		22,973,644	26,280,659
58	Advances for Gas (166-167)		0	
59	Interest and Dividends Receivable (171)		20,633	24,973
60	Rents Receivable (172)		3,665,325	2,934,797
61	Accrued Utility Revenues (173)		0	

62	Miscellaneous Current and Accrued Assets (174)		113,893	236,392
63	Derivative Instrument Assets (175)		4,056,941	1,523,219
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		2,658,520	596,015
65	Derivative Instrument Assets - Hedges (176)		0	
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)		0	
67	Total Current and Accrued Assets (Lines 34 through 66)		369,117,027	316,411,846
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		16,420,883	15,341,337
70	Extraordinary Property Losses (182.1)	230a	0	
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	
72	Other Regulatory Assets (182.3)	232	833,162,908	717,281,643
73	Prelim. Survey and Investigation Charges (Electric) (183)		0	
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	
75	Other Preliminary Survey and Investigation Charges (183.2)		0	
76	Clearing Accounts (184)		122,784	152,201
77	Temporary Facilities (185)		0	
78	Miscellaneous Deferred Debits (186)	233	50,762,924	29,826,563
79	Def. Losses from Disposition of Utility Plt. (187)		0	
80	Research, Devel. and Demonstration Expend. (188)	352	0	
81	Unamortized Loss on Reaquired Debt (189)		6,768,288	7,512,371
82	Accumulated Deferred Income Taxes (190)	234	256,362,574	216,728,536
83	Unrecovered Purchased Gas Costs (191)		21,025,867	1,433,580
84	Total Deferred Debits (lines 69 through 83)		1,184,626,228	988,276,231
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		6,620,312,538	6,152,522,013

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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	1,341,011,707	1,249,688,206
3	Preferred Stock Issued (204)	250	0	
4	Capital Stock Subscribed (202, 205)		0	
5	Stock Liability for Conversion (203, 206)		0	
6	Premium on Capital Stock (207)		0	
7	Other Paid-In Capital (208-211)	253	(10,696,711)	(10,696,711)
8	Installments Received on Capital Stock (212)	252	0	
9	(Less) Discount on Capital Stock (213)	254	0	
10	(Less) Capital Stock Expense (214)	254b	(49,837,072)	(47,076,877)
11	Retained Earnings (215, 215.1, 216)	118	781,020,474	771,613,505
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118	4,609,991	(13,577,380)
13	(Less) Reaquired Capital Stock (217)	250	0	
14	Noncorporate Proprietorship (Non-major only) (218)		0	
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	(11,038,551)	(14,378,164)
16	Total Proprietary Capital (lines 2 through 15)		2,154,743,982	2,029,726,333
17	**LONG-TERM DEBT**			
18	Bonds (221)	256	2,157,200,000	2,017,200,000
19	(Less) Reaquired Bonds (222)	256	83,700,000	83,700,000
20	Advances from Associated Companies (223)	256	51,547,000	51,547,000
21	Other Long-Term Debt (224)	256	0	
22	Unamortized Premium on Long-Term Debt (225)		124,367	133,250
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		757,032	843,651
24	Total Long-Term Debt (lines 18 through 23)		2,124,414,335	1,984,336,599
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases - Noncurrent (227)		66,068,171	67,716,314
27	Accumulated Provision for Property Insurance (228.1)		0	
28	Accumulated Provision for Injuries and Damages (228.2)		731,009	395,000
29	Accumulated Provision for Pensions and Benefits (228.3)		153,467,368	211,880,117
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	
31	Accumulated Provision for Rate Refunds (229)		409,971	3,820,594
32	Long-Term Portion of Derivative Instrument Liabilities		4,525,064	37,427,278
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	
34	Asset Retirement Obligations (230)		17,141,793	17,194,050
35	Total Other Noncurrent Liabilities (lines 26 through 34)		242,343,376	338,433,353
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Notes Payable (231)		284,000,000	202,000,000
38	Accounts Payable (232)		127,662,677	104,217,591
39	Notes Payable to Associated Companies (233)		1,404,713	8,742,915
40	Accounts Payable to Associated Companies (234)		18,595	
41	Customer Deposits (235)		3,702,706	3,028,142
42	Taxes Accrued (236)	262	41,669,378	45,266,874
43	Interest Accrued (237)		16,347,042	15,884,942
44	Dividends Declared (238)		0	
45	Matured Long-Term Debt (239)		0	
46	Matured Interest (240)		0	
47	Tax Collections Payable (241)		137,825	111,813
48	Miscellaneous Current and Accrued Liabilities (242)		69,109,875	60,781,094
49	Obligations Under Capital Leases-Current (243)		4,300,958	4,249,213
50	Derivative Instrument Liabilities (244)		33,326,256	51,435,582
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		4,525,064	37,427,278
52	Derivative Instrument Liabilities - Hedges (245)		0	
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	
54	Total Current and Accrued Liabilities (lines 37 through 53)		577,154,961	458,290,889
55	**DEFERRED CREDITS**			
56	Customer Advances for Construction (252)		3,624,489	2,444,383
57	Accumulated Deferred Investment Tax Credits (255)	266	29,313,176	29,866,627
58	Deferred Gains from Disposition of Utility Plant (256)		0	
59	Other Deferred Credits (253)	269	30,183,652	31,450,029
60	Other Regulatory Liabilities (254)	278	571,662,225	473,121,377

61	Unamortized Gain on Reaquired Debt (257)		1,189,285	1,318,822
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272	0	
63	Accum. Deferred Income Taxes-Other Property (282)		618,900,933	603,415,433
64	Accum. Deferred Income Taxes-Other (283)		266,782,124	200,118,168
65	Total Deferred Credits (lines 56 through 64)		1,521,655,884	1,341,734,839
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		6,620,312,538	6,152,522,013

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

6. Do not report fourth quarter data in columns (e) and (f)
7. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility column in 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.
8. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
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 purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stockholders 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.

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)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
1	UTILITY OPERATING INCOME											
2	Operating Revenues (400)	300	1,495,585,923	1,379,875,645			1,022,015,983	942,731,364	473,569,940	437,144,281		
3	Operating Expenses											
4	Operation Expenses (401)	320	865,148,582	762,581,592			557,603,571	479,296,895	307,545,011	283,284,697		
5	Maintenance Expenses (402)	320	80,137,861	74,568,922			64,169,603	58,433,891	15,968,258	16,135,031		
6	Depreciation Expense (403)	336	177,443,227	181,300,837			136,516,432	142,059,284	40,926,795	39,241,553		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336	0				0		0			
8	Amort. & Depl. of Utility Plant (404-405)	336	53,212,301	44,668,607			39,430,494	32,861,811	13,781,807	11,806,796		
9	Amort. of Utility Plant Acq. Adj. (406)	336	99,047	99,047			99,047	99,047	0			
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		0									
11	Amort. of Conversion Expenses (407.2)		0				0		0			
12	Regulatory Debits (407.3)		14,824,439	12,453,020			9,015,832	8,161,579	5,808,607	4,291,441		
13	(Less) Regulatory Credits (407.4)		52,533,715	57,223,861			46,406,409	47,876,238	6,127,306	9,347,623		
14	Taxes Other Than Income Taxes (408.1)	262	116,909,168	114,634,576			87,398,430	86,303,016	29,510,738	28,331,560		
15	Income Taxes - Federal (409.1)	262	846,571	(41,194,492)			(1,109,426)	(21,919,271)	1,955,997	(19,275,221)		
16	Income Taxes - Other (409.1)	262	876,303	654,441			30,939	(214,113)	845,364	868,554		
17	Provision for Deferred Income Taxes (410.1)	234, 272	151,017,644	134,834,319			88,830,716	83,467,206	62,186,928	51,367,113		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	144,624,499	82,145,804			83,402,751	61,963,304	61,221,748	20,182,500		
19	Investment Tax Credit Adj. - Net (411.4)	266	(553,452)	(577,334)			(548,446)	(562,691)	(5,006)	(14,643)		
20	(Less) Gains from Disp. of Utility Plant (411.6)		0									
21	Losses from Disp. of Utility Plant (411.7)		0									
22	(Less) Gains from Disposition of Allowances (411.8)		0									
23	Losses from Disposition of Allowances (411.9)		0									
24	Accretion Expense (411.10)		0									
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,262,803,477	1,144,653,870			851,628,032	758,147,112	411,175,445	386,506,758	0	
27	Net Util Oper Inc (Enter Tot line 2 less 25)		232,782,446	235,221,775			170,387,951	184,584,252	62,394,495	50,637,523	0	
28	Other Income and Deductions											
29	Other Income											
30	Nonutilty Operating Income											
31	Revenues From Merchandising, Jobbing and Contract Work (415)		0									

32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		0									
33	Revenues From Nonutility Operations (417)		299,756	108,256								
34	(Less) Expenses of Nonutility Operations (417.1)		5,295,279	5,439,625								
35	Nonoperating Rental Income (418)		(31,838)	(31,838)								
36	Equity in Earnings of Subsidiary Companies (418.1)	119	23,555,382	5,304,376								
37	Interest and Dividend Income (419)		3,650,892	3,448,647								
38	Allowance for Other Funds Used During Construction (419.1)		589,900	338,811								
39	Miscellaneous Nonoperating Income (421)		0									
40	Gain on Disposition of Property (421.1)		109,527	289,281								
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		22,878,340	4,017,908								
42	Other Income Deductions											
43	Loss on Disposition of Property (421.2)		0									
44	Miscellaneous Amortization (425)		5,616	(815,484)								
45	Donations (426.1)		2,499,499	2,999,603								
46	Life Insurance (426.2)		3,591,498	3,072,596								
47	Penalties (426.3)		22,039	(17,039)								
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,935,266	1,773,265								
49	Other Deductions (426.5)		4,448,958	3,494,855								
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		12,502,876	10,507,796								
51	Taxes Applic. to Other Income and Deductions											
52	Taxes Other Than Income Taxes (408.2)	262	564,779	923,792								
53	Income Taxes-Federal (409.2)	262	(1,628,247)	(60,470)								
54	Income Taxes-Other (409.2)	262	(472,315)	800								
55	Provision for Deferred Inc. Taxes (410.2)	234, 272	3,042,777	218,831								
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272	2,944,321	3,167,528								
57	Investment Tax Credit Adj.-Net (411.5)		0									
58	(Less) Investment Tax Credits (420)											
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		(1,437,327)	(2,084,575)								
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		11,812,791	(4,405,313)								
61	Interest Charges											
62	Interest on Long-Term Debt (427)		91,728,400	88,943,779								
63	Amort. of Debt Disc. and Expense (428)		941,948	937,453								
64	Amortization of Loss on Reaquired Debt (428.1)		1,592,056	2,222,423								
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)		515,447	186,289								
68	Other Interest Expense (431)		4,860,055	6,170,081								
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		2,367,356	2,152,002								
70	Net Interest Charges (Total of lines 62 thru 69)		97,261,667	96,299,140								
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		147,333,570	134,517,322								
72	Extraordinary Items											
73	Extraordinary Income (434)		0									
74	(Less) Extraordinary Deductions (435)											
75			0									

	Net Extraordinary Items (Total of line 73 less line 74)											
76	Income Taxes-Federal and Other (409.3)	262	0									
77	Extraordinary Items After Taxes (line 75 less line 76)		0									
78	Net Income (Total of line 71 and 77)		147,333,570	134,517,322								

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly report.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, 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 for 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 for 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, attach them at page 122.

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		726,160,557	705,980,176
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
4.1				
4.2				
4.3				
4.4				
4.5				
4.6				
4.7				
4.8				
4.9				
4.10				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Adjustments to Retained Earnings Debit			
10.1				
10.2				
10.3				
10.4				
10.5				
10.6				
10.7				
10.8				
10.9				
10.10				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		123,778,188	129,212,946
17	Appropriations of Retained Earnings (Acct. 436)			
17.1	Excess Earnings		(6,065,368)	(4,274,423)
17.2				
17.3				
17.4				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		(6,065,368)	(4,274,423)
23	Dividends Declared-Preferred Stock (Account 437)			
23.1				
23.2				
23.3				
23.4				
23.5				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
30.1	Dividends Declared - Common Stock		(119,739,230)	(110,253,196)
30.2				
30.3				
30.4				
30.5				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		(119,739,230)	(110,253,196)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		5,368,011	5,495,054
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		729,502,158	726,160,557
39	APPROPRIATED RETAINED EARNINGS (Account 215)			
39.1	Appropriated Retained Earnings		51,518,316	45,452,948
39.2				

39.3				
39.4				
39.5				
39.6				
45	TOTAL Appropriated Retained Earnings (Account 215)		51,518,316	45,452,948
	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)		51,518,316	45,452,948
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		781,020,474	771,613,505
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)		(13,577,380)	(13,386,701)
50	Equity in Earnings for Year (Credit) (Account 418.1)		23,555,382	5,304,376
51	(Less) Dividends Received (Debit)		5,000,000	5,000,000
52	TOTAL other Changes in unappropriated undistributed subsidiary earnings for the year		(368,011)	(495,055)
52.1	Corporate Costs Allocated to Subsidiaries		(368,011)	(495,055)
53	Balance-End of Year (Total lines 49 thru 52)		4,609,991	(13,577,380)

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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 Instructions 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)	147,333,570	134,517,322
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	230,655,529	225,969,444
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of Deferred Power and Natural Gas Costs	(52,577,211)	(9,923,228)
5.2	Amortization of Debt Expense	2,525,120	3,150,992
5.3	Amortization of Investment in Exchange Power		
8	Deferred Income Taxes (Net)	6,486,442	49,739,817
9	Investment Tax Credit Adjustment (Net)	(553,451)	(577,334)
10	Net (Increase) Decrease in Receivables	(25,394,061)	[(d)](51,466,229)
11	Net (Increase) Decrease in Inventory	(16,791,851)	[(e)](464,901)
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	36,379,201	6,150,782
14	Net (Increase) Decrease in Other Regulatory Assets	(12,914,300)	[(f)](9,597,307)
15	Net Increase (Decrease) in Other Regulatory Liabilities	(219,421)	(4,626,804)
16	(Less) Allowance for Other Funds Used During Construction	6,923,631	6,711,875
17	(Less) Undistributed Earnings from Subsidiary Companies	23,555,382	5,304,376
18	Other (provide details in footnote):		
18.1	Other (provide details in footnote):	[(a)](8,217,476)	[(g)]7,562,553
18.2	Allowance for Doubtful Accounts	4,134,701	4,149,939
18.3	Changes in Other Non-Current Assets and Liabilities	(4,576,245)	8,520,219
18.4	Cash Paid for Settlement of Interest Rate Swaps	(17,568,000)	(33,499,271)
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	258,223,534	317,589,743
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(441,862,369)	[(h)](399,504,892)
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):		
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(441,862,369)	[(i)](399,504,892)
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	923,995	570,225
39	Investments in and Advances to Assoc. and Subsidiary Companies	(7,338,616)	[(j)](6,476,269)
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Disposition of Investments in (and Advances to) Associated and Subsidiary Companies		
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		
46	Loans Made or Purchased		
47	Collections on Loans		
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):		
53.1	Other	(45,145)	(1,362,792)
53.2	Dividends Received from Subsidiaries	5,000,000	5,000,000
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(443,322,135)	(401,773,728)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	140,000,000	165,000,000
62	Preferred Stock		

63	Common Stock	89,997,928	72,200,592
64	Other (provide details in footnote):		
66	Net Increase in Short-Term Debt (c)	82,000,000	19,700,000
67	Other (provide details in footnote):		
70	Cash Provided by Outside Sources (Total 61 thru 69)	311,997,928	256,900,592
72	Payments for Retirement of:		
73	Long-term Debt (b)		[(k)](52,000,000)
74	Preferred Stock		
75	Common Stock	(141,494)	
76	Other (provide details in footnote):		
76.1	Other (provide details in footnote):	[(b)](993,608)	[(l)][(m)](2,408,161)
76.2	Debt Issuance Costs	[(c)](2,912,384)	[(n)](3,376,862)
78	Net Decrease in Short-Term Debt (c)		
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	(118,210,572)	[(o)](110,253,196)
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	189,739,870	88,862,373
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	Net Increase (Decrease) in Cash and Cash Equivalents (Total of line 22, 57 and 83)	4,641,269	4,678,388
88	Cash and Cash Equivalents at Beginning of Period	8,632,483	3,954,095
90	Cash and Cash Equivalents at End of Period	13,273,752	8,632,483

FOOTNOTE DATA

(a) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivities

Power and natural gas deferrals 544,574; Change in special deposits (17,564,058); Change in other current assets 2,703,327; Non-cash stock compensation 4,712,916; Gain on sale of property and equipment (109,527); Other 1,171,392; Cash received on interest rate swap 323,900

(b) Concept: OtherRetirementsOfBalancesImpactingCashFlowsFromFinancingActivities

Payment of minimum tax withholdings for share-based payment awards (993,608)

(c) Concept: OtherRetirementsOfBalancesImpactingCashFlowsFromFinancingActivities

Original value: -3376862

(d) Concept: NetIncreaseDecreaseInReceivablesOperatingActivities

Original value: -51466229

(e) Concept: NetIncreaseDecreaseInInventoryOperatingActivities

Original value: -464901

(f) Concept: NetIncreaseDecreaseInOtherRegulatoryAssetsOperatingActivities

Original value: -7416054

(g) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivities

Power and natural gas deferrals 1,092,888Change in special deposits 1,579,362Change in other current assets (861,790)Non-cash stock compensation 5,846,058Gain on sale of property and equipment (289,281)Other 195,316

(h) Concept: GrossAdditionsToUtilityPlantLessNuclearFuelInvestingActivities

Original value: -401686145

(i) Concept: CashOutflowsForPlant

Original value: -401686145

(j) Concept: InvestmentsInAndAdvancesToAssociatedAndSubsidiaryCompanies

Original value: -6476269

(k) Concept: PaymentsForRetirementOfLongTermDebtFinancingActivities

Original value: -52000000

(l) Concept: OtherRetirementsOfBalancesImpactingCashFlowsFromFinancingActivities

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

(m) Concept: OtherRetirementsOfBalancesImpactingCashFlowsFromFinancingActivities

Original value: -2408161

(n) Concept: OtherRetirementsOfBalancesImpactingCashFlowsFromFinancingActivities

Original value: -3376862

(o) Concept: DividendsOnCommonStock

Original value: -110253196

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

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.

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 Resource 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 Systems 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", (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 reported amounts 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, Oregon and Alaska. 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:

	2021	2020
Avista Utilities		
Ratio of depreciation to average depreciable property	3.54%	3.43%

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

	Avista Utilities
Electric thermal/other production	26
Hydroelectric production	81
Electric transmission	50
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 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:

	2021	2020
Avista Corp.	7.19%	7.25%

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 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 assets and liabilities and regulatory assets and liabilities 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 2021or 2020. 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 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):

	2021	2020
Stock-based compensation expense	$ 4,713	$ 5,846
Income tax benefits	990	1,228
Excess tax expenses on settled share-based employee payments	(909)	(165)

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. 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.

The Company accounts for both the TSR awards and CEPS awards 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 CEPS awards was estimated on the date of grant as the share price of Avista Corp. common stock on the date of grant.

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:

	2021	2020
Restricted Shares		
Shares granted during the year	62,594	45,540
Shares vested during the year	34,854	56,203
Unvested shares at end of year	96,127	71,706
Unrecognized compensation expense at end of year		

	2021	2020
(in thousands)	$ 2,215	$ 2,003
TSR Awards		
TSR shares granted during the year	64,910	47,848
TSR shares vested during the year	77,174	71,299
TSR shares earned based on market metrics	58,652	
Unvested TSR shares at end of year	107,854	122,133
Unrecognized compensation expense at end of year (in thousands)	$ 2,653	$ 2,296
CEPS Awards		
CEPS shares granted during the year	64,910	47,848
CEPS shares vested during the year	38,590	35,622
CEPS shares earned based on market metrics	26,627	63,763
Unvested CEPS shares at end of year	107,854	83,464
Unrecognized compensation expense at end of year (in thousands)	$ 1,223	$ 1,090

Outstanding restricted, TSR and CEPS share awards include a dividend component that is paid in cash. A liability for the dividends payable related to these awards is accrued as dividends are announced throughout the life of the award. As of December 31, 2021 and 2020, the Company had recognized a liability of $1.5 million and $0.8 million, respectively, related to the dividend equivalents payable 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 Purchase 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 costs are recovered or returned to customers through retail rates as a component of interest expense.

Appropriated Retained Earnings

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

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

	2021	2020
Appropriated retained earnings	$ 51,518	$ 45,453

Contingencies

The Company has unresolved regulatory, legal and tax issues which have inherently uncertain outcomes. The Company accrues a loss contingency if it is probable that a liability has been incurred and the amount of the loss or impairment can be reasonably estimated. The Company also discloses loss contingencies that do not meet these conditions for accrual, if there is a reasonable possibility that a material loss may be incurred. As of December 31, 2021, 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, 2021, the Company has deferred net costs of $1.1 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):

	2021	2020
Avista Capital	$ 16,645	$ (2,489)
AERC	6,910	7,795
Total equity in earnings of subsidiary companies	$ 23,555	$ 5,307

Subsequent Events

Management has evaluated the impact of events occurring after December 31, 2021 up to February 22, 2022, 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) 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):

	2021	2020
Unbilled accounts receivable	$ 71,752	$ 68,545

Non-Derivative Wholesale Contracts

The Company has certain wholesale contracts which are not accounted for as derivatives and, accordingly, 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 rate regulated sales above.

Alternative Revenue Programs (Decoupling)

ASC 606 retained existing GAAP associated with alternative revenue programs, which specified that alternative revenue programs are contracts between an entity and a regulator of utilities, not a contract between an entity and a customer. GAAP requires that an entity present revenue arising from alternative revenue programs separately from revenues arising from contracts with customers on the face of the Statements of Income. The Company's decoupling mechanisms (also known as a FCA in Idaho) qualify as alternative revenue programs. Decoupling revenue deferrals are recognized in the Statements of Income during the period they occur (i.e. during the period of revenue shortfall or excess due to fluctuations in customer usage), subject to certain limitations, and a regulatory asset or liability is established which will be surcharged or rebated to customers in future periods. GAAP requires that for any alternative revenue program, like decoupling, the revenue must be expected to be collected from customers within 24 months of the deferral to qualify for recognition in the current period 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 specifically 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 that are entered into and settled within the same month.

Other Utility Revenue

Other utility revenue includes rent, sales of materials, late fees and other charges that do not represent contracts with customers. 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

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):

	2021	2020
Utility-related taxes	$ 62,736	$ 59,319

Significant Judgments and Unsatisfied Performance Obligations

The only significant judgments involving revenue recognition are estimates surrounding unbilled revenue and receivables from contracts with customers and estimates surrounding the amount of decoupling revenues that will be collected from customers within 24 months (discussed above).

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. As of December 31, 2021, the Company estimates it had unsatisfied capacity performance obligations of $17.4 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):

	2021	2020
Revenue from contracts with customers	$ 1,244,314	$ 1,168,207
Derivative revenues	247,676	203,099
Alternative revenue programs	(6,635)	(3,814)
Deferrals and amortizations for rate refunds to customers	1,093	4,795
Other utility revenues	9,138	7, 589
Total	1,495,586	1,379,876

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):

	2021	2020
ELECTRIC OPERATIONS		
Revenue from contracts with customers		
Residential	$ 394,717	$ 377,785
Commercial and governmental	326,173	303,972
Industrial	117,165	113,563
Public street and highway lighting	7,472	7,303
Total retail revenue	845,527	802,624
Transmission	21,005	18,236
Other revenue from contracts with customers	33,870	19,252
Total revenue from contracts with customers	$ 900,402	$ 840,112

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):

	2021	2020
NATURAL GAS OPERATIONS		
Revenue from contracts with customers		
Residential	$ 221,405	$ 213,612
Commercial	100,819	94,937
Industrial and interruptible	7,796	7,128
Total retail revenue	330,020	315,677
Transportation	8,547	7,917
Other revenue from contracts with customers	5,345	4,501
Total revenue from contracts with customers	$ 343,912	$ 328,095

NOTE 4. LEASES

ASC 842, outlines a model for entities to use in accounting for leases. 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 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 adjustment - depending on the outcome of ongoing litigation between the State of 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 should return to Avista Corp. 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 72 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, 2021 are immaterial.

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

	2021	2020
Operating lease cost:		
Fixed lease cost	$ 4,970	$ 4,746
Variable lease cost	1,180	1,099
Total operating lease cost	$ 6,150	$ 5,845

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

	2021	2020
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash outflows:		
Operating lease payments	$ 4,805	$ 4,612

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

	December 31, 2021	December 31, 2020
Operating Leases		
Operating lease ROU assets (Utility Plant)	$ 70,133	$ 71,891
Obligations under capital lease - current	$ 4,301	$ 4,249
Obligations under capital lease - noncurrent	66,068	67,716
Total operating lease liabilities	$ 70,369	$ 71,965

Weighted Average Remaining Lease Term		
Operating leases	24.22 years	25.20 years
Weighted Average Discount Rate		
Operating leases	4.28 %	4.28 %

Maturities of lease liabilities (including principal and interest) were as follows as of December 31, 2021 (dollars in thousands):

	Operating Leases
2022	$ 4,820
2023	4,849
2024	4,875
2025	4,882
2026	4,867
Thereafter	91,845
Total lease payments	$ 116,138
Less: imputed interest	(45,769)
Total	$ 70,369

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

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 mitigates the 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 at other times during 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, 2021 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
2022	129		7,114	61,405	234	452	3,933	31,485
2023			378	23,218			1,360	9,323
2024			228	3,413			1,370	228
2025							1,115	

As of December 31, 2021, 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, 2020 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
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 were no expected deliveries of energy commodity derivatives after 2025.

(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 scheduled to be 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. The short term natural gas transactions are 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):

	2021	2020
Number of contracts	25	22
Notional amount (in United States dollars)	$ 8,571	$ 3,860
Notional amount (in Canadian dollars)	10,957	4,949

Interest Rate Swap Derivatives

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

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

Balance Sheet Date	Number of Contracts	Notional Amount	Mandatory Cash Settlement Date
December 31, 2021	13	140,000	2022
	2	20,000	2023
	1	10,000	2024
December 31, 2020	4	45,000	2021
	11	120,000	2022
	1	10,000	2023

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 September 2021.

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, 2021 and December 31, 2020 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, 2021 (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 liabilities current	$	$ (19)	$	$ (19)
Interest rate swap derivatives				
Long-term portion of derivative assets	1,149			1,149
Derivative instrument liabilities current	1,170	(25,196)		(24,026)
Long-term portion of derivative liabilities		(78)		(78)
Energy commodity derivatives				
Derivative instrument assets current	1,506	(107)		1,399
Long-term portion of derivative assets	6,844	(5,335)		1,509
Derivative instrument liabilities current	25,771	(39,616)	9,089	(4,756)
Long-term portion of derivative liabilities	141	(4,589)		(4,448)
Total derivative instruments recorded on the balance sheet	$ 36,581	$ (74,940)	$ 9,089	$ (29,270)

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			
				Net Asset (Liability)

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

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):

	2021	2020
Energy commodity derivatives		
Cash collateral posted	$ 30,567	$ 4,953
Letters of credit outstanding	34,000	23,500
Balance sheet offsetting (cash collateral against net derivative positions)	9,089	616
Interest rate swap derivatives		
Cash collateral posted (offset by net derivative positions)		8,050

There were no letters of credit outstanding related to interest rate swap derivatives as of December 31, 2021 and December 31, 2020.

Certain of Avista Corp.'s derivative instruments contain provisions that require Avista Corp. 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):

	2021	2020
Interest rate swap derivatives		
Liabilities with credit-risk-related contingent features	$ 25,274	$ 50,813
Additional collateral to post	25,274	42,763

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):

	2021	2020
Utility plant in service	$ 395,028	$ 391,922
Accumulated depreciation	(302,220)	(284,282)

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 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 the ratemaking process.

