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

FERC FINANCIAL REPORT
FERC FORM No. 2: Annual Report of Major Natural Gas Companies and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Natural Gas Act, Sections 10(a), and 16 and 18 CFR Parts 260.1 and 260.300. 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 a confidential nature.

Exact Legal Name of Respondent (Company) Avista Corporation	Year/Period of Report: End of: 2023/ Q4

FERC FORM NO. 2 (02-04)

INSTRUCTIONS FOR FILING FERC FORMS 2, 2-A and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Forms 2, 2-A, and 3-Q are designed to collect financial and operational information from natural gas companies subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be a non-confidential public use forms.

II. Who Must Submit

Each natural gas company whose combined gas transported or stored for a fee exceed 50 million dekatherms in each of the previous three years must submit FERC Form 2 and 3-Q.

Each natural gas company not meeting the filing threshold for FERC Form 2, but having total gas sales or volume transactions exceeding 200,000 dekatherms in each of the previous three calendar years must submit FERC Form 2-A and 3-Q.

Newly established entities must use projected data to determine whether they must file the FERC Form 3-Q and FERC Form 2 or 2-A.

III. What and Where to Submit

a. Submit FERC Form Nos. 2, 2-A and 3-Q electronically through the eCollection portal at https://eCollection.ferc.gov, and according to the specifications in the Form 2, 2-A and 3-Q taxonomies..
b. The Corporate Officer Certification must be submitted electronically as part of the FERC Form 2 and 3-Q filings.
c. Submit immediately upon publication, by either eFiling or mailing two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders and any annual financial or statistical report regularly prepared and distributed to bondholders, security analysts, or industry associations. Do not include monthly and quarterly reports. Indicate by checking the appropriate box on Form 2, Page 3, List of Schedules, if the reports to stockholders will be submitted or if no annual report to stockholders is prepared. Unless eFiling the Annual Report to Stockholders, mail these reports to the Secretary of the Commission at:

   Secretary of the Commission
   Federal Energy Regulatory Commission
   888 First Street, NE
   Washington, DC 20426
d. For the Annual CPA certification, submit with the original submission of this form, a letter or report (not applicable to respondents classified as Class C or Class D prior to January 1, 1984) prepared in conformity with the current standards of reporting which will:

   i. Contain a paragraph attesting to the conformity, in all material respects, of the schedules listed below with the Commission's applicable Uniform Systems of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and
   ii. 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. §§ 158.10-158.12 for specific qualifications.)

Reference	Reference 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

   Filers should state in the letter or report, which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist
e. Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. Further instructions are found on the Commission website at https://www.ferc.gov/ferc-online/ferc-online/frequently-asked-questions-faqs-efilingferc-online .
f. Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 2 and 2-A free of charge from: https://www.ferc.gov/industries-data/natural-gas/industry-forms . Copies may also be obtained from the Public Reference and Files Maintenance Branch, Federal Energy Regulatory Commission, 888 First Street, NE. Room 2A, Washington, DC 20426 or by calling (202).502-8371

IV. When to Submit:

FERC Forms 2, 2-A, and 3-Q must be filed by the dates:

a. FERC Form 2 and 2-A --- by April 18th of the following year (18 C.F.R. §§ 260.1 and 260.2)
b. FERC Form 3-Q --- Natural gas companies that file a FERC Form 2 must file the FERC Form 3-Q within 60 days after the reporting quarter (18 C.F.R.§ 260.300), and
c. FERC Form 3-Q --- Natural gas companies that file a FERC Form 2-A must file the FERC Form 3-Q within 70 days after the reporting quarter (18 C.F.R. § 260.300).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the Form 2 collection of information is estimated to average 1,671.66 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 Form 2A collection of information is estimated to average 295.66 hours per response. The public reporting burden for the Form 3-Q collection of information is estimated to average 167 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 all reports in conformity with the Uniform System of Accounts (USofA) (18 C.F.R. Part 201). Interpret all accounting words and phrases in accordance with the USofA.
II. Enter in whole numbers (dollars or Dth) 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, indicate whether a schedule has been omitted by entering "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, page 2.
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.**
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. Footnote and further explain accounts or pages as necessary.
IX. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.
X. 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.
XI. Report all gas volumes in Dth unless the schedule specifically requires the reporting in another unit of measurement.
XII. Schedule specific instructions are found in the applicable taxonomy and on the applicable blank rendered form.

DEFINITIONS

I. Btu per cubic foot – The total heating value, expressed in Btu, produced by the combustion, at constant pressure, of the amount of the gas which would occupy a volume of 1 cubic foot at a temperature of 60°F if saturated with water vapor and under a pressure equivalent to that of 30°F, and under standard gravitational force (980.665 cm. per sec) with air of the same temperature and pressure as the gas, when the products of combustion are cooled to the initial temperature of gas and air when the water formed by combustion is condensed to the liquid state (called gross heating value or total heating value).
II. Commission Authorization -- 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.
III. Dekatherm – A unit of heating value equivalent to 10 therms or 1,000,000 Btu.
IV. Respondent – The person, corporation, licensee, agency, authority, or other legal entity or instrumentality on whose behalf the report is made.

EXCERPTS FROM THE LAW

Natural Gas Act, 15 U.S.C. 717-717w

"Sec. 10(a). Every natural-gas company shall file with the Commission such annual and other periodic or special reports as the Commission may by rules and regulations or order prescribe as necessary or appropriate to assist the Commission in the proper administration of this act. The Commission may prescribe the manner and form in which such reports shall be made and require from such natural-gas companies specific answers to all questions upon which the Commission may need information. The Commission may require that such reports include, among other things, full information as to assets and liabilities, capitalization, investment and reduction thereof, gross receipts, interest dues and paid, depreciation, amortization, and other reserves, cost of facilities, costs of maintenance and operation of facilities for the production, transportation, delivery, use, or sale of natural gas, costs of renewal and replacement of such facilities, transportation, delivery, use and sale of natural gas..."

"Section 16. The Commission shall have power to perform all and any acts, and to prescribe, issue, make, amend, 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 form or forms of all statements declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and time within they shall be filed..."

General Penalties

The Commission may assess up to $1 million per day per violation of its rules and regulations. See NGA § 22(a), 15 U.S.C. §717t-1(a).

FERC FORM NO. 2
REPORT OF MAJOR NATURAL GAS COMPANIES

IDENTIFICATION

01 Exact Legal Name of Respondent Avista Corporation	02 Year/ Period of Report End of: 2023/ Q4
03 Previous Name and Date of Change (if name changed during year) /	
04 Address of Principal Office at End of Year (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 Officer
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)

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.

11 Name Ryan L. Krasselt	12 Title VP, Controller, Prin Acctg Officer
13 Signature Ryan L. Krasselt	14 Date Signed

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:	Year/Period of Report: End of: 2023/ Q4

List of Schedules (Natural Gas Company)

Enter in column (d) the terms "none," "not applicable," or "NA" as appropriate, to indicate no information or amounts have been reported for certain pages.

45	**Other Regulatory Liabilities**	278	REV 12-07	
	INCOME ACCOUNT SUPPORTING SCHEDULES			
46	**Monthly Quantity & Revenue Data**	299	NEW 12-08	
47	**Gas Operating Revenues**	300	REV 12-07	
48	**Revenues From Transportation Of Gas Of Others Through Gathering Facilities**	302	12-96	
49	**Revenues From Transportation Of Gas Of Others Through Transmission Facilities**	304	12-96	
50	**Revenues From Storing Gas Of Others**	306	12-96	
51	**Other Gas Revenues**	308	12-96	
52	**Discounted Rate Services And Negotiated Rate Services**	313	NEW 12-07	
53	**Gas Operation And Maintenance Expenses**	317	12-96	
54	**Exchange And Imbalance Transactions**	328	12-96	
55	**Gas Used In Utility Operations**	331	12-96	
56	**Transmission And Compression Of Gas By Others**	332	12-96	
57	**Other Gas Supply Expenses**	334	12-96	
58	**Miscellaneous General Expenses-Gas**	335	12-96	
59	**Depreciation, Depletion, and Amortization of Gas Plant**		12-96	
59	**Section A. Summary of Depreciation, Depletion, and Amortization Charges**	336	12-96	
59	**Section B. Factors Used in Estimating Depreciation Charges**	338	12-96	
60	**Particulars Concerning Certain Income Deductions And Interest Charges Accounts**	340	12-96	
	COMMON SECTION		12-96	
61	**Regulatory Commission Expenses**	350	12-96	
62	**Employee Pensions And Benefits (Account 926)**	352	NEW 12-07	
63	**Distribution Of Salaries And Wages**	354	REVISED	
64	**Charges For Outside Professional And Other Consultative Services**	357	REVISED	
65	**Transactions With Associated (Affiliated) Companies**	358	NEW 12-07	
	GAS PLANT STATISTICAL DATA			
66	**Compressor Stations**	508	REV 12-07	
67	**Gas Storage Projects**	512	12-96	
67	**Gas Storage Projects**	513	12-96	
68	**Transmission Lines**	514	12-96	
69	**Transmission System Peak Deliveries**	518	12-96	
70	**Auxiliary Peaking Facilities**	519	12-96	
71	**Gas Account - Natural Gas**	520	REV 01-11	
72	**Shipper Supplied Gas for the Current Quarter**	521	REVISED 02-11	
73	**System Maps**	522.1	REV. 12-96	
74	**Footnote Reference**			
75	**Footnote Text**			
76	**Stockholder's Reports (check appropriate box)**			
	☐ Four copies will be submitted ☐ No annual report to stockholders is prepared			

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

General Information

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Ryan L. Krasselt

VP, Controller, Prin Acctg Officer

1411 East 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.

WA State 3/15/1889
State of Incorporation: WA

Date of Incorporation: 03/15/1889

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.

None
(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:	Year/Period of Report: End of: 2023/ 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.
4. In column (b) designate type of control of the respondent as "D" for direct, an "I" for indirect, or a "J" for joint control.

DEFINITIONS
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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 that 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)	Type of Control (b)	Kind of Business (c)	Percent Voting Stock Owned (d)	Footnote Reference (e)
1	Avista Capital, Inc.	D	Parent to the Company's subsidiaries	100%	
2	Avista Development	I	Investment in Real Estate	100%	
3	Avista Edge, Inc.	I	Investment in Technology providing high speed internet	100%	
4	Pentzer Corporation	I	Parent of Bay Area Mfg and Penture Venture Holdings	100%	
5	Pentzer Venture Holdings II	I	Holding Company-Inactive	100%	
6	University Development Company, LLC	I	Facilitates Property Acquisitions	100%	
7	Avista Capital II	D	Affiliated business trust issued pref trust Securities	100%	
8	Avista Northwest Resources, LLC	I	Owns an interest in a venture fund investment	100%	
9	Courtyard Office Center, LLC	I	Inactive	100%	
10	Salix, Inc.	I	Liquified Natural Gas Operations	100%	
11	Alaska Energy and Resources Company (AERC)	D	Parent Co of Alaska Operations	100%	
12	Alaska Electric Light and Power Company	I	Utility Operations in Juneau	100%	
13	AJT Mining Properties, Inc.	I	Inactive mining Co holding certain properties	100%	
14	Snettisham Electric Company	I	Right to Purchase Snettisham	100%	

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Security Holders and Voting Powers

1. Give the names and addresses of the 10 security holders of the respondent who, at the date of the latest closing of the stock book or compilation of list of stockholders of the respondent, prior to the end of the year, had the highest voting powers in the respondent, and state the number of votes that each could cast on that date if a meeting were held. If any such holder held in trust, give in a footnote the known particulars of the trust (whether voting trust, etc.), duration of trust, and principal holders of beneficiary interests in the trust. If the company did not close the stock book or did not compile a list of stockholders within one year prior to the end of the year, or if since it compiled the previous list of stockholders, some other class of security has become vested with voting rights, then show such 10 security holders as of the close of the year. Arrange the names of the security holders in the order of voting power, commencing with the highest. Show in column (a) the titles of officers and directors included in such list of 10 security holders.
2. If any security other than stock carries voting rights, explain in a supplemental statement how such security became vested with voting rights and give other important details concerning the voting rights of such security. State whether voting rights are actual or contingent; if contingent, describe the contingency.
3. If any class or issue of security has any special privileges in the election of directors, trustees or managers, or in the determination of corporate action by any method, explain briefly in a footnote.
4. Furnish details concerning any options, warrants, or rights outstanding at the end of the year for others to purchase securities of the respondent or any securities or other assets owned by the respondent, including prices, expiration dates, and other material information relating to exercise of the options, warrants, or rights. Specify the amount of such securities or assets any officer, director, associated company, or any of the 10 largest security holders is entitled to purchase. This instruction is inapplicable to convertible securities or to any securities substantially all of which are outstanding in the hands of the general public where the options, warrants.

1. Give date of the latest closing of the stock book prior to end of year, and, in a footnote, state the purpose of such closing: 12/31/2023	2. State the total number of votes cast at the latest general meeting prior to the end of year for election of directors of the respondent and number of such votes cast by proxy. Total: 68,120,835 By Proxy: 68,120,835	3. Give the date and place of such meeting: 2023-05-11T00:00:00.00 Spokane, WA

Line No.	Name (Title) and Address of Security Holder (a)	VOTING SECURITIES 4. Number of votes as of (date): 12/31/2023			
		Total Votes (b)	Common Stock (c)	Preferred Stock (d)	Other (e)
5	TOTAL votes of all voting securities	74,936,291	74,936,291		
6	TOTAL number of security holders	6,122	6,122		
7	TOTAL votes of security holders listed below	42,153,138	42,153,138		
8	BlackRock Institutional Trust	13,911,870	13,911,870		
9	The Vanguard Group	9,473,316	9,473,316		
10	State Street Global Advisors (US)	4,611,776	4,611,776		
11	PSP Investments	3,539,985	3,539,985		
12	First Trust Advisors	2,082,225	2,082,225		
13	Hotchkis and Wiley Capital Management	1,937,599	1,937,599		
14	Westwood Management Corp. (Texas)	1,729,700	1,729,700		
15	Nuance Investments, LLC	1,657,277	1,657,277		
16	Geode Capital Management	1,650,709	1,650,709		
17	Columbia Threadneedle Investments (UK)	1,558,681	1,558,681		

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Important Changes During the Year

Give details concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Answer each inquiry. Enter "none" or "not applicable" where applicable. If the answer is given elsewhere in the report, refer to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration and state from whom the franchise rights were acquired. If the franchise rights were 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: Briefly describe the property, and the related transactions, and cite Commission authorization, if any was required. Give date journal entries called for by 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 conditions. 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 cite 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 or assumed by respondent as guarantor for the performance by another of any agreement or obligation, including ordinary commercial paper maturing on demand or not later than one year after date of issue: State on behalf of whom the obligation was assumed and amount of the obligation. Cite Commission authorization if any was required.
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, 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. Estimated increase or decrease in annual revenues caused by important rate changes: State effective date and approximate amount of increase or decrease for each revenue classification. State the number of customers affected.
12. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
13. 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.

1. None

2. None

3. None

4. None

5. None

6. Reference is made to Notes 10, 11 and 12 of the Notes to the Financial Statements

7. None

8. Average annual wage increases were 5.4% for non-exempt employees effective February 27, 2023. Average annual wage increases were 5.8% for exempt employees effective February 27, 2023. Officers received average increases of 6.4% effective February 13, 2023. Certain bargaining unit employees received average increases of 3.5% effective March 26, 2023 and April 1, 2023.

9. Reference is made to Note 15 of the Notes to the Financial Statements.

10. None

11. ***Washington General Rate Cases***

2022 General Rate Cases

In January 2022, we filed multi-year electric and natural gas general rate cases with the WUTC. In December 2022, the WUTC issued an order approving the multi-party settlement agreement filed in June 2022. The approved rates were designed to increase annual base electric revenues by $38.0 million, or 6.9 percent, effective in December 2022, and $12.5 million, or 2.1 percent, effective in December 2023. The approved rates were also designed to increase annual base natural gas revenues by $7.5 million, or 6.5 percent, effective in December 2022, and $1.5 million, or 1.2 percent, effective in December 2023.

To mitigate the overall impact of the revenue increases on customers, part of the 2022 base rate increase was offset with tax customer credits. The total estimated benefits of these credits, $27.6 million for electric customers and $12.5 million for natural gas customers, are being returned over a two-year period from December 2022 to December 2024.

In addition, the order approved a separate tracking mechanism and tariff for purposes of recovering existing and prospective Colstrip costs.

The WUTC approved an ROR of 7.03 percent, but the settlement does not specify an explicit ROE, cost of debt or capital structure.

These general rate cases require a subsequent review of additions to utility plant included in rates and a refund of revenues if capital expenditures are less than the level contemplated in the rate case. The review of 2022 capital was completed in 2023, and no refunds were required.

2024 General Rate Cases

On January 18, 2024, we filed multi-year electric and natural gas general rate cases with the WUTC. If approved, new rates would be effective in December 2024 and December 2025.

The proposed rates are designed to increase annual base electric revenues by $77.1 million, or 13.0 percent, effective in December 2024, and $53.7 million, or 11.7 percent, effective in December 2025.

For natural gas, the proposed rates are designed to increase annual base natural gas revenues by $17.3 million, or 13.6 percent, effective in December 2024, and $4.6 million, or 3.2 percent, effective in December 2025.

The proposed electric and natural gas revenue increase requests are based on a 10.4 percent return on equity with a common equity ratio of 48.5 percent and a rate of return on rate base of 7.61 percent. Increasing power supply costs, operating and maintenance costs, and ongoing capital investments (including clean energy hydroelectric projects, continued investment in the wildfire resiliency plan, replacement of natural gas distribution pipe and technology upgrades) were the main drivers of proposed increases.