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):

	2021	2020
Asset retirement obligation at beginning of year	$ 17,194	$ 20,338
Liabilities incurred	825	(2,315)
Liabilities settled	(1,541)	(1,645)
Accretion expense	664	816
Asset retirement obligation at end of year	$ 17,142	$ 17,194

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. Employees eligible for the plan continue to accrue benefits. 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 $42.0 million in cash to the pension plan in 2021, and $22.0 million in 2020. The Company expects to contribute $42.0 million in cash to the pension plan in 2022.

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):

	2022	2023	2024	2025	2026	Total 2027-2031
Expected benefit payments	$ 43,282	$ 43,218	$ 43,675	$ 44,319	$ 43,810	$ 228,585

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):

	2022	2023	2024	2025	2026	Total 2027-2031
Expected benefit payments	$ 6,960	$ 7,140	$ 7,291	$ 7,453	$ 7,560	$ 39,646

The Company expects to contribute $7.2 million to other postretirement benefit plans in 2022, 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, 2021 and 2020 and the components of net periodic benefit costs for the years ended December 31, 2021 and 2020(dollars in thousands):

	Pension Benefits		Other Post-retirement Benefits	
	2021	2020	2021	2020
Change in benefit obligation:				
Benefit obligation as of beginning of year	$ 826,915	$ 742,382	$ 161,233	$ 159,296
Service cost	25,306	22,392	4,114	3,902
Interest cost	26,160	27,853	5,139	6,042
Actuarial (gain)/loss	(13,997)	74,688	2,808	(2,589)
Benefits paid	(65,342)	(40,400)	(5,696)	(5,418)
Benefit obligation as of end of year	$ 799,042	$ 826,915	$ 167,598	$ 161,233
Change in plan assets:				
Fair value of plan assets as of beginning of year	$ 722,024	$ 642,063	$ 52,173	$ 44,853
Actual return on plan assets	50,370	96,591	7,371	7,320
Employer contributions	42,000	22,000		
Benefits paid	(63,431)	(38,630)		
Fair value of plan assets as of end of year	$ 750,963	$ 722,024	$ 59,544	$ 52,173
Funded status	$ (48,079)	$ (104,891)	$ (108,054)	$ (109,060)
Amounts recognized in the Balance Sheets:				
Current liabilities	$ (1,951)	$ (1,943)	$ (684)	$ (669)
Non-current liabilities	(46,128)	(102,948)	(107,370)	(108,391)
Net amount recognized	$ (48,079)	$ (104,891)	$ (108,054)	$ (109,060)
Accumulated pension benefit obligation	$ 685,493	$ 710,023		
Accumulated postretirement benefit obligation:				
For retirees			$ 78,347	$ 75,876
For fully eligible employees			$ 32,144	$ 32,097
For other participants			$ 57,107	$ 53,260
Included in accumulated other comprehensive loss (income) (net of tax):				
Unrecognized prior service cost (credit)	$ 1,699	$ 1,902	$ (2,741)	$ (3,570)
Unrecognized net actuarial loss	94,109	119,318	48,872	53,737
Total	95,808	121,220	46,131	50,167
Less regulatory asset	(85,550)	(108,301)	(45,350)	(48,708)
Accumulated other comprehensive loss for unfunded benefit obligation for pensions and other postretirement benefit plans	$ 10,258	$ 12,919	$ 781	$ 1,459

	Pension Benefits		Other Post-retirement Benefits	
	2021	2020	2021	2020
Weighted-average assumptions as of December 31:				
Discount rate for benefit obligation	3.39%	3.25%	3.40%	3.27%
Discount rate for annual expense	3.25%	3.85%	3.27%	3.89%

Expected long-term return on plan assets	5.40%	5.50%	4.60%	5.30%
Rate of compensation increase	4.66%	4.74%		
Medical cost trend pre-age 65 - initial			6.00%	6.25%
Medical cost trend pre-age 65 - ultimate			5.00%	5.00%
Ultimate medical cost trend year pre-age 65			2026	2026
Medical cost trend post-age 65 - initial			6.00%	6.25%
Medical cost trend post-age 65 - ultimate			5.00%	5.00%
Ultimate medical cost trend year post-age 65			2026	2026

			Other Post-retirement Benefits		
	2021	2020		2021	2020
Components of net periodic benefit cost:					
Service cost (a)	$ 25,306	$ 22,392		$ 4,114	$ 3,902
Interest cost	26,160	27,853		5,139	6,042
Expected return on plan assets	(39,088)	(34,886)		(2,400)	(2,377)
Amortization of prior service cost (credit)	257	257		(921)	(958)
Net loss recognition	6,645	6,717		3,865	4,871
Net periodic benefit cost	$ 19,280	$ 22,333		$ 9,797	$ 11,480

(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:

	2021	2020
Equity securities	55%	35%
Debt securities	40%	49%
Real estate	5%	7%
Absolute return	0%	9%

The target investment allocation percentages were revised in the first quarter of 2021 and the pension plan assets were reinvested to move toward the new target investment allocation percentages. 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, 2021 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$	$ 6,259	$	$ 6,259
Fixed income securities:				
U.S. government issues		19,310		19,310
Corporate issues		233,496		233,496
International issues		34,270		34,270
Municipal issues		18,558		18,558
Mutual funds:				
U.S. equity securities	236,552			236,552
International equity securities	112,873			112,873
Plan assets measured at NAV (not subject to hierarchy disclosure)				
Common/collective trusts:				
Real estate				31,040
Partnership/closely held investments:				
Absolute return (1)				363
International equity securities				50,427
Real estate				7,815
Total	$ 349,425	$ 311,893	$	$ 750,963

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

(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. For investment securities for which market prices are not readily available, the investment manager will determine fair value 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 2021 and 2020.

The fair value of other postretirement plan assets was determined as of December 31, 2021 and 2020.

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, 2021 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Balanced index mutual fund (1)	$ 59,545	$	$	$ 59,545

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

(1)The balanced index fund for 2021 and 2020 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):

	2021	2020
Employer 401(k) matching contributions	$ 11,671	$ 11,742

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):

	2021	2020
Deferred compensation assets and liabilities	$ 9,513	$ 9,174

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, 2021, the Company had $17.1 million of state tax credit carryforwards. Of the total amount, the Company believes that it is more likely than not that it will only be able to utilize $7.5 million of the state tax credits. As such, the Company has recorded a valuation allowance of $9.6 million against the state tax credit carryforwards and reflected the net amount of $7.5 million as an asset as of December 31, 2021. State tax credits expire from 2022 to 2035.

Status of Internal Revenue Service (IRS) and State Examinations

The Company and its eligible subsidiaries file consolidated federal income tax returns. All tax years after 2017 are open for an IRS tax examination.

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

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

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):

	2021	2020
Utility power resources	$ 431,199	$ 324,297

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):

	2022	2023	2024	2025	2026	Thereafter	Total
Power resources	$ 198,052	$ 187,552	$ 200,693	$ 193,877	$ 184,230	$ 1,888,038	$ 2,852,442
Natural gas resources	87,228	66,508	42,581	36,423	32,094	382,981	647,815
Total	$ 285,280	$ 254,060	$ 243,274	$ 230,300	$ 216,324	$ 2,271,019	$ 3,500,257

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 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, 2021 (principal and interest) was $278.3 million.

In addition, Avista Corp. has operating agreements, settlements and other contractual obligations related to its generating facilities and transmission and distribution services. The 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):

	2022	2023	2024	2025	2026	Thereafter	Total
Contractual obligations	$ 28,912	$ 29,680	$ 30,471	$ 31,287	$ 32,127	$ 212,852	$ 365,329

NOTE 11. NOTES PAYABLE

Avista Corp. has a committed line of credit with various financial institutions in the total amount of $400.0 million. In June 2021, the Company entered into an amendment to its committed line of credit that extends the expiration date to June 2026, with the option to extend for an additional one year period (subject to customary conditions). 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 "total debt" to "total capitalization" of Avista Corp. to be greater than 65 percent at any time. As of December 31, 2021, 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):

	2021	2020
Balance outstanding at end of period	$ 284,000	$ 102,000
Letters of credit outstanding at end of period	$ 34,000	$ 27,618
Average interest rate at end of period	1.11%	1.22%

As of December 31, 2021 and 2020, 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. The Company borrowed the entire $100 million available under this agreement in April 2020 and repaid the outstanding balance in April 2021.

NOTE 13. BONDS

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

Maturity Year	Description	Interest Rate	2021	2020
Avista Corp. Secured Long-Term Debt				
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	3.07%	165,000	165,000
2051	First Mortgage Bonds	3.54%	175,000	175,000
2051	First Mortgage Bonds (2)	2.90%	140,000	
	Total Avista Corp. secured long-term bonds		2,157,200	2,017,200
	Secured Pollution Control Bonds held by Avista Corporation (1)		(83,700)	(83,700)
	Total long-term bonds		$ 2,073,500	$ 1,933,500

(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 2021, the Company issued and sold $70.0 million of 2.90 percent first mortgage bonds due in 2051 pursuant to a bond purchase agreement with institutional investors in the private placement market. In December 2021, the Company issued and sold the remaining $70.0 million of bonds pursuant to the same agreement. The total net proceeds from the sale of the bonds were used to 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 September 2021, the Company cash settled four interest rate swap derivatives (notional aggregate amount of $45.0 million) and paid a net amount of $17.2 million. See Note 7 for a discussion of interest rate swap derivatives.

The following table details future long-term debt maturities including long-term debt to affiliated trusts (see Note 14) (dollars in thousands):

	2022	2023	2024	2025	2026	Thereafter	Total
Debt maturities	$ 250,000	$ 13,500	$	$	$	$ 1,810,000	$ 2,073,500

Substantially all of Avista Corp.'s owned properties are subject to the lien of iyd mortgage indenture. Under the Mortgage and Deed of Trust (Mortgage) securing its first mortgage bonds (including secured medium-term notes), Avista Corp.'s may each issue additional first mortgage bonds under their specific 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 of that entity which have not previously been made the basis of any application under that entity's Mortgage, or
- an equal principal amount of retired first mortgage bonds of that entity which have not previously been made the basis of any application under that entity's 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 the particular entity issuing the bonds 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, 2021, property additions and retired bonds would have allowed, and the net earnings test would not have prohibited, the issuance of $1.8 billion in an aggregate principal amount of additional first mortgage bonds at an assumed interest rate of 8 percent.

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:

	2021	2020
Low distribution rate	0.99%	1.10%
High distribution rate	1.10%	2.79%
Distribution rate at the end of the year	1.05%	1.10%

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):

	2021		2020	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Long-term debt (Level 2)	$ 963,500	$ 1,157,651$	963,500	$ 1,189,824
Long-term debt (Level 3)	1,110,000	1,258,674	1,970,000	1,125,618
Long-term debt to affiliated trusts (Level 3)	51,547	43,299	51,547	43,815

These estimates of fair value of long-term debt and long-term debt to affiliated trusts were primarily based on available market information, which generally consists of estimated market prices from third party brokers for debt with similar risk and terms. The price ranges obtained from the third party brokers consisted of par values of 84.0 to 140.27, where a par value of 100.00 represents the carrying value recorded on the Balance Sheets. Level 2 long-term debt represents publicly issued bonds with quoted market prices; however, due to their limited trading activity, they are classified as Level 2 because brokers must generate quotes and make estimates using comparable debt with similar risk and terms if there is no trading activity near a period end. Level 3 long-term debt consists of private placement bonds and debt to affiliated trusts, which typically have no secondary trading activity. Fair values in Level 3 are estimated based on market prices from third party brokers using secondary market quotes for debt with similar risk and terms to generate quotes for Avista Corp. bonds.

The following table discloses by level within the fair value hierarchy the Company's assets and liabilities measured and reported on the Balance Sheets as of December 31, 2021 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, 2021					
Assets:					
Energy commodity derivatives	$	$ 34,119	$	$ (31,211)	$ 2,908
Level 3 energy commodity derivatives:					
Natural gas exchange agreements			143	(143)	
Interest rate swap derivatives		2,319		(1,170)	1,149
Deferred compensation assets:					
Mutual Funds:					
Fixed income securities	1,809				1,809
Equity securities	7,594				7,594
Total	$ 9,403	$ 36,438	$ 143	$ (32,524)	$ 13,460
Liabilities:					
Energy commodity derivatives	$	$ 41,733	$	$ (40,300)	$ 1,433
Level 3 energy commodity derivatives:					
Natural gas exchange agreement			7,914	(143)	7,771
Foreign currency exchange derivatives		19			19
Interest rate swap derivatives		25,274		(1,170)	24,104
Total	$	$ 67,026	$ 7,914	$ (41,613)	$ 33,327

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:					

Level 3 energy commodity derivatives:					
Natural gas exchange agreement			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

(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 $0.1 million as of December 31, 2021 and $0.5 million as of December 31, 2020.

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, 2021 (dollars in thousands):

	Fair Value (Net) at December 31, 2021	Valuation Technique	Unobservable Input	Range
Natural gas exchange	(7,771)	Internally derived weighted average cost of gas	Forward purchase prices	$2.35 - $4.08/mmBTU $2.96 Weighted Average
			Forward sales prices	$2.38 - $9.50/mmBTU $4.51 Weighted Average
			Purchase volumes	130,000 - 310,000 mmBTUs
			Sales volumes	25,000 - 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, 2021:			
Balance as of January 1, 2021	$ (8,410)	$	$ (8,410)
Total gains or (losses) (realized/unrealized):			
Included in regulatory assets (1)	4,292		4,292
Settlements	(3,653)		(3,653)
Ending balance as of December 31, 2021 (2)	$ (7,771)	$	$ (7,771)
Year ended December 31, 2020:			
Balance as of January 1, 2020	$ (2,976)	$	$ (2,976)
Total gains or (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)

(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, 2021 was $322.3 million.

The Company has 10 million authorized shares of preferred stock. The Company did not have any preferred stock outstanding as of December 31, 2021 and 2020.

Common Stock Issuances

The Company issued common stock in 2021 for total net proceeds of $90.0 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 4.3 million shares under these agreements, of which 2.1 million remain unissued as of December 31, 2021. In 2021, 2.2 million shares were issued under these agreements resulting in total net proceeds of $88.5 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. The Company's largest represented group, representing approximately 90 percent of Avista Corp.'s bargaining unit employees in Washington and Idaho, were covered under a three-year agreement which expired in March 2021. In March 2022, a new four-year collective bargaining agreement was reached with the IBEW. The new agreement is retroactive to March 2021 and expires in March 2025. The new agreement's impact on the financial statements was consistent with management's expectations.

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 continues to vigorously defend itself in the litigation. However, the Company cannot predict the outcome of these matters.

Road 11 Fire

On April 13, 2022, Avista Corp. received a notice of claim from a property owner seeking damages in connection with a fire that occurred in Douglas County, Washington, just west of State Route 172, on July 11, 2020. The fire, which was designated as the "Road 11 Fire," occurred in the vicinity of Avista Corp.'s Chelan-Stratford 115kv line, resulting in damage to three overhead transmission structures. The fire occurred during a high wind event and grew to 10,000 acres before being contained. The property owner's notice of claims states that they are seeking damages of $5 million. The Company disputes that it is liable for the fire, and will vigorously defend itself in any legal action that might be commenced in connection with the same.

Labor Day Windstorm

General

In September 2020, a severe windstorm occurred in eastern Washington and northern Idaho. The extreme weather event resulted in customer outages and multiple wildfires in the region.

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. With respect to the Christensen Road Fire and the Mile Marker 49 Fire, 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. See further discussion below regarding the Babb Road Fire.

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.

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.

Babb Road Fire

On May 14, 2021 the Company learned that the Washington Department of Natural Resources (DNR) had completed its investigation and issued a report on the Babb Road Fire. The Babb Road fire covered approximately 15,000 acres and destroyed approximately 220 structures. There are no reports of personal injury or death resulting from the fire.

The DNR report concluded, among other things, that

- the fire was ignited when a branch of a multi-dominant Ponderosa Pine tree was broken off by the wind and fell on an Avista Corp. distribution line;
- the tree was located approximately 30 feet from the center of Avista Corp.'s distribution line and approximately 20 feet beyond Avista Corp.'s right-of-way;
- the tree showed some evidence of insect damage, damage at the top of the tree from porcupines, a small area of scarring where a lateral branch/leader (LBL) had broken off in the past, and some past signs of Gall Rust disease.

The DNR report concluded as follows: "It is my opinion that because of the unusual configuration of the tree, and its proximity to the powerline, a closer inspection was warranted. A nearer inspection of the tree should have revealed the cut LBL ends and its previous failure, and necessitated determination of the failure potential of the adjacent LBL, implicated in starting the Babb Road Fire."

The DNR report acknowledged that, other than the multi-dominant nature of the tree, the conditions mentioned above would not have been easily visible without close-up inspection of, or cutting into, the tree. The report also acknowledged that, while the presence of multiple tops would have been visible from the nearby roadway, the tree did not fail at a v-fork due to the presence of multiple tops. The Company contends that applicable inspection standards did not require a closer inspection of the otherwise healthy tree, nor was the Company negligent with respect to its maintenance, inspection or vegetation management practices.

Five lawsuits seeking unspecified damages have been filed in connection with the Babb Road fire. These include a negligence action filed in the Superior Court of Spokane County, Washington on behalf approximately 44 individual plaintiffs; negligence-based subrogation actions filed in the Superior Courts of Spokane and Whitman County, Washington on behalf of 23 insurance carriers; and a class action lawsuit filed in the Superior Court of Spokane County Washington alleging negligence, private nuisance, trespass and inverse condemnation. The Company intends to vigorously defend itself in all such legal proceedings.

Colstrip

Colstrip Owners Arbitration and Litigation

Colstrip Units 3 & 4 are jointly owned by the Company, Puget Sound Energy (PSE), Pacificorp, Portland General Electric (PGE) (collectively, the "Western Co-Owners"), as well as NorthWestern and Talen, and are operated pursuant to an Ownership and Operating Agreement dated May 6, 1981, as amended (O&O Agreement). Avista Corp. is a 15 percent owner in Units 3 & 4. No single owner owns more than 30 percent of either generating unit.

The Washington Clean Energy Transformation Act (CETA) imposes deadlines by which coal-fired resources, such as Colstrip, must be excluded from the rate base of Washington utilities and by which electricity from such resources may no longer be delivered to Washington retail customers. The co-owners of Colstrip have differing needs for the generating capacity of these units. Accordingly, business disagreements have arisen among the co-owners, including, but not limited to, disagreements as to the shut-down date or dates of these units. These business disagreements, in turn, have led to disagreements as to the interpretation of the O&O Agreement, including, but not limited to, what percentage voting requirement under the O&O Agreement (55 percent vs. 100 percent) is needed to remove one or more of the Colstrip units from service or to make a determination that the project can no longer be operated consistent with prudent utility practice or the requirements of governmental agencies having jurisdiction. These disagreements are the subject of pending litigation in Montana Federal District Court in which the Western Co-Owners are plaintiffs and NorthWestern and Talen are defendants, as well as in the Montana District for Yellowstone County, in which Talen is the plaintiff and the Western Co-Owners and NorthWestern are defendants.

In addition, there are legal proceedings pending in Montana Federal District Court with respect to the validity and constitutionality of changes to Montana law enacted in 2021 after the foregoing disputes arose. The Western Co-Owners are plaintiffs in those proceedings and NorthWestern and Talen are defendants. The changes to Montana law at issue purport to (a) dictate the location of any arbitration under the O&O Agreement, overriding the express provisions of that agreement; and (b) define actions relating to closing or not operating Colstrip as violations of Montana's Consumer Protection Act. These legal proceedings remain pending.

The Company is not able to predict the outcome, nor an amount or range of potential impact in the event of an outcome that is adverse to the Company's interests. However, the Company will continue to vigorously defend and protect its interests (and those of its stakeholders) in all legal proceedings relating to Colstrip.

Burnett et al. v. Talen et al.

Multiple property owners have initiated a legal proceeding (titled *Burnett et al. v. Talen et al.*) in the Montana District Court for Rosebud County against Talen, PSE, Pacificorp, PGE, Avista Corp., NorthWestern, and Westmoreland Rosebud Mining. The plaintiffs allege a failure to contain coal dust in connection with the operation of Colstrip, and seek unspecified damages. The Company will vigorously defend itself in the litigation, but at this time is unable to predict the outcome, nor an amount or range of potential impact in the event of an outcome that is adverse to the Company's interests.

Westmoreland Mine Permits

Two lawsuits have been commenced by the Montana Environmental Information Center, challenging certain permits relating to the operation of the Westmoreland Rosebud Mine, which provides coal to Colstrip. The first, filed in the Montana District Court for Rosebud County, challenges the approval, by the Montana Board of Environmental Review, of a permit for mining what is designated as the "AM4" area of the mine, alleging procedural flaws in the approval process and substantive errors in its assessment of environmental impacts. On January 28, 2022, the Montana District Court for Rosebud County issued an order vacating the AM4 permit but deferring the annulment until April 1, 2022.

The second proceeding, filed in the Montana Federal District Court, challenged the Office of Surface Mining Reclamation and Enforcement's decision approving Westmoreland's expansion of the mine into what is designated as "Area F" on the grounds that it violated the National Environmental Protection Act and the Endangered Species Act. On February 11, 2022, a Magistrate Judge issued findings and recommended that approval decision be vacated but that the annulment be delayed for 365 days from the date of a final order.

Avista Corp. is not a party to either of these proceedings. Avista Corp. is continuing to monitor the progress of both lawsuits and assess the impact, if any, of the proceedings on Westmoreland's ability to meet its contractual coal supply obligations.

National Park Service (NPS) - Natural and Cultural Damage Claim

In March 2017, the Company accessed property managed by the National Park Service (NPS) to prevent the imminent failure of a power pole that was surrounded by flood water in the Spokane River. The Company voluntarily reported its actions to the NPS several days later. Thereafter, in March 2018, the NPS notified the Company that it might seek recovery for unspecified costs and damages allegedly caused during the incident pursuant to the System Unit Resource Protection Act (SURPA), 54 U.S.C. 100721 et seq. In January 2021, the United States Department of Justice (DOJ) requested that the Company and the DOJ renew discussions relating to the matter. In July 2021, the DOJ communicated that it may seek damages of approximately $2 million in connection with the incident for alleged damage to "natural and cultural resources". In addition, the DOJ indicated that it may seek treble damages under the SURPA and state law, bringing its total potential claim to approximately $6 million.

The Company disputes the position taken by the DOJ with respect to the incident, as well as the nature and extent of the DOJ's alleged damages, and will vigorously defend itself in any litigation that may arise with respect to the matter. The Company and the DOJ have agreed to engage in discussions to understand their respective positions and determine whether a resolution of the dispute may be possible. However, the Company cannot predict the outcome of the matter.

Rathdrum, Idaho Natural Gas Incident

In October 2021, there was an incident in Rathdrum, Idaho involving the Company's natural gas infrastructure. The incident occurred after a third party damaged those facilities during the course of excavation work. The incident resulted in a fire which destroyed one residence and resulted in minor injuries to the occupants. At this time, the Company is unable to predict the likelihood of a claim arising out of the matter, nor an amount or range of a potential loss, if any, in the event of such a claim.

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.

The Company has potential liabilities under the Endangered Species Act and similar state statutes 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 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 2021, the Company recognized a pre-tax expense of $7.7 million under the ERM in Washington compared to a benefit of $6.2 million for 2020. Total net deferred power costs under the ERM were a liability of $11.9 million as of December 31, 2021 and a liability of $37.9 million as of December 31, 2020. 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 $10.8 million as of December 31, 2021 and $2.5 million as of December 31, 2020. 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 $21.0 million as of December 31, 2021 and $1.4 million as of December 31, 2020. 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 rate of return (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.

The Company has proposed to modify this earnings test in its 2022 general rate case, so that if the Company earns more than 0.5 percent higher than the ROR authorized by the WUTC in the multi-year rate plan, the Company would defer these excess revenues and later return them to customers.

Idaho FCA and Earnings Sharing Mechanisms

In Idaho, the IPUC approved the implementation of FCAs for electric and natural gas through March 31, 2025.

Oregon Decoupling Mechanism

In Oregon, the Company has a decoupling mechanism for natural gas. 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 return on earnings, 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.

Cumulative Decoupling and Earnings Sharing Mechanism Balances

As of December 31, 2021 and December 31, 2020, the Company had the following cumulative balances outstanding related to decoupling and earnings sharing mechanisms in its various jurisdictions (dollars in thousands):

	December 31, 2021		December 31, 2020	
Washington				
Decoupling surcharge	$	13,522	$	21,340
Idaho				
Decoupling (rebate) surcharge	$	(1,450)	$	1,202
Provision for earnings sharing rebate		(686)		(686)
Oregon				
Decoupling surcharge (rebate)	$	3,152	$	(1,262)

There were no earnings sharing rebates associated with Washington and Oregon as of December 31, 2021 and December 31, 2020.

19. SUPPLEMENTAL CASH FLOW INFORMATION

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

		2021		2020
Cash paid for interest	$	92,143	$	91,188
Cash paid for income taxes		1,476		701
Cash received for income tax refunds		(22,330)		(984)

NOTE 20. SUBSEQUENT EVENTS

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

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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)	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 116, Line 78) (i)	Total Comprehensive Income (j)
1	Balance of Account 219 at Beginning of Preceding Year		(10,258,024)					(10,258,024)		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income							0		
3	Preceding Quarter/Year to Date Changes in Fair Value		(4,120,140)					(4,120,140)		
4	Total (lines 2 and 3)	0	(4,120,140)					(4,120,140)	134,517,322	130,397,182
5	Balance of Account 219 at End of Preceding Quarter/Year	0	(14,378,164)					(14,378,164)		
6	Balance of Account 219 at Beginning of Current Year	0	(14,378,164)					(14,378,164)		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income							0		
8	Current Quarter/Year to Date Changes in Fair Value		3,339,613					3,339,613		
9	Total (lines 7 and 8)		3,339,613					3,339,613	147,333,570	150,673,183
10	Balance of Account 219 at End of Current Quarter/Year	0	(11,038,551)					(11,038,551)		

Name of Respondent:	This report is:	Date of Report:	Year/Period of Report
Avista Corporation	(1) ☑ An Original (2) ☐ A Resubmission	04/15/2022	End of: 2021/ 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)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)
1	UTILITY PLANT							
2	In Service							
3	Plant in Service (Classified)	6,983,399,354	4,775,009,486	1,487,315,761				721,074,107
4	Property Under Capital Leases	70,132,733						[(a)]70,132,733
5	Plant Purchased or Sold							
6	Completed Construction not Classified							
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	7,053,532,087	4,775,009,486	1,487,315,761				791,206,840
9	Leased to Others							
10	Held for Future Use	18,875,451	17,420,225	190,585				1,264,641
11	Construction Work in Progress	196,305,682	170,124,544	6,889,479				19,291,659
12	Acquisition Adjustments	268,032	268,032					
13	Total Utility Plant (8 thru 12)	7,268,981,252	4,962,822,287	1,494,395,825				811,763,140
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	2,465,058,317	1,740,009,100	447,762,096				277,287,121
15	Net Utility Plant (13 less 14)	4,803,922,935	3,222,813,187	1,046,633,729				534,476,019
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	2,274,836,782	1,705,515,338	447,029,979				122,291,465
19	Amortization and Depletion of Producing Natural Gas Land and Land Rights							
20	Amortization of Underground Storage Land and Land Rights							
21	Amortization of Other Utility Plant	190,221,535	34,493,762	732,117				154,995,656
22	Total in Service (18 thru 21)	2,465,058,317	1,740,009,100	447,762,096				277,287,121
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	Amortization of Plant Acquisition Adjustment							
33	Total Accum Prov (equals 14) (22,26,30,31,32)	2,465,058,317	1,740,009,100	447,762,096				277,287,121

FOOTNOTE DATA

(a) Concept: UtilityPlantInServicePropertyUnderCapitalLeases

Total of $70,132,733 relates to ROU Assets booked due to ASC 842

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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 the 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) 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.

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
1	1. INTANGIBLE PLANT						
2	(301) Organization						
3	(302) Franchise and Consents	46,691,581	505			90,840	46,782,926
4	(303) Miscellaneous Intangible Plant	31,934,915	7,999,471	785,814		733,976	39,882,548
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	78,626,496	7,999,976	785,814		824,816	86,665,474
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights	3,863,336	(5,753)				3,857,583
9	(311) Structures and Improvements	140,719,044	562,483	70,814		(3,279)	141,207,434
10	(312) Boiler Plant Equipment	193,639,431	3,993,794	3,621,626		(3,612)	194,007,987
11	(313) Engines and Engine-Driven Generators	1,080,879	(539,819)				541,060
12	(314) Turbogenerator Units	58,189,080	1,722,060			(2,501)	59,908,639
13	(315) Accessory Electric Equipment	30,840,159	578,483	10,276		(3,775)	31,404,591
14	(316) Misc. Power Plant Equipment	17,640,074	(539,839)			126	17,100,361
15	(317) Asset Retirement Costs for Steam Production	14,711,074	825,177				15,536,251
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	460,683,077	6,596,586	3,702,716		(13,041)	463,563,906
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	64,899,349	1,068,867	79,240			65,888,976
28	(331) Structures and Improvements	98,195,701	6,674,544	94,427		681,001	105,456,819
29	(332) Reservoirs, Dams, and Waterways	193,977,040	1,339,113	40,142		623,335	195,899,346
30	(333) Water Wheels, Turbines, and Generators	234,353,977	1,155,042	743,568		(179,658)	234,585,793
31	(334) Accessory Electric Equipment	75,374,302	6,670,131	580,676		(72,807)	81,390,950
32	(335) Misc. Power Plant Equipment	13,042,016	185,003	50,469		(10,837)	13,165,713
33	(336) Roads, Railroads, and Bridges	3,649,100				(489)	3,648,611
34	(337) Asset Retirement Costs for Hydraulic Production						
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	683,491,485	17,092,700	1,588,522		1,040,545	700,036,208
36	D. Other Production Plant						
37	(340) Land and Land Rights	905,167					905,167
38	(341) Structures and Improvements	17,439,411	22,991	95,069		(266)	17,367,067
39	(342) Fuel Holders, Products, and Accessories	21,069,206	512			(263)	21,069,455
40	(343) Prime Movers	23,507,372	(2,064,158)			689	21,443,903
41	(344) Generators	221,122,751	16,825,057	403,437		(732)	237,543,639
42	(345) Accessory Electric Equipment	22,541,451	3,159,955	30,669		(1,347)	25,669,390
43	(346) Misc. Power Plant Equipment	1,641,386	257			374	1,642,017
44	(347) Asset Retirement Costs for Other Production	351,683					351,683
44.1	(348) Energy Storage Equipment - Production						
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	308,578,427	17,944,614	529,175		(1,545)	325,992,321
46		1,452,752,989	41,633,900	5,820,413		1,025,959	1,489,592,435

	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)						
47	3. Transmission Plant						
48	(350) Land and Land Rights	30,964,535	(966,709)			68,483	30,066,309
48.1	(351) Energy Storage Equipment - Transmission						
49	(352) Structures and Improvements	28,655,332	1,609,883	1,227		6,885	30,270,873
50	(353) Station Equipment	311,464,032	42,550,310	5,620,842		(92,840)	348,300,660
51	(354) Towers and Fixtures	17,253,303	24,848			233	17,278,384
52	(355) Poles and Fixtures	299,324,482	32,901,678	1,734,967		(50,861)	330,440,332
53	(356) Overhead Conductors and Devices	165,777,290	10,185,335	1,862,679		(20,319)	174,079,627
54	(357) Underground Conduit	3,830,622	(305,937)				3,524,685
55	(358) Underground Conductors and Devices	3,178,541	4,339,736	366,405		741	7,152,613
56	(359) Roads and Trails	2,153,985	404,762			(218)	2,558,529
57	(359.1) Asset Retirement Costs for Transmission Plant						
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	862,602,122	90,743,906	9,586,120		(87,896)	943,672,012
59	4. Distribution Plant						
60	(360) Land and Land Rights	18,139,966	(4,914,748)			7,171	13,232,389
61	(361) Structures and Improvements	34,830,606	(6,635,169)	18,098		(21,480)	28,155,859
62	(362) Station Equipment	156,517,973	5,263,691	791,916		18,840	161,008,588
63	(363) Energy Storage Equipment – Distribution	2,428,752	1,685	2,599,530		169,093	0
64	(364) Poles, Towers, and Fixtures	461,243,463	37,419,786	1,512,289		(13,592)	497,137,368
65	(365) Overhead Conductors and Devices	298,797,672	20,262,886	114,645		(49,276)	318,896,637
66	(366) Underground Conduit	133,960,477	10,004,169	33,255		(1,585)	143,929,806
67	(367) Underground Conductors and Devices	232,245,687	19,334,055	267,202		(13,926)	251,298,614
68	(368) Line Transformers	293,764,412	14,422,269	203,249		(3,013)	307,980,419
69	(369) Services	190,188,557	11,222,444	121,631		(310)	201,289,060
70	(370) Meters	82,138,055	3,081,141	298,687		58,884	84,979,393
71	(371) Installations on Customer Premises	3,125,624	191,506			916	3,318,046
72	(372) Leased Property on Customer Premises						
73	(373) Street Lighting and Signal Systems	69,804,366	5,731,634	581,609		(54)	74,954,337
74	(374) Asset Retirement Costs for Distribution Plant						
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,977,185,610	115,385,349	6,542,111		151,668	2,086,180,516
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				378,388	885,665
87	(390) Structures and Improvements	10,633,456	9,582,051	96,760		46,748	20,165,495
88	(391) Office Furniture and Equipment	1,985,065	(239,949)	253,005		454,423	1,946,534
89	(392) Transportation Equipment	52,859,185	3,428,256	1,227,252		33,667	55,093,856
90	(393) Stores Equipment	387,400	85,318			66	472,784
91	(394) Tools, Shop and Garage Equipment	6,806,217	765,051	84,502		20,854	7,507,620
92	(395) Laboratory Equipment	1,898,077	1,201,817			(223)	3,099,671
93	(396) Power Operated Equipment	30,983,867	55,985	783,800		440	30,256,492
94	(397) Communication Equipment	47,822,654	2,913,024	1,780,033		226,877	49,182,522
95	(398) Miscellaneous Equipment	278,483	14,577	4,784		134	288,410
96	SUBTOTAL (Enter Total of lines 86 thru 95)	154,161,681	17,806,130	4,230,136		1,161,374	168,899,049
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)	154,161,681	17,806,130	4,230,136		1,161,374	168,899,049
100	TOTAL (Accounts 101 and 106)	4,525,328,898	273,569,261	26,964,594		3,075,921	4,775,009,486
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)	4,525,328,898	273,569,261	26,964,594		3,075,921	4,775,009,486

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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	Transmission Plant Land, Spokane, Washington	07/01/2014	12/31/2026	62,168
3	Transmission Plant Land, Sandpoint, Idaho	07/01/2019	12/31/2026	486,299
4	Distribution Plant Land, Spokane, Washington	03/01/2011	12/31/2026	540,307
5	Transmission Plant Land, Spokane, Washington	01/01/2017	12/31/2026	56,311
6	Distribution Plant Land, Cheney, Washington	05/01/2021	12/31/2026	5,072,099
7				
8	Distribution Plant Land, Carlin Bay, Idaho	12/01/2010	12/31/2026	162,352
9	Steam Production Plant Land, Spokane, Washington	12/01/2015	12/31/2026	3,544,725
10	Transmission Plant Land, Spokane, Washington	12/01/2011	12/31/2026	411,202
11	Transmission Plant Land, Noxon, Montana	03/01/2016	12/31/2026	3,241,366
12	Distribution Plant Land, Spokane, Washington	06/01/2019	12/31/2026	2,889,619
13	Distribution Plant Land, Coeur d'Alene, Idaho	11/01/2020	12/31/2026	775,530
14	Other Production Plant Land, Spokane, Washington	12/01/2011	12/31/2026	40,896
15	Distribution Plant Land, Colville, Washington	06/01/2019	12/31/2026	104,527
21	Other Property:			
22	Distribution Structure and Improvement Spokane, Washington	07/01/2019	12/31/2026	32,824
47	TOTAL			17,420,225

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	50,775,001
2	KF Fuel Yard Equipment Replacement	19,103,619
3	Saddle Mountain Integration Phase 2	18,182,274
4	Substation Rebuilds	15,997,825
5	Energy Imbalance Market	6,770,153
6	Long Lake Plant Upgrades	4,296,130
7	Colstrip Capital Additions	3,867,132
8	Transportation Equip	3,518,270
9	Clark Fork Implement PME Agreement	3,477,378
10	LL HED Stability Enhancement	3,212,244
11	N Lewiston Auto Replacement	2,827,298
12	New Substations	2,766,267
13	Cabinet Gorge Unit 4 Protection & Control Upgrade	2,199,403
14	CG HED Station Service Replacement	2,150,842
15	HMI Control Software	1,869,049
16	Distribution Line Relocations	1,750,656
17	Distribution - Spokane North & West	1,657,940
18	Lolo-Oxbow 230kV Transmission Line Rebuild Project	1,235,798
19	SCADA to all Substations	1,120,756
20	Downtown Network - Performance & Capacity	1,100,416
21	Substation Asset Mgmt Capital Maintenance	1,057,650
22	Minor Projects under $1,000,000	15,768,978
23	R&D/Strategic Initiatives	5,419,465
43	Total	170,124,544

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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 12, column (c), and that reported for electric plant in service, page 204, column (d), 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.

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)
	Section A. Balances and Changes During Year				
1	Balance Beginning of Year	1,607,056,988	1,607,056,988		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	136,516,432	136,516,432		
4	(403.1) Depreciation Expense for Asset Retirement Costs	0			
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	4,710,300	4,710,300		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9.1					
9.2					
9.3					
9.4					
9.5					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	141,226,732	141,226,732		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(21,970,822)	(21,970,822)		
13	Cost of Removal	2,002,349	2,002,349		
14	Salvage (Credit)	92,640	92,640		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(19,875,833)	(19,875,833)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Depreciation offset for non-recoverable plant for Boulder Park	(112,280)	(112,280)		
17.2	AMI/MDM Deferral	(1,171,292)	(1,171,292)		
17.3	Difference of DJ 105 Accrual from 2020 to 2021	(51,870)	(51,870)		
17.4	AFUDC Reg Asset Reversal in 2021	4,944,025	4,944,025		
17.5	ARO Depreciation	805,682	805,682		
17.6	Powerplan transfer amounts among different plant accounts	(2,379,838)	(2,379,838)		
17.7	Change in Removal Work in Progress	(6,753,880)	(6,753,880)		
17.8	General Plant Common Allocated Depr Exp	(18,173,096)	(18,173,096)		
18	Book Cost or Asset Retirement Costs Retired	0			
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	1,705,515,338	1,705,515,338		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	362,591,380	362,591,380		
21	Nuclear Production				
22	Hydraulic Production-Conventional	173,246,476	173,246,476		
23	Hydraulic Production-Pumped Storage				
24	Other Production	157,241,665	157,241,665		
25	Transmission	249,901,494	249,901,494		
26	Distribution	688,522,138	688,522,138		
27	Regional Transmission and Market Operation				
28	General	74,012,185	74,012,185		
29	TOTAL (Enter Total of lines 20 thru 28)	1,705,515,338	1,705,515,338		

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Account 123.1, Investments in Subsidiary Companies.
2. Provide a subheading for each company and list thereunder 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.
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 from investments, including such revenues from 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 different 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.

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	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)
1	Investment in Avista Capital	01/01/1997		256,138,971			256,138,971	
2	Avista Capital - Equity in Earnings			(155,335,303)	16,645,418		(138,689,885)	
3	Investment in AERC	07/01/2014		89,816,380			89,816,380	
4	AERC - Equity in Earnings			16,790,283	6,909,964	5,000,000	18,700,247	
42	Total Cost of Account 123.1 $		Total	207,410,331	23,555,382	5,000,000	225,965,713	0

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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)	4,088,628	4,388,454	[(a)] (1)
2	Fuel Stock Expenses Undistributed (Account 152)		0	
3	Residuals and Extracted Products (Account 153)		0	
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	36,162,860	43,599,763	[(b)] (1)
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	3,661,588	4,379,679	[(c)] (1)
8	Transmission Plant (Estimated)	170,727	254,532	[(d)] (1)
9	Distribution Plant (Estimated)	727,662	611,259	[(e)] (1)
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	11,131,219	11,432,175	[(f)] (1), (2)
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	51,854,056	60,277,408	
13	Merchandise (Account 155)		0	
14	Other Materials and Supplies (Account 156)		0	
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)		0	
16	Stores Expense Undistributed (Account 163)		0	
17				
18				
19				
20	TOTAL Materials and Supplies	55,942,684	64,665,862	

FOOTNOTE DATA

(a) Concept: FuelStockDepartmentsUsingMaterial
(b) Concept: PlantMaterialsAndOperatingSuppliesConstructionDepartmentsUsingMaterial
(1) Electric (2) Natural Gas
(c) Concept: PlantMaterialsAndOperatingSuppliesProductionPlantDepartmentsUsingMaterial
(1) Electric (2) Natural Gas
(d) Concept: PlantMaterialsAndOperatingSuppliesTransmissionPlantDepartmentsUsingMaterial
(1) Electric (2) Natural Gas
(e) Concept: PlantMaterialsAndOperatingSuppliesDistributionPlantDepartmentsUsingMaterial
(1) Electric (2) Natural Gas
(f) Concept: PlantMaterialsAndOperatingSuppliesOtherDepartmentsUsingMaterial
(1) Electric (2) Natural Gas

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

Transmission Service and Generation Interconnection Study Costs

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

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
20	Total				
21	**Generation Studies**				
22	Gordon Butte Project #50	9,230	186200		
23	Aurora Solar Project #59	79,333	186200	76,515	186210
24	Rattlesnake II Wind Proj #62	120,344	186200	119,949	186210
25	Post Falls HED Project #63	83,094	186200		
26	Kettle Falls Upgrade Proj #66	61,211	186200		
27	Old Milwaukee Solar Proj #67	34,448	186200		
28	Clearwater Wind II Proj #68	7,349	186200		
29	Clearwater Wind III Proj #69	7,809	186200		
30	EnerNOC Batt. Storage Proj #70	6,611	186200		
31	Geronimo Solar Project #71	16,067	186200		
32	Sprague Solar Project #73	13,130	186200		
33	Royal City Solar Project #76	4,396	186200		
34	Elf II Solar Project #79	53,670	186200	42,465	186210
35	Elf I Solar Project #80	39,855	186200	30,972	186210
36	Ralston Solar Project #81	3,767	186200		
37	Haymaker Wind Proj #82	4,353	186200		
38	Martinsdale Wind Proj #83	3,290	186200		
39	Rainier Solar Project #85	840	186200		
40	Acadia Solar Project #84	43,907	186200	32,353	186210
41	Jane Wind 2 Proj #96	1,717	186200		
42	Jane Wind Proj #95	1,620	186200		
43	Lolo Solar Project #97	57,962	186200		
44	Wahatis Solar Project #99	4,494	186200		
45	Stringtown Solar Project #100	5,673	186200		
46	Harrington Solar Project #103	2,913	186200		
47	Colville Solar Project #105	1,849	186200		
48	Latah Wind Project #104	2,231	186200		
49	Big Sky Connector Line Project	2,130	186200		
50	Broadview IV Project #107	2,391	186200		
51	Ursus Wind Project #108	2,324	186200		
52	Rathdrum CT #109	8,308	186200		
53	Cloudwalker Wind&Solar Q110	1,756	186200		
54	Daydreamer Solar Q112	1,760	186200		
55	Sweet Apple Solar Q111	1,642	186200		
56	Gordon Butte South Wind Q116	2,791	186200		
57	CS PV Q113	939	186200		
58	CS Wind 2 Q115	619	186200		
59	CS Wind 1 Q114	746	186200		
60	Triple Oak Connector Line	1,775	186200		
61	Silverstrike Storage	3,007	186200		
62	North Plains Connector Line	775	186200		
63	Ursiane Wind #118	497	186200		
64	Saddle Mt Wind Unsuspend Q46	373	186200		
65	Geronimo Solar Project #72	41,350	186200	41,350	186210
39	Total	[a]744,346		[b]343,604	
40	Grand Total	744,346		343,604	

FOOTNOTE DATA

(a) Concept: StudyCostsIncurred
Total life to date costs
(b) Concept: StudyCostsReimbursements
Total life to date reimbursements

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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 Quarter/Year Account Charged (d)	CREDITS: Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	[a] WA Excess Nat Gas Line Extension Allowance	8,597,671	0	407	2,134,643	6,463,028
2	[b] Reg Asset Post Ret Liabilility	202,321,377	6,863,397	228	37,813,141	171,371,633
3	[c] Regulatory Asset FAS 109 Utility Plant	93,708,282	1,785,604	283	1,588,902	93,904,984
4	Regulatory Asset FAS 109 DSIT Non Plant	2,344,905	2,594,946	283	2,592,721	2,347,130
5	[d] Regulatory Asset Lake CDA Settlement-Varies	40,042,767	0	407	1,116,805	38,925,962
6	[e] Reg Assets-Decoupling Surcharges - 2 years	10,093,117	16,072,572	456, 495	15,285,711	10,879,978
7	[f] Reg Asset - Colstrip	7,891,134	4,844,304	407	1,942,176	10,793,262
8	[g] Regulatory Asset Commodity MTM ST & LT	7,794,852	40,479,053	244, 175	32,888,608	15,385,297
9	[h] Regulatory Asset FAS 143 Asset Retirement Obligation	1,916,300	121,561		0	2,037,861
10	[i] Regulatory Asset Workers Comp	1,017,959	263,400	242	394,351	887,008
11	[j] Interest Rate Swap Asset	214,851,166	359,365,554	Various	374,462,938	199,753,782
12	[k] DSM Asset	3,813,813	1,693,097	Various	1,532,733	3,974,177
13	[l] Deferred ITC	3,910,987	0	283, 410	70,968	3,840,019
14	[m] Regulatory Asset MDM System	26,378,924	12,510,989	407, 419	2,882,249	36,007,664
15	[n] Regulatory Asset BPA Residential Exchange	1,484,961	1,441,496	407	1,786,380	1,140,077
16	[o] Regulatory Asset FISERV	2,720,100	0	407, 419	1,627,243	1,092,857
17	[p] Regulatory Asset AFUDC (PIS,WIP) & Equity DFIT	52,370,433	83,632,429	Various	80,968,179	55,034,683
18	Regulatory Asset ID PCA Deferral	2,547,168	14,419,413	557, 419	6,191,599	10,774,982
19	[q] Existing Meters/ERTS Retirement Def	25,913,958	891,495	108, 407	5,389,928	21,415,525
20	[r] Regulatory Asset Colstrip Community Fund	1,500,000	0		0	1,500,000
21	[s] Regulatory Asset COVID-19	2,859,947	7,132,376	186, 407	8,011,896	1,980,427
22	[t] Regulatory Asset Energy Imbalance Market	194,925	574,493	407	53,629	715,789
23	[u] Regulatory Asset Oregon CAT Tax	829,587	93,982	407, 419	24,949	898,620
24	[v] Regulatory Asset- Wildfire Resiliency	1,006,452	3,376,998	407	0	4,383,450
25	[w] Deferral for CS2 & Colstrip (O&M, Excess Depr)	1,108,935	4,711,925	407	710,974	5,109,886
26	[x] Regulatory Asset Tax Basis Flow through	0	131,806,591		0	131,806,591
27	[y] Tax Reform Deferral	0	685,595			685,595
28	[z] Other Regulatory Assets	61,923	60,168	407, 419	69,450	52,641
44	TOTAL	717,281,643	695,421,438		579,540,173	833,162,908

FOOTNOTE DATA

(a) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

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.

(b) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Recognition of the overfunded and underfunded status of a defined benefit post retirement plan based on ASC 715 for financial reporting.

(c) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

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

(d) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

WA Docket UE-080416 & ID Order AVU-E-08-01. Amortization thru 2059.

(e) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

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.

(f) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

For Washington Electric, amortization period is 33.75 years as per Order 09, dockets UE-190334, UG-190335, UE-190222 (Consolidated). For Idaho Electric, amortization is for 34.75 years as per Order 34276, AVU-E-18-03. Amortization ends in 2054 for both jurisdictions.

(g) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Washington Docket# UE-002066 and Idaho Order# 28648

(h) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

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.

(i) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Quarterly adjustments to workers comp reserve for current unpaid claims.

(j) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Settled swaps are amortized over the life of the associated debt.

(k) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Amortization period varies depending on timing of transactions.

(l) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Amortization period varies depending on underlying transactions.

(m) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Washington Docket#s UE-180418, UG-180419

(n) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

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.

(o) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Idaho Order# 33494, Docket Nos. AVU-E-16-01 and Stipulation and Settlement Docket# AVU-E-19-04

(p) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Deferring the difference between FERC formula and State approved AFUDC rates from 2010 to present.

(q) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Washington Docket# UE-002066 and Idaho Order# 28648

(r) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

WA Order 09 in Dockets UE-190334, UE-190222. Deferral of customer portion for future rate recovery. The funds are set aside to help the Colstrip community transition away from economic activity related to coal-fired generation.

(s) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

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.

(t) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

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

(u) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

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

(v) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Deferral of O&M wildfire expenses as per Idaho PUC Order 34883 and WA Dockets UE-200900, UG-200901, and UE-200894.

(w) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

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

(x) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

WA Order 01, Dockets UE-200895 and UG-200896, ID Case Nos. AVU-E-20-12 and AVU-G-20-07 Order No. 34906, and OR Docket# UM 2124 Order# 21-131 - Accounting method change for federal income tax expense associated with Industry Director Directive No. 5 mixed service costs for meters.

(y) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Balance remaining after 1 year amortization of 2019 Temporary Tax Rebate based on Oregon Advice# 19-01-G.

(z) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Deferred Regulatory Fees of $26,308 - Oregon Docket No. UG 415/Advice No. 21-06-G. Amortization of amounts deferred previously in Order No. 20-254 in UG 395.

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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 Credits Account Charged (d)	CREDITS Credits Amount (e)	Balance at End of Year (f)
1	Reg Asset - Battery Storage	0	3,848,745			3,848,745
2	Colstrip Common Facility	3,466,641				3,466,641
3	Plant Alloc of Clearing Journal	3,964,981	4,153,244			8,118,225
4	Reg Asset - ERM	0	7,929,925			7,929,925
5	Gas Supply Transactions	517,205	15,686			532,891
6	WA REC Deferral	394,831		557	394,831	0
7	Reg Asset - Decoupling Deferred	15,376,953		VAR	1,201,997	14,174,956
8	Reg Asset - COVID 19 Deferral	5,305,694	6,304,500			11,610,194
9	Nez Perce Settlement	119,125		VAR	5,188	113,937
10	Union Contract Nego	11,703	110,016			121,719
11	Misc. Deferred Debits <$100,000	896,248		VAR	231,787	664,461
12	ERM, DSM & BPA Tariff Riders Expense	0	181,230			181,230
13	(a) Timber Harvest	(226,818)		253	(226,818)	0
47	Miscellaneous Work in Progress	0				0
48	Deferred Regulatroy Comm. Expenses (See pages 350 - 351)	0				0
49	TOTAL	29,826,563				50,762,924

FOOTNOTE DATA

(a) Concept: DescriptionOfMiscellaneousDeferredDebits

At 12/31/2020, this credit was embedded in a suspense account with multiple other debit amounts which fully offset this credit balance. This credit amount has been embedded in the suspense account since 2015, the Company identified this amount during 2021 and reclassified it to account 253 as of 12/31/2021.

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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 at Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	Electric	102,475,097	115,179,928
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	102,475,097	115,179,928
9	Gas		
10	Gas	21,374,121	30,295,536
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)	21,374,121	30,295,536
17.1	[a] Other	92,879,318	110,887,110
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	216,728,536	256,362,574

Notes

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: DescriptionOfAccumulatedDeferredIncomeTax

	Beg. Balance	End. Balance
Pension, Medical, and SERP	33,779,058	49,617,069
Federal Income Tax Carryforwards	11,857,126	19,821,038
State Income Tax Carryforwards	18,682,559	18,379,565
Derivative Instruments	10,930,946	8,903,303
Compensation and Payroll	7,695,408	6,589,381
Plant Excess Deferred Gross Up	8,069,077	6,552,622
Other Common Deferred Tax Assets	1,865,144	1,024,132
Total	92,879,318	110,887,110

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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.
3. Give 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 noncumulative.
5. State in a footnote if any capital stock that has been nominally issued is nominally outstanding at end of year.
6. 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 purpose of pledge.