In the second year of the proposed electric multi-year rate plan, in compliance with Washington's CETA, we have removed from customers' rates the costs associated with generation from Colstrip.

As a part of the electric rate case, we proposed certain updates to power supply costs. The updated power supply costs included as a part of the first rate year, accounts for $18.5 million of our overall electric request. For electric rate year 2, the net effect of increasing base power supply costs (primarily to make up for the loss of Colstrip from our generation portfolio), offset by reductions in customer rates through the removal of Colstrip rate base and expenses, accounts for $35.1 million of our overall $53.7 million request.

Additionally, we are proposing changes to the ERM. Under the present construct, the ERM consists of a $4 million deadband, and then an asymmetric sharing band between $4 million and $10 million. All costs above $10 million are shared on a 90 percent customer, 10 percent company basis. As part of this rate case, we are proposing moving the entire mechanism to a 95 percent customer, 5 percent company sharing of power supply cost above or below the authorized level.

If the multi-year rate plans are approved, we would not file new general rate cases for new rate plans to be effective prior to December 2026.

The WUTC has up to eleven months to review the general rate case filings and issue a decision.

Idaho General Rate Cases

2023 General Rate Cases

In February 2023, we filed multi-year electric and natural gas general rate cases with the IPUC. In August 2023, the IPUC approved the multi-party settlement agreement designed to increase annual base electric revenues by $22.1 million, or 8.0 percent, effective in September 2023, and $4.3 million, or 1.4 percent, effective in September 2024. The agreement was designed to increase annual base natural gas revenues by $1.3 million, or 2.7 percent, effective in September 2023, and a negligible increase effective in September 2024.

The settlement was based on an ROE of 9.4 percent, with a common equity ratio of 50 percent, and an ROR of 7.19 percent.

Oregon General Rate Cases

2023 General Rate Case

In March 2023, we filed a natural gas general rate case with the OPUC. In October 2023, the OPUC approved the all party settlement agreement filed in August 2023. The approved rates are designed to increase annual base natural gas revenues by $7.2 million, or 9.4 percent. The OPUC approved an ROR of 7.24 percent, a common equity ratio of 50 percent, and an ROE of 9.5 percent. New rates were effective on January 1, 2024.

12. Effective May 11th, 2023, Kristianne Blake retired from the Company's Board of Directors. On May 11th, 2023, Kevin Jacobson was elected to the Board of Directors.

On May 1, 2023, Mark Thies, Executive Vice President, Chief Financial Officer, and Treasurer, announced to the Company's board of directors that he would retire, effective October 1, 2023. Following the announcement, the Company's board of directors appointed Kevin Christie as Chief Financial Officer, Treasurer, and Senior Vice President Regulatory Affairs, effective May 11, 2023. Mr. Thies continued to serve as Executive Vice President until his retirement date.

Effective May 11, 2023, Latisha Hill added corporate communications, customer service and energy efficiency to her previous responsibilities. Her new title is Vice President of Community Affairs and Chief Customer Officer.

Effective June 1, 2023, Wayne Manuel joined the Company as Vice President, Chief Information Officer and Chief Security Officer. This role was previously held by Jim Kensok, who retired from the Company effective August 1, 2023.

Effective October 1, 2023, Senior Vice President and COO Heather Rosentrater became President and COO of the Company. Also effective October 1, 2023, Vice President, Safety and Chief People Officer Bryan Cox became Senior Vice President, Safety and Chief People Officer.

13. Proprietary capital is not less than 30 percent.

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Comparative Balance Sheet (Assets And Other Debits)

Line No.	Title of Account (a)	Reference Page Number (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	7,852,959,203	7,477,186,308
3	Construction Work in Progress (107)	200-201	170,812,964	155,475,677
4	TOTAL Utility Plant (Total of lines 2 and 3)	200-201	8,023,772,167	7,632,661,985
5	(Less) Accum. Provision for Depr., Amort., Depl. (108, 111, 115)		2,796,332,034	2,624,302,472
6	Net Utility Plant (Total of line 4 less 5)		5,227,440,133	5,008,359,513
7	Nuclear Fuel (120.1 thru 120.4, and 120.6)		0	0
8	(Less) Accum. Provision for Amort., of Nuclear Fuel Assemblies (120.5)		0	0
9	Nuclear Fuel (Total of line 7 less 8)		0	0
10	Net Utility Plant (Total of lines 6 and 9)		5,227,440,133	5,008,359,513
11	Utility Plant Adjustments (116)	122	0	0
12	Gas Stored-Base Gas (117.1)	220	6,992,076	6,992,076
13	System Balancing Gas (117.2)	220	0	0
14	Gas Stored in Reservoirs and Pipelines-Noncurrent (117.3)	220	0	0
15	Gas Owed to System Gas (117.4)	220	0	0
16	**OTHER PROPERTY AND INVESTMENTS**			
17	Nonutility Property (121)		22,796,933	11,036,947
18	(Less) Accum. Provision for Depreciation and Amortization (122)		110,345	103,609
19	Investments in Associated Companies (123)	222-223	11,547,000	11,547,000
20	Investments in Subsidiary Companies (123.1)	224-225	265,210,641	260,760,970
22	Noncurrent Portion of Allowances		0	0
23	Other Investments (124)	222-223	14,094	73,448
24	Sinking Funds (125)		0	0
25	Depreciation Fund (126)		0	0
26	Amortization Fund - Federal (127)		0	0
27	Other Special Funds (128)		15,335,490	11,797,054
28	Long-Term Portion of Derivative Assets (175)		0	2,944,915
29	Long-Term Portion of Derivative Assets - Hedges (176)		0	0
30	TOTAL Other Property and Investments (Total of lines 17-20, 22-29)		314,793,813	298,056,725
31	**CURRENT AND ACCRUED ASSETS**			
32	Cash (131)		11,843,507	4,465,295
33	Special Deposits (132-134)		0	66,141,689
34	Working Funds (135)		758,362	776,205
35	Temporary Cash Investments (136)	222-223	15,991,036	496,573
36	Notes Receivable (141)		0	0
37	Customer Accounts Receivable (142)		199,763,204	219,394,599
38	Other Accounts Receivable (143)		38,651,095	67,155,969
39	(Less) Accum. Provision for Uncollectible Accounts - Credit (144)		4,905,146	6,345,841
40	Notes Receivable from Associated Companies (145)		20,584,744	9,364,617
41	Accounts Receivable from Associated Companies (146)		978,859	787,177
42	Fuel Stock (151)		4,683,150	4,252,607
43	Fuel Stock Expenses Undistributed (152)		0	0
44	Residuals (Elec) and Extracted Products (Gas) (153)		0	0
45	Plant Materials and Operating Supplies (154)		79,492,528	73,453,924
46	Merchandise (155)		0	0
47	Other Materials and Supplies (156)		0	0
48	Nuclear Materials Held for Sale (157)		0	0
49	Allowances (158.1 and 158.2)		30,071,678	0
50	(Less) Noncurrent Portion of Allowances		0	0
51	Stores Expense Undistributed (163)		0	0
52	Gas Stored Underground-Current (164.1)	220	16,271,620	[a]26,788,026
53	Liquefied Natural Gas Stored and Held for Processing (164.2 thru 164.3)	220	0	0

54	Prepayments (165)	230	50,221,552	28,311,482
55	Advances for Gas (166 thru 167)		0	0
56	Interest and Dividends Receivable (171)		2,627,341	621,880
57	Rents Receivable (172)		7,380,742	4,556,651
58	Accrued Utility Revenues (173)		0	0
59	Miscellaneous Current and Accrued Assets (174)		0	230,226
60	Derivative Instrument Assets (175)		11,821,033	21,142,956
61	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	2,944,915
62	Derivative Instrument Assets - Hedges (176)		0	0
63	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)		0	0
64	TOTAL Current and Accrued Assets (Total of lines 32 thru 63)		486,235,305	518,649,120
65	**DEFERRED DEBITS**			
66	Unamortized Debt Expense (181)		21,586,301	20,719,467
67	Extraordinary Property Losses (182.1)	230	0	0
68	Unrecovered Plant and Regulatory Study Costs (182.2)	230	0	0
69	Other Regulatory Assets (182.3)	232	898,192,107	912,434,228
70	Preliminary Survey and Investigation Charges (Electric)(183)		0	0
71	Preliminary Survey and Investigation Charges (Gas)(183.1 and 183.2)		0	0
72	Clearing Accounts (184)		858,506	872,806
73	Temporary Facilities (185)		0	0
74	Miscellaneous Deferred Debits (186)	233	87,517,904	68,920,168
75	Deferred Losses from Disposition of Utility Plant (187)		0	0
76	Research, Development, and Demonstration Expend. (188)		0	0
77	Unamortized Loss on Reacquired Debt (189)		5,701,051	6,177,054
78	Accumulated Deferred Income Taxes (190)	234-235	214,152,188	269,470,612
79	Unrecovered Purchased Gas Costs (191)		51,370,535	52,091,145
80	TOTAL Deferred Debits (Total of lines 66 thru 79)		1,279,378,592	1,330,685,480
81	TOTAL Assets and Other Debits (Total of lines 10-15,30,64,and 80)		7,314,839,919	7,162,742,914

FOOTNOTE DATA

(a) Concept: GasStoredCurrent
Fuel is accounted for within injections and withdrawal accounts. All gas reported is current working gas. Avista uses the inventory method to report all working gas stored.

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Comparative Balance Sheet (Liabilities and Other Credits)

Line No.	Title of Account (a)	Reference Page Number (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**PROPRIETARY CAPITAL**			
2	Common Stock Issued (201)	250-251	1,596,986,047	1,481,787,168
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)	252	0	0
5	Stock Liability for Conversion (203, 206)	252	0	0
6	Premium on Capital Stock (207)	252	0	0
7	Other Paid-In Capital (208-211)	253	(2,732,405)	(10,696,711)
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254	(50,073,294)	(54,094,483)
11	Retained Earnings (215, 215.1, 216)	118-119	798,215,179	772,567,765
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	43,138,900	38,974,396
13	(Less) Reacquired Capital Stock (217)	250-251	0	0
14	Accumulated Other Comprehensive Income (219)	117	(357,109)	(2,058,225)
15	TOTAL Proprietary Capital (Total of lines 2 thru 14)		2,485,323,906	2,334,668,876
16	**LONG TERM DEBT**			
17	Bonds (221)	256-257	2,543,700,000	2,307,200,000
18	(Less) Reacquired Bonds (222)	256-257	83,700,000	83,700,000
19	Advances from Associated Companies (223)	256-257	51,547,000	51,547,000
20	Other Long-Term Debt (224)	256-257	0	0
21	Unamortized Premium on Long-Term Debt (225)	258-259	106,600	115,483
22	(Less) Unamortized Discount on Long-Term Debt-Dr (226)	258-259	795,576	841,286
23	(Less) Current Portion of Long-Term Debt		0	0
24	TOTAL Long-Term Debt (Total of lines 17 thru 23)		2,510,858,024	2,274,321,197
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases-Noncurrent (227)		63,558,661	64,284,097
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		995,000	1,320,000
29	Accumulated Provision for Pensions and Benefits (228.3)		89,829,937	93,900,990
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		618,329	774,805
32	Long-Term Portion of Derivative Instrument Liabilities		17,902,180	7,891,963
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		18,058,399	15,783,066
35	TOTAL Other Noncurrent Liabilities (Total of lines 26 thru 34)		190,962,506	183,954,921
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Current Portion of Long-Term Debt		0	0
38	Notes Payable (231)		349,000,000	463,000,000
39	Accounts Payable (232)		136,101,468	195,759,919
40	Notes Payable to Associated Companies (233)		0	0
41	Accounts Payable to Associated Companies (234)		0	114
42	Customer Deposits (235)		11,208,693	6,929,872
43	Taxes Accrued (236)	262-263	31,879,207	38,520,487
44	Interest Accrued (237)		22,318,892	19,663,017
45	Dividends Declared (238)		0	0
46	Matured Long-Term Debt (239)		0	0
47	Matured Interest (240)		0	0
48	Tax Collections Payable (241)		40,534	202,211
49	Miscellaneous Current and Accrued Liabilities (242)	268	99,744,896	84,650,630
50	Obligations Under Capital Leases-Current (243)		4,490,212	4,348,776
51	Derivative Instrument Liabilities (244)		35,118,959	34,802,627
52	(Less) Long-Term Portion of Derivative Instrument Liabilities		17,902,180	7,891,963

53	Derivative Instrument Liabilities - Hedges (245)		0	0
54	(Less) Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
55	TOTAL Current and Accrued Liabilities (Total of lines 37 thru 54)		672,000,681	839,985,690
56	**DEFERRED CREDITS**			
57	Customer Advances for Construction (252)		4,436,513	4,211,506
58	Accumulated Deferred Investment Tax Credits (255)		28,233,162	28,784,445
59	Deferred Gains from Disposition of Utility Plant (256)		0	0
60	Other Deferred Credits (253)	269	32,918,243	48,402,602
61	Other Regulatory Liabilities (254)	278	479,233,915	525,409,545
62	Unamortized Gain on Reacquired Debt (257)	260	942,384	1,059,748
63	Accumulated Deferred Income Taxes - Accelerated Amortization (281)		0	0
64	Accumulated Deferred Income Taxes - Other Property (282)		653,219,870	636,821,685
65	Accumulated Deferred Income Taxes - Other (283)		256,710,715	285,122,699
66	TOTAL Deferred Credits (Total of lines 57 thru 65)		1,455,694,802	1,529,812,230
67	TOTAL Liabilities and Other Credits (Total of lines 15,24,35,55,and 66)		7,314,839,919	7,162,742,914

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Statement of Income

Quarterly

1. Enter in column (d) the balance for the reporting quarter and in column (e) the balance for the same three month period for the prior year.
2. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in (k) the quarter to date amounts for other utility function for the current year quarter.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in (k) the quarter to date amounts for other utility function for the prior year quarter.
4. If additional columns are needed place them in a footnote.

Annual or Quarterly, if applicable

5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility 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.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
8. Report data for lines 8, 10 and 11 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1 and 407.2.
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)	Reference Page Number (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current Three Months Ended Quarterly Only No Fourth Quarter (e)	Prior Three Months Ended Quarterly Only No Fourth Quarter (f)	Elec. Utility Current Year to Date (in dollars) (g)	Elec. 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	Gas Operating Revenues (400)	300-301	1,813,140,867	1,753,175,600			1,193,674,365	1,167,462,735	619,466,502	585,712,865		
3	Operating Expenses											
4	Operation Expenses (401)	317-325	1,129,074,478	1,115,606,858			674,026,748	702,986,085	455,047,730	412,620,773		
5	Maintenance Expenses (402)	317-325	86,720,955	90,443,526			71,447,477	73,669,737	15,273,478	16,773,789		
6	Depreciation Expense (403)	336-338	194,611,959	185,002,792			149,272,689	142,463,452	45,339,270	42,539,340		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-338	0	0			0	0	0	0		
8	Amort. & Depl. of Utility Plant (404-405)	336-338	62,239,993	56,467,917			46,738,641	42,661,543	15,501,352	13,806,374		
9	Amortization of Utility Plant Acu. Adjustment (406)	336-338	0	0			0	0	0	0		
10	Amort. of Prop. Losses, Unrecovered Plant and Reg. Study Costs (407.1)		0	0								
11	Amortization of Conversion Expenses (407.2)		0	0			0	0	0	0		
12	Regulatory Debits (407.3)		64,155,411	18,495,696			21,751,021	12,678,285	42,404,390	5,817,411		
13	(Less) Regulatory Credits (407.4)		102,019,225	49,733,468			43,048,247	44,548,411	58,970,978	5,185,057		
14	Taxes Other Than Income Taxes (408.1)	262-263	118,141,439	121,401,780			79,882,775	86,410,192	38,258,664	34,991,588		
15	Income Taxes-Federal (409.1)	262-263	2,419,168	(1,018,866)			(7,715,052)	(3,578,734)	10,134,220	2,559,868		
16	Income Taxes-Other (409.1)	262-263	895,264	789,848			20,224	(43,263)	875,040	833,111		
17	Provision of Deferred Income Taxes (410.1)	234-235	36,404,931	40,312,733			29,355,257	29,270,294	7,049,674	11,042,439		
18	(Less) Provision for Deferred Income Taxes-Credit (411.1)	234-235	74,741,597	64,172,849			47,088,945	46,062,769	27,652,652	18,110,080		
19	Investment Tax Credit Adjustment-Net (411.4)		(551,283)	(528,730)			(546,563)	(528,748)	(4,720)	18		
20	(Less) Gains from Disposition of Utility Plant (411.6)		0	0								
21	Losses from Disposition of Utility Plant (411.7)		0	0								
22	(Less) Gains from Disposition of Allowances (411.8)		0	0								