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)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Shares (e)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Amount (f)	Held by Respondent As Reacquired Stock (Acct 217) Shares (g)	Held by Respondent As Reacquired Stock (Acct 217) Cost (h)	Held by Respondent In Sinking and Other Funds Shares (i)	Held by Respondent In Sinking and Other Funds Amount (j)
1	Common Stock (Account 201)									
2	No Par Value	200,000,000			71,497,523	1,341,011,707				
3	Restricted Shares								96,127	3,598,034
11	Total	200,000,000			71,497,523	1,341,011,707				
12	Preferred Stock (Account 204)									
13	Cumulative	10,000,000								
16	Total	10,000,000				0				
1	Capital Stock (Accounts 201 and 204) - Data Conversion									
2										
3										
4										
5	Total									

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2022-04-15	Year/Period of Report End of: 2021/ Q4

Other Paid-in Capital

1. 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 a total of all accounts for reconciliation with the balance sheet, page 112. 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 briefly explain the origin and purpose of each donation.
b. Reduction in Par or Stated Value of Capital Stock (Account 209) - State amount and briefly explain the capital changes that gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
c. Gain or 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 that, together with brief explanations, disclose the general nature of the transactions that gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	**Donations Received from Stockholders (Account 208)**	
2	Beginning Balance Amount	
3	Increases (Decreases) from Sales of Donations Received from Stockholders	
4	Ending Balance Amount	
5	**Reduction in Par or Stated Value of Capital Stock (Account 209)**	
6	Beginning Balance Amount	
7	Increases (Decreases) Due to Reductions in Par or Stated Value of Capital Stock	
8	Ending Balance Amount	
9	**Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210)**	
10	Beginning Balance Amount	
11	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock	
12	Ending Balance Amount	
13	**Miscellaneous Paid-In Capital (Account 211)**	
14	Beginning Balance Amount	(10,696,711)
15	Increases (Decreases) Due to Miscellaneous Paid-In Capital	
16	Ending Balance Amount	(10,696,711)
17	**Historical Data - Other Paid in Capital**	
18	Beginning Balance Amount	
19	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	0
40	Total	(10,696,711)

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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	(49,837,072)
22	TOTAL	(49,837,072)

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

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

1. Report by Balance Sheet Account the 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. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds, and in column (b) include the related account number.
3. 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, and in column (b) include the related account number.
4. For receivers' certificates, show in column (a) the name of the court and date of court order under which such certificates were issued, and in column (b) include the related account number.
5. In a supplemental statement, 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) principal repaid during year. Give Commission authorization numbers and dates.
6. If the respondent has pledged any of its long-term debt securities, give particulars (details) in a footnote, including name of the pledgee and purpose of the pledge.
7. If the respondent has any long-term securities that have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
8. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (m). Explain in a footnote any difference between the total of column (m) and the total Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
9. Give details concerning any long-term debt authorized by a regulatory commission but not yet issued.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Related Account Number (b)	Principal Amount of Debt Issued (c)	Total Expense, Premium or Discount (d)	Total Expense (e)	Total Premium (f)	Total Discount (g)	Nominal Date of Issue (h)	Date of Maturity (i)	AMORTIZATION PERIOD Date From (j)	AMORTIZATION PERIOD Date To (k)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (l)	Interest for Year Amount (m)
1	Bonds (Account 221)												
2	FMBS - SERIES A - 7.53% DUE 05/05/2023	221334	5,500,000		42,712			05/06/1993	05/05/2023	05/06/1993	05/05/2023	5,500,000	414,150
3	FMBS - SERIES A - 7.54% DUE 5/05/2023	221335	1,000,000		7,766			05/07/1993	05/05/2023	05/07/1993	05/05/2023	1,000,000	75,400
4	FMBS - SERIES A - 7.18% DUE 8/11/2023	221336	7,000,000		54,364			08/12/1993	08/11/2023	08/12/1993	08/11/2023	7,000,000	502,600
5	FMBS - SERIES C - 6.37% DUE 06/18/2028	221300	25,000,000		158,304			06/19/1998	06/19/2028	06/19/1998	06/19/2028	25,000,000	1,592,500
6	FMBS - 6.25% DUE 12-01-35	221400	150,000,000		1,812,935		367,500	11/17/2005	12/01/2035	11/17/2005	12/01/2035	150,000,000	9,375,000
7	FMBS - 5.70% DUE 07-01-2037	221420	150,000,000		4,702,304		222,000	12/15/2006	07/01/2037	12/15/2006	07/01/2037	150,000,000	8,550,000
8	5.125% SERIES DUE 04-01-2022	221480	250,000,000		2,284,788		575,000	09/22/2009	04/01/2022	09/22/2009	04/01/2022	250,000,000	12,812,500
9	COLSTRIP 2010A PCRBs DUE 2032	221350	66,700,000					12/15/2010	10/01/2032	12/15/2010	10/01/2032	66,700,000	85,106
10	COLSTRIP 2010B PCRBs DUE 2034	221360	17,000,000					12/15/2010	03/01/2034	12/15/2010	03/01/2034	17,000,000	21,691
11	5.55% SERIES DUE 12-20-2040	221540	35,000,000		258,834			12/20/2010	12/20/2040	12/20/2010	12/20/2040	35,000,000	1,942,500
12	4.45% SERIES DUE 12-14-2041	221560	85,000,000		692,833			12/14/2011	12/14/2041	12/14/2011	12/14/2041	85,000,000	3,782,500
13	4.23% SERIES DUE 11-29-2047	221580	80,000,000		730,832			11/30/2012	11/29/2047	11/30/2012	11/29/2047	80,000,000	3,384,000
14	4.11% SERIES DUE 12-1-2044	221610	60,000,000		428,205			12/18/2014	12/01/2044	12/18/2014	12/01/2044	60,000,000	2,466,000
15	4.37% SERIES DUE 12-1-2045	221620	100,000,000		590,761			12/16/2015	12/01/2045	12/16/2015	12/01/2045	100,000,000	4,370,000
16	3.54% SERIES DUE 2051	221630	175,000,000		1,042,569			12/15/2016	12/01/2051	12/15/2016	12/01/2051	175,000,000	6,195,000
17	3.91% SERIES DUE 12-1-2047	221640	90,000,000		552,539			12/14/2017	12/01/2047	12/14/2017	12/01/2047	90,000,000	3,519,000
18	4.35% SERIES DUE 6-1-2048	221650	375,000,000		4,246,448		378,750	05/22/2018	06/01/2048	05/22/2018	06/01/2048	375,000,000	16,312,500
19	3.43% SERIES DUE 12-1-2049	221660	180,000,000		1,108,340			11/26/2019	12/01/2049	11/26/2019	12/01/2049	180,000,000	6,174,000
20	3.07% SERIES DUE 9-1-2050	221670	165,000,000		1,074,990			09/30/2020	09/30/2050	09/30/2020	09/30/2050	165,000,000	5,065,500
21	2.90% SERIES DUE 10/01/2051	221680	140,000,000		1,051,805			09/28/2021	10/01/2051	09/28/2021	10/01/2051	140,000,000	693,583
22	Subtotal		2,157,200,000		20,841,329	0	1,543,250					2,157,200,000	87,333,530
23	Reacquired Bonds (Account 222)												
24	COLSTRIP 2010A PCRBs DUE 2032	221350	66,700,000					12/15/2010	10/01/2032	12/15/2010	10/01/2032	66,700,000	85,106
25	COLSTRIP 2010B PCRBs DUE 2034	221360	17,000,000					12/15/2010	03/01/2034	12/15/2010	03/01/2034	17,000,000	21,691
26	Subtotal		83,700,000									83,700,000	106,797
27	Advances from Associated Companies (Account 223)												
28	ADVANCE ASSOCIATED-AVISTA CAPITAL II (ToPRS)	223011	51,547,000		1,296,086			06/03/1997	06/01/2037	06/03/1997	06/01/2037	51,547,000	420,879
29	Subtotal		51,547,000		1,296,086							51,547,000	420,879
30	Other Long Term Debt (Account 224)												
31													
32													
33													
34	Subtotal											0	

33	TOTAL		2,292,447,000									2,125,047,000	87,861,206

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	147,333,570
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	Contributions in Aid of Construction	12,275,803
9	Deductions Recorded on Books Not Deducted for Return	
10	Book Depreciation	246,404,844
11	Federal Income Tax Expense	4,716,706
12	State Income Tax Expense	291,365
13	Subsidiary Overheads	2,252,926
14	Other	65,355,817
14	Income Recorded on Books Not Included in Return	
15	Subsidiary Earnings	23,555,382
16	Other	4,289,414
19	Deductions on Return Not Charged Against Book Income	
20	Tax Depreciation	218,913,627
21	Plant Basis Adjustments	108,612,988
22	Other	123,939,170
27	Federal Tax Net Income	(679,550)
28	Show Computation of Tax:	
29	Federal Tax at 21%	(142,706)
30	Prior Year True Ups	(157,137)
31	Customer refunds related to prior years at 35%	(481,833)
32	Total Federal Current Tax Expense	(781,676)

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

TAXES ACCRUED, PREPAID AND CHARGES 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 known, 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 (g) and (h). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (g) 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.
5. If any tax (exclude Federal and State income taxes) covers more than one year, show the required information separately for each tax year, identifying the year in column (d).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (i) 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 (l) through (o) how the taxes were distributed. Report in column (o) 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 409.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (o) 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.

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED			
					Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)				Taxes Accrued (Account 236) (j)	Prepaid Taxes (Included in Account 165) (k)	Electric (Account 408.1, 409.1) (l)	Extraordinary Items (Account 409.3) (m)	Adjustment to Ret. Earnings (Account 439) (n)	Other (o)
1	Income Tax 2014	Federal Tax		2014		0				0					
2	Income Tax 2015	Federal Tax		2015		0				0					
3	Income Tax 2017	Federal Tax		2017		0				0					
4	Income Tax 2018	Federal Tax		2018		0				0					
5	Income Tax 2019	Federal Tax		2019		0		(22,000,000)	(22,000,000)	0					
6	Income Tax 2020	Federal Tax		2020		0	(1,067,141)		1,067,141	0		(1,108,994)			(889,188)
7	Income Tax 2021	Federal Tax		2021			33,162	545,000	511,838	0		(432)			1,110,000
8	**Subtotal Federal Tax**				0	0	(1,033,979)	(21,455,000)	(20,421,021)	0	0	(1,109,426)	0	0	220,812
9	Payroll Taxes 2020	Unemployment Tax	WA	2020	(235,053)		0	62,298	1	(297,350)					
10	Payroll Taxes 2021	Unemployment Tax	WA	2021			877,216	583,051		294,165		3,034,798			
11	**Subtotal Unemployment Tax**				(235,053)	0	877,216	645,349	1	(3,185)	0	3,034,798	0	0	0
12	Property Tax 2020	Property Tax	WA	2020	18,089,813		(1)	8,794,393		9,295,419					
13	Property Tax 2021	Property Tax	WA	2021			18,194,877	8,800,184		9,394,693		14,462,413			
14	Property Tax 2020	Property Tax	ID	2020	3,933,011		(1,014)	3,932,039		(42)		(1,014)			
15	Property Tax 2021	Property Tax	ID	2021			7,788,449	3,905,993		3,882,456		6,129,636			
16	Property Tax 2018	Property Tax	MT	2018			240	240		0		240			
17	Property Tax 2020	Property Tax	MT	2020	5,898,062		10,258	5,908,319		1		10,258			
18	Property Tax 2021	Property Tax	MT	2021			9,550,410	4,794,326		4,756,084		9,550,410			
19	Property Tax 2020	Property Tax	OR	2020		(4,047,487)	4,072,730	25,246	(8,094,975)	0	4	1,765,170			
20	Property Tax 2021	Property Tax	OR	2021			4,273,508	8,547,021		0	4,273,513	1,813,436			(160)
21	**Subtotal Property Tax**				27,920,886	(4,047,487)	43,889,457	44,707,761	(8,094,975)	27,328,611	4,273,517	33,730,549	0	0	(160)
22	Excise Tax 2016	Excise Tax	WA	2016	892,951		(252,399)	640,552		0					(252,399)
23	Excise Tax 2020	Excise Tax	WA	2020	2,930,000		10,827	2,922,485		18,342		10,093			(16)
24	Excise Tax 2021	Excise Tax	WA	2021			28,713,253	25,720,692		2,992,561		22,359,019			3,809
25	Corp Activities Tax-CAT 2020	Excise Tax	OR	2020	200,004		(24,949)	300,000	124,945	0					
26	Corp Activities Tax-CAT 2021	Excise Tax	OR	2021			800,000	750,000	(50,000)	0					
27	Timber Excise Tax	Excise Tax	WA	2021						0					
28	Thermal Fuel Tax	Excise Tax	WA	2021	1,912		87,594	81,329		8,177					87,594
29	**Subtotal Excise Tax**				4,024,867	0	29,334,326	30,415,058	74,945	3,019,080	0	22,369,112	0	0	(161,012)
30	Natural Gas Use Tax	Sales And Use Tax	WA	2021	480		4,881	4,382		979		4,881			
31	Sales And Use Tax 2019	Sales And Use Tax	WA	2019	(1)		(1)	(2)		0					(3)
32	Sales And Use Tax 2020	Sales And Use Tax	WA	2020	115,214		69,975	184,299		890					70,855
33	Sales And Use Tax 2021	Sales And Use Tax	WA	2021			1,369,417	1,232,495		136,922					1,369,417
34	Sales And Use Tax 2020	Sales And Use Tax	ID	2020	27,502		(754)	26,781		(33)					(754)
35	Sales And Use Tax 2021	Sales And Use Tax	ID	2021			144,335	137,350		6,985					144,335

36	**Subtotal Sales And Use Tax**				143,195	0	1,587,853	1,585,305	0	145,743	0	4,881	0	0	1,583,850
37	Municipal Occupation Tax	Local Tax	WA	2021	3,065,253		25,138,504	25,102,476		3,101,281		19,544,378			(18,837)
38	**Subtotal Local Tax**				3,065,253	0	25,138,504	25,102,476	0	3,101,281	0	19,544,378	0	0	(18,837)
39	Community Solar	Other Taxes	WA	2021	688			688		0					
40	Hydro Relicensing	Other Taxes	ID	2021			30,997	30,997		0		30,997			
41	KWH Tax 2020	Other Taxes	ID	2020	28,115		(545)	27,570		0		(545)			
42	KWH Tax 2021	Other Taxes	ID	2021			356,535	315,351		41,184		356,535			
43	Irrigation Credit 2020	Other Taxes	ID	2020			0	0		0		(2,028)			2,028
44	Irrigation Credit 2021	Other Taxes	ID	2021			0	0		0		2,999			(2,999)
45	Colstrip Generation Tax	Other Taxes	MT	2021						0					
46	KWH Tax 2020	Other Taxes	MT	2020	201,716		0	203,745		(2,029)					
47	KWH Tax 2021	Other Taxes	MT	2021			1,060,591	801,945		258,646		1,060,591			
48	WA Renewable Energy Credits	Other Taxes	WA	2021			(754,446)	(752,135)		(2,311)					(754,446)
49	Misc Distribution	Other Taxes		2021	326		1,985			2,311		1,014			971
50	**Subtotal Other Taxes**				230,845	0	695,117	628,161	0	297,801	0	1,449,563	0	0	(754,446)
51	Income Tax 2019	State Tax	ID	2019				(329,840)	(329,840)	0					
52	Income Tax 2020	State Tax	ID	2020			100	160	60	0		85			
53	Income Tax 2021	State Tax	ID	2021			100	160	60	0		85			
54	Income Tax 2020	State Tax	MT	2020			52	0	(52)	0		52			
55	Income Tax 2021	State Tax	MT	2021			50	50		0		50			
56	Income Tax 2021	State Tax	OR	2021			100,000	100,000		0		30,332			(518)
57	Income Tax 2021	State Tax	CA	2021			800	800		0					
58	**Subtotal State Tax**				0	0	101,102	(228,670)	(329,772)	0	0	30,604	0	0	(518)
59	Payroll Taxes 2020	Payroll Tax	ID	2020	(16,105)		(1)	7,019		(23,125)					
60	Payroll Taxes 2021	Payroll Tax	ID	2021			38,069	30,832		7,237		542,188			
61	Payroll Taxes 2020	Payroll Tax	MT	2020	(4,910)		11,064	10,848		(4,694)		157,034			(157,034)
62	Payroll Taxes 2020	Payroll Tax	OR	2020	(9,574)		0	757		(10,331)					
63	Payroll Taxes 2021	Payroll Tax	OR	2021			42,539	37,858		4,681		7,525			
64	Payroll Taxes 2020	Payroll Tax		2020	(402)			67		(469)					
65	Payroll Taxes 2021	Payroll Tax		2021				2,346		(2,346)					
66	Payroll Taxes 2021	Payroll Tax		2021	8,019,298		15,642,569	18,133,447		5,528,420					7,548,872
67	**Subtotal Payroll Tax**				7,988,307	0	15,734,240	18,223,174	0	5,499,373	0	706,747	0	0	7,391,838
68	Franchise Tax 2019	Franchise Tax	ID	2019	14					14					
69	Franchise Tax 2020	Franchise Tax	ID	2020	1,090,306		0	1,090,286		20		(953)			1,296
70	Franchise Tax 2021	Franchise Tax	ID	2021			4,819,276	3,734,871		1,084,405		3,674,464			(5,171)
71	Franchise Tax 2020	Franchise Tax	OR	2020	1,038,154		677	1,038,832		(1)					1,030
72	Franchise Tax 2021	Franchise Tax	OR	2021			4,207,361	3,011,158		1,196,203					(3,220)
73	**Subtotal Franchise Tax**				2,128,474	0	9,027,314	8,875,147	0	2,280,641	0	3,673,511	0	0	(6,065)
74	Consumer Council Fee	Other License And Fees Tax	MT	2021	58		(25)	25		8		(25)			
75	Public Commission Fee	Other License And Fees Tax	MT	2021	42		164	181		25		164			
76	**Subtotal Other License And Fees Tax**				100	0	139	206	0	33	0	139	0	0	0
77	Income Tax 2021	Income Tax		2021			950	850	(100)	0		335			518
78	**Subtotal Income Tax**				0	0	950	850	(100)	0	0	335	0	0	518
40	TOTAL				45,266,874	(4,047,487)	125,352,239	108,499,817	(28,770,922)	41,669,378	4,273,517	83,435,191	0	0	8,255,980

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)	Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION (j)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)				
1	Electric Utility									
2	3%									
3	10%									
4	Fed ITC	28,661,919			411.4	520,104		28,141,815		
5	Idaho ITC	1,023,779	411.4	43	411.4	28,384		995,438		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	29,685,698		43		548,488		29,137,253		
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
10	Gas Property (100%									
11	Idaho ITC	180,929	411.4	7	411.4	5,013		175,923		
47	OTHER TOTAL	180,929		7		5,013	0	175,923		
48	GRAND TOTAL	29,866,627						29,313,176		

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OTHER DEFERRED 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		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	(a) Deferred Gas Exchange	1,125,000	495	5,343,750	5,625,000	1,406,250
2	Bills Pole Rentals	646,335	172	1,118,568	804,432	332,199
3	Defer Comp Active Execs	9,173,880	128	962,528	1,301,966	9,513,318
4	Executive Incent Plan	140,000	214	140,000		0
5	Unbilled Revenue	105,445	908	16,104,598	18,158,584	2,159,431
6	(b) WA Energy Recovery Mechanism	11,383,248	186	11,383,248		0
7	(c) Decoupling Deferred Credits	1,855,168	182, 456, 495	1,131,297	6,189,577	6,913,448
8	(d) Reg Liability-COVID-19 Deferral	6,660,724			1,088,376	7,749,100
9	(e) WA REC Deferrals	0	186, 431	51,900	1,440,095	1,388,195
10	(f) Misc Deferred Credits	360,229	186, 550, 514, 545	579,095	713,759	494,893
11	(g) Timber Harvest	0	186		226,818	226,818
47	TOTAL	31,450,029		36,814,984	35,548,607	30,183,652

(a) Concept: DescriptionOfOtherDeferredCredits

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.

(b) Concept: DescriptionOfOtherDeferredCredits

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.

(c) Concept: DescriptionOfOtherDeferredCredits

Washington and Idaho Decoupling orders for electric and natural gas 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.

(d) Concept: DescriptionOfOtherDeferredCredits

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.

(e) Concept: DescriptionOfOtherDeferredCredits

WA Docket UE-190334, Schedule 98.

(f) Concept: DescriptionOfOtherDeferredCredits

Kettle Falls Generation Station underground fuel leak of $64,140 - Continuing remediation liability is recorded.

(g) Concept: DescriptionOfOtherDeferredCredits

At 12/31/2020, this credit was embedded in a suspense account with multiple other debit amounts which fully offset this credit balance. This credit amount has been embedded in the suspense account since 2015, the Company identified this amount during 2021 and reclassified it to account 253 as of 12/31/2021.

ACCUMULATED DEFERRED 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.
3. Use footnotes as required.

			CHANGES DURING YEAR				ADJUSTMENTS				
							Debits		Credits		
Line No.	Account (a)	Balance at Beginning of Year (b)	Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	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)
1	Account 282										
2	Electric	398,244,120	9,376,181	70,652,238					182 / 254	71,392,284	408,360,347
3	Gas	143,910,347	4,199,524	49,365,500					182 / 254	50,206,033	148,950,404
4	Other (Specify)	61,260,966	(740,059)						182 / 254	1,069,275	61,590,182
5	Total (Total of lines 2 thru 4)	603,415,433	12,835,646	120,017,738						122,667,592	618,900,933
6											
7											
8											
9	TOTAL Account 282 (Total of Lines 5 thru 8)	603,415,433	12,835,646	120,017,738						122,667,592	618,900,933
10	Classification of TOTAL										
11	Federal Income Tax	603,415,433	12,835,646	120,017,738						122,667,592	618,900,933
12	State Income Tax										
13	Local Income Tax										

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
							Debits		Credits		
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 283										
2	Electric										
3	Electric	12,928,052	7,073,200	263,167	19,136	1,179			182 / 254	17,909,782	37,665,824
9	TOTAL Electric (Total of lines 3 thru 8)	12,928,052	7,073,200	263,167	19,136	1,179		0		17,909,782	37,665,824
10	Gas										
11	Gas	3,042,547	7,431,692	611,207	113,646				182	12,426,198	22,402,876
17	TOTAL Gas (Total of lines 11 thru 16)	3,042,547	7,431,692	611,207	113,646			0		12,426,198	22,402,876
18	TOTAL Other	184,147,569	5,647,754	176,665	20,483				182 / 254	17,074,283	206,713,424
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	200,118,168	20,152,646	1,051,039	153,265	1,179		0		47,410,263	266,782,124
20	Classification of TOTAL										
21	Federal Income Tax	200,118,168	20,152,646	1,051,039	153,265	1,179				47,410,263	266,782,124
22	State Income Tax										
23	Local Income Tax										

NOTES

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	(a) Idaho Investment Tax Credit	8,874,779	190	1,108,577	0	7,766,202
2	(b) Interest Rate Swaps	15,045,752	427, 175	17,886,002	17,902,790	15,062,540
3	Nez Perce	506,300	557	22,008	0	484,292
4	Idaho Earnings Test	686,970		0	0	686,970
5	(c) Decoupling Rebate	2,335,746	495, 182	3,571,861	4,154,224	2,918,109
6	(d) WA ERM	26,486,130	186, 557	19,067,343	12,401,822	19,820,609
7	(e) Deferred Federal ITC - Varies	7,821,976	190	141,936	0	7,680,040
8	(f) Plant Excess Deferred	382,938,797	190, 282	47,165,951	4,146,763	339,919,609
9	Reg Liability MDM System	897,416	431	11,291	78,050	964,175
10	(g) AFUDC Equity Tax Deferral	2,606,448	407	666,038	70,577	2,010,987
11	(h) Exist Meters/ERTS Excess Depr Deferred	1,879,242	182	2,571,853	692,611	0
12	(i) DSM Tariff Rider	540,275		0	5,827,354	6,367,629
13	(j) Low Income Energy Assistance	3,783,957	242, 908	160,974	3,120,839	6,743,822
14	(k) Reg Liability - OR Tax Strategy Deferral	0		0	1,322,007	1,322,007
15	(l) Reg Liability - Tax Reform Amortization - 1 year	994,068	407, 431	2,319,765	1,506,823	181,126
16	(m) Reg Liability - Energy Efficiency Assistance	1,532,183	242, 908	103,349	0	1,428,834
17	(n) Reg Liability - Colstrip Community Fund	3,357,111	232, 407	3,357,111	0	0
18	(o) Reg Liability - COVID-19 Deferral	4,288,655	407	187,911	650,402	4,751,146
19	(p) Reg Liability - Tax Customer Credit	0	190, 410	11,449,638	155,311,627	143,861,989
20	(q) Other Regulatory Liabilities - Varies	8,545,572	143, 190, 407	376,835	1,523,402	9,692,139
41	TOTAL	473,121,377		110,168,443	208,709,291	571,662,225

FOOTNOTE DATA

(a) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Not amortized

(b) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

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.

(c) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

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

(d) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

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.

(e) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Noxon ITC - 65 year amortization, ends 2077

Community Solar ITC - 20 year amortization, ends 2035

Nine Mile ITC - 65 year amortization, ends 2080

(f) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

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

(g) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Washington Dockets UE-200900, UG-200901, UE-200894 effective 10/01/2021, amortization over one year.

Idaho Electric Settlement AVU-E-19-04 ordered a transfer to account 254320 for Idaho portion.

(h) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Washington Docket#s UE-180418 and UG-180419

(i) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

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

(j) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

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)

(k) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Oregon Docket No. UM 2124. Deferral of associated state tax savings of approximately $1.3M thru 12/31/2022.

(l) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Washington Docket#s UE-170485, UG-170486 (Schedule 174, amortization ended 5/31/2019)

Oregon Advice# ADV 923/19-01-G (Schedule 474, amortization ended 2/28/2021)

Idaho Case# GNR-U-18-01 (Schedule 74, amortization ended 3/31/2020)

(m) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

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

(n) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

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

(o) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

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.

(p) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

WA Order 01, Dockets UE-200895 and UG-200896, ID Case Nos. AVU-E-20-12 and AVU-G-20-07 Order No. 34906, and OR Docket# UM 2124 Order# 21-131

Accounting method change for federal income tax from normalization to flow-through for Industry Director Directive No. 5 mixed service costs and meters.

(q) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Oregon BETC Credit of $11,558 is not amortized.

Non Plant Excess Deferred balance of $74,329 amortized over 1 year.

State income tax net operating loss carryforward of $7.5M 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 $0.6M per Idaho Order No. 34276, Case Nos. AVU-E-18--03 and AVU-G-18-02.

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

Electric Operating Revenues

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.
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 page 108, 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.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)	MEGAWATT HOURS SOLD Year to Date Quarterly/Annual (d)	MEGAWATT HOURS SOLD Amount Previous year (no Quarterly) (e)	AVG.NO. CUSTOMERS PER MONTH Current Year (no Quarterly) (f)	AVG.NO. CUSTOMERS PER MONTH Previous Year (no Quarterly) (g)
1	Sales of Electricity						
2	(440) Residential Sales	394,716,831	377,785,465	3,955,384	3,807,041	356,387	349,890
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	326,172,980	303,971,920	3,157,795	2,994,648	44,110	43,399
5	Large (or Ind.) (See Instr. 4)	117,164,929	113,563,149	2,090,406	2,042,265	1,205	1,297
6	(444) Public Street and Highway Lighting	7,472,432	7,303,244	17,479	17,654	666	639
7	(445) Other Sales to Public Authorities	0		0		0	
8	(446) Sales to Railroads and Railways	0		0		0	
9	(448) Interdepartmental Sales	1,460,683	1,422,102	13,784	13,435	150	152
10	TOTAL Sales to Ultimate Consumers	846,987,855	804,045,880	9,234,848	8,875,043	402,518	395,377
11	(447) Sales for Resale	93,585,801	82,055,793	2,519,288	2,796,393		
12	TOTAL Sales of Electricity	940,573,656	886,101,673	11,754,136	11,671,436	402,518	395,377
13	(Less) (449.1) Provision for Rate Refunds	0	(1,601,776)	0			
14	TOTAL Revenues Before Prov. for Refunds	940,573,656	887,703,449	11,754,136	11,671,436	402,518	395,377
15	Other Operating Revenues						
16	(450) Forfeited Discounts	0					
17	(451) Miscellaneous Service Revenues	104,104	150,458				
18	(453) Sales of Water and Water Power	623,668	515,996				
19	(454) Rent from Electric Property	3,624,446	2,028,311				
20	(455) Interdepartmental Rents	0					
21	(456) Other Electric Revenues	58,044,783	35,962,624				
22	(456.1) Revenues from Transmission of Electricity of Others	19,045,326	16,370,526				
23	(457.1) Regional Control Service Revenues	0					
24	(457.2) Miscellaneous Revenues	0					
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	81,442,327	55,027,915				
27	TOTAL Electric Operating Revenues	1,022,015,983	942,731,364				

Line12, column (b) includes $ 643,778 of unbilled revenues.
Line12, column (d) includes 3,957 MWH relating to unbilled revenues

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. 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	01 Residential Service	3,803,623	364,321,244	337,588	11,267.0563	0.0958
2	02 Fixed-Income Senior and Disabled Residential Service	7,550	485,308	566	13,339.2226	0.0643
3	11 General Service	0	(35,648)	0		
4	12 Residential & Farm General Service	94,286	13,673,991	16,317	5,778.3906	0.145
5	21 Large General Service	0	(11,513)	0		
6	22 Residential and Farm Large General Service	38,832	3,642,765	63	616,384.2857	0.0938
7	31 Pumping Service	43	4,710	6	7,151.6667	0.1098
8	32 Residential and Farm Pumping Service	11,136	1,401,638	1,847	6,029.4965	0.1259
9	48 Residential and Farm Area Lighting	3,165	1,181,905	0		0.3734
10	58 Tax Adjustment	0	10,638,585	0		
11	95 Optional Renewable Power	0	191,660	0		
41	TOTAL Billed Residential Sales	3,958,635	395,494,645	356,387	11,107.6863	0.0999
42	TOTAL Unbilled Rev. (See Instr. 6)	(3,251)	(777,814)			0.2393
43	TOTAL	3,955,384	394,716,831	356,387	11,098.5642	0.0998

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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 Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. 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	980,352	113,574,807	40,291	24,331.7863	0.1159
2	13 Optional Commercial Electric Vehicle Rate - General Service	39	4,398	1	27,394.3662	0.1131
3	21 Large General Service	1,700,789	163,850,977	2,464	690,255.276	0.0963
4	23 Optional Commercial Electric Vehicle Rate - Large General Service	88	20,543	2	45,609.375	0.2346
5	25 Extra Large General Service	341,170	22,723,084	13	26,243,860.7692	0.0666
6	31 Pumping Service	122,833	11,398,102	1,339	91,729.1723	0.0928
7	47 Area Light	4,495	1,470,253	0		0.3271
8	49 Area Lighting	2,161	703,093	0		0.3253
9	58 Tax Adjustment	0	11,323,130	0		
10	95 Optional Renewable Power	0	121,140	0		
41	TOTAL Billed Small or Commercial	3,151,927	325,189,527	44,110	71,456.0644	0.1032
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)	5,868	983,453			0.1676
43	TOTAL Small or Commercial	3,157,795	326,172,980	44,110	71,589.0954	0.1033

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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 Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. 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	10,766	1,250,823	211	51,024.6445	0.1162
2	21 Large General Service	150,932	14,436,319	117	1,286,391.0338	0.0956
3	25 Extra Large General Service	1,831,214	91,558,648	21	87,200,666.6667	0.05
4	31 Pumping Service	90,735	8,052,238	738	122,947.1545	0.0887
5	32 Residential and Farm Pumping Service	5,246	488,008	118	44,487.7883	0.093
6	47 Area Light	127	31,970	0		0.2527
7	48 Residential and Farm Area Lighting	0	245	0		0.5214
8	49 Area Lighting	46	13,712	0		0.2968
9	58 Tax Adjustment	0	893,987	0		
10	95 Optional Renewable Power	0	840	0		
41	TOTAL Billed Large (or Ind.) Sales	2,089,066	116,726,790	1,205	1,733,664.7303	0.0559
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)	1,340	438,139			0.327
43	TOTAL Large (or Ind.)	2,090,406	117,164,929	1,205	1,734,776.7635	0.056

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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 Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. 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)
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41	TOTAL Billed Commercial and Industrial Sales			0		
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL	0	0			

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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 Page 310.
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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	41 Company Owned Steet Light Service	35	6,420	6	6,286.7384	0.183
2	42 Company Owned Steet Light Service	14,398	6,869,854	558	25,802.8674	0.4771
3	44 Company Owned Steet Light Energy & Maintenance Service - High Pressure Sodium Vapor	413	70,184	25	16,501.6	0.1701
4	45 Company Owned Steet Light Energy Service	774	65,797	13	59,547.6923	0.085
5	46 Company Owned Steet Light Energy Service	1,859	206,944	64	29,123.6096	0.1113
6	58 Tax Adjustment	0	253,233	0		
41	TOTAL Billed Public Street and Highway Lighting	17,479	7,472,432	666	26,244.7447	0.4275
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL	17,479	7,472,432	666	26,244.7447	0.4275

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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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)
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41	TOTAL Billed Other Sales to Public Authorities			0		
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL	0	0	0		

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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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)
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41	TOTAL Billed Sales To Railroads and Railways			0		
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL	0	0	0		

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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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	01 Residential Service	183	17,555	15	12,200	0.0959
2	11 General Service	3,746	445,868	108	34,685.1852	0.119
3	12 Residential & Farm General Service	1	246	1	1,000	0.246
4	13 Optional Commercial Electric Vehicle Rate - General Service	38	5,704	3	12,666.6667	0.1501
5	21 Large General Service	8,739	862,784	17	514,058.8235	0.0987
6	31 Pumping Service	969	87,016	5	193,800	0.0898
7	32 Residential and Farm Pumping Service	21	2,181	1	21,000	0.1039
8	47 Area Light	84	37,124	0		0.442
9	48 Residential and Farm Area Lighting	1	346	0		0.346
10	49 Area Lighting	2	1,149	0		0.5745
11	58 Tax Adjustment	0	710	0		
41	TOTAL Billed Interdepartmental Sales	13,784	1,460,683	150	91,893.3333	0.106
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL	13,784	1,460,683	150	91,893.3333	0.106

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

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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)
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41	TOTAL Billed Provision For Rate Refunds			0		
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL	0	0			

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

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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)
41	TOTAL Billed - All Accounts	9,230,891	846,344,077	402,518	22,932.8651	0.0917
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	3,957	643,778			0.1627
43	TOTAL - All Accounts	9,234,848	846,987,855	402,518	22,942.6957	0.0917

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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).
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.

   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 (g) through (k).
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,line 24.
10. Footnote entries as required and provide explanations following all required data.

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)	Megawatt Hours Sold (g)	REVENUE: Demand Charges ($) (h)	REVENUE: Energy Charges ($) (i)	REVENUE: Other Charges ($) (j)	Total ($) (h+i+j) (k)
1	Avangrid Renewables, LLC	SF	Tariff 9				142,782		6,022,371		6,022,371
2	Avangrid Renewables, LLC	SF	Tariff 9					(av) 423,950			423,950
3	Avangrid Renewables, LLC	LF	(ad) Tariff 12				45		1,002		1,002
4	BP Energy Company	SF	Tariff 9				2,408		115,053		115,053
5	Black Hills Power, Inc.	SF	Tariff 9				2,620		332,970		332,970
6	Bonneville Power Administration	LF	(ae) Tariff 8				44,950		2,636,407		2,636,407
7	Bonneville Power Administration	LF	(af) Tariff 8				2,825		145,101		145,101
8	Bonneville Power Administration	SF	Tariff 9				116,089		4,399,082		4,399,082
9	Bonneville Power Administration	LF	(ag) Tariff 12				71		1,868		1,868
10	British Columbia Hydro and Power Authority	LF	(ah) Tariff 12				169		13,295		13,295
11	Brookfield Energy Marketing LP	SF	Tariff 9				1,238		48,469		48,469
12	Brookfield Energy Marketing LP	(c) IF	Tariff 9				48		2,807		2,807
13	California Independent System Operator Corporation	SF	Tariff 9				219,055		10,762,418		10,762,418
14	Calpine Energy Services, LP	SF	Tariff 9				12,804		585,924		585,924
15	Chelan County PUD No. 1	SF	Tariff 9				16		530		530
16	Chelan County PUD No. 1	LF	(ai) Tariff 12				7		180		180
17	Citigroup Energy, Inc.	SF	Tariff 9				4,000		90,500		90,500
18	Clatskanie Peoples PUD	SF	Tariff 9				1,953		102,323		102,323
19	ConocoPhillips Company	SF	Tariff 9				42,327		1,472,620		1,472,620
20	(a) Douglas County PUD No. 1	SF	Tariff 9						12,097		12,097
21	Dynasty Power, Inc.	SF	Tariff 9				4,594		410,329		410,329
22	Dynasty Power, Inc.	(d) IF	Tariff 9				291		92,932		92,932
23	EDF Trading North America, LLC	SF	Tariff 9				58,073		2,478,351		2,478,351
24	EDF Trading North America, LLC	SF	Tariff 9					(aw) 43,800			43,800
25	Energy Keepers, Inc.	SF	Tariff 9				17,097		982,826		982,826
26	Eugene Water Electric Board	SF	Tariff 9				12,273		591,403		591,403
27	Exelon Generation Company, LLC	SF	Tariff 9				31,910		1,470,134		1,470,134
28	Grant County PUD No. 2	LF	(aj) Tariff 12				2		46		46
29	Grant County PUD No. 2	SF	Tariff 9				16,200		951,750		951,750
30	Gridforce Energy Management, LLC	LF	(ak) Tariff 12				219		7,785		7,785
31	Guzman Energy, LLC	SF	Tariff 9				2,011		152,666		152,666
32	Guzman Energy, LLC	(e) IF	Tariff 9				670		64,141		64,141
33	Idaho Power Company	LF	(al) Tariff 12				14		602		602
34	Idaho Power Company Balancing	SF	Tariff 9				3,961		137,740		137,740

35	Idaho Power Company Balancing	(f) IF	Tariff 9				7,814		538,320		538,320
36	Kootenai Electric Cooperative	LF	(am) Tariff 8				1,398		71,994		71,994
37	Macquarie Energy LLC	SF	Tariff 9				61,702		2,557,920		2,557,920
38	Macquarie Energy LLC	(g) IF	Tariff 9				1,118		127,001		127,001
39	Mercuria Energy America, LLC	(h) IF	Tariff 9				62		3,191		3,191
40	Mizuho Securities USA Inc.	(i) OS	NA				0			(14,352,636)	(14,352,636)
41	Morgan Stanley Capital Group Inc.	SF	Tariff 9				450,735		19,348,251		19,348,251
42	Morgan Stanley Capital Group Inc.	(j) IF	Tariff 9				6,177		572,962		572,962
43	Morgan Stanley Capital Group Inc.	(k) IF	Tariff 9				391,920		15,812,201		15,812,201
44	Morgan Stanley Capital Group Inc.	SF	Tariff 9					(ax) 275,940			275,940
45	Morgan Stanley Capital Group Inc.	SF	Tariff 9					(ay) 275,940			275,940
46	NaturEner Power Watch, LLC	LF	(an) Tariff 12				130		3,276		3,276
47	Nevada Power Company	SF	Tariff 9				894		195,365		195,365
48	NorthWestern Energy	SF	Tariff 9				42,446		2,084,045		2,084,045
49	NorthWestern Energy	(l) IF	Tariff 9				249		13,063		13,063
50	NorthWestern Energy	LF	(ao) Tariff 12				40		979		979
51	NorthWestern Energy	(m) LF	Tariff 9				6,200		326,069		326,069
52	PacifiCorp	SF	Tariff 9				113,095		5,590,888		5,590,888
53	PacifiCorp	LF	(ap) Tariff 12				56		2,619		2,619
54	PacifiCorp	(n) LF	Tariff 9				3,945		207,499		207,499
55	Pend Oreille Public Utility District	(o) LF	Tariff 9					326,049			326,049
56	Pend Oreille Public Utility District	(p) LF	Tariff 9				17,295		787,211		787,211
57	Pend Oreille Public Utility District	SF	Tariff 9				49,852		3,127,903		3,127,903
58	Portland General Electric	SF	Tariff 9				55,830		2,899,725		2,899,725
59	Portland General Electric	LF	(aq) Tariff 12				55		2,313		2,313
60	Powerex Corporation	SF	Tariff 9				95,800		3,060,063		3,060,063
61	Powerex Corporation	(q) IF	Tariff 9				9,218		708,646		708,646
62	Puget Sound Energy	(r) LF	Tariff 9				18,033		948,565		948,565
63	Puget Sound Energy	SF	Tariff 9				37,095		1,680,865		1,680,865
64	Puget Sound Energy	LF	(ar) Tariff 12				8		414		414
65	Rainbow Energy Marketing	SF	Tariff 9				1,925		120,794		120,794
66	Rainbow Energy Marketing	(s) IF	Tariff 9				175		22,498		22,498
67	Sacramento Municipal Utility District	LF	(as) Tariff 12				10		311		311
68	Seattle City Light	SF	Tariff 9				18,986		644,575		644,575
69	Seattle City Light	(t) LF	Tariff 9				546		29,521		29,521
70	Seattle City Light	LF	(at) Tariff 12				80		7,921		7,921
71	Shell Energy N.A.	SF	Tariff 9				84,030		3,884,307		3,884,307
72	Snohomish County PUD	SF	Tariff 9				21,115		1,098,749		1,098,749
73	Sovereign Power	(u) LF	Tariff 9					135,565			135,565
74	Sovereign Power	(v) LF	Tariff 9				14,763		622,636		622,636
75	Tacoma Power	SF	Tariff 9				6,070		219,885		219,885
76	Tacoma Power	(w) LF	Tariff 9				1,610		92,395		92,395
77	Talen Energy Montana, LLC	(x) LF	Tariff 9				14,088		741,066		741,066
78	Tenaska Power Services Co.	SF	Tariff 9				494		14,543		14,543
79	The Energy Authority	SF	Tariff 9				25,664		1,138,780		1,138,780
80	The Energy Authority	(y) IF	Tariff 9				456		31,137		31,137
81	TransAlta Energy Marketing	SF	Tariff 9				214,159		11,871,447		11,871,447
82	TransAlta Energy Marketing	(z) IF	Tariff 9				25		1,347		1,347
83	Turlock Irrigation Dist.	LF	(au) Tariff 12				3		0		0
84	Vitol, Inc.	SF	Tariff 9				3,200		102,700		102,700
85	Wells Fargo Securities, LLC	(aa) OS	NA				0			(10,530,004)	(10,530,004)
86	IntraCompany Wheeling	(ab) LF							(17,311,196)	17,311,196	0
87	IntraCompany Generation	(ac) LF								1,514,192	1,514,192
88		SF	Tariff 9						71,323		71,323

	(b) Powerdex Pricing Accrual										
15	Subtotal - RQ										0
16	Subtotal-Non-RQ						2,519,288	1,481,244	98,161,809	(6,057,252)	93,585,801
17	Total						2,519,288	1,481,244	98,161,809	(6,057,252)	93,585,801

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityReceivingElectricityPurchasedForResale
Energy Imbalance - Dutch Henry Mobile Sub temporary agreement.
(b) Concept: NameOfCompanyOrPublicAuthorityReceivingElectricityPurchasedForResale
To accrue for missing Powerdex prices at year-end.
(c) Concept: StatisticalClassificationCode
Financially Settled Transmission Losses
(d) Concept: StatisticalClassificationCode
Financially Settled Transmission Losses
(e) Concept: StatisticalClassificationCode
Financially Settled Transmission Losses
(f) Concept: StatisticalClassificationCode
Financially Settled Transmission Losses
(g) Concept: StatisticalClassificationCode
Financially Settled Transmission Losses
(h) Concept: StatisticalClassificationCode
Financially Settled Transmission Losses
(i) Concept: StatisticalClassificationCode
Financial SWAP
(j) Concept: StatisticalClassificationCode
Financially Settled Transmission Losses
(k) Concept: StatisticalClassificationCode
Resource Contingent Bundled REC - Energy and Green Attributes 03/01/2019-12/31/2023.
(l) Concept: StatisticalClassificationCode
Financially Settled Transmission Losses
(m) Concept: StatisticalClassificationCode
NorthWestern Energy LLC sale expires October 31, 2023.
(n) Concept: StatisticalClassificationCode
PacifiCorp sale terminates October 31, 2023.
(o) Concept: StatisticalClassificationCode
Contract expires September 30, 2026.
(p) Concept: StatisticalClassificationCode
Deviation Energy
(q) Concept: StatisticalClassificationCode
Financially Settled Transmission Losses
(r) Concept: StatisticalClassificationCode
Puget Sound Energy sale terminates October 31, 2023.
(s) Concept: StatisticalClassificationCode
Financially Settled Transmission Losses
(t) Concept: StatisticalClassificationCode
Financially Settled Transmission Losses
(u) Concept: StatisticalClassificationCode
Sovereign Power contract terminates September 30, 2026.
(v) Concept: StatisticalClassificationCode
Deviation Energy
(w) Concept: StatisticalClassificationCode
Financially Settled Transmission Losses
(x) Concept: StatisticalClassificationCode
Talen Energy sale terminates October 31, 2023.
(y) Concept: StatisticalClassificationCode
Financially Settled Transmission Losses
(z) Concept: StatisticalClassificationCode
Financially Settled Transmission Losses
(aa) Concept: StatisticalClassificationCode
Financial SWAP
(ab) Concept: StatisticalClassificationCode
IntraCompany Wheeling terminates September 30, 2023.
(ac) Concept: StatisticalClassificationCode
IntraCompany Generation - Sale of Ancillary Services.
(ad) Concept: RateScheduleTariffNumber
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
(ae) Concept: RateScheduleTariffNumber
BPA Contract Terminates September 30, 2028.
(af) Concept: RateScheduleTariffNumber
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.
(ag) Concept: RateScheduleTariffNumber
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
(ah) Concept: RateScheduleTariffNumber
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
(ai) Concept: RateScheduleTariffNumber
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
(aj) Concept: RateScheduleTariffNumber
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
(ak) Concept: RateScheduleTariffNumber
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
(al) Concept: RateScheduleTariffNumber
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
(am) Concept: RateScheduleTariffNumber
Kootenai Contract Terminates March 31, 2024
(an) Concept: RateScheduleTariffNumber
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
(ao) Concept: RateScheduleTariffNumber

Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
(ap) Concept: RateScheduleTariffNumber
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
(aq) Concept: RateScheduleTariffNumber
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
(ar) Concept: RateScheduleTariffNumber
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
(as) Concept: RateScheduleTariffNumber
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
(at) Concept: RateScheduleTariffNumber
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
(au) Concept: RateScheduleTariffNumber
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
(av) Concept: DemandChargesRevenueSalesForResale
Capacity
(aw) Concept: DemandChargesRevenueSalesForResale
Reserves
(ax) Concept: DemandChargesRevenueSalesForResale
Capacity
(ay) Concept: DemandChargesRevenueSalesForResale
Capacity

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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) (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	371,419	354,806
5	(501) Fuel	34,555,011	29,506,761
6	(502) Steam Expenses	3,410,780	3,514,368
7	(503) Steam from Other Sources	0	
8	(Less) (504) Steam Transferred-Cr.	0	
9	(505) Electric Expenses	707,246	743,487
10	(506) Miscellaneous Steam Power Expenses	5,582,569	4,636,347
11	(507) Rents	0	
12	(509) Allowances	0	
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	44,627,025	38,755,769
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	773,701	660,566
16	(511) Maintenance of Structures	723,571	776,895
17	(512) Maintenance of Boiler Plant	7,818,349	7,796,381
18	(513) Maintenance of Electric Plant	2,056,873	2,263,602
19	(514) Maintenance of Miscellaneous Steam Plant	1,153,608	1,186,306
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	12,526,102	12,683,750
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	57,153,127	51,439,519
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	0	
25	(518) Fuel	0	
26	(519) Coolants and Water	0	
27	(520) Steam Expenses	0	
28	(521) Steam from Other Sources	0	
29	(Less) (522) Steam Transferred-Cr.	0	
30	(523) Electric Expenses	0	
31	(524) Miscellaneous Nuclear Power Expenses	0	
32	(525) Rents	0	
33	TOTAL Operation (Enter Total of lines 24 thru 32)	0	
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	0	
36	(529) Maintenance of Structures	0	
37	(530) Maintenance of Reactor Plant Equipment	0	
38	(531) Maintenance of Electric Plant	0	
39	(532) Maintenance of Miscellaneous Nuclear Plant	0	
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	0	
41	TOTAL Power Production Expenses-Nuclear. Power (Enter Total of lines 33 & 40)	0	
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	2,203,417	1,909,402
45	(536) Water for Power	1,149,414	1,417,118
46	(537) Hydraulic Expenses	8,626,222	9,826,421
47	(538) Electric Expenses	5,746,493	5,782,034
48	(539) Miscellaneous Hydraulic Power Generation Expenses	1,168,693	1,089,381
49	(540) Rents	6,847,161	6,590,160
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	25,741,400	26,614,516
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintentance Supervision and Engineering	627,755	577,244
54	(542) Maintenance of Structures	681,202	2,148,575
55	(543) Maintenance of Reservoirs, Dams, and Waterways	780,343	347,512
56	(544) Maintenance of Electric Plant	3,386,126	3,116,588
57	(545) Maintenance of Miscellaneous Hydraulic Plant	624,586	672,199
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	6,100,012	6,862,118

59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)	31,841,412	33,476,634
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	407,941	387,513
63	(547) Fuel	97,277,819	53,865,752
64	(548) Generation Expenses	1,835,082	2,362,990
64.1	(548.1) Operation of Energy Storage Equipment	0	
65	(549) Miscellaneous Other Power Generation Expenses	942,690	407,606
66	(550) Rents	87,122	84,304
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	100,550,654	57,108,165
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	706,634	681,138
70	(552) Maintenance of Structures	91,546	178,602
71	(553) Maintenance of Generating and Electric Plant	4,974,985	4,117,018
71.1	(553.1) Maintenance of Energy Storage Equipment	0	
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	858,287	408,807
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	6,631,452	5,385,565
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	107,182,106	62,493,730
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	156,401,039	136,251,226
76.1	(555.1) Power Purchased for Storage Operations	(3,938,836)	
77	(556) System Control and Load Dispatching	757,040	708,451
78	(557) Other Expenses	33,704,826	33,286,543
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	186,924,069	170,246,220
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	383,100,714	317,656,103
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	1,807,039	2,195,597
85	(561.1) Load Dispatch-Reliability	32,205	25,215
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,101,498	1,203,318
87	(561.3) Load Dispatch-Transmission Service and Scheduling	947,297	1,008,482
88	(561.4) Scheduling, System Control and Dispatch Services	0	
89	(561.5) Reliability, Planning and Standards Development	523,067	483,110
90	(561.6) Transmission Service Studies	0	655
91	(561.7) Generation Interconnection Studies	0	4,366
92	(561.8) Reliability, Planning and Standards Development Services	0	
93	(562) Station Expenses	406,546	477,902
93.1	(562.1) Operation of Energy Storage Equipment	0	
94	(563) Overhead Lines Expenses	582,254	423,608
95	(564) Underground Lines Expenses	0	
96	(565) Transmission of Electricity by Others	18,301,413	16,539,039
97	(566) Miscellaneous Transmission Expenses	3,224,770	2,365,717
98	(567) Rents	103,366	185,537
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	27,029,455	24,912,546
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	449,358	426,853
102	(569) Maintenance of Structures	656,084	429,943
103	(569.1) Maintenance of Computer Hardware	0	
104	(569.2) Maintenance of Computer Software	0	
105	(569.3) Maintenance of Communication Equipment	0	
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant	0	
107	(570) Maintenance of Station Equipment	856,933	761,185
107.1	(570.1) Maintenance of Energy Storage Equipment	0	
108	(571) Maintenance of Overhead Lines	1,951,772	1,346,772
109	(572) Maintenance of Underground Lines	18,408	3,651
110	(573) Maintenance of Miscellaneous Transmission Plant	85,457	35,220
111	TOTAL Maintenance (Total of Lines 101 thru 110)	4,018,012	3,003,624
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	31,047,467	27,916,170
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision	0	
116	(575.2) Day-Ahead and Real-Time Market Facilitation	0	
117	(575.3) Transmission Rights Market Facilitation	0	
118	(575.4) Capacity Market Facilitation	0	
119	(575.5) Ancillary Services Market Facilitation	0	

120	(575.6) Market Monitoring and Compliance	0	
121	(575.7) Market Facilitation, Monitoring and Compliance Services	0	
122	(575.8) Rents	0	
123	Total Operation (Lines 115 thru 122)	0	
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements	0	
126	(576.2) Maintenance of Computer Hardware	0	
127	(576.3) Maintenance of Computer Software	0	
128	(576.4) Maintenance of Communication Equipment	0	
129	(576.5) Maintenance of Miscellaneous Market Operation Plant	0	
130	Total Maintenance (Lines 125 thru 129)	0	
131	TOTAL Regional Transmission and Market Operation Expenses (Enter Total of Lines 123 and 130)	0	
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	3,834,402	3,716,544
135	(581) Load Dispatching	0	
136	(582) Station Expenses	1,033,177	641,798
137	(583) Overhead Line Expenses	2,986,138	2,561,515
138	(584) Underground Line Expenses	1,766,600	1,747,358
138.1	(584.1) Operation of Energy Storage Equipment	0	
139	(585) Street Lighting and Signal System Expenses	9,754	38,628
140	(586) Meter Expenses	1,897,373	1,634,878
141	(587) Customer Installations Expenses	730,717	689,416
142	(588) Miscellaneous Expenses	5,301,940	4,826,245
143	(589) Rents	236,112	275,841
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	17,796,213	16,132,223
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	1,335,012	1,374,983
147	(591) Maintenance of Structures	501,697	566,579
148	(592) Maintenance of Station Equipment	688,988	494,075
148.1	(592.2) Maintenance of Energy Storage Equipment	0	
149	(593) Maintenance of Overhead Lines	16,559,877	13,734,825
150	(594) Maintenance of Underground Lines	656,866	676,586
151	(595) Maintenance of Line Transformers	346,050	430,900
152	(596) Maintenance of Street Lighting and Signal Systems	105,195	141,014
153	(597) Maintenance of Meters	35,578	50,253
154	(598) Maintenance of Miscellaneous Distribution Plant	1,364,862	553,027
155	TOTAL Maintenance (Total of Lines 146 thru 154)	21,594,125	18,022,242
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	39,390,338	34,154,465
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	173,172	149,519
160	(902) Meter Reading Expenses	771,368	1,204,370
161	(903) Customer Records and Collection Expenses	7,235,525	7,480,445
162	(904) Uncollectible Accounts	6,543,365	7,961,674
163	(905) Miscellaneous Customer Accounts Expenses	93,399	145,713
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	14,816,829	16,941,721
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	0	
168	(908) Customer Assistance Expenses	34,479,894	33,716,712
169	(909) Informational and Instructional Expenses	721,166	1,029,735
170	(910) Miscellaneous Customer Service and Informational Expenses	321,468	320,788
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	35,522,528	35,067,235
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision	0	
175	(912) Demonstrating and Selling Expenses	131,462	
176	(913) Advertising Expenses	0	
177	(916) Miscellaneous Sales Expenses	0	
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	131,462	
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	32,391,556	27,858,120

182	(921) Office Supplies and Expenses	4,031,699	4,275,810
183	(Less) (922) Administrative Expenses Transferred-Credit	100,690	103,030
184	(923) Outside Services Employed	12,782,457	10,580,489
185	(924) Property Insurance	2,039,037	1,673,027
186	(925) Injuries and Damages	7,352,763	4,251,143
187	(926) Employee Pensions and Benefits	29,316,292	31,925,253
188	(927) Franchise Requirements	1,200	1,200
189	(928) Regulatory Commission Expenses	6,681,340	6,021,061
190	(929) (Less) Duplicate Charges-Cr.	0	
191	(930.1) General Advertising Expenses	0	
192	(930.2) Miscellaneous General Expenses	5,236,355	6,469,003
193	(931) Rents	793,091	566,423
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	100,525,100	93,518,499
195	Maintenance		
196	(935) Maintenance of General Plant	13,299,900	12,476,593
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	113,825,000	105,995,092
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	617,834,338	537,730,786

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

PURCHASED POWER (Account 555)

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.