23	Losses from Disposition of Allowances (411.9)		0	0								
24	Accretion Expense (411.10)		0	0								
25	TOTAL Utility Operating Expenses (Total of lines 4 thru 24)		1,517,351,493	1,513,067,237			974,096,025	995,377,663	543,255,468	517,689,574	0	0
26	Net Utility Operating Income (Total of lines 2 less 25)		295,789,374	240,108,363			219,578,340	172,085,072	76,211,034	68,023,291	0	0
28	OTHER INCOME AND DEDUCTIONS											
29	Other Income											
30	Nonutilty Operating Income											
31	Revenues From Merchandising, Jobbing and Contract Work (415)		0	0								
32	(Less) Costs and Expense of Merchandising, Job & Contract Work (416)		0	0								
33	Revenues From Nonutility Operations (417)		0	75,755								
34	(Less) Expenses of Nonutility Operations (417.1)		7,891,784	11,488,060								
35	Nonoperating Rental Income (418)		(1,034)	(6,089)								
36	Equity in Earnings of Subsidiary Companies (418.1)	119	4,449,671	39,795,257								
37	Interest and Dividend Income (419)		15,537,184	2,112,087								
38	Allowance for Other Funds Used During Construction (419.1)		(39,011)	804,751								
39	Miscellaneous Nonoperating Income (421)		16,773	0								
40	Gain on Disposition of Property (421.1)		0	1,747,858								
41	TOTAL Other Income (Total of lines 31 thru 40)		12,071,799	33,041,559								
42	Other Income Deductions											
43	Loss on Disposition of Property (421.2)		40,896	0								
44	Miscellaneous Amortization (425)		5,616	5,616								
45	Donations (426.1)	340	2,755,476	2,832,367								
46	Life Insurance (426.2)		2,661,064	3,588,360								
47	Penalties (426.3)		25,450	24,039								
48	Expenditures for Certain Civic, Political and Related Activities (426.4)		1,775,518	1,731,972								
49	Other Deductions (426.5)		1,410,301	4,469,119								
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)	340	8,674,321	12,651,473								
51	Taxes Applic. to Other Income and Deductions											
52	Taxes Other Than Income Taxes (408.2)	262-263	462,271	670,496								
53	Income Taxes-Federal (409.2)	262-263	(2,079,651)	(478,795)								
54	Income Taxes-Other (409.2)	262-263	(75,004)	(668,970)								
55	Provision for Deferred Income Taxes (410.2)	234-235	3,954,988	1,568,707								
56	(Less) Provision for Deferred Income Taxes-Credit (411.2)	234-235	2,286,595	4,155,913								
57	Investment Tax Credit Adjustments-Net (411.5)		0	0								
58	(Less) Investment Tax Credits (420)											

59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		(23,991)	(3,064,475)									
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		3,421,469	23,454,561									
61	INTEREST CHARGES												
62	Interest on Long-Term Debt (427)		110,131,468	99,558,755									
63	Amortization of Debt Disc. and Expense (428)	258-259	1,544,188	470,608									
64	Amortization of Loss on Reacquired Debt (428.1)		1,317,067	1,433,640									
65	(Less) Amortization of Premium on Debt-Credit (429)	258-259	8,883	8,883									
66	(Less) Amortization of Gain on Reacquired Debt-Credit (429.1)												
67	Interest on Debt to Associated Companies (430)	340	2,503,671	1,062,531									
68	Other Interest Expense (431)	340	21,435,607	9,696,574									
69	(Less) Allowance for Borrowed Funds Used During Construction-Credit (432)		8,892,489	3,826,333									
70	Net Interest Charges (Total of lines 62 thru 69)		128,030,629	108,386,892									
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		171,180,214	155,176,032									
72	EXTRAORDINARY ITEMS												
73	Extraordinary Income (434)		0	0									
74	(Less) Extraordinary Deductions (435)												
75	Net Extraordinary Items (Total of line 73 less line 74)		0	0									
76	Income Taxes-Federal and Other (409.3)	262-263	0	0									
77	Extraordinary Items after Taxes (line 75 less line 76)		0	0									
78	Net Income (Total of line 71 and 77)		171,180,214	155,176,032									

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Statement of Accumulated Comprehensive Income and Hedging Activities

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

Line No.	Item (a)	Unrealized Gains and Losses on available-for-sale securities (b)	Minimum Pension liabililty Adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Insert Footnote at Line 1 to specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 114, Line 78) (i)	Total Comprehensive Income (j)
1	Balance of Account 219 at Beginning of Preceding Year		(11,038,551)					(11,038,551)		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income									
3	Preceding Quarter/Year to Date Changes in Fair Value		8,980,326					8,980,326		
4	Total (lines 2 and 3)		8,980,326					8,980,326	155,176,032	164,156,358
5	Balance of Account 219 at End of Preceding Quarter/Year		(2,058,225)					(2,058,225)		
6	Balance of Account 219 at Beginning of Current Year		(2,058,225)					(2,058,225)		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income									
8	Current Quarter/Year to Date Changes in Fair Value		1,701,116					1,701,116		
9	Total (lines 7 and 8)		1,701,116					1,701,116	171,180,214	172,881,330
10	Balance of Account 219 at End of Current Quarter/Year		(357,109)					(357,109)		

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Statement of Retained Earnings

1. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
2. 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).
3. State the purpose and amount for each reservation or appropriation of retained earnings.
4. 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.
5. Show dividends for each class and series of capital stock.

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			
1	Balance-Beginning of Period		717,509,955	729,502,158
2	Changes (Identify by prescribed retained earnings accounts)			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit (Debit)			
6	Balance Transferred from Income (Account 433 less Account 418.1)		166,730,543	115,380,775
7	Appropriations of Retained Earnings (Account 436)			
7.1	Excess Earnings		(1,835,879)	(3,539,494)
8	Appropriations of Retained Earnings Amount			
9	Dividends Declared-Preferred Stock (Account 437)			
10	Dividends Declared-Preferred Stock Amount			
11	Dividends Declared-Common Stock (Account 438)			
11.1	Dividends		(141,368,296)	(129,264,336)
12	Dividends Declared-Common Stock Amount			
13	Transfers from Account 216.1, Unappropriated Undistributed Subsidiary Earnings		285,167	5,430,852
14	Balance-End of Period (Total of lines 1, 4, 5, 6, 8, 10, 12, and 13)		741,321,490	717,509,955
15	APPROPRIATED RETAINED EARNINGS (Account 215)			
16	TOTAL Appropriated Retained Earnings (Account 215) (footnote details)		56,893,689	55,057,810
17	APPROPRIATED RETAINED EARNINGS-AMORTIZATION RESERVE, FEDERAL (Account 215.1)			
18	TOTAL Appropriated Retained Earnings-Amortization Reserve, Federal (Account 215.1)			
19	TOTAL Appropriated Retained Earnings (Accounts 215, 215.1) (Total of lines of 16 and 18)		56,893,689	55,057,810
20	TOTAL Retained Earnings (Accounts 215, 215.1, 216) (Total of lines 14 and 19)		798,215,179	772,567,765
21	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account 216.1)			
	Report only on an Annual Basis no Quarterly			
22	Balance-Beginning of Year (Debit or Credit)		38,974,396	4,609,991
23	Equity in Earnings for Year (Credit) (Account 418.1)		4,449,671	39,795,257
24	(Less) Dividends Received (Debit)		0	5,000,000
25	Other Changes (Explain)		(285,167)	(430,852)
25.1	Corporate Costs Allocated to Subsidiaries		(285,167)	(430,852)
26	Balance-End of Year		43,138,900	38,974,396

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ 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 27) 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 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 114)	171,180,214	155,176,032
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	256,851,952	241,470,709
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of deferred power and gas costs, debt expense and exchange power	10,024,219	(75,986,952)
6	Deferred Income Taxes (Net)	(36,037,425)	(26,131,896)
7	Investment Tax Credit Adjustments (Net)	(551,283)	(528,731)
8	Net (Increase) Decrease in Receivables	39,845,414	(57,081,996)
9	Net (Increase) Decrease in Inventory	4,047,260	(22,224,699)
10	Net (Increase) Decrease in Allowances Inventory	(30,071,678)	
11	Net Increase (Decrease) in Payables and Accrued Expenses	[a](50,860,477)	[d]83,122,813
12	Net (Increase) Decrease in Other Regulatory Assets	(53,098,758)	583,561
13	Net Increase (Decrease) in Other Regulatory Liabilities	34,302,152	10,248,033
14	(Less) Allowance for Other Funds Used During Construction	6,340,790	6,543,085
15	(Less) Undistributed Earnings from Subsidiary Companies	4,449,671	39,795,257
16	Other Adjustments to Cash Flows from Operating Activities		
16.1	Power and natural gas deferrals	(6,119,299)	(1,797,792)
16.2	Change in special deposits	129,225,987	(141,014,015)
16.3	Change in other current assets	(26,445,069)	(6,946,745)
16.4	Non-cash stock compensation	8,441,581	8,716,734
16.5	Loss (Gain) on sale of property and equipment	40,896	(1,747,858)
16.6	Other	(3,283,209)	1,378,349
16.7	Allowance for Doubtful Accounts	3,917,172	3,545,696
16.8	Changes in other non-current assets and liabilities	(13,741,356)	6,069,824
16.9	Cash paid for settlement of interest rate swaps	(409,000)	(17,035,230)
16.10	Cash Received for Settlement of Interest Rate Swaps	7,868,930	
18	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 16)	434,337,762	113,477,495
20	Cash Flows from Investment Activities:		
21	Construction and Acquisition of Plant (including land):		
22	Gross Additions to Utility Plant (less nuclear fuel)	[b](490,335,100)	[e](449,340,115)
23	Gross Additions to Nuclear Fuel		
24	Gross Additions to Common Utility Plant		
25	Gross Additions to Nonutility Plant		
26	(Less) Allowance for Other Funds Used During Construction		
27	Other Construction and Acquisition of Plant, Investment Activities		
28	Cash Outflows for Plant (Total of lines 22 thru 27)	(490,335,100)	(449,340,115)
30	Acquisition of Other Noncurrent Assets (d)		
31	Proceeds from Disposal of Noncurrent Assets (d)		1,913,172
33	Investments in and Advances to Associated and Subsidiary Companies	(11,411,922)	(10,836,472)
34	Contributions and Advances from Associated and Subsidiary Companies		5,000,000
36	Disposition of Investments in (and Advances to) Associated and Subsidiary Companies		
38	Purchase of Investment Securities (a)		
39	Proceeds from Sales of Investment Securities (a)		
40	Loan Made or Purchased		
41	Collections on Loans		
43	Net (Increase) Decrease in Receivables		

44	Net (Increase) Decrease in Inventory		
45	Net (Increase) Decrease in Allowances Held for Speculation		
46	Net Increase (Decrease) in Payables and Accrued Expenses		
47	Other Adjustments to Cash Flows from Investment Activities:		
47.1	Changes in other property and investments	1,199,766	1,820,492
49	Net Cash Provided by (Used in) Investing Activities (Total of lines 28 thru 47)	(500,547,256)	(451,442,923)
51	Cash Flows from Financing Activities:		
52	Proceeds from Issuance of:		
53	Proceeds from Issuance of Long-Term Debt (b)	250,000,000	399,856,000
54	Proceeds from Issuance of Preferred Stock		
55	Proceeds from Issuance of Common Stock	112,308,131	137,778,394
56	Net Increase in Debt (Long Term Advances)		
57	Net Increase in Short-term Debt (c)		179,000,000
59	Cash Provided by Outside Sources (Total of lines 53 thru 58)	362,308,131	716,634,394
61	Payments for Retirement		
62	Payments for Retirement of Long-Term Debt (b)	(13,500,000)	(250,000,000)
63	Payments for Retirement of Preferred Stock		
64	Payments for Retirement of Common Stock		
65	Other Retirements		
65.1	Other	[e](4,820,847)	[f](7,143,646)
66	Net Decrease in Short-Term Debt (c)	(114,000,000)	
67	Other Adjustments to Financing Cash Flows		
68	Dividends on Preferred Stock		
69	Dividends on Common Stock	(140,922,959)	(129,060,998)
70	Net Cash Provided by (Used in) Financing Activities (Total of lines 59 thru 69)	89,064,325	330,429,750
73	Net Increase (Decrease) in Cash and Cash Equivalents		
74	(Total of line 18, 49 and 71)	22,854,831	(7,535,678)
76	Cash and Cash Equivalents at Beginning of Period	5,738,074	13,273,752
78	Cash and Cash Equivalents at End of Period	28,592,905	5,738,074

(a) Concept: NetIncreaseDecreaseInPayablesAndAccruedExpensesOperatingActivities
Cash paid (received) during the period for: Income taxes: $(1,439,727) Interest: $125,249,194
(b) Concept: GrossAdditionsToUtilityPlantLessNuclearFuelInvestingActivities
Additions to PPE in Accounts Payable: $33,691,044
(c) Concept: OtherRetirementsOfBalancesImpactingCashFlowsFromFinancingActivities
Debt Issuance costs (3,323,740); Minimum tax withholdings (1,497,107)
(d) Concept: NetIncreaseDecreaseInPayablesAndAccruedExpensesOperatingActivities
Cash paid during the period for: Income taxes: $445,203 Interest: $101,077,254
(e) Concept: GrossAdditionsToUtilityPlantLessNuclearFuelInvestingActivities
Additions to PPE in Accounts Payable: $27,708,348
(f) Concept: OtherRetirementsOfBalancesImpactingCashFlowsFromFinancingActivities
Debt Issuance costs (5,681,390); Minimum tax withholdings (1,462,256)

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Notes to Financial Statements

1. Provide important disclosures regarding the Balance Sheet, Statement of Income for the Year, Statement of Retained Earnings for the Year, and Statement of Cash Flow, or any account thereof. Classify the disclosures according to each financial statement, providing a subheading for each statement except where a disclosure is applicable to more than one statement. The disclosures must be on the same subject matters and in the same level of detail that would be required if the respondent issued general purpose financial statements to the public or shareholders.
2. Furnish details as to any significant contingent assets or liabilities existing at year end, and briefly explain any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or a claim for refund of income taxes of a material amount initiated by the utility. Also, briefly explain any dividends in arrears on cumulative preferred stock.
3. Furnish details on the respondent's pension plans, post-retirement benefits other than pensions (PBOP) plans, and post-employment benefit plans as required by instruction no. 1 and, in addition, disclose for each individual plan the current year's cash contributions. Furnish details on the accounting for the plans and any changes in the method of accounting for them. Include details on the accounting for transition obligations or assets, gains or losses, the amounts deferred and the expected recovery periods. Also, disclose any current year's plan or trust curtailments, terminations, transfers, or reversions of assets. Entities that participate in multiemployer postretirement benefit plans (e.g. parent company sponsored pension plans) disclose in addition to the required disclosures for the consolidated plan, (1) the amount of cost recognized in the respondent's financial statements for each plan for the period presented, and (2) the basis for determining the respondent's share of the total plan costs.
4. Furnish details on the respondent's asset retirement obligations (ARO) as required by instruction no. 1 and, in addition, disclose the amounts recovered through rates to settle such obligations. Identify any mechanism or account in which recovered funds are being placed (i.e. trust funds, insurance policies, surety bonds). Furnish details on the accounting for the asset retirement obligations and any changes in the measurement or method of accounting for the obligations. Include details on the accounting for settlement of the obligations and any gains or losses expected or incurred on the settlement.
5. Provide a list of all environmental credits received during the reporting period.
6. Provide a summary of revenues and expenses for each tracked cost and special surcharge.
7. Where Account 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 item. See General Instruction 17 of the Uniform System of Accounts.
8. Explain concisely any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
9. Disclose details on any significant financial changes during the reporting year to the respondent or the respondent's consolidated group that directly affect the respondent's gas pipeline operations, including: sales, transfers or mergers of affiliates, investments in new partnerships, sales of gas pipeline facilities or the sale of ownership interests in the gas pipeline to limited partnerships, investments in related industries (i.e., production, gathering), major pipeline investments, acquisitions by the parent corporation(s), and distributions of capital.
10. Explain concisely unsettled rate proceedings where a contingency exists such that the company may need to refund a material amount to the utility's customers or that the utility may receive a material refund with respect to power or gas purchases. State for each year affected the gross revenues or costs to which the contingency relates and the tax effects and explain the major factors that affect the rights of the utility to retain such revenues or to recover amounts paid with respect to power and gas purchases.
11. Explain concisely 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 summarize the adjustments made to balance sheet, income, and expense accounts.
12. Explain concisely only those significant 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 approximate dollar effect of such changes.
13. 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.
14. 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.
15. 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.

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.

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 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 Regulation 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 as required by U.S. GAAP. The accompanying financial statements include the Company's proportionate share of utility plant and related operations associated with 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 amounts reported for assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Significant estimates include:

- determining the market value of energy commodity derivative assets and liabilities,
- pension and other postretirement benefit plan obligations,
- contingent liabilities,
- goodwill impairment testing,
- 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 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:

	2023	2022
Avista Corp.	3.52%	3.50%

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

Electric thermal/other production	26
Hydroelectric production	79
Electric transmission	50
Electric distribution	40
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:

	2023	2022
Avista Corp.	7.03%	7.12%

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 has elected to account for transferable tax credits as a component of the income tax provision. The Company recognizes the benefit of production tax credits as a reduction of income tax expense in the period the credit is generated, which corresponds to the period the energy production occurs. The Company applies the deferral method of accounting for investment tax credits (ITCs). Under this method, ITCs are amortized as a reduction to income tax expense over the estimated useful lives of the underlying property that gave rise to the credit.

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 penalties on income tax positions in 2023or 2022. The Company would recognize interest accrued related to income tax positions as interest expense or interest income and penalties incurred as other operating expense.

Stock-Based Compensation

The Company issues three types of stock-based compensation awards - restricted shares, market-based awards and performance-based awards. 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):

	2023	2022
Stock-based compensation expense	$ 7,144	$ 7,567
Income tax benefits	1,500	1,589
Excess tax benefits (expenses) on settled share-based employee payments	84	(19)

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 have vested 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 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 incorporating the probability of meeting the market targets based on historical returns relative to a peer group. CEPS awards are valued at the close of market of the Company's common stock on the grant date.