   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, excluding purchases for energy storage. Report in column (h) the megawatthours shown on bills rendered to the respondent for energy storage purchases. Report in columns (i) and (j) 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 (k), energy charges in column (l), and the total of any other types of charges, including out-of-period adjustments, in column (m). Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (n) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (m) 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 columns (g) through (n) must be totaled on the last line of the schedule. The total amount in columns (g) and (h) must be reported as Purchases on Page 401, line 10. The total amount in column (i) must be reported as Exchange Received on Page 401, line 12. The total amount in column (j) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

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)	MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES MegaWatt Hours Received (i)	POWER EXCHANGES MegaWatt Hours Delivered (j)	COST/SETTLEMENT OF POWER Demand Charges ($) (k)	COST/SETTLEMENT OF POWER Energy Charges ($) (l)	COST/SETTLEMENT OF POWER Other Charges ($) (m)	COST/SETTLEMENT OF POWER Total (k+l+m) of Settlement ($) (n)
1	Adams Nielson Solar, LLC	LU	PURPA				43,328					1,753,484		1,753,484
2	Avangrid Renewables, LLC	SF	Tariff 9				105,393					3,103,982		3,103,982
3	[(a)] Avangrid Renewables, LLC	LF	NWPP				14					411		411
4	BP Energy	SF	Tariff 9				400					137,688		137,688
5	Black Hills Power, Inc.	SF	Tariff 9				40					3,000		3,000
6	[(b)] Bonneville Power Administration	LF	Tariff 8				274							0
7	Bonneville Power Administration	SF	Tariff 9				52,106					3,021,866		3,021,866
8	[(c)] Bonneville Power Administration	LF	NWPP				236					10,050		10,050
9	[(d)] Bonneville Power Administration	LF	Tariff 8				22,514					959,757		959,757
10	[(e)] Bonneville Power Administration	LF	Tariff 8				1,829					100,286		100,286
11	[(f)] Bonneville Power Administration	OS	BPA OATT										31,004	31,004
12	Brookfield Energy Marketing LP	SF	Tariff 9				5,434					257,342		257,342
13	CP Energy Marketing (US) Inc.	SF	Tariff 9				175					106,550		106,550
14	California Independent System Operator	SF	Tariff 9				10,496					541,173		541,173
15	Calpine Energy Services, LP	SF	Tariff 9				6,145					187,688		187,688
16	Chelan County PUD	IU	Rocky Reach				22,161							0
17	[(g)] Chelan County PUD	IU	Rocky Reach				(23,762)							0
18	Chelan County PUD	SF	Tariff 9				124,200					4,019,800		4,019,800
19	[(h)] Chelan County PUD	LF	NWPP				10					509		509
20	Chelan County PUD	IU	Chelan Sys				404,289				14,300,000			14,300,000
21	City of Spokane	IU	PURPA				50,784					1,916,962		1,916,962
22	City of Spokane	IU	PURPA				119,640					5,636,059		5,636,059
23	Clark Fork Hydro	LU	PURPA				886					55,589		55,589
24	Clatskanie PUD	SF	Tariff 9				854					29,270		29,270

25	Clearwater Paper Company	IU	PURPA				424,874					10,409,413		10,409,413
26	(i) Clearwater Power Company	RQ	NA				185					16,352		16,352
27	Community Solar	LU	PURPA				545							0
28	ConocoPhillips Company	SF	Tariff 9				26,658					1,104,650		1,104,650
29	Deep Creek Energy, LLC	IU	PURPA				223					9,121		9,121
30	Douglas County PUD No. 1	LU	Wells				452,357				3,400,592			3,400,592
31	(j) Douglas County PUD No. 1	LF	NWPP				1					25		25
32	(k) Douglas County PUD No. 1	OS	Wells										1,468,579	1,468,579
33	Douglas County PUD No. 1	EX	Tariff 9							411,720				0
34	Dynasty Power, Inc.	SF	Tariff 9				6,765					1,853,118		1,853,118
35	EDF Trading No America	SF	Tariff 9				3,299					223,394		223,394
36	Enel X North America, Inc.	LU	PURPA				48							0
37	Energy Keepers, Inc.	SF	Tariff 9				1,780					213,450		213,450
38	Eugene Water & Electric Board	SF	Tariff 9				2,711					118,151		118,151
39	Exelon Generation Company, LLC	SF	Tariff 9				17,749					474,198		474,198
40	Ford Hydro Limited Partnership	LU	PURPA				2,989					234,443		234,443
41	Grant County PUD No. 2	LU	Priest Rapids				332,485				11,276,183			11,276,183
42	(l) Grant County PUD No. 2	LF	NWPP				18					850		850
43	(m) Grant County PUD No. 2	EX	FERC #104										(58,028)	(58,028)
44	Grant County PUD No. 2	SF	Tariff 9				41					2,229		2,229
45	Great Northern Spokane, LLC	LU	PURPA				106							0
46	(n) Gridforce Energy Management, LLC	LF	NWPP				16					741		741
47	Guzman Energy, LLC	SF	Tariff 9				3,970					193,831		193,831
48	Hydro Technology Systems	IU	PURPA				7,709					275,368		275,368
49	Idaho County Power & Light	LU	PURPA				2,640					133,149		133,149
50	(o) Idaho Power Company	OS	Idaho Power Co OATT										189	189
51	Idaho Power Company	SF	Tariff 9				15,025					647,729		647,729
52	(p) Idaho Power Company	LF	Tariff 9				56					7,766		7,766
53	(q) Inland Power & Light Company	RQ	208				168					11,971		11,971
54	(r) Kootenai Electric Cooperative	LF	Tariff 8				1,320					70,095		70,095
55	Macquarie Energy, LLC	SF	Tariff 9				18,243					847,327		847,327
56	(s) Mizuho Securities USA, Inc.	OS	NA										(3,188,064)	(3,188,064)
57	Morgan Stanley Capital Group	SF	Tariff 9				40,024					1,494,857		1,494,857
58	(t) Nevada Power Company	OS	NV Energy OATT										(1,033)	(1,033)
59	(u) Nevada Power Company	LF	Tariff 9				5					124		124
60	NextEra Energy Power Marketing, LLC	SF	Tariff 9				800					35,200		35,200
61	NorthWestern Energy	SF	Tariff 9				42,570					1,244,444		1,244,444
62	(v) NorthWestern Energy	LF	NWPP				33					1,390		1,390
63	(w) NorthWestern Energy	IF	Tariff 9				4,475					211,030		211,030
64	(x) NorthWestern Energy	OS	NorthWestern Energy OATT										19,976	19,976
65	PacifiCorp	SF	Tariff 9				19,310					898,754		898,754
66	(y) PacifiCorp	LF	NWPP				68					3,072		3,072

67	[z] PacifiCorp	OS	PacifiCorp OATT										(1,392)	(1,392)
68	Palouse Wind, LLC	LU	PPA				360,783					23,057,642		23,057,642
69	Pend Oreille County PUD No. 1	SF	Pend O'				20,971					722,988		722,988
70	[aa][ab] Pend Oreille County PUD No. 1	LF	Pend O'				6,925					223,805		223,805
71	Pend Oreille County PUD No. 1	LF	Pend O'				482					12,494		12,494
72	[ac] Portland General Electric Company	EX	Tariff 9						7,890	7,889				0
73	Portland General Electric Company	SF	Tariff 9				40,097					1,864,140		1,864,140
74	[ad] Portland General Electric Company	LF	NWPP				46					1,590		1,590
75	[ae] Portland General Electric Company	LF	Tariff 9				4,364					144,824		144,824
76	Powerex Corp	SF	Tariff 9				61,728					3,538,850		3,538,850
77	Puget Sound Energy	SF	Tariff 9				55,857					2,877,377		2,877,377
78	[af] Puget Sound Energy	LF	NWPP				67					3,006		3,006
79	[ag] Puget Sound Energy	LF	Tariff 9				10					560		560
80	Rainbow Energy Marketing Co.	SF	Tariff 9				1,299					93,800		93,800
81	Rathdrum Power, LLC	LU	Lancaster				1,820,368					28,827,646		28,827,646
82	Rattlesnake Flat, LLC	LU	PPA				423,510					12,747,296		12,747,296
83	Seattle City Light	SF	Tariff 9				8,070					331,920		331,920
84	[ah] Seattle City Light	LF	NWPP				26					1,159		1,159
85	Sheep Creek Hydro	IU	PURPA				6,641					316,546		316,546
86	Shell Energy	SF	Tariff 9				77,032					2,658,619		2,658,619
87	Snohomish County PUD No. 1	SF	Tariff 9				22,440					2,269,580		2,269,580
88	[ai] Sovereign Power	LF	Sovereign				7,917					285,711		285,711
89	Spokane County	LU	PURPA				1,123					31,507		31,507
90	Stimson Lumber	IU	PURPA				35,127					1,521,376		1,521,376
91	Tacoma Power	SF	Tariff 9				13,722					943,975		943,975
92	[aj] Tacoma Power	LF	NWPP				12					489		489
93	The City of Cove	LU	PURPA				2,337					91,479		91,479
94	The Energy Authority	SF	Tariff 9				20,757					922,835		922,835
95	TransAlta Energy Marketing	SF	Tariff 9				59,274					2,079,496		2,079,496
96	Turlock Irrigation District	SF	Tariff 9				7,482					178,040		178,040
97	Vitol Inc.	SF	Tariff 9				2,000					60,320		60,320
98	[ak] Wells Fargo Securities, LLC	OS	NA										(750,772)	(750,772)
99	[al] IntraCompany Generation Services	OS	OATT										1,514,192	1,514,192
100	Other - Inadvertent Interchange	EX								747				0
101	[am] Powerdex Pricing Accrual	SF	Tariff 9									2,835		2,835
15	TOTAL						5,437,179	0	7,890	420,356	28,976,775	128,389,613	(965,349)	156,401,039

FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.

(b) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

BPA Self Supply for NITSA customers.

(c) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Reserve sharing under the NorthWest Power Pool Reserve Sharing Agreement.

(d) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

BPA contract terminates September 30, 2028.

(e) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

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.

(f) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Ancillary Services - Spinning & Supplemental

(g) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Canadian Entitlement

(h) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.

(i) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Service to Ahsahka, Idaho from Clearwater Power Company. No demand charges associated with the agreement.

(j) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.

(k) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Canadian Entitlement associated with Wells contract.

(l) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.

(m) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Exchange

(n) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.

(o) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Energy Imbalance Charges

(p) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Financially Settled Transmission Losses

(q) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Service to Deer Lake from Inland Power and Light. No demand charges associated with the agreement.

(r) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Kootenai contract terminates March 31, 2024.

(s) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Financial SWAP

(t) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Energy Imbalance Charges

(u) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Financially Settled Transmission Losses

(v) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.

(w) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Financially Settled Transmission Losses

(x) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Energy Imbalance Charges

(y) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.

(z) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Energy Imbalance Charges

(aa) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Pend Oreille County PUD contract expires September 30, 2026.

(ab) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Pend Oreille County PUD contract expires September 30, 2026.

(ac) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Exchange

(ad) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.

(ae) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Financially Settled Transmission Losses

(af) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.

(ag) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Financially Settled Transmission Losses

(ah) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.

(ai) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Sovereign contract terminates September 30, 2026.

(aj) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.

(ak) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Financial SWAP

(al) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Ancillary Services

(am) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

To accrue for missing Powerdex prices at year-end.

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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.
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.
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 (0) 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.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)	Ferc Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS			
									Megawatt Hours Received (i)	Megawatt Hours Delivered (j)	Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total Revenues ($) (k+l+m) (n)
1	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	FNO	FERC Trf No. 8	AVA.BPAT	AVA.SYS		2,103,384	2,103,384	7,070,473		[a]1,459,138	8,529,611
2	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	OS	RS No. T1110								[b]924,000	924,000
3	Bonneville Power Administration	Bonneville Power Administration	Idaho Power Company	NF	FERC Trf No. 8				23,297	23,297	156,784			156,784
4	Bonneville Power Administration	Bonneville Power Administration	Avista Corporation	NF	FERC Trf No. 8				12	12	79			79
5	Bonneville Power Administration	Bonneville Power Administration	Avista Corporation	SFP	FERC Trf No. 8				9,819	9,819				0
6	Brookfield Renewable Trading and Marketing LP	NorthWestern Energy	Bonneville Power Administration	SFP	FERC Trf No. 8				800	800	4,227			4,227
7	Brookfield Renewable Trading and Marketing LP	NorthWestern Energy	Grant County PUD	NF	FERC Trf No. 8				400	400	2,308			2,308
8	Brookfield Renewable Trading and Marketing LP	NorthWestern Energy	Grant County PUD	SFP	FERC Trf No. 8				400	400	2,113			2,113
9	City of Spokane	City of Spokane	Avista Corporation	OLF	PURPA								[c]27,973	27,973
10	Consolidated Irrigation	Bonneville Power Administration	Consolidated Irrigation	LFP	FERC Trf No. 8	AVA.BPAT	AVA.SYS	4	7,637	7,637	32,365		[d]11,063	43,428
11	Shell Energy North America	Bonneville Power Administration	Idaho Power Company	NF	FERC Trf No. 8				3,091	3,091	21,674			21,674
12	Shell Energy North America	Bonneville Power Administration	Idaho Power Company	SFP	FERC Trf No. 8				1,167	1,167	125,881			125,881
13	Shell Energy North America	Bonneville Power Administration	NorthWestern Energy	NF	FERC Trf No. 8				351	351	2,427			2,427
14	Shell Energy North America	NorthWestern Energy	Bonneville Power Administration	NF	FERC Trf No. 8				681	681	3,932			3,932
15	Shell Energy North America	NorthWestern Energy	Grant County PUD	NF	FERC Trf No. 8				1,041	1,041	7,012			7,012
16	Shell Energy North America	NorthWestern Energy	Grant County PUD	SFP	FERC Trf No. 8				211,973	211,973	724,285			724,285
17	Shell Energy North America	NorthWestern Energy	PacifiCorp	SFP	FERC Trf No. 8				2,044	2,044	7,431			7,431
18	Shell Energy North America	PacifiCorp	Idaho Power Company	NF	FERC Trf No. 8				120	120	848			848
19	Shell Energy North America	PacifiCorp	NorthWestern Energy	NF	FERC Trf No. 8				14	14	104			104
20	Shell Energy North America	Grant County PUD	Idaho Power Company	NF	FERC Trf No. 8				405	405	3,189			3,189
21	Shell Energy North America	Grant County PUD	Idaho Power Company	SFP	FERC Trf No. 8				3,376	3,376	304,619			304,619
22	Shell Energy North America	Grant County PUD	NorthWestern Energy	NF	FERC Trf No. 8				257	257	1,618			1,618
23	Shell Energy North America	Grant County PUD	NorthWestern Energy	SFP	FERC Trf No. 8				560	560	2,657			2,657
24	Shell Energy North America	Idaho Power Company	NorthWestern Energy	NF	FERC Trf No. 8				2,483	2,483	20,025			20,025
25	Shell Energy North America	Idaho Power Company	Grant County PUD	NF	FERC Trf No. 8				1,903	1,903	13,389			13,389
26	Shell Energy North America	Avista Corporation	Idaho Power Company	SFP	FERC Trf No. 8				8	8	1,498			1,498

27	Deep Creek Hydro	Deep Creek	Avista Corporation	OLF	PURPA								[e]603	603
28	Douglas County PUD	Bonneville Power Administration	Avista Corporation	NF	FERC Trf No. 8								[f]11,358	11,358
29	Douglas County PUD	Bonneville Power Administration	Avista Corporation	NF	FERC Trf No. 8				144	144	831			831
30	Douglas County PUD	Douglas County PUD	Avista Corporation	NF	FERC Trf No. 8				4,083	4,083	23,948			23,948
31	Dynasty Power Inc.	Bonneville Power Administration	Idaho Power Company	NF	FERC Trf No. 8				791	791	5,081			5,081
32	Dynasty Power Inc.	Bonneville Power Administration	NorthWestern Energy	NF	FERC Trf No. 8				301	301	1,960			1,960
33	Dynasty Power Inc.	Bonneville Power Administration	Avista Corporation	NF	FERC Trf No. 8				660	660	4,311			4,311
34	Dynasty Power Inc.	Bonneville Power Administration	Avista Corporation	SFP	FERC Trf No. 8				100	100	805			805
35	Dynasty Power Inc.	NorthWestern Energy	Bonneville Power Administration	NF	FERC Trf No. 8				237	237	1,400			1,400
36	Dynasty Power Inc.	NorthWestern Energy	Idaho Power Company	NF	FERC Trf No. 8				932	932	6,687			6,687
37	Dynasty Power Inc.	NorthWestern Energy	PacifiCorp	SFP	FERC Trf No. 8				1,626	1,626	9,510			9,510
38	Dynasty Power Inc.	NorthWestern Energy	Puget Sound Energy	SFP	FERC Trf No. 8				566	566	4,558			4,558
39	Dynasty Power Inc.	PacifiCorp	Idaho Power Company	NF	FERC Trf No. 8				215	215	1,464			1,464
40	Dynasty Power Inc.	Idaho Power Company	Bonneville Power Administration	SFP	FERC Trf No. 8				701	701	5,645			5,645
41	Dynasty Power Inc.	Idaho Power Company	PacifiCorp	SFP	FERC Trf No. 8				1,302	1,302	10,485			10,485
42	Dynasty Power Inc.	Idaho Power Company	Avista Corporation	SFP	FERC Trf No. 8				2,202	2,202	17,733			17,733
43	Dynasty Power Inc.	Avista Corporation	Bonneville Power Administration	NF	FERC Trf No. 8				100	100	594			594
44	Dynasty Power Inc.	Avista Corporation	Avista Corporation	SFP	FERC Trf No. 8						64,610			64,610
45	EDR Trading North America	Bonneville Power Administration	NorthWestern Energy	NF	FERC Trf No. 8				6,452	6,452	43,797			43,797
46	EDR Trading North America	Bonneville Power Administration	NorthWestern Energy	SFP	FERC Trf No. 8				5,170	5,170	474,736			474,736
47	EDR Trading North America	NorthWestern Energy	Bonneville Power Administration	NF	FERC Trf No. 8				125	125	777			777
48	EDR Trading North America	NorthWestern Energy	Bonneville Power Administration	SFP	FERC Trf No. 8				173	173	10,482			10,482
49	EDR Trading North America	NorthWestern Energy	Grant County PUD	SFP	FERC Trf No. 8				464	464	28,113			28,113
50	EDR Trading North America	NorthWestern Energy	PacifiCorp	SFP	FERC Trf No. 8				1,600	1,600	86,670			86,670
51	EDR Trading North America	NorthWestern Energy	Avista Corporation	NF	FERC Trf No. 8				447	447	3,362			3,362
52	EDR Trading North America	Idaho Power Company	Bonneville Power Administration	SFP	FERC Trf No. 8				400	400	7,384			7,384
53	EDR Trading North America	Avista Corporation	Bonneville Power Administration	NF	FERC Trf No. 8				80	80	566			566
54	Energy Keepers	Bonneville Power Administration	NorthWestern Energy	NF	FERC Trf No. 8				520	520	4,414			4,414
55	Energy Keepers	Bonneville Power Administration	NorthWestern Energy	SFP	FERC Trf No. 8				34,392	34,392	210,627			210,627
56	Energy Keepers	NorthWestern Energy	Bonneville Power Administration	NF	FERC Trf No. 8				247	247	1,500			1,500
57	Energy Keepers	NorthWestern Energy	Bonneville Power Administration	SFP	FERC Trf No. 8				2,925	2,925	26,815			26,815
58	Energy Keepers	NorthWestern Energy	Idaho Power Company	SFP	FERC Trf No. 8				384	384	8,283			8,283
59	Energy Keepers	NorthWestern Energy	PacifiCorp	SFP	FERC Trf No. 8				1,152	1,152	24,849			24,849
60	Energy Keepers	Avista Corporation	Bonneville Power Administration	SFP	FERC Trf No. 8				1,558	1,558	8,738			8,738
61	Exelon	PacifiCorp	Bonneville Power Administration	NF	FERC Trf No. 8						6			6
62	Grant County PUD	Grant County PUD	Grant County PUD	OLF	RS No. 104	Stratford	Coulee City/Wilson		100,256	100,256	28,409			28,409
63	Guzman Energy	Bonneville Power Administration	Idaho Power Company	NF	FERC Trf No. 8				1,495	1,495	12,189			12,189
64	Guzman Energy	Bonneville Power Administration	Idaho Power Company	SFP	FERC Trf No. 8				231	231	2,186			2,186

65	Guzman Energy	Bonneville Power Administration	NorthWestern Energy	NF	FERC Trf No. 8				1,624	1,624	15,730			15,730
66	Guzman Energy	Bonneville Power Administration	NorthWestern Energy	SFP	FERC Trf No. 8				1,188	1,188	12,283			12,283
67	Guzman Energy	Bonneville Power Administration	PacifiCorp	NF	FERC Trf No. 8				80	80	930			930
68	Guzman Energy	Bonneville Power Administration	PacifiCorp	SFP	FERC Trf No. 8				190	190	2,040			2,040
69	Guzman Energy	NorthWestern Energy	Bonneville Power Administration	NF	FERC Trf No. 8				736	736	6,828			6,828
70	Guzman Energy	NorthWestern Energy	Bonneville Power Administration	SFP	FERC Trf No. 8				14,693	14,693	115,099			115,099
71	Guzman Energy	NorthWestern Energy	Idaho Power Company	NF	FERC Trf No. 8				228	228	2,274			2,274
72	Guzman Energy	Idaho Power Company	Bonneville Power Administration	NF	FERC Trf No. 8				1,507	1,507	12,025			12,025
73	Guzman Energy	Idaho Power Company	Bonneville Power Administration	SFP	FERC Trf No. 8				48	48	399			399
74	Guzman Energy	Idaho Power Company	Avista Corporation	NF	FERC Trf No. 8				50	50	350			350
75	Guzman Energy	Avista Corporation	Idaho Power Company	NF	FERC Trf No. 8				325	325	2,416			2,416
76	Hydro Tech Industries	Meyers Falls	Avista Corporation	OLF	PURPA								(g)6,120	6,120
77	Idaho Power Company	Bonneville Power Administration	Idaho Power Company	LFP	FERC Trf No. 8	MIDC	LOLO	100	800,736	800,736	1,600,000			1,600,000
78	Idaho Power Company	Bonneville Power Administration	Idaho Power Company	NF	FERC Trf No. 8				541	541	9,434			9,434
79	Idaho Power Company	Bonneville Power Administration	Idaho Power Company	SFP	FERC Trf No. 8				126,172	126,172	130,088			130,088
80	Idaho Power Company	Bonneville Power Administration	NorthWestern Energy	SFP	FERC Trf No. 8				51,667	51,667	94,552			94,552
81	Idaho Power Company	PacifiCorp	Idaho Power Company	NF	FERC Trf No. 8				60	60	959			959
82	Idaho Power Company	PacifiCorp	Idaho Power Company	SFP	FERC Trf No. 8				6,995	6,995	27,391			27,391
83	Idaho Power Company	Puget Sound Energy	Idaho Power Company	SFP	FERC Trf No. 8				3,754	3,754	2,798			2,798
84	Idaho Power Company	Grant County PUD	Idaho Power Company	SFP	FERC Trf No. 8				35,232	35,232	33,526			33,526
85	Idaho Power Company	Grant County PUD	NorthWestern Energy	SFP	FERC Trf No. 8				200	200	1,185			1,185
86	Idaho Power Company	Idaho Power Company	NorthWestern Energy	SFP	FERC Trf No. 8				201	201	50,816			50,816
87	Idaho Power Company	Chelan County PUD	Idaho Power Company	SFP	FERC Trf No. 8				29,878	29,878	29,327			29,327
88	Idaho Power Company	Chelan County PUD	NorthWestern Energy	SFP	FERC Trf No. 8				1,461	1,461	8,656			8,656
89	Idaho Power Company	Avista Corporation	Bonneville Power Administration	SFP	FERC Trf No. 8				128	128	100			100
90	Idaho Power Company	Avista Corporation	Idaho Power Company	SFP	FERC Trf No. 8				1,800	1,800	1,267			1,267
91	Idaho Power Company	Avista Corporation	NorthWestern Energy	SFP	FERC Trf No. 8				2,377	2,377	17,716			17,716
92	Kootenai Electric	Avista Corporation	Idaho Power Company	LFP	FERC Trf No. 8	AVA.SYS	LOLO	3	14,497	14,497	78,735		(h)16,911	95,646
93	Macquarie Energy LLC	Bonneville Power Administration	NorthWestern Energy	NF	FERC Trf No. 8				3,415	3,415	23,039			23,039
94	Macquarie Energy LLC	Bonneville Power Administration	NorthWestern Energy	SFP	FERC Trf No. 8				22,040	22,040	103,165			103,165
95	Macquarie Energy LLC	NorthWestern Energy	Bonneville Power Administration	NF	FERC Trf No. 8				1,219	1,219	7,907			7,907
96	Macquarie Energy LLC	NorthWestern Energy	Bonneville Power Administration	SFP	FERC Trf No. 8				10,327	10,327	77,809			77,809
97	Macquarie Energy LLC	Avista Corporation	Bonneville Power Administration	NF	FERC Trf No. 8				82	82	685			685
98	Macquarie Energy LLC	Avista Corporation	Bonneville Power Administration	SFP	FERC Trf No. 8				175	175	673			673
99	Mercuria Energy America LLC	Bonneville Power Administration	PacifiCorp	NF	FERC Trf No. 8				1,471	1,471	9,376			9,376
100	Mercuria Energy America LLC	NorthWestern Energy	Bonneville Power Administration	SFP	FERC Trf No. 8				600	600	2,308			2,308
101	Morgan Stanley Capital Group	Bonneville Power Administration	Idaho Power Company	NF	FERC Trf No. 8				845	845	5,530			5,530
102	Morgan Stanley Capital Group	Bonneville Power Administration	Idaho Power Company	SFP	FERC Trf No. 8				649	649	3,572			3,572

103	Morgan Stanley Capital Group	Bonneville Power Administration	NorthWestern Energy	NF	FERC Trf No. 8				5,855	5,855	45,584			45,584
104	Morgan Stanley Capital Group	Bonneville Power Administration	NorthWestern Energy	SFP	FERC Trf No. 8				89,265	89,265	374,679			374,679
105	Morgan Stanley Capital Group	Bonneville Power Administration	PacifiCorp	NF	FERC Trf No. 8				2,454	2,454	18,341			18,341
106	Morgan Stanley Capital Group	Bonneville Power Administration	PacifiCorp	SFP	FERC Trf No. 8				17,458	17,458	71,622			71,622
107	Morgan Stanley Capital Group	NorthWestern Energy	Bonneville Power Administration	NF	FERC Trf No. 8				2,348	2,348	15,604			15,604
108	Morgan Stanley Capital Group	NorthWestern Energy	Bonneville Power Administration	SFP	FERC Trf No. 8				11,270	11,270	61,931			61,931
109	Morgan Stanley Capital Group	NorthWestern Energy	Idaho Power Company	NF	FERC Trf No. 8				2,421	2,421	15,569			15,569
110	Morgan Stanley Capital Group	NorthWestern Energy	Idaho Power Company	SFP	FERC Trf No. 8				7,708	7,708	43,534			43,534
111	Morgan Stanley Capital Group	NorthWestern Energy	Grant County PUD	NF	FERC Trf No. 8				2,184	2,184	13,983			13,983
112	Morgan Stanley Capital Group	NorthWestern Energy	Grant County PUD	SFP	FERC Trf No. 8				14,033	14,033	78,525			78,525
113	Morgan Stanley Capital Group	NorthWestern Energy	PacifiCorp	NF	FERC Trf No. 8				482	482	3,443			3,443
114	Morgan Stanley Capital Group	NorthWestern Energy	PacifiCorp	SFP	FERC Trf No. 8				67	67	275			275
115	Morgan Stanley Capital Group	Grant County PUD	Idaho Power Company	NF	FERC Trf No. 8				10,226	10,226	73,403			73,403
116	Morgan Stanley Capital Group	Grant County PUD	Idaho Power Company	SFP	FERC Trf No. 8				13,598	13,598	76,068			76,068
117	Morgan Stanley Capital Group	Grant County PUD	NorthWestern Energy	NF	FERC Trf No. 8				1,739	1,739	13,322			13,322
118	Morgan Stanley Capital Group	Grant County PUD	NorthWestern Energy	SFP	FERC Trf No. 8				1,930	1,930	10,066			10,066
119	Morgan Stanley Capital Group	Idaho Power Company	Bonneville Power Administration	SFP	FERC Trf No. 8				2,400	2,400	13,414			13,414
120	Morgan Stanley Capital Group	Idaho Power Company	NorthWestern Energy	SFP	FERC Trf No. 8				9	9	37			37
121	Morgan Stanley Capital Group	Idaho Power Company	Grant County PUD	NF	FERC Trf No. 8				1,566	1,566	10,164			10,164
122	Morgan Stanley Capital Group	Idaho Power Company	Grant County PUD	SFP	FERC Trf No. 8				16,066	16,066	86,889			86,889
123	Morgan Stanley Capital Group	Chelan County PUD	Idaho Power Company	NF	FERC Trf No. 8				1,213	1,213	7,873			7,873
124	Morgan Stanley Capital Group	Chelan County PUD	Idaho Power Company	SFP	FERC Trf No. 8				58	58	368			368
125	Morgan Stanley Capital Group	Chelan County PUD	NorthWestern Energy	NF	FERC Trf No. 8				34	34	241			241
126	NorthWestern Energy	Bonneville Power Administration	NorthWestern Energy	NF	FERC Trf No. 8				5,296	5,296	35,953			35,953
127	NorthWestern Energy	NorthWestern Energy	Bonneville Power Administration	NF	FERC Trf No. 8				2,962	2,962	17,864			17,864
128	NorthWestern Energy	Avista Corporation	Bonneville Power Administration	NF	FERC Trf No. 8				44	44	265			265
129	PacifiCorp	PacifiCorp	Bonneville Power Administration	NF	FERC Trf No. 8				32,131	32,131	237,425			237,425
130	PacifiCorp	PacifiCorp	Idaho Power Company	NF	FERC Trf No. 8				298	298	2,221			2,221
131	PacifiCorp	PacifiCorp	PacifiCorp	NF	FERC Trf No. 8				476	476	3,431			3,431
132	PacifiCorp	PacifiCorp	PacifiCorp	OLF	RS No. 182	Dry Gulch	Dry Gulch		32,776	32,776	232,841			232,841
133	PacifiCorp	Idaho Power Company	PacifiCorp	NF	FERC Trf No. 8				1	1	6			6
134	PacifiCorp	Idaho Power Company	PacifiCorp	SFP	FERC Trf No. 8				2,328	2,328	47,996			47,996
135	Portland General Electric	Bonneville Power Administration	NorthWestern Energy	NF	FERC Trf No. 8				2,989	2,989	18,631			18,631
136	Portland General Electric	NorthWestern Energy	Bonneville Power Administration	NF	FERC Trf No. 8				5,343	5,343	45,776			45,776
137	Portland General Electric	NorthWestern Energy	Portland General Electric	NF	FERC Trf No. 8				2,833	2,833	19,420			19,420
138	Avangrid Renewables	Bonneville Power Administration	Idaho Power Company	NF	FERC Trf No. 8				120	120	1,460			1,460
139	Avangrid Renewables	Idaho Power Company	Bonneville Power Administration	NF	FERC Trf No. 8				325	325	2,602			2,602
140	Avangrid Renewables	Idaho Power Company	Bonneville Power Administration	SFP	FERC Trf No. 8						4,615			4,615
141	Powerex	Bonneville Power Administration	Idaho Power Company	NF	FERC Trf No. 8				223	223	1,860			1,860
142	Powerex	Bonneville Power Administration	Idaho Power Company	SFP	FERC Trf No. 8				113,862	113,862	676,982			676,982

143	Powerex	Bonneville Power Administration	NorthWestern Energy	NF	FERC Trf No. 8				3,588	3,588	23,125			23,125
144	Powerex	Bonneville Power Administration	NorthWestern Energy	SFP	FERC Trf No. 8				14,351	14,351	88,398			88,398
145	Powerex	NorthWestern Energy	Bonneville Power Administration	NF	FERC Trf No. 8				342	342	2,508			2,508
146	Powerex	NorthWestern Energy	Idaho Power Company	SFP	FERC Trf No. 8				23,660	23,660	153,367			153,367
147	Powerex	PacifiCorp	Bonneville Power Administration	NF	FERC Trf No. 8				240	240	2,058			2,058
148	Powerex	Puget Sound Energy	Idaho Power Company	SFP	FERC Trf No. 8				147,344	147,344	1,004,298			1,004,298
149	Powerex	Chelan County PUD	Idaho Power Company	SFP	FERC Trf No. 8				3,689	3,689	20,212			20,212
150	Rainbow Energy Marketing Corporation	Bonneville Power Administration	NorthWestern Energy	NF	FERC Trf No. 8				600	600	3,462			3,462
151	Rainbow Energy Marketing Corporation	Bonneville Power Administration	NorthWestern Energy	SFP	FERC Trf No. 8				1,295	1,295	13,197			13,197
152	Rainbow Energy Marketing Corporation	Bonneville Power Administration	PacifiCorp	NF	FERC Trf No. 8				100	100	1,154			1,154
153	Rainbow Energy Marketing Corporation	NorthWestern Energy	Bonneville Power Administration	SFP	FERC Trf No. 8				188	188	866			866
154	Rainbow Energy Marketing Corporation	NorthWestern Energy	PacifiCorp	SFP	FERC Trf No. 8				313	313	1,442			1,442
155	Rainbow Energy Marketing Corporation	Idaho Power Company	NorthWestern Energy	SFP	FERC Trf No. 8				125	125	1,274			1,274
156	Rainbow Energy Marketing Corporation	Idaho Power Company	Grant County PUD	SFP	FERC Trf No. 8				2,400	2,400	12,680			12,680
157	Rainbow Energy Marketing Corporation	Idaho Power Company	PacifiCorp	SFP	FERC Trf No. 8				400	400	4,076			4,076
158	Rainbow Energy Marketing Corporation	Idaho Power Company	Avista Corporation	SFP	FERC Trf No. 8				399	399	4,066			4,066
159	Seattle City Light	Seattle City Light	Grant County PUD	OLF	FERC Trf No. 8	Chelan-Stratford	Stratford		125,364	125,364	166,210		(i)90,228	256,438
160	Seattle City Light	Seattle City Light	Grant County PUD	SFP	FERC Trf No. 8				13,942	13,942				0
161	Spokane Tribe	Bonneville Power Administration	Spokane Tribe	LFP	FERC Trf No. 8	AVA.BPAT	AVA.SYS	3	4,014	4,014	19,684		(j)8,326	28,010
162	Stimson	Plummer	Avista Corporation	OLF	PURPA								(k)8,448	8,448
163	The Energy Authority	Bonneville Power Administration	Idaho Power Company	NF	FERC Trf No. 8				1,991	1,991	15,944			15,944
164	The Energy Authority	Bonneville Power Administration	NorthWestern Energy	NF	FERC Trf No. 8				1,173	1,173	7,376			7,376
165	The Energy Authority	Bonneville Power Administration	Avista Corporation	NF	FERC Trf No. 8				198	198	1,177			1,177
166	The Energy Authority	NorthWestern Energy	Bonneville Power Administration	NF	FERC Trf No. 8				1,129	1,129	8,363			8,363
167	The Energy Authority	NorthWestern Energy	Bonneville Power Administration	SFP	FERC Trf No. 8				7,793	7,793	42,319			42,319
168	The Energy Authority	Idaho Power Company	Bonneville Power Administration	NF	FERC Trf No. 8				2,919	2,919	17,321			17,321
169	Transalta Energy Marketing	Bonneville Power Administration	Idaho Power Company	NF	FERC Trf No. 8				72	72	1,771			1,771
170	Transalta Energy Marketing	Bonneville Power Administration	NorthWestern Energy	NF	FERC Trf No. 8				249	249	1,680			1,680
171	Transalta Energy Marketing	NorthWestern Energy	Bonneville Power Administration	NF	FERC Trf No. 8				477	477	3,618			3,618
172	Transalta Energy Marketing	Idaho Power Company	Bonneville Power Administration	NF	FERC Trf No. 8				42	42	242			242
173	Tacoma Power	Idaho Power Company	Grant County PUD	SFP	FERC Trf No. 8				14,089	14,089				0
174	Tacoma Power	Tacoma Power	Grant County PUD	OLF	FERC Trf No. 8	Chelan-Stratford	Stratford		125,342	125,342	222,102		(l)90,228	312,330
175	East Greenacres	Bonneville Power Administration	East Green Acres	LFP	FERC Trf No. 8	AVA.BPAT	AVA.SYS	3	4,391	4,391	11,810		(m)7,396	19,206
35	TOTAL							113	4,593,055	4,593,055	16,383,534	0	2,661,792	19,045,326

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Ancillary services
(b) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Parallel Capacity Support Agreement
(c) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Use of facilities
(d) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Ancillary services
(e) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Use of facilities
(f) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Ancillary services
(g) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Use of facilities
(h) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Ancillary services
(i) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Use of facilities
(j) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Ancillary services
(k) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Use of facilities
(l) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Use of facilities
(m) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Ancillary services

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)

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: MegaWatt Hours Received (c)	TRANSFER OF ENERGY: MegaWatt 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			1,507,622			1,507,622
2	Bonneville Power Admin	LFP			10,644,888		[a]2,158,968	12,803,856
3	Bonneville Power Admin	OS					[b]54,432	54,432
4	Bonneville Power Admin	FNS			1,126,462		[c]230,721	1,357,183
5	Bonneville Power Admin	NF	140,215	140,215		746,865		746,865
6	Avangrid Renewables, LLC	NF	125	125		156		156
7	Energy Keepers, Inc	NF	32,503	32,503		144,858		144,858
8	Idaho Power Company	NF	2,263	2,263		13,115		13,115
9	Kootenai Electric Coop	LFP			47,538			47,538
10	Nevada Power Company	NF	400	400		2,128		2,128
11	Northern Lights, Inc	LFP			139,052			139,052
12	NorthWestern Energy	NF	28,361	28,361		166,113		166,113
13	NorthWestern Energy	SFP			634,244		[d]26,116	660,360
14	PacifiCorp	NF	1	1		5		5
15	Portland General Elect	NF	2,610	2,610		3,173		3,173
16	Portland General Elect	LFP			628,000		[e]14,989	642,989
17	Puget Sound Energy	NF	375	375		801		801
18	Seattle City Light	NF	2,039	2,039		3,324		3,324
19	Snohomish County PUD	NF	7,016	7,016		7,844		7,844
	TOTAL		215,908	215,908	14,727,806	1,088,382	2,485,226	18,301,414

FOOTNOTE DATA
(a) Concept: OtherChargesTransmissionOfElectricityByOthers
Ancillary Services
(b) Concept: OtherChargesTransmissionOfElectricityByOthers
Use of Facilities
(c) Concept: OtherChargesTransmissionOfElectricityByOthers
Ancillary Services
(d) Concept: OtherChargesTransmissionOfElectricityByOthers
Ancillary Services and Regulation & Frequency Response
(e) Concept: OtherChargesTransmissionOfElectricityByOthers
Ancillary Services

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	1,065,965
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	684,439
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than $5,000	
6	Community Relations	525,657
7	Board of Director Activities	1,497,266
8	Education, Information & Training	344,510
9	Emergency Operating Procedure Events	736,374
10	Misc Employee Expenses	15,213
11	Misc Legal, Professional & General Services	145,744
12	Misc Transportation	149,400
13	Other Misc Expenses <$5,000	71,787
46	TOTAL	5,236,355

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

Depreciation and Amortization of Electric Plant (Account 403, 404, 405)

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 B 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 of 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			6,224,736		6,224,736
2	Steam Production Plant	16,498,144				16,498,144
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	14,702,293				14,702,293
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	10,646,929				10,646,929
7	Transmission Plant	18,773,312				18,773,312
8	Distribution Plant	53,293,772				53,293,772
9	Regional Transmission and Market Operation					
10	General Plant	4,428,885		424,532		4,853,417
11	Common Plant-Electric	18,173,097		32,781,226		50,954,323
12	TOTAL	136,516,432		39,430,494		175,946,926

B. Basis for Amortization Charges

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							
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Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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.
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 columns (f), (g), and (h), expenses incurred during the 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						
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 Expenses for Current Year (d)	Deferred in Account 182.3 at Beginning of Year (e)	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)
1	Federal Energy Regulatory Commission - Charges include annual fee and license fees for the Spokane River Project, the Cabinet Gorge Project and the Noxon Rapids Project	3,012,871	187,113	3,199,984		Electric	928	3,199,983				
2	Washington Utilities and Transportation Commission											
3	Electric - Includes annual fee and various other electric dockets	1,083,148	952,811	2,035,959		Electric	928	2,035,959				
4	Gas - Includes annual fee and various other natural gas dockets	319,906	200,524	520,430		Gas	928	520,430				
5	Idaho Public Utilities Commission											
6	Electric - Includes annual fee and various other electric dockets	521,315	248,972	770,287		Electric	928	770,288				
7	Gas - Includes annual fee and various other natural gas dockets	128,397	77,144	205,541		Gas	928	205,541				
8	Public Utility Commission of Oregon											
9	Includes annual fees and various other natural gas dockets	644,573	430,479	1,075,052	59,519	Gas	928	1,075,052	34,567	407	67,777	26,309
10	Not directly assigned Electric		675,110	675,110		Electric	928	675,110				
11	Not directly assigned Natural Gas		286,289	286,289		Gas	928	286,289				
46	TOTAL	5,710,210	3,058,442	8,768,652	59,519			8,768,652	34,567		67,777	26,309

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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 and 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 and 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 and 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 and D Performed Externally:
     1. Research Support to the electrical Research Council or the Electric Power Research Institute
     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 and 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 and 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 and 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 and 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.

Line No.	Classification (a)	Description (b)	Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR: Amounts Charged In Current Year: Account (e)	AMOUNTS CHARGED IN CURRENT YEAR: Amounts Charged In Current Year: Amount (f)	Unamortized Accumulation (g)
1	A. Electric (3) Distribution	Battery Storage and Electric Vehicle Supply Equipment	663,214	(853,101)	107	(189,887)	
2	A. Electric (3) Distribution	Battery Storage and Electric Vehicle Supply Equipment	1,031		108	1,031	
3	A. Electric (3) Distribution	Battery Storage and Electric Vehicle Supply Equipment	148,276		182	14,276	
4	A. Electric (3) Distribution	Battery Storage and Electric Vehicle Supply Equipment		17,049	557	17,049	
5	A. Electric (3) Distribution	Battery Storage and Electric Vehicle Supply Equipment	28,743	339	587	29,082	
6	A. Electric (3) Distribution	Battery Storage and Electric Vehicle Supply Equipment	18,500	17,508	598	36,008	
7	A. Electric (3) Distribution	Battery Storage and Electric Vehicle Supply Equipment	1,839	66,134	909	67,973	
8	A. Electric (3) Distribution	Battery Storage and Electric Vehicle Supply Equipment	2,102	129,360	912	131,462	
9	A. Electric (3) Distribution	Battery Storage and Electric Vehicle Supply Equipment	85,837		920	85,837	
10	A. Electric (3) Distribution	Battery Storage and Electric Vehicle Supply Equipment	644	35,178	930	35,822	
11	A. Electric (6) Other - Testing Lab & Facility	HUB-Morris Center Lab Test Facility	25,748	292,265	107	318,013	
12	A. Electric (6) Other - Testing Lab & Facility	HUB-Morris Center Lab Test Facility	34,693		182	34,693	

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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	13,568,766		
4	Transmission	4,739,365		
5	Regional Market			
6	Distribution	10,274,320		
7	Customer Accounts	5,840,091		
8	Customer Service and Informational	371,441		
9	Sales			
10	Administrative and General	25,718,437		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	60,512,420		
12	Maintenance			
13	Production	5,177,241		
14	Transmission	1,173,286		
15	Regional Market			
16	Distribution	5,708,075		
17	Administrative and General			
18	TOTAL Maintenance (Total of lines 13 thru 17)	12,058,602		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	18,746,007		
21	Transmission (Enter Total of lines 4 and 14)	5,912,651		
22	Regional Market (Enter Total of Lines 5 and 15)	0		
23	Distribution (Enter Total of lines 6 and 16)	15,982,395		
24	Customer Accounts (Transcribe from line 7)	5,840,091		
25	Customer Service and Informational (Transcribe from line 8)	371,441		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	25,718,437		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	72,571,022	6,461,523	79,032,545
29	Gas			
30	Operation			
31	Production - Manufactured Gas			
32	Production-Nat. Gas (Including Expl. And Dev.)			
33	Other Gas Supply	1,133,446		
34	Storage, LNG Terminaling and Processing	3,436		
35	Transmission			
36	Distribution	5,919,606		
37	Customer Accounts	2,646,571		
38	Customer Service and Informational	240,643		
39	Sales			
40	Administrative and General	10,562,731		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	20,506,433		
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	1,808,742		
48	Distribution	3,268,997		
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	5,077,739		
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)	1,133,446		
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru	3,436		
56	Transmission (Lines 35 and 47)	1,808,742		
57	Distribution (Lines 36 and 48)	9,188,603		

58	Customer Accounts (Line 37)	2,646,571		
59	Customer Service and Informational (Line 38)	240,643		
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)	10,562,731		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	25,584,172	1,365,111	26,949,283
63	Other Utility Departments			
64	Operation and Maintenance			0
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	98,155,194	7,826,634	105,981,828
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	45,200,050	5,321,807	50,521,857
69	Gas Plant	14,348,191	1,689,342	16,037,533
70	Other (provide details in footnote):			0
71	TOTAL Construction (Total of lines 68 thru 70)	59,548,241	7,011,149	66,559,390
72	Plant Removal (By Utility Departments)			
73	Electric Plant	2,037,150	98,219	2,135,369
74	Gas Plant	552,595	26,644	579,239
75	Other (provide details in footnote):			0
76	TOTAL Plant Removal (Total of lines 73 thru 75)	2,589,745	124,863	2,714,608
77	Other Accounts (Specify, provide details in footnote):			
78	Stores Expense (163)	2,589,304	(2,589,304)	0
79	Preliminary Survey and Investigation (183)			
80	Small Tool Expense (184)	4,644,702	(4,644,702)	0
81	Miscellaneous Deferred Debits (186)	1,216,883		1,216,883
82	Non-operating Expenses (417)	267,369		267,369
83	Retirement Bonus/SERP/HRA (228)	117,285		117,285
84	Other Income Deductions (426)	1,031,477		1,031,477
85	Employee Incentive Plan (232380)	5,777,825	(5,777,825)	0
86	DSM Tariff Rider (242600)	1,950,815	(1,950,815)	0
87	Incentive/Stock Compensation (238000)	395,932		395,932
88	Payroll Equalization Liability (242700)	25,041,157		25,041,157
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	43,032,749	(14,962,646)	28,070,103
96	TOTAL SALARIES AND WAGES	203,325,929	0	203,325,929

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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 Electric 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 the order of the Commission or other authorization.

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

Acct. No.	Description	
303	Intangible	319,471,994
389	Land and Land Rights	13,911,007
390	Structures and Improvements	157,798,438
391	Office Furniture and Equipment	86,347,195
392	Transportation Equipment	14,365,395
393	Stores Equipment	5,342,136
394	Tools, Shop & Garage Equipment	16,874,689
395	Laboratory Equipment	1,507,791
396	Power Operated Equipment	1,990,188
397	Communications Equipment	102,761,409
398	Miscellaneous Equipment	703,865
399	Asset Retirement Cost	0
	Total Common Plant	721,074,107
	Const. Work in Progress	19,291,659
	Total Utility Plant	740,365,766
	Acc. Prov. for Dep. & Amort.	277,287,121
	Net Utility Plant	463,078,645

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	331,583	173,172	158,411	# of Customers
902	Meter reading expenses	1,276,592	771,368	505,224	# of Customers
903	Cust rec & collectn expenses	13,604,472	7,173,501	6,430,971	# of Customers
904	Uncollectible accounts	0	0	0	# of Customers
905	Misc cust acct expenses	179,052	93,399	85,653	# of Customers
907	Cust svce & Info exp supervision	0	0	0	# of Customers
908	Cust assistance expenses	453,572	274,066	179,506	# of Customers
909	Info & instruct advert expenses	1,075,978	641,720	434,258	# of Customers
910	Misc cust serv & info expenses	616,275	321,468	294,807	# of Customers
911	Sales expense -supervision	0	0	0	# of Customers
912	Demo and selling expenses	0	0	0	# of Customers
913	Advertising expenses	0	0	0	# of Customers
916	Misc sales expenses	0	0	0	# of Customers
920	Admin & gen salaries	43,625,619	30,599,691	13,025,928	Four Factor
921	Office supplies & expenses	5,674,724	3,974,599	1,700,125	Four Factor
922	Admin expenses tranf-credit	0	0	0	Four Factor
923	Outside services employed	16,297,694	11,418,485	4,879,209	Four Factor
924	Property insurance	2,347,761	1,643,386	704,375	Four Factor
925	Injuries and damages	7,581,997	5,420,014	2,161,983	Four Factor
926	Employee pensions&benefits	86,261,481	60,481,229	25,780,252	Four Factor
927	Franchise requirement	0	0	0	Four Factor
928	Regulatory commission expenses	1,935,994	1,431,228	504,766	Four Factor
929	Duplicate charges-credit	0	0	0	Four Factor
930.1	General advertising expenses	0	0	0	Four Factor
930.2	Misc general expenses	5,974,867	4,201,670	1,773,197	Four Factor
931	Rents	640,688	454,983	185,705	Four Factor
935	Maint of general plant	16,580,612	11,765,393	4,815,219	Four Factor
403	Depreciation	25,614,667	18,173,096	7,441,571	Four Factor
404	Amort of LTD term plant	46,429,589	32,781,226	13,648,363	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

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

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

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	14,762	28,702	488,378	540,510
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)	(3,363,663)	(5,662,948)	(7,830,656)	(9,994,433)
4	Transmission Rights				
5	Ancillary Services	(7,026)	(11,808)	(17,104)	(22,975)
6	Other Items (list separately)				
7	Access Charge	149	141	85,897	97,635
8	Cost Recovery	107	131	5,047	5,616
9	Day Ahead Energy-Congestion Losses	(47)	(46)	(10,645)	(10,904)
10	FERC Fees	1	1	518	589
11	GMC	30,593	55,614	76,483	93,291
12	Hour Ahead Scheduling Process-RT Settlement	10,192	4,512	65,229	95,087
13	Other	(20)	(282)	(298)	(6,254)
46	TOTAL	(3,314,952)	(5,585,983)	(7,137,151)	(9,201,838)

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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), and (e) report the amount of ancillary services purchased and sold during the year.
2. On Line 2 columns (b), (c), (d), and (e) report the amount of reactive supply and voltage control services purchased and sold during the year.
3. On Line 3 columns (b), (c), (d), and (e) report the amount of regulation and frequency response services purchased and sold during the year.
4. On Line 4 columns (b), (c), (d), and (e) report the amount of energy imbalance services purchased and sold during the year.
5. On Lines 5 and 6, columns (b), (c), (d), and (e) report the amount of operating reserve spinning and supplement services purchased and sold during the period.
6. On Line 7 columns (b), (c), (d), and (e) 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)	Dollar (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				84	MW	1,078,411
4	Energy Imbalance	25,663	MWh	[a]1,130,138	49,173	MWh	[b]2,853,502
5	Operating Reserve - Spinning				18	MW	226,818
6	Operating Reserve - Supplement				18	MW	208,963
7	Other	845	MW	[c]10,590,952	845	MW	[d]10,590,952
8	Total (Lines 1 thru 7)	26,508		11,721,090	50,138		14,958,646

FOOTNOTE DATA

(a) Concept: AncillaryServicesPurchasedAmount
Includes both Energy Imbalance and Generator Imbalance
(b) Concept: AncillaryServicesSoldAmount
Includes both Energy Imbalance and Generator Imbalance
(c) Concept: AncillaryServicesPurchasedAmount
Amounts reported are offsetting imputed amounts reflecting the self-provision of ancillary service for bundled retail native load customers under state jurisdiction.
(d) Concept: AncillaryServicesSoldAmount
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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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.

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)
	NAME OF SYSTEM: Avista Corporation									
1	January	2,122	5	16	1,466	264	282	14	110	322
2	February	2,592	18	9	1,477	367	282	18	466	413
3	March	2,071	31	8	1,267	292	290	11	222	65
4	Total for Quarter 1				4,210	923	854	43	798	800
5	April	1,947	12	8	1,190	303	297	20	157	30
6	May	2,201	17	18	1,207	252	398	18	344	558
7	June	3,415	28	14	1,745	369	394	23	907	145
8	Total for Quarter 2				4,142	924	1,089	61	1,408	733
9	July	3,400	30	17	1,581	361	398	22	1,060	47
10	August	3,574	11	18	1,572	350	393	24	1,259	100
11	September	2,507	9	17	1,210	248	393	19	656	342
12	Total for Quarter 3				4,363	959	1,184	65	2,975	489
13	October	2,207	12	8	1,193	290	388	25	336	284
14	November	2,216	17	8	1,381	300	382	11	153	90
15	December	2,696	29	18	1,620	394	382	16	300	10
16	Total for Quarter 4				4,194	984	1,152	52	789	384
17	Total				16,909	3,790	4,279	221	5,970	2,406

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2022-04-15	Year/Period of Report End of: 2021/ 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)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	9,234,848
3	Steam	1,844,534	23	Requirements Sales for Resale (See instruction 4, page 311.)	
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	2,519,288
5	Hydro-Conventional	3,598,488	25	Energy Furnished Without Charge	0
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	11,101
7	Other	1,790,247	27	Total Energy Losses	492,745
8	Less Energy for Pumping		27.1	Total Energy Stored	
9	Net Generation (Enter Total of lines 3 through 8)	7,233,269	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	12,257,982
10	Purchases (other than for Energy Storage)	5,437,179			
10.1	Purchases for Energy Storage	0			
11	Power Exchanges:				
12	Received	7,890			
13	Delivered	420,356			
14	Net Exchanges (Line 12 minus line 13)	(412,466)			
15	Transmission For Other (Wheeling)				
16	Received	4,593,055			
17	Delivered	4,593,055			
18	Net Transmission for Other (Line 16 minus line 17)	0			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of Lines 9, 10, 10.1, 14, 18 and 19)	12,257,982			

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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).

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirement Sales for Resale & Associated Losses (c)	Monthly Peak - Megawatts (d)	Monthly Peak - Day of Month (e)	Monthly Peak - Hour (f)
	NAME OF SYSTEM: Avista Corporation					
29	January	1,115,980	220,394	1,526	5	16
30	February	1,059,390	211,249	1,675	12	12
31	March	959,957	139,540	1,365	1	8
32	April	869,755	174,770	1,261	1	9
33	May	1,100,127	393,758	1,254	17	18
34	June	1,044,682	224,126	1,889	30	18
35	July	1,052,964	139,509	1,749	1	15
36	August	976,498	147,533	1,759	11	18
37	September	901,622	199,073	1,355	7	18
38	October	941,430	203,498	1,254	12	9
39	November	1,047,232	236,634	1,434	17	8
40	December	1,188,345	229,204	1,696	29	18
41	Total					

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ Q4

Steam Electric Generating Plant Statistics

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.
9. Items under Cost of Plant are based on USofA 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.