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:

	2023	2022
Restricted Shares		
Shares granted during the year	76,806	115,746
Shares vested during the year	75,007	44,829
Unvested shares at end of year	152,140	157,860
Unrecognized compensation expense at end of year (in thousands)	$ 3,477	$ 3,923
TSR Awards		
TSR shares granted during the year	34,912	69,814
TSR shares vested during the year	61,456	43,730
TSR shares earned based on market metrics	44,863	48,890
Unvested TSR shares at end of year	96,915	130,567
Unrecognized compensation expense at end of year (in thousands)	$ 2,235	$ 3,533
CEPS Awards		
CEPS shares granted during the year	104,685	69,814
CEPS shares vested during the year	61,456	43,730
CEPS shares earned based on performance metrics	33,801	
Unvested CEPS shares at end of year	161,235	130,567
Unrecognized compensation expense at end of year (in thousands)	$ 2,439	$ 2,471

Outstanding restricted, TSR and CEPS share awards include a dividend component 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, 2023 and 2022, the Company had recognized a liability of $2.2 million and $1.7 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

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 11 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 (PGAs), the Energy Recovery Mechanism (ERM) in Washington, the Power Cost Adjustment (PCA) mechanism in Idaho, and periodic general rate cases. The resulting regulatory assets associated with energy commodity derivative instruments are 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 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 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 allowing 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 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 swaps and foreign currency exchange contracts, are reported at estimated fair value on the Balance Sheets. See Note 13 for the Company's fair value disclosures.

Regulatory Deferred Charges and Credits

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

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

Regulatory accounting practices require 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), to be 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 2 for discussion on decoupling revenue deferrals.

If at some point in the future the Company determines 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 and discounts paid to repurchase debt are amortized over the remaining life of the original debt 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 premium and discount 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 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):

	2023	2022
Appropriated retained earnings	$ 56,894	$ 55,058

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, 2023, the Company has not recorded significant amounts related to unresolved contingencies. See Note 15 for further discussion of the Company's commitments and contingencies.

Equity in Earnings (Losses) of Subsidiaries

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

	2023	2022
Avista Capital	$ (4,288)	$ 32,423
AERC	8,738	7,372
Total equity in earnings of subsidiary companies	$ 4,450	$ 39,795

Subsequent Events

Management has evaluated the impact of events occurring after December 31, 2023 up to February 20, 2024, 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. REVENUE

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. Since 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. Since all revenue recognition criteria are met upon the delivery of energy to customers, revenue is recognized 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,

tariff 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 meter reading and customer billing occurs.

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

	2023	2022
Unbilled accounts receivable	$ 75,650	$ 78,873

Non-Derivative Wholesale Contracts

The Company has certain wholesale contracts that are not accounted for as derivatives and are 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 alternative revenue programs are contracts between an entity and a regulator of utilities, not a contract between an entity and a customer. GAAP requires the presentation of revenue arising from alternative revenue programs separately from revenues arising from contracts with customers on 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 an 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 Statements of Income. 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 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 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 transactions 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 excluded from revenue from contracts with customers, 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 imposed on Avista Corp. as opposed to being imposed on 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 included in revenue from contracts with customers were as follows for the years ended December 31 (dollars in thousands):

	2023	2022
Utility-related taxes	$ 75,404	$ 69,931

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 has one capacity agreement where the customer makes payments throughout the year. As of December 31, 2023, the Company estimates it had unsatisfied capacity performance obligations of $7.4 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.

NOTE 3. LEASES

The core principle of lease accounting is that an entity should recognize the ROU assets and liabilities 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 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. 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 includes 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 the Company will exercise that option. Lease expense is recognized on a straight-line basis over the lease term. The 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. In addition, the State of Montana and Avista Corp. were engaged in litigation regarding lease terms, including how much money, if any, the State of Montana should return to Avista Corp.; however, that litigation was dismissed as premature pending the outcome of the ongoing litigation between the State of Montana and NorthWestern. Any reduction in future lease payments or the return to Avista Corp. of amounts previously paid will be included in the future ratemaking process.

In addition to the lease with the State of Montana, the Company 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 70 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 material residual value guarantees or material restrictive covenants.

In March 2023, the Company entered into an agreement with Rathdrum Power, LLC amending and restating a PPA for the output of the Lancaster Plant. The restated PPA meets the accounting definition of a lease, and all payments are variable in nature, based on capacity, usage, or performance of the plant. Therefore, there is no lease obligation or corresponding ROU asset recorded by the Company related to this agreement. The variable lease costs related to this agreement are included in resource costs on the Statements of Income.

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, 2023 are immaterial.

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

	2023	2022	2021
Operating lease cost:			
Fixed lease cost (Other operating expenses)	$ 5,096	$ 4,986	$ 4,970
Variable lease cost (Other operating expenses and Resource costs)	24,628	1,567	1,180
Total operating lease cost	$ 29,724	$ 6,553	$ 6,150

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

	2023	2022	2021
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash outflows:			
Operating lease payments	$ 4,960	$ 4,828	$ 4,805

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

	December 31, 2023	December 31, 2022
Operating Leases		
Operating lease ROU assets (Utility Plant)	$ 67,585	$ 68,238
Obligations under capital lease - current	$ 4,490	$ 4,349
Obligations under capital lease - noncurrent	63,559	64,284
Total operating lease liabilities	$ 68,049	$ 68,633
Weighted Average Remaining Lease Term		
Operating leases	22.28 years	23.28 years
Weighted Average Discount Rate		
Operating leases	4.29 %	4.28 %

Maturities of lease liabilities (including principal and interest) were as follows as of December 31, 2023 (dollars in thousands):

	Operating Leases
2024	$ 4,988
2025	4,984
2026	4,981
2027	5,007
2028	4,992
Thereafter	83,532
Total lease payments	$ 108,484
Less: imputed interest	(40,435)
Total	$ 68,049

Maturities of lease liabilities (including principal and interest) were as follows as of December 31, 2022 (dollars in thousands):

	Operating Leases
2023	$ 4,850
2024	4,877
2025	4,884
2026	4,869
2027	4,880
Thereafter	86,991
Total lease payments	$ 111,351
Less: imputed interest	(42,718)
Total	$ 68,633

NOTE 4. DERIVATIVES AND RISK MANAGEMENT

Energy Commodity Derivatives

Avista Corp. is exposed to market risks relating to changes in electricity and natural gas commodity prices and certain other fuel prices. Market risk is, in general, the risk of fluctuation in the market price of the commodity being traded and is influenced primarily by supply and demand. Market risk includes the fluctuation in the market price of associated derivative commodity instruments. Avista Corp. utilizes derivative instruments, such as forwards, futures, swap derivatives and options 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, Avista Corp. engages in an ongoing process of resource optimization, which involves the economic selection from available energy resources to serve Avista Corp.'s load obligations and 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. Based on 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, 2023 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
2024	9		22,747	74,596	472	510	1,723	12,038
2025			12,505	19,590	11	96	1,115	1,125
2026			5,570	3,940				

As of December 31, 2023, there are no expected deliveries of energy commodity derivatives after 2026.

The following table presents the underlying energy commodity derivative volumes as of December 31, 2022 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
2023	5		19,140	79,253	136	1,011	4,145	29,473
2024			533	30,658			1,370	9,668
2025			450	4,895			1,115	1,125

As of December 31, 2022, 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 recovered 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 outstanding as of December 31 (dollars in thousands):

	2023	2022
Number of contracts	5	19
Notional amount (in United States dollars)	$ 81	$ 8,563
Notional amount (in Canadian dollars)	109	11,659

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. may hedge a portion of its interest rate risk with financial derivative instruments, including interest rate swap derivatives. These interest rate swap derivatives 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 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, 2023	2	$ 20,000	2024
	1	10,000	2025
December 31, 2022	4	$ 40,000	2023
	1	10,000	2024

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, 2023 and December 31, 2022 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, 2023 (dollars in thousands):

	Fair Value			
Derivative and Balance Sheet Location	Gross Asset	Gross Liability	Collateral Netting	Net Asset (Liability) on Balance Sheet
Foreign currency exchange derivatives				
Derivative instrument assets current	$ 2	$	$	$ 2
Interest rate swap derivatives				
Derivative instrument assets current	3,667			3,667
Long-term portion of derivative liabilities		(182)		(182)
Energy commodity derivatives				
Derivative instrument assets current	8,531	(379)		8,152
Derivative instrument liabilities current	19,510	(79,082)	42,355	(17,217)
Long-term portion of derivative liabilities	2,913	(20,633)		(17,720)
Total derivative instruments recorded on the balance sheet	$ 34,623	$ (100,276)	$ 42,355	$ (23,298)

The following table presents the fair values and locations of derivative instruments recorded on the Balance Sheets as of December 31, 2022 (dollars in thousands):

	Fair Value			
Derivative and Balance Sheet Location	Gross Asset	Gross Liability	Collateral Netting	Net Asset (Liability) on Balance Sheet
Foreign currency exchange derivatives				
Derivative instrument assets current	$ 43	$	$	$ 43
Derivative instrument liabilities current		(3)		(3)
Interest rate swap derivatives				
Derivative instrument assets current	8,536			8,536
Long-term portion of derivative assets	2,648			2,648
Derivative instrument liabilities current		(52)		(52)
Energy commodity derivatives				
Derivative instrument assets current	32,257	(22,638)		9,619
Long-term portion of derivative assets	312	(16)		296
Derivative instrument liabilities current	107,902	(229,607)	94,850	(26,855)
Long-term portion of derivative liabilities	6,049	(24,530)	10,589	(7,892)
Total derivative instruments recorded on the balance sheet	$ 157,747	$ (276,846)	$ 105,439	$ (13,660)

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 changes in market prices or a downgrade in Avista Corp.'s credit ratings or other established credit criteria, 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 collateral outstanding related to its derivative instruments as of December 31 (dollars in thousands):

	2023	2022
Energy commodity derivatives		
Cash collateral posted	$ 43,095	$ 171,581
Letters of credit outstanding	20,000	49,425
Balance sheet offsetting (cash collateral against net derivative positions)	42,355	105,439

There were no letters of credit outstanding related to interest rate swap derivatives as of December 31, 2023 and December 31, 2022.

Certain of Avista Corp.'s derivative instruments contain provisions requiring 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 in a liability position and the amount of additional collateral Avista Corp. could be required to post as of December 31 (dollars in thousands):

	2023
Interest rate swap derivatives	
Liabilities with credit-risk-related contingent features	$ 182
Additional collateral to post	182
Energy commodity derivatives	
Liabilities with credit-risk-related contingent features	$ 18,016
Additional collateral to post	15,125

NOTE 5. JOINTLY OWNED ELECTRIC FACILITIES

The Company has a 15 percent ownership interest in Units 3 and 4 of Colstrip, 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):

	2023	2022
Utility plant in service	$ 394,398	$ 390,852
Accumulated depreciation	(334,338)	(315,223)

See Note 6 for further discussion of AROs.

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

In January 2023, the Company entered into an agreement with NorthWestern to transfer its ownership in Colstrip Units 3 and 4. The Company will retain responsibility for remediation obligations in existence at the time the transaction closes. See further discussion of the transaction within Note 15.

NOTE 6. 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 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):

	2023	2022
Asset retirement obligation at beginning of year	$ 15,783	$ 17,142
Liabilities incurred	1,927	
Liabilities settled	(232)	(1,964)
Accretion expense	580	605
Asset retirement obligation at end of year	$ 18,058	$ 15,783

NOTE 7. PENSION PLANS AND OTHER POSTRETIREMENT BENEFIT PLANS

The Company has a defined benefit pension plan covering the majority of regular full-time non-union employees at Avista Corp. hired prior to January 1, 2014 and regular full-time union employees that were hired prior to January 1, 2024. 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 and union employees hired on or after January 1, 2024 participate in a defined contribution 401(k) plan in lieu of a defined benefit pension plan. The Company's funding policy is to contribute at least the minimum amounts required to be funded under the Employee Retirement Income Security Act, but not more than the maximum amounts currently deductible for income tax purposes. The Company contributed $10.0 million in cash to the pension plan in 2023, and $42.0 million in 2022. The Company expects to contribute $10.0 million in cash to the pension plan in 2024.

In 2022, the defined benefit pension plan lump sum payments exceeded the annual service and interest costs for the plan. This resulted in a partial settlement of the plan, and the Company recorded a settlement loss of $11.8 million for the previously unrecognized losses in the year ended December 31, 2022. This loss was deferred as a regulatory asset and is being amortized over 12 years in accordance with regulatory accounting orders.

The Company has a SERP providing additional pension benefits to certain executive officers and certain key employees of the Company. The SERP provides 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 benefit payments under the pension plan and the SERP will total (dollars in thousands):

	2024	2025	2026	2027	2028	Total 2029-2033
Expected benefit payments	$ 41,562	$ 42,123	$ 42,941	$ 43,517	$ 44,700	$ 232,345

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 hired prior to January 1, 2014. The Company accrues the estimated cost of postretirement benefit obligations during the years 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 benefit payments under other postretirement benefit plans will total (dollars in thousands):

	2024	2025	2026	2027	2028	Total 2029-2033
Expected benefit payments	$ 7,084	$ 7,266	$ 7,436	$ 7,608	$ 7,822	$ 40,805

The Company expects to contribute $7.1 million to other postretirement benefit plans in 2024. 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, 2023 and 2022 and the components of net periodic benefit costs for the years ended December 31, 2023 and 2022 (dollars in thousands):

	Pension Benefits		Other Post-retirement Benefits	
	2023	2022	2023	2022
Change in benefit obligation:				
Benefit obligation as of beginning of year	$ 557,709	$ 799,042	$ 115,635	$ 167,598
Service cost	14,350	23,877	2,394	4,369
Interest cost	33,245	26,536	6,766	5,503
Actuarial (gain)/loss	21,373	(204,775)	4,799	(54,120)
Plan change		3,302		
Settlement		(60,206)		
Benefits paid	(41,432)	(30,067)	(7,210)	(7,715)
Benefit obligation as of end of year	$ 585,245	$ 557,709	$ 122,384	$ 115,635
Change in plan assets:				
Fair value of plan assets as of beginning of year	$ 540,703	$ 750,963	$ 49,472	$ 59,544
Actual return on plan assets	78,838	(163,866)	8,654	(10,072)
Employer contributions	10,000	42,000		
Settlement		(60,206)		
Benefits paid	(39,558)	(28,188)		
Fair value of plan assets as of end of year	$ 589,983	$ 540,703	$ 58,126	$ 49,472
Funded status	$ 4,738	$ (17,006)	$ (64,258)	$ (66,163)
Amounts recognized in the Balance Sheets:				
Non-current assets	$ 32,997	$ 13,382	$	$
Current liabilities	(2,212)	(1,934)	(652)	(706)
Non-current liabilities	(26,047)	(28,454)	(63,606)	(65,457)
Net amount recognized	$ 4,738	$ (17,006)	$ (64,258)	$ (66,163)
Accumulated pension benefit obligation	$ 514,295	$ 495,654		
Accumulated postretirement benefit obligation:				
For retirees			$ 68,087	$ 61,984
For fully eligible employees			$ 16,054	$ 19,731
For other participants			$ 38,243	$ 33,920
Included in accumulated other comprehensive loss (income) (net of tax):				
Unrecognized prior service cost (credit)	$ 3,717	$ 4,105	$ (1,081)	$ (1,911)
Unrecognized net actuarial loss	69,002	83,794	13,103	13,643
Total	72,719	87,899	12,022	11,732
Less regulatory asset	(71,983)	(85,198)	(12,401)	(12,375)
Accumulated other comprehensive loss for unfunded benefit obligation for pensions and other postretirement benefit plans	$ 736	$ 2,701	$ (379)	$ (643)

	Pension Benefits		Other Post-retirement Benefits	
	2023	2022	2023	2022
Weighted-average assumptions as of December 31:				
Discount rate for benefit obligation	5.86%	6.10%	5.83%	6.10%
Discount rate for annual expense	6.10%	3.39%	6.10%	3.40%
Expected long-term return on plan assets	8.30%	5.80%	7.20%	4.70%
Rate of compensation increase	4.87%	4.69%		
Medical cost trend pre-age 65 - initial			6.50%	6.25%
Medical cost trend pre-age 65 - ultimate			5.00%	5.00%
Ultimate medical cost trend year pre-age 65			2030	2028
Medical cost trend post-age 65 - initial			6.50%	6.25%
Medical cost trend post-age 65 - ultimate			5.00%	5.00%
Ultimate medical cost trend year post-age 65			2030	2028

	Pension Benefits		Other Post-retirement Benefits	
	2023	2022	2023	2022
Components of net periodic benefit cost:				
Service cost (1)	$ 14,350	$ 23,877	$ 2,394	$ 4,369
Interest cost	33,245	26,536	6,766	5,503
Expected return on plan assets	(43,656)	(43,872)	(3,562)	(2,799)
Amortization of prior service cost (credit)	491	257	(1,050)	(1,050)
Net loss recognition	4,915	4,180	319	3,344
Settlement loss (2)		11,828		
Net periodic benefit cost	$ 9,345	$ 22,806	$ 4,867	$ 9,367

(1)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.

(2)The settlement loss was deferred as a regulatory asset and is being amortized over 12 years in accordance with regulatory accounting orders.

Plan Assets

The Finance Committee of the 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, and trusts and partnerships that hold marketable debt and equity securities and real estate. 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 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:

	2023	2022
Equity securities	55%	55%
Debt securities	40%	40%
Real estate	5%	5%

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 comparable in coupon, rating, maturity and industry).

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

The plan's investments in common/collective trusts have redemption limitations that permit quarterly redemptions following notice requirements of 45 to 60 days. Most of the plan's investments in closely held investments and partnership interests have redemption limitations ranging from bi-monthly to semi-annually following redemption notice requirements of 60 to 90 days.

The following table discloses by level within the fair value hierarchy (see Note 13 for a description of the fair value hierarchy) of the pension plan's assets measured and reported as of December 31, 2023 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$	$ 6,984	$	$ 6,984
Fixed income securities:				
U.S. government issues		19,293		19,293
Corporate issues		175,460		175,460
International issues		27,052		27,052
Municipal issues		13,772		13,772
Mutual funds:				
U.S. equity securities	169,993			169,993
International equity securities	74,749			74,749
Plan assets measured at NAV (not subject to hierarchy disclosure)				
Common/collective trusts: real estate				25,284
Partnership/closely held investments:				
International equity securities				70,652
Real estate				6,744
Total	$ 244,742	$ 242,561	$	$ 589,983

The following table discloses by level within the fair value hierarchy (see Note 13 for a description of the fair value hierarchy) of the pension plan's assets measured and reported as of December 31, 2022 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$	$ 5,110	$	$ 5,110
Fixed income securities:				
U.S. government issues		16,732		16,732
Corporate issues		161,180		161,180
International issues		23,108		23,108
Municipal issues		13,427		13,427
Mutual funds:				
U.S. equity securities	154,442			154,442
International equity securities	58,933			58,933
Plan assets measured at NAV (not subject to hierarchy disclosure)				
Common/collective trusts: real estate				30,406
Partnership/closely held investments:				
International equity securities				69,792
Real estate				7,573
Total	$ 213,375	$ 219,557	$	$ 540,703

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 determines fair value based upon other inputs (including valuations of securities comparable in coupon, rating, maturity and industry). The target asset allocation was 60 percent equity securities and 40 percent debt securities in both 2023 and 2022.

The fair value of other postretirement plan assets was determined to be $58.1 million and $49.5 million as of December 31, 2023 and 2022, respectively. The assets consist of a balanced index mutual fund, which is a single mutual fund that includes a percentage of U.S. equity and fixed income securities and International equity and fixed income securities. This mutual fund is classified as Level 1 in the fair value hierarchy (see Note 13 for a description of the fair value hierarchy).

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):

	2023	2022
Employer 401(k) matching contributions	$ 15,022	$ 13,258

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

	2023	2022
Deferred compensation assets and liabilities	$ 7,794	$ 7,541

NOTE 8. 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, 2023, the Company had $17.3 million of state tax credit carryforwards. Of the total amount, the Company believes that it is more likely than not that it will only be able to utilize $6.8 million of the state tax credits. As such, the Company has recorded a valuation allowance of $10.5 million against the state tax credit carryforwards and reflected the net amount of $6.8 million as an asset as of December 31, 2023. State tax credits expire from 2024 to 2037.

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 2018 are open for an IRS tax examination. The IRS is reviewing tax year 2019.

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

All tax years after 2019 are open for examination in Idaho, Oregon, Montana and Alaska.

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

NOTE 9. ENERGY PURCHASE CONTRACTS

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

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

	2023	2022
Utility power resources	$ 607,155	$ 660,967

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):

	2024	2025	2026	2027	2028	Thereafter	Total
Power resources	$ 336,766	$ 293,389	$ 266,251	$ 235,751	$ 234,756	$ 2,245,762	$ 3,612,675
Natural gas resources	122,241	81,141	46,033	41,708	41,168	280,562	612,853
Total	$ 459,007	$ 374,530	$ 312,284	$ 277,459	$ 275,924	$ 2,526,324	$ 4,225,528

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. 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 future contractual commitments for power resources include fixed contractual amounts related to the Company's contracts with Public Utility Districts (PUDs) to purchase portions of the output of certain generating facilities. Although Avista Corp. has no investment in the PUD generating facilities, the 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, 2023 (principal and interest) was $275.1 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):

	2024	2025	2026	2027	2028	Thereafter	Total
Contractual obligations	$ 39,156	$ 40,226	$ 18,630	$ 19,085	$ 9,390	$ 177,553	$ 304,040

NOTE 10. NOTES PAYABLE

Lines of Credit

Avista Corp. has a committed line of credit in the total amount of $500.0 million. with expiration date of June 2028. The Company has the option to extend for two additional one year periods (subject to customary conditions). In June 2023, the then-existing agreement was amended to increase the capacity of the committed line of credit from $400.0 million to $500.0 million, extend the expiration date, and replace the London Interbank Offered Rate (LIBOR) provisions with Secured Overnight Financing Rate (SOFR) provisions. 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.

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

	2023	2022
Balance outstanding at end of period	$ 349,000	$ 313,000
Letters of credit outstanding at end of period	4,700	35,563
Average interest rate at end of period	6.46%	5.31%

In December 2022, Avista Corp. entered into an additional revolving credit agreement in the amount of $100.0 million. As of December 31, 2022, the Company did not have any outstanding borrowings under this agreement. The agreement was terminated in June 2023.

As of December 31, 2023 and 2022, the borrowings outstanding under Avista Corp.'s committed lines of credit were classified as short-term borrowings on the Balance Sheets.

2022 Term Loan

In December 2022, the Company entered into a term loan agreement in the amount of $150.0 million with a maturity date of March 30, 2023. The Company borrowed the entire $150.0 million available under the agreement in 2022 and repaid the entire outstanding balance in March 2023. The borrowings outstanding under this agreement were classified as short-term borrowings on the Balance Sheets.

2022 Letter of Credit Facility

In December 2022, the Company entered into a continuing letter of credit agreement in the aggregate amount of $50.0 million. Either party may terminate the agreement at any time.

The Company had $20.0 million and $18.5 million in letters of credit outstanding under this agreement as of December 31, 2023 and December 31, 2022, respectively. Letters of credit are not reflected on the Balance Sheets. If a letter of credit were drawn upon by the holder, we would have an immediate obligation to reimburse the bank that issued that letter.

Covenants and Default Provisions

The short-term borrowing agreements contain customary covenants and default provisions, including a change in control (as defined in the agreements). The events of default under each of the credit facilities also include a cross default from other indebtedness (as defined) and in some cases other obligations. Most of the short-term borrowing agreement also include 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, 2023, the Company complied with this covenant.

NOTE 11. BONDS

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

Maturity Year	Description	Interest Rate	2023	2022
Avista Corp. Secured Long-Term Debt				
2023	Secured Medium-Term Notes	7.18%-7.54%		13,500
2028	Secured Medium-Term Notes	6.37%	25,000	25,000
2032	Secured Pollution Control Bonds (1)	(1)	66,700	66,700

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	2.90%	140,000	140,000
2052	First Mortgage Bonds	4.00%	400,000	400,000
2053	First Mortgage Bonds (2)	5.66%	250,000	
	Total Avista Corp. secured long-term debt		2,543,700	2,307,200
	Secured Pollution Control Bonds held by Avista Corporation (1)		(83,700)	(83,700)
	Total long-term debt		$ 2,460,000	$ 2,223,500

(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. The new bonds were not offered to the public and were purchased by Avista Corp. due to market conditions. The Company can remarket these bonds to unaffiliated investors at a later date, subject to market conditions. So long as Avista Corp. is the holder of these bonds, the bonds are not reflected as an asset or a liability on the Balance Sheets. In April 2024, the Company remarketed these bonds. See Note 18 for further discussion.

(2)In March 2023, the Company issued and sold $250.0 million of 5.66 percent first mortgage bonds due in 2053 with institutional investors in the private placement market. A portion of the net proceeds from the sale of these bonds was used for the construction or improvement of utility facilities, and a portion was used to refinance existing indebtedness, including the repayment of Avista Corp.'s $150.0 million term loan. In connection with the pricing of the first mortgage bonds in March 2023, the Company cash settled four interest rate swap derivatives (notional aggregate amount of $40.0 million) and received a net amount of $7.5 million. See Note 4 for a discussion of interest rate swap derivatives.

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

	2024	2025	2026	2027	2028	Thereafter	Total
Debt maturities	$ 15,000	$	$	$	$ 25,000	$ 2,561,547	$ 2,601,547

Substantially all of Avista Corp's owned properties are subject to the lien of their respective mortgage indentures. Under the Mortgages and Deeds of Trust (Mortgages) securing their first mortgage bonds (including secured medium-term notes), Avista Corp. may 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 to the Company (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 individually 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 that entity's 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, 2023, property additions and retired bonds would have allowed, and the net earnings test would not have prohibited, the issuance of $1.2 billion in an aggregate principal amount of additional first mortgage bonds at an assumed interest rate of 8 percent.

NOTE 12. ADVANCES FROM ASSOCIATED COMPANIES

In 1997, the Company issued Floating Rate Junior Subordinated Deferrable Interest Debentures, Series B, with a principal amount of $51.5 million to Avista Capital II, an affiliated business trust formed by the Company. Avista Capital II issued $50.0 million of Preferred Trust Securities with a floating distribution rate of LIBOR plus 0.875 percent, calculated and reset quarterly. Effective on July 3, 2023, the reference to LIBOR in the formulation for the distribution rate on these securities was replaced, by operation of law, with three-month CME Term SOFR, as calculated and published by CME Group Benchmark Administration, Ltd. (a successor administrator), plus a tenor spread adjustment of 0.26 percent. Accordingly, the distribution rate on the Preferred Trust Securities is now three-month CME Term SOFR plus 1.137 percent.

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

	2023	2022	2021
Low distribution rate	5.64%	1.05%	0.99%
High distribution rate	6.55%	5.64%	1.10%
Distribution rate at the end of the year	6.51%	5.64%	1.05%

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 Avista Capital II has funds available for such payments from the respective debt securities. Upon maturity or prior redemption of such debt securities, the Preferred Trust Securities will be mandatorily redeemed.

NOTE 13. FAIR VALUE

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

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

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

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

Level 2 - Pricing inputs are other than quoted prices in active markets included in Level 1, but which are either directly or indirectly observable as of the reporting date. Level 2 includes financial instruments 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 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):

	2023		2022	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Bonds (Level 2)	$ 1,100,000	$ 968,893	$ 1,113,500	$ 966,881
Bonds (Level 3)	1,360,000	1,088,500	1,110,000	805,802
Advances from associated companies (Level 3)	51,547	46,098	51,547	42,836

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 62.73 to 107.245, 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, 2023 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, 2023					
Assets:					
Energy commodity derivatives (2)	$	$ 30,954	$	$ (22,802)	$ 8,152
Foreign currency exchange derivatives		2			2
Interest rate swap derivatives		3,667			3,667
Deferred compensation assets:					
Mutual Funds:					
Fixed income securities	1,117				1,117
Equity securities	6,524				6,524
Total	$ 7,641	$ 34,623	$	$ (22,802)	$ 19,462
Liabilities:					
Energy commodity derivatives (2)	$	$ 91,844	$ 8,250	$ (65,157)	$ 34,937
Interest rate swap derivatives		182			182
Total	$	$ 92,026	$ 8,250	$ (65,157)	$ 35,119

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, 2022 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, 2022					
Assets:					
Energy commodity derivatives (2)	$	$ 146,232	$ 288	$ (136,605)	$ 9,915
Foreign currency exchange derivatives		43			43
Interest rate swap derivatives		11,184			11,184
Deferred compensation assets:					
Mutual Funds:					
Fixed income securities	1,267				1,267
Equity securities	6,132				6,132
Total	$ 7,399	$ 157,459	$ 288	$ (136,605)	$ 28,541
Liabilities:					
Energy commodity derivatives (2)	$	$ 258,769	$ 18,022	$ (242,044)	$ 34,747
Foreign currency exchange derivatives		3			3
Interest rate swap derivatives		52			52
Total	$	$ 258,824	$ 18,022	$ (242,044)	$ 34,802

(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 payables and receivables for cash collateral held or placed with these same counterparties.

(2)The Level 3 energy commodity derivative balances are associated with natural gas exchange agreements.

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 quoted 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 U.S. 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.

Level 3 Fair Value

Natural Gas Exchange Agreement

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 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, 2023 (dollars in thousands):

	Fair Value (Net) at December 31, 2023	Valuation Technique	Unobservable Input	Range
Natural gas exchange	$ (8,250)	Internally derived weighted average cost of gas	Forward purchase prices	$1.64 - $3.07/mmBTU $2.40 Weighted Average
			Forward sales prices	$2.13 - $8.99/mmBTU $5.45 Weighted Average
			Purchase volumes	300,000 - 310,000 mmBTUs
			Sales volumes	75,000 - 310,000 mmBTUs

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

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

	Natural Gas Exchange Agreement (1)
Year ended December 31, 2023:	
Balance as of January 1, 2023	$ (17,734)
Total gains or (losses) (realized/unrealized):	
Included in regulatory assets	9,238
Settlements	246
Ending balance as of December 31, 2023	$ (8,250)
Year ended December 31, 2022:	
Balance as of January 1, 2022	$ (7,771)
Total gains or (losses) (realized/unrealized):	
Included in regulatory assets	(4,740)
Settlements	(5,223)
Ending balance as of December 31, 2022	$ (17,734)

(1)There were no purchases, issuances or transfers from other categories of derivatives instruments during the periods presented in the table above.

NOTE 14. COMMON STOCK

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

- certain covenants applicable to preferred stock (when outstanding) contained in the Company's Restated Articles of Incorporation, as amended (currently there are no preferred shares outstanding),
- certain covenants applicable to the Company's outstanding long-term debt and committed line of credit agreements,
- the hydroelectric licensing requirements of section 10(d) of the FPA (see Note 1), and
- certain requirements under the OPUC approval of the AERC acquisition in 2014. The OPUC's AERC acquisition order requires Avista Corp. to maintain a capital structure of no less than 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, 2023 was $295.6 million.

The Company has 10 million authorized shares of preferred stock. The Company did not have preferred stock outstanding as of December 31, 2023 and 2022.

Common Stock Issuances

The Company issued common stock for total net proceeds of $112.3 million in 2023. 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. In 2023, 3.0 million shares were issued under these agreements resulting in total net proceeds of $111.8 million.

NOTE 15. COMMITMENTS AND CONTINGENCIES

In the course of its business, the Company becomes involved in various claims, controversies, disputes and other contingent matters, including the items described in this Note. Some of these claims, controversies, disputes and other contingent matters involve litigation or other contested proceedings. For all such matters, the Company will vigorously protect and defend its interests and pursue its rights. However, no assurance can be given as to the ultimate outcome of any matter because litigation and other contested proceedings are subject to numerous uncertainties. For matters affecting 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 36 percent of all 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, are covered under a four year agreement which expires in March 2025.

The current agreement includes a clause to negotiate wages in effect for the last year of the agreement. The Company is in the process of negotiating these wages. There is a risk that if an agreement on wages is not reached, the employees subject to the agreement could strike. Given the number of employees that are covered by the collective bargaining agreement, a strike could result in disruptions to the Company's operations. However, the Company believes the possibility of this occurring is remote.

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 of 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 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., along with its independent vegetation management contractors Asplundh Tree Company and CN Utility Consulting, were negligent in failing to identify and remove the tree before it came into contact with the line. Avista Corp. disputes that it was negligent in failing to identify and remove the tree in question. Additional lawsuits were subsequently 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, at this time the Company is unable to predict the likelihood of an adverse outcome or estimate a range of potential loss in the event of such an outcome.

Road 11 Fire

In April 2022, Avista Corp. received a notice of claim from property owners seeking damages of $5 million in connection with a fire that occurred in Douglas County, Washington, in July 2020. In June 2022, those claimants filed suit in the Superior Court of Douglas County, Washington, seeking unspecified damages. The fire, which was designated as the "Road 11 Fire," occurred in the vicinity of an Avista Corp. 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 Company disputes that it is liable for the fire and will vigorously defend itself in the pending legal proceeding; however, at this time the Company is unable to predict the likelihood of an adverse outcome or estimate a range of potential loss in the event of such an outcome.

Labor Day 2020 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 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. However, the Company's investigations found no evidence of negligence with respect to any of those fires. Consistent with that conclusion, the statute of limitations with respect to the claims arising out of the Labor Day 2020 Windstorm has now passed and, except with respect to the Babb Road Fire discussed below, no legal action has been commenced.

Babb Road Fire

In May 2021 the Company learned 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.

Eleven lawsuits have been filed in connection with the Babb Road fire. Asplundh Tree Company and CNUC Utility Consulting, which both perform vegetation management services as independent contractors to the Company, are also named as defendants in each of the lawsuits. The lawsuits include six subrogation actions filed by insurance companies seeking to recover approximately $23 million purportedly paid to insureds to date; four actions on behalf of individual plaintiffs seeking unspecified damages; and a class action lawsuit seeking unspecified damages. All proceedings, except for one action filed on September 1, 2023 on behalf of three individual plaintiffs, have been consolidated in the Superior Court of Spokane County Washington under the lead action *Blakeley v. Avista Corporation et al.*, and variously assert causes of action for negligence, private nuisance, and trespass (the Blakeley Proceeding).

In November 2023, all parties to the Blakeley Proceeding agreed to a stipulated order, which was presented to and entered by the Superior Court of Spokane County, Washington. The order consolidates the Blakeley Proceeding for trial (in addition to discovery and pre-trial proceedings) and bifurcates the trial into liability and damages phases, such that the initial trial in the case will focus solely on whether the defendants are legally responsible for the Babb Road Fire. A trial date on the liability phase has been set for May 5, 2025.

In addition, the order memorializes the plaintiffs' agreement to voluntarily dismiss all claims asserting inverse condemnation as a theory of liability without prejudice to their ability to seek permission from the Court to refile those claims at a later date if there is good cause to do so. The individual action that was not consolidated into the Blakeley Proceeding does not include claims for inverse condemnation. The parties to the Blakeley Proceeding agreed to a preliminary mediation no later than 60 days prior to the liability trial, and, if there is a trial following that mediation and if the jury returns a verdict in the plaintiffs' favor in the liability trial, a second mediation within 90 days following the verdict focusing on damages. Finally, the plaintiffs agreed to complete a damages questionnaire identifying all claimed damages being sought in connection with the litigation.