Line No.	Item (a)	Plant Name: Boulder Park	Plant Name: Colstrip	Plant Name: Coyote Springs 2	Plant Name: Kettle Falls	Plant Name: Rathdrum	Plant Name: Spokane N. E.
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Internal Comb	Steam	Gas Turbine	Steam	Gas Turbine	Gas Turbine
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional	Conventional	Not Applicable	Conventional	Not Applicable	Not Applicable
3	Year Originally Constructed	2002	1984	2003	1983	1995	1978
4	Year Last Unit was Installed	2002	1985	2003	1983	1995	1978
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	24.6	233.4	295	50.7	166.5	61.8
6	Net Peak Demand on Plant - MW (60 minutes)	26	227	318	96	162	77
7	Plant Hours Connected to Load	3,006	7,320	5,656	7,751	1,361	32
8	Net Continuous Plant Capability (Megawatts)	25	222	295	54	167	65
9	When Not Limited by Condenser Water	0	222	295	54	0	0
10	When Limited by Condenser Water	0	222	295	54	0	0
11	Average Number of Employees	2	249	29	28	1	1
12	Net Generation, Exclusive of Plant Use - kWh	69,727,000	1,521,720,000	1,533,635,000	322,814,000	182,100,000	1,668,000
13	Cost of Plant: Land and Land Rights	185,629	1,289,395	0	2,568,188	621,682	138,753
14	Structures and Improvements	1,273,892	112,359,069	11,757,925	28,937,123	3,584,502	751,025
15	Equipment Costs	32,601,756	222,856,911	191,737,688	80,506,783	61,614,151	13,591,014
16	Asset Retirement Costs	0	15,212,465	351,682	323,787	0	0
17	Total cost (total 13 thru 20)	34,061,277	351,717,840	203,847,295	112,335,881	65,820,335	14,480,792
18	Cost per KW of Installed Capacity (line 17/5) Including	1,384.6048	1,506.9316	691.0078	2,215.6979	395.3173	234.317
19	Production Expenses: Oper, Supv, & Engr	4,475	177,823	119,916	193,588	2,338	2,904
20	Fuel	2,337,492	26,059,737	42,436,779	8,383,104	6,727,089	81,938
21	Coolants and Water (Nuclear Plants Only)						
22	Steam Expenses	0	2,830,284	0	580,496	0	0
23	Steam From Other Sources	0	0	0	0	0	0
24	Steam Transferred (Cr)	0	0	0	0	0	0
25	Electric Expenses	240,857	(60,959)	1,300,684	768,239	206,874	15,102
26	Misc Steam (or Nuclear) Power Expenses	35,113	5,005,425	534,816	443,058	28,673	10,844
27	Rents	0	0	87,122	0	0	0
28	Allowances	0	0	0	0	0	0
29	Maintenance Supervision and Engineering	44,765	586,670	167,990	128,663	55,069	44,733
30	Maintenance of Structures	1,685	629,289	78,259	92,869	0	7,914
31	Maintenance of Boiler (or reactor) Plant	0	5,966,269	0	1,851,090	1,362	0
32	Maintenance of Electric Plant	431,959	1,842,272	4,017,117	214,283	461,903	59,131
33	Maintenance of Misc Steam (or Nuclear) Plant	131,878	675,159	539,793	478,386	133,369	42,660
34	Total Production Expenses	3,228,224	43,711,969	49,282,476	13,133,776	7,616,677	265,226
35	Expenses per Net kWh	0.0463	0.0287	0.0321	0.0407	0.0418	0.159

35	**Plant Name**	Boulder Park	Colstrip	Colstrip	Coyote Springs 2	Kettle Falls	Kettle Falls	Rathdrum	Spokane N. E.
36	Fuel Kind	Gas	Coal	Oil	Gas	Gas	Wood	Gas	Gas
37	Fuel Unit	MCF	Ton	BBL	MCF	MCF	Ton	MCF	MCF
38	Quantity (Units) of Fuel Burned	631,165	943,534	2,207	10,088,230	5,301	504,628	2,174,374	20,395
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1,020,000	16,970,000	5,880,000	1,020,000	1,020,000	8,600,000	1,020,000	1,020,000
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	3.703	27.423	83.617	4.207	3.025	16.581	3.094	4.018
41	Average Cost of Fuel per Unit Burned	3.703	27.423	83.617	4.207	3.025	16.581	3.094	4.018
42	Average Cost of Fuel Burned per Million BTU	3.631	1.616	14.221	4.124	2.966	1.928	3.033	3.939
43	Average Cost of Fuel Burned per kWh Net Gen	0.034	0.017	0.0001	0.028	0.034	0.026	0.037	0.049
44	Average BTU per kWh Net Generation	9,233	10,531	0	6,710	0	13,463	12,179	12,472

Hydroelectric Generating Plant Statistics

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.
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.

Line No.	Item (a)	FERC Licensed Project No. 2058 Plant Name: Cabinet Gorge	FERC Licensed Project No. 2545 Plant Name: Little Falls	FERC Licensed Project No. 2545 Plant Name: Long Lake	FERC Licensed Project No. 2545 Plant Name: Monroe Street	FERC Licensed Project No. 2545 Plant Name: Nine Mile Falls	FERC Licensed Project No. 2058 Plant Name: Noxon Rapids	FERC Licensed Project No. 2545 Plant Name: Post Falls	FERC Licensed Project No. 2545 Plant Name: Upper Falls
1	Kind of Plant (Run-of-River or Storage)	Storage	Run-of-River	Storage	Run-of-River	Run-of-River	Storage	Storage	Run-of-River
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional	Conventional	Conventional	Conventional	Outdoor	Conventional	Conventional
3	Year Originally Constructed	1952	1910	1915	1890	1908	1959	1906	1922
4	Year Last Unit was Installed	1953	1911	1924	1992	1994	1977	1980	1922
5	Total installed cap (Gen name plate Rating in MW)	265	43.2	71.1	14.8	37.6	487.8	14.8	10
6	Net Peak Demand on Plant-Megawatts (60 minutes)	264	55	95	26	33	545	17	19
7	Plant Hours Connect to Load	8,496	6,384	6,590	8,395	6,568	4,688	6,273	8,760
8	**Net Plant Capability (in megawatts)**								
9	(a) Under Most Favorable Oper Conditions	255	43	90	15	38	581	18	10
10	(b) Under the Most Adverse Oper Conditions	295	43	90	15	38	623	18	10
11	Average Number of Employees	2	1	1	4	5	11	5	4
12	Net Generation, Exclusive of Plant Use - kWh	1,002,923,000	207,022,000	478,013,000	89,308,000	131,047,000	1,568,975,000	65,021,000	56,179,000
13	**Cost of Plant**								
14	Land and Land Rights	16,380,178	4,325,371	2,421,233	51,600	33,429	37,198,948	4,161,522	1,081,854
15	Structures and Improvements	25,858,472	5,471,930	9,392,686	12,227,712	20,041,697	24,923,796	7,651,530	1,120,559
16	Reservoirs, Dams, and Waterways	44,791,705	6,393,918	37,884,295	9,972,020	30,933,636	35,956,791	26,063,988	7,728,573
17	Equipment Costs	69,985,749	53,713,357	14,091,675	14,506,197	60,755,809	112,771,402	5,364,056	5,584,290
18	Roads, Railroads, and Bridges	1,671,013	0	0	50,448	594,870	259,750	577,944	508,242
19	Asset Retirement Costs	0	0	0	0	0	0	0	0
20	Total cost (total 13 thru 20)	158,687,117	69,904,576	63,789,889	36,807,977	112,359,441	211,110,687	43,819,040	16,023,518
21	Cost per KW of Installed Capacity (line 20 / 5)	598.8193	1,618.1615	897.1855	2,487.0255	2,988.283	432.7812	2,960.7459	1,602.3518
22	**Production Expenses**								
23	Operation Supervision and Engineering	30,151	4,589	6,139	3,399	13,820	130,631	371,049	1,419
24	Water for Power	0	0	0	0	0	0	0	0
25	Hydraulic Expenses	3,033	8,161	8,161	669	0	80,550	3,042	1,055
26	Electric Expenses	1,006,044	681,239	755,481	494,244	640,262	911,898	599,150	514,196
27	Misc Hydraulic Power Generation Expenses	166,939	70,661	93,290	20,092	105,538	224,651	55,075	26,295
28	Rents	0	1,214,253	0	0	0	0	0	0
29	Maintenance Supervision and Engineering	619	7,234	4,051	2,656	12,232	87,221	9,069	4,298
30	Maintenance of Structures	117,890	25,860	22,383	24,497	22,486	384,666	15,423	37,420
31	Maintenance of Reservoirs, Dams, and Waterways	117,627	49,571	56,373	6,516	25,755	404,222	59,278	19,235
32	Maintenance of Electric Plant	838,603	208,043	219,689	91,357	224,127	662,132	372,902	61,730
33	Maintenance of Misc Hydraulic Plant	13,789	3,292	4,227	1,718	15,859	123,989	22,618	5,605
34	Total Production Expenses (total 23 thru 33)	2,294,695	2,272,903	1,169,794	645,148	1,060,079	3,009,960	1,507,606	671,253
35	Expenses per net kWh	0.0023	0.011	0.0024	0.0072	0.0081	0.0019	0.0232	0.0119

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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.
3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 402.
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.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (MW) (c)	Net Peak Demand MW (60 min) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)	Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses: Fuel Production Expenses (i)	Production Expenses: Maintenance Production Expenses (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Generation Type (m)
1	Kettle Falls CT	2002	7.2	11	3,117,000	9,567,500	1,323,903	143,170	135,410	22,018	Nat Gas	359	Gas Turbine

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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. If required by a State commission to report individual lines for all voltages, do so but do not group totals for each voltage under 132 kilovolts.
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. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
4. 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 ty 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.
5. 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.
6. 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).
7. 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. I 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.
8. 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.
9. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

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	Size of Conductor and Material	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES			
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line			Land	Construction Costs	Total Costs	Operation Expenses	Maintenance Expenses	Rents	Tota Expens
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
1	Group Sum - 60kV		60	60		1				136,038	636,193	772,231				
2	Group Sum - 115kV		115	115		1,557				12,402,478	306,818,954	319,221,432	948,124	988,227		1,936,3
3	Beacon Sub #4	BPA Bell Sub	230	230	Steel Pole	1		1	1272 ACSS			0				
4	Beacon Sub #4	BPA Bell Sub	230	230	H Type	5		1	1272 ACSS	17,912	1,429,421	1,447,333	0	2,555		2,5
5	Beacon Sub #5	BPA Bell Sub	230	230	Steel Tower	3		1	1272 ACSS			0				
6	Beacon Sub #5	BPA Bell Sub	230	230	H Type	3		1	1272 ACSS	30,323	3,275,357	3,305,680	0	141		1
7	Beacon	Cabinet Gorge Plant	230	230	Steel Tower	1		1	1590 ACSS			0				
8	Beacon	Cabinet Gorge Plant	230	230	Steel Pole	41		2	1590 ACSS			0				
9	Beacon	Cabinet Gorge Plant	230	230	H Type	52		1	1590 ACSR	1,156,196	41,768,911	42,925,107	1,756	57,679		59,4
10	Beacon Sub	Lolo Sub	230	230	Steel Tower	1		1	1590 ACSS			0				
11	Beacon Sub	Lolo Sub	230	230	Steel Pole	37		2	1590 ACSS			0				
12	Beacon Sub	Lolo Sub	230	230	H Type	63		1	1272 AAC			0				
13	Beacon Sub	Lolo Sub	230	230	H Type	8		1	1272 ACSS	456,162	23,265,747	23,721,909	0	23,386		23,3
14	Benewah	Shawnee	230	230	Steel Pole	1		1	1622 ACSS			0				
15	Benewah	Shawnee	230	230	Steel Pole	59		1	1590 ACSS	570,207	48,748,733	49,318,940	11,125	4,265		15,3
16	Noxon Plant	Pine Creek Sub	230	230	Steel Pole	29		1	1272 ACSR			0				
17	Noxon Plant	Pine Creek Sub	230	230	H Type	1		1	1590 ACSS			0				
18	Noxon Plant	Pine Creek Sub	230	230	H Type	14		1	954 AAC	1,097,679	19,429,809	20,527,488	26,892	762,129		789,0
19	Cabinet Gorge Plant	Noxon	230	230	H Type	2		1	795 ACSR			0				
20	Cabinet Gorge Plant	Noxon	230	230	H Type	18		1	954 AAC	184,211	1,943,437	2,127,648	4,617	19,750		24,3
21	Benewah Sw. Station	Pine Creek Sub	230	230	H Type	43		1	954 AAC	399,821	5,265,773	5,665,594	0	42,985		42,9
22	Divide Creek	Lolo Sub	230	230	H Type	43		1	1272 AAC	165,333	18,115,308	18,280,641	784	21,785		22,5
23	North Lewiston	Walla Walla	230	230	H Type	39		1	1272 AAC			0				
24	North Lewiston	Walla Walla	230	230	H Type	4		1	1272 ACSR			0				
25	North Lewiston	Walla Walla	230	230	Steel Pole	4		1	1272 ACSR	623,984	6,817,004	7,440,988	1,317	9,543		10,8
26	North Lewiston	Shawnee	230	230	Steel Pole	7		1	1272 ACSR			0				
27	North Lewiston	Shawnee	230	230	H Type	27		1	1272 ACSR	872,150	10,043,381	10,915,531	19,051	0		19,0
28	Saddle Mtn-Walla Walla	Wanapum	230	230	Steel Tower	2		1	1590 ACSS			0				

29	Saddle Mtn-Walla Walla	Wanapum	230	230	H Type	76		1	1272 AAC	254,484	14,007,631	14,262,115	0	3,024		3,0
30	BPA (Libby)	Noxon Plant	230	230	Steel Tower	1		1	1272 ACSR			0				
31	BPA/Hot Springs #1	Noxon Plant	230	230	Steel Tower	1		1	1272 ACSR	0	19,521	19,521	0	187		1
32	BPA/Hot Springs #2	Noxon Plant	230	230	Steel Pole	2		1	1272 ACSR			0				
33	BPA/Hot Springs #2	Noxon Plant	230	230	H Type	67		1	1272 AAC	3,604,148	10,102,223	13,706,371	36,339	136,977		173,3
34	Coulee	West Side Sub	230	230	Steel Pole	2		2	1272 ACSR	8,482	0	8,482				
35	BPA Line	West Side Sub	230	230	Steel Pole	2		2	1272 ACSR	36,461	1,442,964	1,479,425		647		6
36	Hatwai	N. Lewiston Sub	230	230	H Type	7		1	1590 ACSR	155,244	2,221,692	2,376,936	491	0		4
37	Divide Creek	Imnaha	230	230	H Type	20		1	1272 AAC	205,262	1,312,224	1,517,486	0	0		
38	Colstrip Plant	Broadview	500	500		0				595,789	38,413,938	39,009,727	95,762	97,941	87,664	281,3
36	TOTAL					2,244	0	39		22,972,364	555,078,221	578,050,585	1,146,258	2,171,221	87,664	3,405,1

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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 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.

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE		CONDUCTORS			Voltage KV (Operating)	LINE COST					Construction
	From	To		Type	Average Number per Miles	Present	Ultimate	Size	Specification	Configuration and Spacing		Land and Land Rights	Poles, Towers and Fixtures	Conductors and Devices	Asset Retire. Costs	Total	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
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44	TOTAL																

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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).
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.

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment: Type of Equipment (i)	Conversion Apparatus and Special Equipment: Number of Units (j)	Conversion Apparatus and Special Equipment: Total Capacity (In MVa) (k)
1	Airway Heights (WA)	Distribution	Unattended	115	13.8		24	2		Frcd Oil & Air Fan & Caps	39	40
2	Barker Road (WA)	Distribution	Unattended	115	13.8		12	1		Two Stage Fan	1	20
3	Beacon (Trans. & Dist.) (WA)	Transmission	Unattended	230	115	13.8	536	4		Two Stage Fan	2	560
4	Boulder (Trans. & Dist.) (WA)	Transmission	Unattended	230	115	13.8	318	3		Two Stage Fan	3	530
5	Chester (WA)	Distribution	Unattended	115	13.8		24	2		Frcd Oil & Air Fan	2	40
6	Chewelah 115Kv (WA)	Distribution	Unattended	115	13.2		12	1		Two Stage Fan	1	20
7	Colbert (WA)	Distribution	Unattended	115	13.8		12	1		Frcd Oil & Air Fan & Caps	16	20
8	College & Walnut (WA)	Distribution	Unattended	115	13.8		36	2		Two Stage Fan	2	60
9	Colville 115 Kv (WA)	Distribution	Unattended	115	13.8		32	3		Frcd Oil & Air Fan	3	49
10	Critchfield (WA)	Distribution	Unattended	115	13.8		12	1		Two Stage Fan	1	20
11	Deer Park (WA)	Distribution	Unattended	115	13.8		12	1		Two Stage Fan	1	20
12	Dry Creek (WA)	Transmission	Unattended	230	115	13.8	150	1		Two Stage Fan & Caps	224	250
13	Dry Gulch (WA)	Distribution	Unattended	115	13.8		12	1		Frcd Oil & Air Fan	1	20
14	East Colfax (WA)	Distribution	Unattended	115	13.8		12	1		Frcd Oil & Air Fan	1	20
15	East Farms (WA)	Distribution	Unattended	115	13.8		12	1		Two Stage Fan	1	20
16	Fort Wright (WA)	Distribution	Unattended	115	13.8		24	2		Frcd Oil & Air & Two Stage Fan	2	40
17	Francis and Cedar (WA)	Distribution	Unattended	115	13.8		36	2		Two Stage Fan	2	60
18	Gifford (WA)	Distribution	Unattended	115	34		16	2		One Stage Fan	1	18
19	Glenrose (WA)	Distribution	Unattended	115	13.8		12	1		Frcd Oil & Air Fan	1	20
20	Greenacres (WA)	Distribution	Unattended	115	13.8		18	1		Two Stage Fan	1	30
21	Greenwood (WA)	Distribution	Unattended	115	13.8		12	1		Two Stage Fan	1	20
22	Hallett & White (WA)	Distribution	Unattended	115	13.8		36	2		Two Stage Fan	2	60
23	Indian Trail (WA)	Distribution	Unattended	115	13.8		12	1		Two Stage Fan	1	20
24	Kettle Falls (WA)	Distribution	Unattended	115	13.8		12	1		Frcd Oil & Air Fan	1	20
25	Lee & Reynolds (WA)	Distribution	Unattended	115	13.8		36	2		Two Stage Fan	2	60
26	Liberty Lake (WA)	Distribution	Unattended	115	13.8		24	2		Two Stage Fan	2	40
27	Lind (WA)	Distribution	Unattended	115	13.8		12	1		Two Stage Fan	1	20
28	Little Falls 115/34 Kv (WA)	Distribution	Unattended	115	34		12	1				
29	Lyons & Standard (WA)	Distribution	Unattended	115	13.8		36	2		Two Stage Fan	2	60
30	Mead (WA)	Distribution	Unattended	115	13.8		18	1		Two Stage Fan	1	30
31	Metro (WA)	Distribution	Unattended	115	13.8		24	2		Two Stage Fan	2	40
32	Milan (WA)	Distribution	Unattended	115	13.8		24	2		Frcd Oil & Air Fan	2	40
33	Millwood (WA)	Distribution	Unattended	115	13.8		24	2		Two Stage Fan	2	40
34	Ninth & Central (WA)	Distribution	Unattended	115	13.8		36	2		Two Stage Fan	2	60

35	Northeast (WA)	Distribution	Unattended	115	13.8		24	2		Two Stage Fan	2	40
36	Northwest (WA)	Distribution	Unattended	115	13.8		24	2		Two Stage Fan	2	40
37	Opportunity (WA)	Distribution	Unattended	115	13.8		12	1		Two Stage Fan	1	20
38	Othello (WA)	Distribution	Unattended	115	13.8		24	2	2	Frcd Oil & Air Fan & Two Stage Fan	2	40
39	Post Street (WA)	Distribution	Unattended	115	13.8		60	2		Frcd Oil	2	60
40	Pound Lane (WA)	Distribution	Unattended	115	13.8		24	2		Two Stage Fan	2	40
41	Ross Park (WA)	Distribution	Unattended	115	13.8		33	2		Two Stage Fan	2	57
42	Roxboro (WA)	Distribution	Unattended	115	24		24	2		Two Stage Fan	2	40
43	Saddle Mountain (WA)	Transmission	Unattended	230	115	13.8	150	1		Two Stage Fan	1	250
44	Shawnee (WA)	Transmission	Unattended	230	115	13.8	150	1		Two Stage Fan	1	250
45	Silver Lake (WA)	Distribution	Unattended	115	13.8		12	1		Two Stage Fan	1	20
46	Southeast (WA)	Distribution	Unattended	115	13.8		36	2		Two Stage Fan	2	60
47	South Othello (WA)	Distribution	Unattended	115	13.8		12	1		Two Stage Fan	1	20
48	South Pullman (WA)	Distribution	Unattended	115	13.8		30	2		Two Stage Fan	2	50
49	Spokane Industrial Park (WA)	Distribution	Unattended	115	13.8		24	2		Two Stg, Frcd Oil Fan & Caps	14	40
50	Sunset (WA)	Distribution	Unattended	115	13.8		33	2	2	Two Stage Fan & Caps	50	55
51	Terre View (WA)	Distribution	Unattended	115	13.8		12	1		Two Stage Fan	1	20
52	Third & Hatch (WA)	Distribution	Unattended	115	13.8		54	3		Two Stage Fan & Caps	103	90
53	Turner (WA)	Distribution	Unattended	115	13.8		36	2		Two Stage Fan	2	60
54	Waikiki (WA)	Distribution	Unattended	115	13.8		24	2		Two Stage Fan	2	40
55	West Side (WA)	Transmission	Unattended	230	115	13.8	300	2		Two Stage Fan	2	500
56	Other: 27 Subs. less than 10MVA (WA)	Distribution	Unattended				164	28				
57	Appleway (ID)	Distribution	Unattended	115	13.8		36	2		Two Stage Fan	2	60
58	Avondale (ID)	Distribution	Unattended	115	13.8		12	1		Two Stage Fan	1	20
59	Benewah (ID)	Transmission	Unattended	230	115	13.8	75	1		Two Stage Fan & Caps	224	125
60	Big Creek (ID)	Distribution	Unattended	115	13.8		17	2		Portable Fan	2	22
61	Blue Creek (ID)	Distribution	Unattended	115	13.8		12	1		Two Stage Fan	1	20
62	Bunker Hill Limited (ID)	Distribution	Unattended	115	13.8		12	1		Frcd Air Fan	1	16
63	Cabinet Gorge (Switchyard) (ID)	Transmission	Unattended	230	115	13.8	75	1		Two Stage Fan	1	125
64	Clark Fork (ID)	Distribution	Unattended	115	21.8		10	1		Frcd Air Fan	1	12
65	Coeur d' Alene 15th Ave. (ID)	Distribution	Unattended	115	13.8		36	2		Two Stage Fan	2	60
66	Cottonwood (ID)	Distribution	Unattended	115	24.9		12	1		Two Stage Fan	1	20
67	Dalton (ID)	Distribution	Unattended	115	13.8		36	2		Two Stage Fan	2	60
68	Grangeville (ID)	Distribution	Unattended	115	13.8		24	4		Frcd Oil & Air & Pt Fan & Caps	17	34
69	Holbrook (ID)	Distribution	Unattended	115	13.8		12	1		Two Stage Fan	1	20
70	Huetter (ID)	Distribution	Unattended	115	13.8		12	1		Two Stage Fan	1	20
71	Idaho Road (ID)	Distribution	Unattended	115	13.8		12	1		Two Stage Fan	1	20
72	Juliaetta (ID)	Distribution	Unattended	115	13.8		12	1		Frcd Oil & Air Fan	1	20
73	Kamiah (ID)	Distribution	Unattended	115	13.8		12	1		Two Stage Fan	1	20
74	Kooskia (ID)	Distribution	Unattended	115	13.8		15	3		Frcd Air Fan	3	20
75	Lewiston Mill Rd (ID)	Distribution	Unattended	115	13.2		18	1		Two Stage Fan	1	30
76	Lolo (Trans. & Dist.) (ID)	Transmission	Unattended	230	115	13.8	262	3		Frcd Oil & Air Fan & Two Stage Fan	1	270

77	Moscow (ID)	Distribution	Unattended	115	13.8		24	2		Frcd Oil & Air & Two Stage	2	40
78	Moscow 230 kV (Trans. & Dist.) (ID)	Transmission	Unattended	230	115	13.8	162	2		Two Stage Fan & Caps	76	270
79	North Lewiston 230kV (Trans. & Dist.) (ID)	Transmission	Unattended	115	13.8		8	1		Frcd Air Fan & Caps	49	9
80	North Moscow (ID)	Distribution	Unattended	115	13.8		12	1		Two Stage Fan	1	20
81	Oden (ID)	Distribution	Unattended	115	21.8		10	1		Frcd Air Fan	1	12
82	Oldtown (ID)	Distribution	Unattended	115	21.8		17	2		Frcd Air Fan	2	22
83	Orofino (ID)	Distribution	Unattended	115	24		20	2		Frcd Oil & Air Fan	1	28
84	Osburn (ID)	Distribution	Unattended	115	13.8		12	1		Portable Fan	1	15
85	Pine Creek (Trans. & Dist.) (ID)	Transmission	Unattended	230	115	13.8	212	3		Two Stage Fan & Caps	47	270
86	Pleasant View (ID)	Distribution	Unattended	115	13.8		12	1		Two Stage Fan	1	20
87	Plummer (ID)	Distribution	Unattended	115	13.8		12	1		Two Stage Fan	1	20
88	Post Falls (ID)	Distribution	Unattended	115	13.8		18	1		Two Stage Fan	1	30
89	Potlatch (ID)	Distribution	Unattended	115	24.9		15	2		Portable Fan	2	19
90	Prairie (ID)	Distribution	Unattended	115	13.8		12	1		Frcd Oil & Air Fan	1	20
91	Priest River (ID)	Distribution	Unattended	115	20.8		10	1		Frcd Air Fan	1	12
92	Rathdrum (Trans. & Dist.) (ID)	Transmission	Unattended	230	115	13.8	474	4		Frcd Oil & Air Fan	2	490
93	Sagle (ID)	Distribution	Unattended	115	21.8		12	1		Two Stage Fan	1	20
94	Sandpoint (ID)	Distribution	Unattended	115	20.8		30	3		Frcd Air Fan	3	38
95	South Lewiston (ID)	Distribution	Unattended	115	13.8		27	4		Portable Fan, Frcd Oil & Air	4	39
96	Sweetwater (ID)	Distribution	Unattended	115	24.9		12	1		Frcd Oil & Air Fan	1	20
97	St. Maries (ID)	Distribution	Unattended	115	23.9		24	2		Two Stage Fan	2	40
98	Tenth & Stewart (ID)	Distribution	Unattended	115	13.8		30	2		Frcd Oil & Air & Two Stage	2	50
99	Other: 13 Subs less than 10 MVA (ID)	Distribution	Unattended				72	13				
100	Other: 1 Sub less than 10 MVA (MT)	Distribution	Unattended				5	1				
101	Boulder Park (WA Gen. Plant)	Transmission	Attended	115	13.8		36	1		Two Stage Fan	1	60
102	Kettle Falls (WA Gen. Plant)	Transmission	Attended	115	13.8		34	1	1	Two Stage Fan	1	62
103	Long Lake (WA Gen. Plant)	Transmission	Attended	115	4		80	4	1			
104	Nine Mile (WA Gen. Plant)	Transmission	Attended	115	13.8		42	2		Two Stage Fan	1	56
105	Little Falls (WA Gen. Plant)	Transmission	Attended	115	4		24	2		Frcd Oil & Air Fan	2	40
106	Northeast (WA Gen. Plant)	Transmission	Attended	115	13.8		36	1		Two Stage Fan	1	60
107	Post Street (WA Gen. Plant)	Transmission	Attended	13.8	4		35	2				
108	Cabinet Gorge (HED) (ID Gen. Plant)	Transmission	Attended	230	13.8		300	6	1			
109	Post Falls (ID Gen. Plant)	Transmission	Attended	115	2.3		12	1		Frcd Air & Oil & Air Fan	1	16
110	Rathdrum (ID Gen. Plant)	Transmission	Attended	115	13.8		114	2	1	Two Stage Fan	2	190
111	Noxon (MT Gen. Plant)	Transmission	Attended	230	13.8		435	9	1	Two Stage Fan	6	635
112	Coyote Springs II (OR Gen. Plant)	Transmission	Attended	500	13.8	18	270	3	2	Two Stage Fan	3	450
113	Distribution Substations			9,660	1,308.2	0	1,984	177	4		357	2,758
114	Distribution Substations Unattended			9,660	1,308.2	0	1,984	177	4		357	2,758
115	Transmission Substations			4,768.8	1,518.5	183.6	4,290	61	7		651	5,468
116	Transmission Substations Attended			1,893.8	124.7	18	1,418	34	7		18	1,569
117	Transmission Substations Unattended			2,875	1,393.8	165.6	2,872	27	0		633	3,899
118	Total						6,274					

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2022	Year/Period of Report End of: 2021/ 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 Good or Service (a)	Name of Associated/Affiliated Company (b)	Account(s) Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Non-Power Goods or Services Provided by Affiliated	Steam Plant Square	931000	64,790
19				
20	**Non-power Goods or Services Provided for Affiliated**			
21	Corporate Support	Salix, Inc.	146000	108,342
22	Corporate Support	Avista Development	146000	166,272
23	Corporate Support	Avista Capital	146000	85,236
24	Corporate Support	AELP	146000	20,045
25	Corporate Support	AJT Mining	146000	2,586
26	Corporate Support	Avista Edge	146000	364,365
42				