The Company will vigorously defend itself in the legal proceedings; however, at this time the Company is unable to predict the likelihood of an adverse outcome or estimate a range of potential loss in the event of such an outcome.

Orofino Fire

In August 2023, a fire subsequently referred to as the "Hospital Fire", started in windy conditions near Orofino, Idaho, burning 53 acres and seven primary residences, as well as several outbuildings. The Idaho Department of Lands investigated and has issued a report in which it concluded the fire was caused by an electrical fault igniting three separate spots which then spread uphill. The Company has a distribution line in the area near the ignition point. While the Company has not yet completed its own investigation, the Company has to date found no evidence suggesting negligence on its part. Except for one claim for damage to personal property, the Company has not, at this time, received any claims in connection with the fire. The Company will vigorously defend itself in the event any such claims are asserted; however, at this time, it is unable to estimate the likelihood of an adverse outcome nor the amount or range of a potential loss in the event of an adverse outcome.

Colstrip

Colstrip Owners Arbitration and Litigation

Colstrip Units 3 and 4 are owned by the Company, PacifiCorp, Portland General Electric (PGE), and Puget Sound Energy (PSE) (collectively, the "Western Co-Owners"), as well as NorthWestern and Talen Montana, LLC (Talen), as tenants in common under an Ownership and Operating Agreement, dated May 6, 1981, as amended (O&O Agreement), in the percentages set forth below:

Co-Owner	Unit 3	Unit 4
Avista	15%	15%
PacifiCorp	10%	10%
PGE	20%	20%
PSE	25%	25%
NorthWestern		30%
Talen	30%	

Colstrip Units 1 and 2, owned by PSE and Talen, were shut down in 2020 and are in the process of being decommissioned. The co-owners of Units 3 and 4 also own undivided interests in facilities common to both Units 3 and 4, as well as in certain facilities common to all four Colstrip units.

The Washington Clean Energy Transformation Act (CETA), among other things, imposes deadlines by which each electric utility must eliminate from its electricity rates in Washington the costs and benefits associated with coal-fired resources, such as Colstrip. The practical impact of CETA is electricity from such resources, including Colstrip, may no longer be delivered to Washington retail customers after 2025.

The co-owners of Colstrip Units 3 and 4 have differing needs for the generating capacity of these units. Accordingly, certain business disagreements have arisen among the co-owners, including, disagreements as to the requirements for shutting down these units. NorthWestern has initiated arbitration pursuant to the O&O Agreement to resolve these business disagreements, and two actions have been initiated to compel arbitration of those disputes: one by Talen in the Montana Thirteenth Judicial District Court for Yellowstone County, and one by the Western Co-Owners, which is pending in Montana Federal District Court. In light of the ownership transfer agreements discussed below, the Colstrip owners agreed to stay both the litigation and the arbitration through March 2024. On April 1, 2024, the agreement to stay lapsed and at least one owner, Puget Sound Energy, has indicated they wish to resume the arbitration proceeding.

Agreement Between Talen and Puget Sound Energy

In September 2022, PSE and Talen entered into an agreement through which PSE has agreed to transfer its 25 percent ownership in Colstrip Units 3 and 4 to Talen at the end of 2025. The terms and conditions of the agreement are similar in most respects to the NorthWestern transaction discussed below.

Agreement Between Avista and NorthWestern

In January 2023, the Company entered into an agreement with NorthWestern under which, subject to the terms and conditions specified in the agreement, the Company will transfer its 15 percent ownership in Colstrip Units 3 and 4 to NorthWestern. There is no monetary exchange included in the transaction. The transaction is scheduled to close on December 31, 2025 or such other date as the parties mutually agree upon.

Under the agreement, the Company will remain obligated through the close of the transaction to pay its share of (i) operating expenses, (ii) capital expenditures, but not in excess of the portion allocable pro rata to the portion of useful life (through 2030) expired through the close of the transaction, and (iii) except for certain costs relating to post-closing activities, site remediation expenses. In addition, the Company would enter into an agreement under which it would retain its voting rights with respect to decisions relating to remediation.

The Company will retain its Colstrip transmission system assets, which are excluded from the transaction.

Under the Colstrip O&O Agreement, each of the other owners of Colstrip has a 90-day period in which to evaluate the transaction and determine whether to exercise their respective rights of first refusal as to a portion of the generation being turned over to NorthWestern. That period has now expired, and no owners have exercised a right to first refusal.

The transaction is subject to the satisfaction of customary closing conditions including the receipt of any required regulatory approvals, as well as NorthWestern's ability to enter into a new coal supply agreement by December 31, 2024.

The Company does not expect this transaction to have a direct material impact on its financial results.

Burnett et al. v. Talen et al.

Multiple property owners 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 adverse to the Company's interests.

Westmoreland Mine Permits

Two lawsuits have been commenced by the Montana Environmental Information Center and others, challenging certain permits relating to the operation of the Westmoreland Rosebud Mine, which provides coal to Colstrip. In the first, the Montana District Court for Rosebud County issued an order vacating a permit for one area of the mine, which decision was subsequently upheld by the Montana Supreme Court. In the second, the Montana Federal District Court vacated a decision by the federal Office of Surface Mining Reclamation and Enforcement, a branch of the United States Department of Interior, approving expansion of the mine into a new area, pending further analysis of potential environmental impact. An initial appeal of that decision to the Ninth Circuit was dismissed for lack of jurisdiction, pending further proceedings before the Department of the Interior. Avista Corp. is not a party to either of these proceedings, but continues to monitor the progress of both issues 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 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 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 engaged 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 excavation work. The incident resulted in a fire which destroyed one residence and resulted in minor injuries to the occupants. In January 2023, the Company was served with a lawsuit filed in the District Court of Kootenai County, Idaho by one property owner, seeking unspecified damages. In February 2024, the Company became aware of a second lawsuit filed by the owners of the adjacent property, seeking damages for personal injury and emotional distress from having witnessed the incident. The Company intends to vigorously defend itself in both actions.

Other Contingencies

In the normal course of business, the Company has various other legal claims and contingent matters outstanding. The Company believes 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 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 States of Montana and Idaho are each conducting general adjudications of water rights in areas that include the Company's facilities in these states. Claims within the Clark Fork River basin and the Spokane River basin could adversely affect the energy production of the Company's hydroelectric facilities. The Company is and will continue to be a participant in the 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 16. REGULATORY MATTERS

Power Cost Deferrals and Recovery Mechanisms

Deferred power supply costs are recorded as a deferred charge or liability on the Balance Sheets for future prudence review and recovery or rebate through retail rates. The power supply costs deferred include certain differences between actual net power supply costs incurred by Avista Corp. and the costs included in base retail rates. This difference in net power supply costs primarily results from changes in:

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

In Washington, the ERM allows Avista Corp. to periodically increase or decrease electric rates with WUTC approval to reflect changes in power supply costs. The ERM is an accounting method used to track certain differences between actual power supply costs, net of wholesale sales and sales of fuel, and the amount included in base retail rates for Washington customers. Under the ERM, the Company defers these differences (over the $4.0 million deadband and sharing bands) for future surcharge or rebate to customers.

The following is a summary of the ERM:

Annual Power Supply Cost Variability	Deferred for Future Surcharge or Rebate to Customers	Expense or Benefit to the Company
within +/- $0 to $4 million (deadband)	0%	100%
higher by $4 million to $10 million	50%	50%
lower by $4 million to $10 million	75%	25%
higher or lower by over $10 million	90%	10%

Total net deferred power costs under the ERM were assets of $37.6 million as of December 31, 2023 and $30.5 million as of December 31, 2022. The deferred power cost assets represent amounts due from customers, and deferred power cost liabilities represent amounts due to customers.

Pursuant to WUTC requirements, should the cumulative deferral balance exceed $30 million in the rebate or surcharge direction, the Company must make a filing with the WUTC to adjust customer rates to either return the balance to customers or recover the balance from customers. Avista Corp. makes an annual filing on, or before, April 1 of each year to provide the opportunity for the WUTC staff and other interested parties to review the prudence of, and audit, the ERM deferred power cost transactions for the prior calendar year. In June 2023, the Company received approval from the WUTC for a rate surcharge to customers over a two-year period, effective July 1, 2023.

In the 2024 Washington general rate case, the Company proposed changing the ERM so the entire mechanism would result in a 95 percent customer, 5 percent company sharing basis. This request is pending WUTC approval.

Avista Corp. has a PCA mechanism in Idaho allowing for the modification of 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 assets of $7.6 million as of December 31, 2023 and $16.3 million as of December 31, 2022. 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. In Oregon, the Company absorbs (cost or benefit) 10 percent of the difference between actual and projected natural gas costs included in base retail rates for supply that is not hedged. Total net deferred natural gas costs were an asset of $51.4 million as of December 31, 2023 and $52.1 million as of December 31, 2022. 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 through March 31, 2025. In the Company's 2024 Washington general rate cases, it requested the mechanisms be extended through December 2026. That request is pending before the WUTC.

Electric and natural gas decoupling surcharge rate adjustments to customers are limited to a 3 percent increase on an annual basis, with remaining surcharge balance carried forward for recovery in a future period. There is no limit on the level of rebate rate adjustments. New customers added after a test period are not decoupled until included in a future test period.

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. Through the 2022 general rate cases, the Company modified its earnings test so that if the Company earns more than 0.5 percent higher than the rate of return 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, 2023 and December 31, 2022, the Company had the following cumulative balances outstanding related to decoupling and earnings sharing mechanisms in its various jurisdictions (dollars in thousands):

	December 31, 2023	December 31, 2022
Washington		
Decoupling rebate	$ (3,232)	$ (13,210)
Idaho		
Decoupling rebate	$ (7,961)	$ (7,889)
Provision for earnings sharing rebate	(572)	(686)
Oregon		
Decoupling (rebate) surcharge	$ (3,724)	$ 2,853

NOTE 17. NOTES RECEIVABLE FROM ASSOCIATED COMPANIES

Avista Capital may borrow up to $80 million from Avista Corp. to cover subsidiary cash needs in accordance with board-approved limits. Avista Capital pays interest on the outstanding amount at a rate at least equal to the Alternate Base Rate as defined in the Avista Corp. credit facility agreement, which is estimated at the Prime rate. This rate will be reset when the Agent bank on the Avista Corp. credit facility agreement changes the Prime rate or the margin.

As of December 31, 2023, the Company had a note receivable balance from Avista Capital of $20.6 with an applicable interest rate of 8.5 percent.

NOTE 18. SUBSEQUENT EVENTS

The Company has evaluated its subsequent events, noting the following events have occurred subsequent to December 31, 2023:

- On April 1, 2024, Avista Corporation (Avista Corp. or the Company) closed on the remarketing of $66.7 million and $17.0 million of the City of Forsyth, Montana Pollution Control Revenue Refunding Bonds due in 2032 and 2034, respectively. These bonds are secured by equal principal amounts of non-transferable first mortgage bonds of the Company. The term interest rate on both series of bonds is 3.875 percent. Avista Corp. purchased the bonds upon original issuance in December 2010, with the intention to hold the bonds until market conditions were favorable for remarketing the bonds to unaffiliated investors. While the Company was the holder of these bonds, the bonds were not reflected as an asset or a liability on the Consolidated Balance Sheets. With the remarketing of these bonds, the Company will recognize long term debt of $83.7 million. The net proceeds from the remarketing of these bonds were used to refinance existing short term debt obligations.

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Summary of Utility Plant and Accumulated Provisions for Depreciation, Amortization and Depletion

Line No.	Item (a)	Total Company For the Current Quarter/Year (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Common (f)
1	UTILITY PLANT					
2	In Service					
3	Plant in Service (Classified)	7,781,458,219	5,352,763,952	1,683,865,098		744,829,169
4	Property Under Capital Leases	67,585,264				67,585,264
5	Plant Purchased or Sold					
6	Completed Construction not Classified					
7	Experimental Plant Unclassified					
8	TOTAL Utility Plant (Total of lines 3 thru 7)	7,849,043,483	5,352,763,952	1,683,865,098		812,414,433
9	Leased to Others					
10	Held for Future Use	3,658,920	2,928,319	180,896		549,705
11	Construction Work in Progress	170,812,964	132,548,007	7,682,114		30,582,843
12	Acquisition Adjustments	256,800	256,800			
13	TOTAL Utility Plant (Total of lines 8 thru 12)	8,023,772,167	5,488,497,078	1,691,728,108		843,546,981
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	2,796,332,034	1,969,142,630	513,678,701		313,510,703
15	Net Utility Plant (Total of lines 13 and 14)	5,227,440,133	3,519,354,448	1,178,049,407		530,036,278
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION					
17	In Service:					
18	Depreciation	2,573,168,761	1,928,168,400	512,558,995		132,441,366
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	223,163,273	40,974,230	1,119,706		181,069,337
22	TOTAL In Service (Total of lines 18 thru 21)	2,796,332,034	1,969,142,630	513,678,701		313,510,703
23	Leased to Others					
24	Depreciation					
25	Amortization and Depletion					
26	TOTAL Leased to Others (Total of lines 24 and 25)					
27	Held for Future Use					
28	Depreciation					
29	Amortization					
30	TOTAL Held for Future Use (Total of lines 28 and 29)					
31	Abandonment of Leases (Natural Gas)					
32	Amortization of Plant Acquisition Adjustment					
33	TOTAL Accum. Provisions (Should agree with line 14 above)(Total of lines 22, 26, 30, 31, and 32)	2,796,332,034	1,969,142,630	513,678,701		313,510,703

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Gas Plant in Service (Accounts 101, 102, 103, and 106)

1. Report below the original cost of gas plant in service according to the prescribed accounts.
2. In addition to Account 101, Gas Plant in Service (Classified), this page and the next include Account 102, Gas Plant Purchased or Sold, Account 103, Experimental Gas Plant Unclassified, and Account 106, Completed Construction Not Classified-Gas.
3. Include in column (c) and (d), as appropriate corrections of additions and retirements for the current or preceding year.
4. Enclose in parenthesis credit adjustments of plant accounts to indicate the negative effect of such accounts.
5. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) reversals of tentative distributions of prior year's unclassified retirements. Include in a footnote, the account 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 Account 101 and 106 will avoid serious omissions of respondent's reported amount for plant actually in service at end of year.
6. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102. In showing the clearance of Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits to primary account classifications.
7. 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 requirements of these pages.
8. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchaser, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give date of such filing.

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
1	INTANGIBLE PLANT						
2	301 Organization						
3	302 Franchise and Consents						
4	303 MiscellaneousIntangiblePlant	2,929,556	1,153,227				4,082,783
5	Total Intangible Plant (Total of lines 2 thru 4)	2,929,556	1,153,227				4,082,783
6	PRODUCTION PLANT						
7	Natural Gas Production and Gathering Plant						
8	325.1 Producing Lands						
9	325.2 Producing Leaseholds						
10	325.3 Gas Rights						
11	325.4 RIghts-of-Way						
12	325.5 Other Land and Land Rights						
13	326 Gas Well Structures						
14	327 Field Compressor Station Structures						
15	328 Field Measuring and Regulating Station Structures						
16	329 Other Structures						
17	330 Producing Gas Wells-Well Construction						
18	331 Producing Gas Wells-Well Equipment						
19	332 Field Lines						
20	333 Field Compressor Station Equipment						
21	334 Field Measuring and Regulating Station Equipment						
22	335 Drilling and Cleaning Equipment						
23	336 Purification Equipment						0
24	337 Other Equipment						
25	338 Unsuccessful Exploration and Development Costs						
26	339 Asset Retirement Costs for Natural Gas Production and Gathering Plant						
27	Total Production and Gathering Plant (Total of lines 8 thru 26)	0	0	0	0	0	0
28	PRODUCTS EXTRACTION PLANT						
29	340 Land and Land Rights						
30	341 Structures and Improvements						
31	342 Extraction and Refining Equipment						
32	343 Pipe Lines						
33	344 Extracted Products Storage Equipment						
34	345 Compressor Equipment						
35	346 Gas Measuring and Regulating Equipment						
36	347 Other equipment						
37	348 Asset Retirement Costs for Products Extraction Plant						
38	Total Products Extraction Plant (Total of lines 29 thru 37)						

39	Total Natural Gas Production Plant (Total of lines 27 and 38)	0	0	0	0	0	0
40	Manufactured Gas Production Plant (Submit supplementary information in a footnote)	59,924	0				59,924
41	Total Production Plant (Total of lines 39 and 40)	59,924	0	0	0	0	59,924
42	NATURAL GAS STORAGE AND PROCESSING PLANT						
43	Underground storage plant						
44	350.1 Land	1,313,516	0				1,313,516
45	350.2 Rights-of-Way	66,742	0				66,742
46	351 Structures and Improvements	3,040,781	382,337				3,423,118
47	352 Wells	19,395,396	382,337				19,777,733
48	352.1 Storage Leaseholds and Rights						
49	352.2 Reservoirs	1,667,492	0				1,667,492
50	352.3 Non-recoverable Natural Gas	5,810,311	0				5,810,311
51	353 Lines	2,229,534	0				2,229,534
52	354 Compressor Station Equipment	18,658,752	382,337				19,041,089
53	355 Measuring and Regulating Equipment	2,183,067	382,338				2,565,405
54	356 Purification Equipment	560,248	0				560,248
55	357 Other Equipment	3,174,521	382,336				3,556,857
56	358 Asset Retirement Costs for Underground Storage Plant						
57	Total Underground Storage Plant (Total of lines 44 thru 56)	58,100,360	1,911,685				60,012,045
58	Other Storage Plant						
59	360 Land and Land Rights						
60	361 Structures and Improvements						
61	362 Gas Holders						
62	363 Purification Equipment						
63	363.1 Liquefaction Equipment						
64	363.2 Vaporizing Equipment						
65	363.3 Compressor Equipment						
66	363.4 Measuring and Regulating Equipment						
67	363.5 Other Equipment						
68	363.6 Asset Retirement Costs for Other Storage Plant						
69	Total Other Storage Plant (Total of lines 58 thru 68)						
70	Base Load Liquefied Natural Gas Terminaling and Processing Plant						
71	364.1 Land and Land Rights						
72	364.2 Structures and Improvements						
73	364.3 LNG Processing Terminal Equipment						
74	364.4 LNG Transportation Equipment						
75	364.5 Measuring and Regulating Equipment						
76	364.6 Compressor Station Equipment						
77	364.7 Communications Equipment						
78	364.8 Other Equipment						
79	364.9 Asset Retirement Costs for Base Load Liquefied Natural Gas						
80	Total Base Load Liquified Natural Gas , Terminating and Processing Plant (Total of lines 71 thru 79)						
81	Total Nat'l Gas Storage and Processing Plant (Total of lines 57, 69, and 80)	58,100,360	1,911,685				60,012,045
82	TRANSMISSION PLANT						
83	365.1 Land and Land Rights						
84	365.2 Rights-of-Way						
85	366 Structures and Improvements						
86	367 Mains						
87	368 Compressor Station Equipment						
88	369 Measuring and Regulating Station Equipment						

89	370 Communication Equipment						
90	371 Other Equipment						
91	372 Asset Retirement Costs for Transmission Plant						
92	Total Transmission Plant (Total of line 81 thru 91)						
93	DISTRIBUTION PLANT						
94	374 Land and Land Rights	1,647,827	51,594				1,699,421
95	375 Structures and Improvements	2,259,240	124,147	6,693			2,376,694
96	376 Mains	760,973,935	52,499,663	780,711			812,692,887
97	377 Compressor Station Equipment						
98	378 Measuring and Regulating Station Equipment-General	13,794,901	817,729	31,462			14,581,168
99	379 Measuring and Regulating Station Equipment-City Gate	10,104,657	324,296	30,405			10,398,548
100	380 Services	480,684,930	24,834,416	243,664			505,275,682
101	381 Meters	177,075,308	16,625,070	657,668			193,042,710
102	382 Meter Installations						
103	383 House Regulators						
104	384 House Regulator Installations						
105	385 Industrial Measuring and Regulating Station Equipment	6,546,951	405,546	39,040			6,913,457
106	386 Other Property on Customers' Premises						
107	387 Other Equipment	601	0				601
108	388 Asset Retirement Costs for Distribution Plant						
109	Total Distribution Plant (Total of lines 94 thru 108)	1,453,088,350	95,682,461	1,789,643			1,546,981,168
110	GENERAL PLANT						
111	389 Land and Land Rights	3,916,534	0				3,916,534
112	390 Structures and Improvements	29,334,233	177,998	3,713			29,508,518
113	391 Office Furniture and Equipment	415,897	0				415,897
114	392 Transportation Equipment	21,211,958	1,044,196	1,063,527		(255,096)	20,937,531
115	393 Stores Equipment	243,144	0				243,144
116	394 Tools, Shop, and Garage Equipment	10,480,542	962,880	376,056			11,067,366
117	395 Laboratory Equipment	452,276	4,078				456,354
118	396 Power Operated Equipment	4,149,421	228,082	78,612			4,298,891
119	397 Communication Equipment	1,896,285		21,323			1,874,962
120	398 Miscellaneous Equipment	9,981	0				9,981
121	Subtotal (Total of lines 111 thru 120)	72,110,271	2,417,234	1,543,231		(255,096)	72,729,178
122	399 Other Tangible Property						
123	399.1 Asset Retirement Costs for General Plant						
124	Total General Plant (Total of lines 121, 122, and 123)	72,110,271	2,417,234	1,543,231		(255,096)	72,729,178
125	Total (Accounts 101 and 106)	1,586,288,461	101,164,607	3,332,874	0	(255,096)	1,683,865,098
126	Gas Plant Purchased (See Instruction 8)						
127	(Less) Gas Plant Sold (See Instruction 8)						
128	Experimental gas plant unclassified						
129	Total Gas Plant In Service (Total of lines 125 thru 128)	1,586,288,461	101,164,607	3,332,874	0	(255,096)	1,683,865,098

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Gas 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 $1,000,000 or more. Group other items of property held for future use.
2. For property having an original cost of $1,000,000 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 in column (b) 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	Gas Distribution Mains and Services, Spokane, WA	03/01/2000	12/31/2026	180,896
45	Total			180,896

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Construction Work in Progress-Gas (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Gas (Account 107) (b)	Estimated Additional Cost of Project (c)
1	Gas Replace-St&Hwy	2,791,835	1,450,000
2	Transportation Equip	1,730,035	3,730,000
3	Minor Projects under $1,000,000	3,160,244	8,388,320
45	TOTAL	7,682,114	13,568,320

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

General Description of Construction Overhead Procedure

1. For each construction overhead explain: (a) the nature and extent of work, etc., the overhead charges are intended to cover, (b) the general procedure for determining the amount capitalized, (c) the method of distribution to construction jobs, (d) whether different rates are applied to different types of construction, (e) basis of differentiation in rates for different types of construction, and (f) whether the overhead is directly or indirectly assigned.
2. Show below the computation of allowance for funds used during construction rates, in accordance with the provisions of Gas Plant Instructions 3 (17) of the Uniform System of Accounts.
3. Where a net-of-tax rate for borrowed funds is used, show the appropriate tax effect adjustment to the computations below in a manner that clearly indicates the amount of reduction in the gross rate for tax effects.

Note: for reporting year 2023, average short-term debt was greater than the rolling 13-month CWIP balance. Audit staff argue in case GPI No. 3(17) that where a pipeline's short-term debt exceeds its CWIP, its maximum AFUDC rate is, solely, its short-term debt rate. To-recalculate this on FERC Form 2 Pg 218, we lowered the average short-term debt balance to equal CWIP, which reflects that all of CWIP is funded by short-term debt, and no other factors are included in the calculation.

COMPUTATION OF ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION RATES

1. For line (5), column (e) below, enter the rate granted in the last rate proceeding. If not available, use the average rate earned during the preceding 3 years.
2. Identify in column (c), the specific entity used as the source for the capital structure figures.
3. Indicate in column (f), if the reported rate of return is one that has been approved in a rate case, black-box settlement rate, or an actual three-year average rate.

1. Components of Formula (Derived from actual book balances and actual cost rates):

Line No.	Title (a)	Amount (b)	Entity Name (c)	Capitalization Ration (percent) (d)	Cost Rate Percentage (e)	Rate Indicator (f)
	(1) Average Short-Term Debt	S 161,401,000				
	(2) Short-Term Interest				s 6.45%	
	(3) Long-Term Debt	D 2,263,500,000		47.8998105%	d 4.87%	
	(4) Preferred Stock	P		0%	p	
	(5) Common Equity	C 2,300,587,424		48.6846%	c 9.4%	
	(6) Total Capitaization	4,725,488,424		97%		
	(7) Average Construction Work in Progress Balance	W 161,401,000				

2. Gross Rate for Borrowed Funds s(S/W) + d[(D/(D+P+C)) (1-(S/W))] -	6.45%
3. Rate for Other Funds [1-(S/W)] [p(P/(D+P+C)) + c(C/(D+P+C))] -	0%
4. Weighted Average Rate Actually Used for the Year:	
(a) Rate for Borrowed Funds -	6.45%
(b) Rate for Other Funds -	0%

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Accumulated Provision for Depreciation of Gas 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 gas plant in service, page 204, column (d), excluding retirements of nondepreciable 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.
5. At lines 7 and 14, add rows as necessary to report all data. Additional rows should be numbered in sequence, e.g., 7.01, 7.02, etc.

Line No.	Item (a)	Total (c+d+e) (b)	Gas Plant in Service (c)	Gas Plant held for Future Use (d)	Gas Plant Leased to Others (e)
	Section A. BALANCES AND CHANGES DURING YEAR				
1	Balance Beginning of Year	479,138,993	479,138,993		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	45,339,270	45,339,270		
4	(403.1) Depreciation Expense for Asset Retirement Costs	0			
5	(413) Expense of Gas Plant Leased to Others				
6	Transportation Expenses - Clearing	1,433,032	1,433,032		
7	Other Clearing Accounts				
8	Other Clearing (Specify) (footnote details):				
9.1					
9.2					
9.3					
9.4					
9.5					
10	TOTAL Deprec. Prov. for Year (Total of lines 3 thru 8)	46,772,302	46,772,302	0	0
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(3,332,875)	(3,332,875)		
13	Cost of Removal	(6,251)	(6,251)		
14	Salvage (Credit)				
15	TOTAL Net Chrgs for Plant Ret. (Total of lines 12 thru 14)	(3,339,126)	(3,339,126)	0	0
16	Other Debit or Credit Items (Describe in footnote details)				
17.1	Change in RWIP	(2,340,672)	(2,340,672)		
17.2	Change in APxAccrual	13,806	13,806		
17.3	Transfers	(246,647)	(246,647)		
17.4	General Plant Common Allocated	(7,439,661)	(7,439,661)		
18	Book Cost of Asset Retirement Costs				
19	Balance End of Year (Total of lines 1,10,15,16 and 18)	512,558,995	512,558,995	0	0
	Section B. BALANCES AT END OF YEAR ACCORDING TO FUNCTIONAL CLASSIFICATIONS				
21	Productions-Manufactured Gas				
22	Production and Gathering-Natural Gas				
23	Products Extraction-Natural Gas				
24	Underground Gas Storage	21,753,861	21,753,861		
25	Other Storage Plant				
26	Base Load LNG Terminaling and Processing Plant				
27	Transmission				
28	Distribution	461,888,805	461,888,805		
29	General	28,916,329	28,916,329		
30	TOTAL (Total of lines 21 thru 29)	512,558,995	512,558,995	0	0

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Gas Stored (Accounts 117.1, 117.2, 117.3, 117.4, 164.1, 164.2, and 164.3)

1. If during the year adjustments were made to the stored gas inventory reported in columns (d), (f), (g), and (h) (such as to correct cumulative inaccuracies of gas measurements), explain in a footnote the reason for the adjustments, the Dth and dollar amount of adjustment, and account charged or credited.
2. Report in (e) all encroachments during the year upon the volumes designated as base gas, column (b), and system balancing gas, column (c), and gas property recordable in the plant accounts.
3. State in a footnote the basis of segregation of inventory between current and noncurrent portions. Also, state in a footnote the method used to report storage (i.e., fixed asset method or inventory method).

Line No.	Description (a)	(Account 117.1) (b)	(Account 117.2) (c)	Noncurrent (Account 117.3) (d)	(Account 117.4) (e)	Current (Account 164.1) (f)	LNG (Account 164.2) (g)	LNG (Account 164.3) (h)	Total (i)
1	Balance at Beginning of Year	6,992,076	0	0	0	[(a)]26,788,026	0		33,780,102
2	Gas Delivered to Storage					25,933,585			25,933,585
3	Gas Withdrawn from Storage					36,449,991			36,449,991
4	Other Debits and Credits								
5	Balance at End of Year	6,992,076	0	0	0	16,271,620	0		23,263,696
6	Dth	1,253,060				7,436,786			8,689,846
7	Amount Per Dth	5.58				2.19			2.68

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: GasStoredCurrent

Fuel is accounted for within injections and withdrawal accounts.

All gas reported is current working gas. Avista uses the inventory method to report all working gas stored.

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Investments (Account 123, 124, and 136)

1. Report below investments in Accounts 123, Investments in Associated Companies, 124, Other Investments, and 136, Temporary Cash Investments. List Account number in column (a).
2. Provide a subheading for each account and list thereunder the information called for: (a) Investment in Securities-List and describe each security owned, giving name of issuer, date acquired and date of maturity. For bonds, also give principal amount, date of issue, maturity, and interest rate. For capital stock (including capital stock of respondent reacquired under a definite plan for resale pursuant to authorization by the Board of Directors, and included in Account 124, Other Investments) state number of shares, class, and series of stock. Minor investments may be grouped by classes. Investments included in Account 136, Temporary Cash Investments, also may be grouped by classes. (b) Investment Advances-Report separately for each person or company the amounts of loans or investment advances that are properly includable in Account 123. Include advances subject to current repayment in Account 145 and 146. 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. Designate any advances due from officers, directors, stockholders, or employees.
3. Designate with an asterisk in column (b) any securities, notes or accounts that were pledged, and in a footnote state the name of pledges and purpose of the pledge.
4. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and cite Commission, date of authorization, and case or docket number.
5. Report in column (k) interest and dividend revenues from investments including such revenues from securities disposed of during the year.
6. In column (l) 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 any dividend or interest adjustment includible in column (k).

Line No.	Description of Investment (a)	* (b)	Date Acquired (c)	Date Matured (d)	Book Cost at Beginning of Year (If book cost is different from cost to respondent, give cost to respondent in a footnote and explain difference) (e)	Purchases or Additions During the Year (f)	Sales or Other Dispositions During Year (g)	Principal Amount (h)	No. of Shares at End of Year (i)	Book Cost at End of Year (If book cost is different from cost to respondent, give cost to respondent in a footnote and explain difference) (j)	Revenues for Year (k)	Gain or Loss from Investment Disposed of (l)
1	Investment in Avista Capital II (123010)				11,547,000					11,547,000		
2	Total Investment in Associated Companies				11,547,000	0	0			11,547,000	0	0
1	Other Investment - WZN Loans Sandpoint (124350)				59,354		59,354			0		
2	Other Investment - Coli Cash Val (124600)				37,967,151	2,790,859				40,758,010		
3	Other Investment - Coli Borrowings (124610)				(37,967,151)		2,790,859			(40,758,010)		
4	Other Investment - WZN Loans Oregon (124680)				14,094					14,094		
5	Total Other Investments				73,448	2,790,859	2,850,213			14,094	0	0
1	Temporary Cash Investments (136000)				496,573	15,494,463				15,991,036		
2	Total Temporary Cash Investments				496,573	15,494,463	0			15,991,036	0	0
4	Total Investments											

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ 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. Designate in a footnote, any securities, notes, or accounts that were pledged, 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 in 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 adjustments includible in column (f).
8. Report on Line 40, 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 for 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			256,138,971			256,138,971	
2	Investment in AERC			89,816,380			89,816,380	
3	AERC - Equity in Earnings			21,072,251	8,737,693		29,809,944	
4	Avista Capital - Equity in Earnings			(106,266,632)	(4,288,022)		(110,554,654)	
40	TOTAL Cost of Account 123.1 $		Total	260,760,970	4,449,671		265,210,641	

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Prepayments (Acct 165), Extraordinary Property Losses (Acct 182.1), Unrecovered Plant and Regulatory Study Costs (Acct 182.2)

PREPAYMENTS (ACCOUNT 165)

1. Report below the particulars (details) on each prepayment.

Line No.	Nature of Payment (a)	Balance at End of Year (in dollars) (b)
1	Prepaid Insurance	4,421,756
2	Prepaid Rents	4,683
3	Prepaid Taxes	4,297,933
4	Prepaid Interest	
5	Miscellaneous Prepayments	41,497,180
6	TOTAL	50,221,552

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Other Regulatory Assets (Account 182.3)

1. Report below the details called for concerning other regulatory assets which are created through the ratemaking actions of regulatory agencies (and not includable in other accounts).
2. For regulatory assets being amortized, show period of amortization in column (b).
3. Minor items (5% of the Balance at End of Year for Account 182.3 or amounts less than $250,000, whichever is less) may be grouped by classes.
4. Report separately any "Deferred Regulatory Commission Expenses" that are also reported on pages 350-351, Regulatory Commission Expenses.
5. Provide in column (c), for each line item, the regulatory citation where authorization for the regulatory asset has been granted (e.g. Commission Order, state commission order, court decision).

Line No.	Description and Purpose of Other Regulatory Assets (a)	Amortization Period (b)	Regulatory Citation (c)	Balance at Beginning Current Quarter/Year (d)	Debits (e)	Written off During Quarter/Year Account Charged (f)	Written off During Period Amount Recovered (g)	Written off During Period Amount Deemed Unrecoverable (h)	Balance at End of Current Quarter/Year (i)
1	[a] WA Excess Nat Gas Line Extension Allowance			4,328,385	0	407	1,745,141		2,583,244
2	[b] Reg Asset Post Ret Liabilility			128,847,130	1,796,907	228	18,181,644		112,462,393
3	[c] Regulatory Asset FAS 109 Utility Plant			80,549,288	1,556,488	283	3,933,322		78,172,454
4	[d] Regulatory Asset FAS 109 DSIT Non Plant			4,442,326	593,287	283	2,353,940		2,681,673
5	[e] Regulatory Asset Lake CDA Settlement-Varies			37,809,157	0	407	1,116,805		36,692,352
6	[f] Reg Assets-Decoupling Surcharges			9,089,302	36,741,461	456, 495	43,395,041		2,435,722
7	[g] Reg Asset - Colstrip			14,976,471	6,165,968	407	1,713,471		19,428,968
8	[h] Regulatory Asset FAS 143 Asset Retirement Obligation			2,165,181	133,388		0		2,298,569
9	[i] Regulatory Asset Workers Comp			989,028	956,123	242	14,986		1,930,165
10	[j] Interest Rate Swap Asset			185,919,054	1,417,272	Various	7,847,927		179,488,399
11	[k] DSM Asset			3,683,352	8,398,035	Various	1,823,901		10,257,486
12	[l] Deferred ITC			3,769,051	0	283, 410	166,945		3,602,106
13	[m] Regulatory Asset MDM System			32,380,865	0	407, 419	3,035,706		29,345,159
14	[n] Regulatory Asset BPA Residential Exchange			1,298,948	1,861,113	407	1,609,846		1,550,215
15	[o] Regulatory Asset FISERV			406,443	117,683	407, 419	353,815		170,311
16	[p] Regulatory Asset AFUDC (PIS,WIP) & Equity DFIT			59,662,251	30,423,065	Various	31,019,224		59,066,092
17	Regulatory Asset ID PCA Deferral			16,341,994	15,169,526	557, 419	23,884,029		7,627,491
18	[q] Existing Meters/ERTS Retirement Def			19,459,498	0	108, 407	1,824,328		17,635,170
19	[r] Regulatory Asset Colstrip Community Fund			1,500,000	562,500	182, 407	1,312,500		750,000
20	[s] Regulatory Asset COVID-19			1,241,772	1,977,642	186, 407	2,561,625		657,789
21	[t] Regulatory Asset Energy Imbalance Market			699,119		182, 407	116,520		582,599
22	[u] Regulatory Asset Oregon CAT Tax			628,249	12,664	407, 419	630,849		10,064
23	[v] Regulatory Asset- Wildfire Resiliency & Balancing			18,186,521	11,788,958	182	6,238,024		23,737,455
24	[w] Deferral for CS2 & Colstrip (O&M, Excess Depr)			1,874,781	2,238,354	182, 407	2,094,878		2,018,257
25	[x] Regulatory Asset Tax Basis Flow through			138,273,552	9,853,657	282, 283	2,958,003		145,169,206
26	[y] Reg Asset - Intervenor Fund Deferral			0	307,699	182	201,760		105,939
27	[z] Unrealized Currency Exchange			1,492,610	0	143	1,492,610		0
28	[aa] Regulatory Asset Commodity MTM ST & LT			130,274,212	272,303,368	244, 175	333,438,131		69,139,449
29	[ab] Regulatory Asset Energy Affordability Act			219,732	1,817,222	182, 908	735,954		1,301,000
30	[ac] Reg Asset - Insurance Balancing Acct			0	411,192	182, 407	122,403		288,789

31	[ad] Reg Asset - CPP			0	594,833		0		594,833
32	[ae] Deferred Regulatory Fees			98,368	2,471,646	407, 419	654,598		1,915,416
33	[af] Regulatory Asset Pension Settlement Deferral			11,827,588	0	182, 407	985,632		10,841,956
34	[ag] Reg Asset - CCA			0	46,022,329	407	0		46,022,329
35	[ah] WA ERM Deferral - Approved for Rebate			0	38,639,584	182, 557	13,161,287		25,478,297
36	[ai] REG ASSET - MT RIVERBED ESCROW INT			0	1,613,960		0		1,613,960
37	[aj] Reg Asset - Depreciation			0	511,800		0		511,800
38	[ak] REG ASSET - CPP RNG			0	25,000		0		25,000
40	TOTAL			912,434,228	496,482,724		510,724,845	0	898,192,107

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. Amort 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
Deferred tax flow through balance on utility plant. Amortization occurs over book life of respective utility plant assets.
(e) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
WA Docket UE-080416, ID Order AVU-E-08-01. Amortization thru 2059.
(f) 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.
(g) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
For WA Elec, amort period is 33.75yrs as per Order 09, dockets UE-190334, UG-190335, UE-190222 (Consolidated). For ID Elec, amort is for 34.75yrs as per Order 34276, AVU-E-18-03, Amor ends in 2054 for both jurisdictions.
(h) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Reg 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
WA Docket Nos 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 WA and Id. Amort is based on customer usage.
(o) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
ID Order No 33494, Docket Nos. AVU-E-16-01 and Stipulation and Settlement Docket No 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
WA Docket No UE-002066 and ID Order No 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 ID PUC Order No 34718, OR PUC Order No 20-401, Docket UM 2069 and WA UTC Order No. 01, Dockets UE-200407 and UG-200408.
(t) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
ID PUC Order No 34606. Deferral of costs related to Avista's entry in the Energy Imbalance Market in March 2022.
(u) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
OR 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 No UM 2124 Order No 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
WA Docket No UG-220596 and UE-220151.
(z) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Recognition of other liability related to foreign exchange hedge rates over a two year period.
(aa) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
WA Docket No UE-002066 and ID Order No 28648.
(ab) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Deferral of costs associated with Oregon House Bill 2475.
(ac) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
To defer costs above or below the baseline in accordance with Order No 10/04 Docket Nos UE-220053, UE-210854, and UG-220054.
(ad) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
To defer costs of compliance with the Climate Protection Plan pursuant to ORS 757.259 and OAR 860-027-0300(4). Docket No. UM2254.
(ae) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
OR Docket No UG415/Advice No. 21-06-G. Amortization of amounts deferred previously in Order No. 20-254 in UG 395. WA Docket No UE-220892 and UG-220893 Order 01.
(af) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
To defer expected impacts associated with the occurrence of pension events and amortization over 12 years - ID Case Nos. AVU-E-22-16 and AVU-G-22-08, WA Docket Nos UE-220898 and UG-220899, and OR UM 2267.
(ag) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
To defer costs of compliance with the Climate Commitment Act in accordance with WAC 480-100-203(3) and WAC 480-90-203(3). WA Docket No UG-220803.
(ah) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
WA ERM Amortizing Deferral - Approved for Rebate Balance. Began amortizing 7/1/23.
(ai) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Deferral for the Montana Riverbed land lease agreement escrow release provisions following Avista and State of Montana Agreement on an updated balance owed.
(aj) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Difference between depreciation rates in GRC verses effective date based on ID Order 35909 Dockets AVU-E-23-01 and AVU-G-23-01.
(ak) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
OR Order 23-145

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Miscellaneous Deferred Debits (Account 186)

1. Report below the details called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (b).
3. Minor items (less than $250,000) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Amortization Period (b)	Balance at Beginning of Year (c)	Debits (d)	Credits Account Charged (e)	Credits Amount (f)	Balance at End of Year (g)
1	Reg Asset - Battery Storage		3,422,093				3,422,093
2	Plant Alloc of Clearing Journal		2,344,921	3,863,077			6,207,998
3	Reg Asset - ERM		35,799,197		VAR	23,638,534	12,160,663
4	WA REC Deferral		0	412,639			412,639
5	Reg Asset - Decoupling Deferred		4,458,589	4,653,520			9,112,109
6	Reg Asset - COVID 19 Deferral		8,551,568	2,932,987			11,484,555
7	Reg Asset - CEIP		67,334	965,873			1,033,207
8	Reg Asset - Williams Outage		0	10,297,716			10,297,716
9	Misc Deferred Debits-Pension		13,381,750	19,622,239			33,003,989
10	Nez Perce Settlement		108,749		557	5,188	103,561
11	City of Post Falls Lease Pay		0	126,851			126,851
12	Post Falls HED Project 63		99,929	1,192			101,121
13	Misc. Deferred Debits <$100,000		686,038		VAR	634,636	51,402
39	Miscellaneous Work in Progress						
40	TOTAL		68,920,168	42,876,094		24,278,358	87,517,904

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ 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.
3. Provide in a footnote a summary of the type and amount of deferred income taxes reported in the beginning-of-year and end-of-year balances for deferred income taxes that the respondent estimates could be included in the development of jurisdictional recourse rates.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Changes During Year Amounts Debited to Account 410.1 (c)	Changes During Year, Amounts Credited to Account 411.1 (d)	Changes During Year Amounts Debited to Account 410.2 (e)	Changes During Year Amounts Credited to Account 411.2 (f)	Adjustments Debits Account No. (g)	Adjustments Debits Amount (h)	Adjustments Credits Account No. (i)	Adjustments Credits Amount (j)	Balance at End of Year (k)
1	Account 190										
2	Electric	105,974,248	5,097,944	(11,231,525)	284,250	268,921	254.3	5,210,584			84,418,866
3	Gas	27,957,319	(902,991)	(3,327,420)		12,676	254.3	1,504,048			24,041,518
4	Other (Define)	(a)135,539,045	5,833,911	(1,767,546)	2,407,475	1,980,805	254.3	21,819,114			105,691,804
5	Total (Total of lines 2 thru 4)	269,470,612	10,028,864	(16,326,491)	2,691,725	2,262,402		28,533,746		0	214,152,188
6	Other (Specify)										
7	TOTAL Account 190 (Total of lines 5 thru 6)	269,470,612	10,028,864	(16,326,491)	2,691,725	2,262,402		28,533,746		0	214,152,188
8	Classification of TOTAL										
9	Federal Income Tax	269,470,612	10,028,864	(16,326,491)	2,691,725	2,262,402		28,533,746			214,152,188
10	State Income Tax										
11	Local Income Tax										

(a) Concept: AccumulatedDeferredIncomeTaxes

	Beg. Balance	End. Balance
Pension, Medical, and SERP	39,011,736	34,671,763
Federal Income Tax Carryforwards	32,930,810	27,406,304
State Income Tax Carryforwards	22,175,174	17,952,286
Derivative Instruments	29,450,122	16,269,451
Compensation and Payroll	6,455,693	6,986,432
Plant Excess Deferred Gross Up	5,388,884	3,951,713
Other Common Deferred Tax Assets	126,626	(1,546,146)
Total	135,539,045	105,691,803

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Capital Stock (Accounts 201 and 204)

1. Report below the 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.
2. Entries in column (c) 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 Exchange (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 amt outstanding without reduction for amts held by respondent) Shares (e)	Outstanding per Bal. Sheet 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			78,074,587	1,596,986,047				
3	Restricted Shares								152,140	6,463,455
4										
5	Total	200,000,000			78,074,587	1,596,986,047				
6	Preferred Stock (Account 204)									
7	Cumulative	10,000,000								
8										
9										
10	Total	10,000,000			0	0				
11	Total									

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Other Paid-In Capital (Accounts 208-211)

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)
15.1	Reclassification of subsidiary APIC	7,964,306
15	Increases (Decreases) Due to Miscellaneous Paid-In Capital	7,964,306
16	Ending Balance Amount	(2,732,405)
17	**Other Paid in Capital**	
18	Beginning Balance Amount	
19	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	
40	Total	(2,732,405)

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Securities Issued or Assumed and Securities Refunded or Retired During the Year

1. Furnish a supplemental statement briefly describing security financing and refinancing transactions during the year and the accounting for the securities, discounts, premiums, expenses, and related gains or losses. Identify as to Commission authorization numbers and dates.
2. Provide details showing the full accounting for the total principal amount, par value, or stated value of each class and series of security issued, assumed, retired, or refunded and the accounting for premiums, discounts, expenses, and gains or losses relating to the securities. Set forth the facts of the accounting clearly with regard to redemption premiums, unamortized discounts, expenses, and gain or losses relating to securities retired or refunded, including the accounting for such amounts carried in the respondent's accounts at the date of the refunding or refinancing transactions with respect to securities previously refunded or retired.
3. Include in the identification of each class and series of security, as appropriate, the interest or dividend rate, nominal date of issuance, maturity date, aggregate principal amount, par value or stated value, and number of shares. Give also the issuance of redemption price and name of the principal underwriting firm through which the security transactions were consummated.
4. Where the accounting for amounts relating to securities refunded or retired is other than that specified in General Instruction 17 of the Uniform System of Accounts, cite the Commission authorization for the different accounting and state the accounting method.
5. For securities assumed, give the name of the company for which the liability on the securities was assumed as well as details of the transactions whereby the respondent undertook to pay obligations of another company. If any unamortized discount, premiums, expenses, and gains or losses were taken over onto the respondent's books, furnish details of these amounts with amounts relating to refunded securities clearly earmarked.

In March 2023, the Company issued and sold $250.0 million of 5.66 percent first mortgage bonds due in 2053 with institutional investors in the private placement market. A portion of the net proceeds from the sale of these bonds was used for the construction or improvement of utility facilities, and a portion was used to refinance existing indebtedness, including the repayment of Avista Corp.'s $150.0 million term loan. In connection with the pricing of the first mortgage bonds in March 2023, the Company cash settled four interest rate swap derivatives (notional aggregate amount of $40.0 million) and received a net amount of $7.5 million. See Note 8 for a discussion of interest rate swap derivatives.

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

1. Order of the Washington Utilities and Transportation Commission in Docket No. 210944 entered February 10, 2022.

2. Order of the Idaho Public Utilities Commission, Order No. 35286 entered January 6, 2021.

3. Order of the Public Utility Commission of Oregon, Order No. 21-486, entered December 28, 2021.

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

The Company issued common stock for total net proceeds of $112.3 million in 2023. 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. In 2023, 3.0 million shares were issued under these agreements resulting in total net proceeds of $111.8 million.

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Long-Term Debt (Accounts 221, 222, 223, and 224)

1. Report by Balance Sheet Account the details concerning long-term debt included in Account 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.
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.
4. For receivers' certificates, show in column (a) the name of the court and date of court order under which such certificates were issued.
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 (f). Explain in a footnote any difference between the total of column (f) 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 and Name of Stock Exchange (a)	Nominal Date of Issue (b)	Date of Maturity (c)	Outstanding (Total amount outstanding without reduction for amts held by respondent) (d)	Interest for Year Rate (in %) (e)	Interest for Year Amount (f)	Held by Respondent Reacquired Bonds (Acct 222) (g)	Held by Respondent Sinking and Other Funds (h)	Redemption Price per $100 at End of Year (i)
1	Bonds (Account 221)								
2	FMBS - SERIES C - 6.37% DUE 06/18/2028	06/19/1998	06/19/2028	25,000,000	6.37%	1,592,500			
3	COLSTRIP 2010A PCRBs DUE 2032	12/15/2010	10/01/2032	66,700,000	3.41%				
4	COLSTRIP 2010B PCRBs DUE 2034	12/15/2010	03/01/2034	17,000,000	3.41%				
5	FMBS - 6.25% DUE 12-01-35	11/17/2005	12/01/2035	150,000,000	6.25%	9,375,000			
6	FMBS - 5.70% DUE 07-01-2037	12/15/2006	07/01/2037	150,000,000	5.7%	8,550,000			
7	5.55% SERIES DUE 12-20-2040	12/20/2010	12/20/2040	35,000,000	5.55%	1,942,500			
8	4.45% SERIES DUE 12-14-2041	12/14/2011	12/14/2041	85,000,000	4.45%	3,782,500			
9	4.11% SERIES DUE 12-1-2044	12/18/2014	12/01/2044	60,000,000	4.11%	2,466,000			
10	4.37% SERIES DUE 12-1-2045	12/16/2015	12/01/2045	100,000,000	4.37%	4,370,000			
11	4.23% SERIES DUE 11-29-2047	11/30/2012	11/29/2047	80,000,000	4.23%	3,384,000			
12	3.91% SERIES DUE 12-1-2047	12/14/2017	12/01/2047	90,000,000	3.91%	3,519,000			
13	4.35% SERIES DUE 6-1-2048	05/22/2018	06/01/2048	375,000,000	4.35%	16,312,500			
14	3.43% SERIES DUE 12-1-2049	11/26/2019	12/01/2049	180,000,000	3.43%	6,174,000			
15	3.07% SERIES DUE 9-1-2050	09/30/2020	09/30/2050	165,000,000	3.07%	5,065,500			
16	2.90% SERIES DUE 10/01/2051	09/28/2021	10/01/2051	140,000,000	2.9%	4,060,000			
17	3.54% SERIES DUE 2051	12/15/2016	12/01/2051	175,000,000	3.54%	6,195,000			
18	4.00% SERIES DUE 4/1/2052	03/17/2022	04/01/2052	400,000,000	4%	16,000,000			
19	5.66% SERIES DUE 04-01-2053	03/29/2023	04/01/2053	250,000,000	5.66%	10,726,613			
20	Subtotal			2,543,700,000		103,515,113		0	
21	Reacquired Bonds (Account 222)								
22	COLSTRIP 2010A PCRBs	12/15/2010	10/01/2032	66,700,000	3.41%	2,272,812			
23	COLSTRIP 2010B PCRBs	12/15/2010	03/01/2034	17,000,000	3.41%	579,277			
24	Subtotal			83,700,000		2,852,089	0	0	
25	Advances from Associated Companies (Account 223)								
26	ADVANCE ASSOCIATED-AVISTA CAPITAL II (ToPRS)	06/03/1997	06/01/2037	51,547,000	4.86%	2,503,671			
27	Subtotal			51,547,000		2,503,671		0	
28	Other Long Term Debt (Account 224)								
29									
30									
31									
32									
33									
34									
35									
36									
30	Subtotal			0					
40	TOTAL			2,678,947,000		108,870,873	0	0	

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Unamortized Debt Expense, Premium and Discount on Long-Term Debt (Accounts 181, 225, 226)

1. Report under separate subheadings for Unamortized Debt Expense, Unamortized Premium on Long-Term Debt and Unamortized Discount on Long-Term Debt, details of expense, premium or discount applicable to each class and series of long-term debt.
2. Show premium amounts by enclosing the figures in parentheses.
3. In column (b) show the principal amount of bonds or other long-term debt originally issued.
4. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
5. Furnish in a footnote details regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.
6. Identify separately undisposed amounts applicable to issues which were redeemed in prior years.
7. Explain any debits and credits other than amortization debited to Account 428, Amortization of Debt Discount and Expense, or credited to Account 429, Amortization of Premium on Debt-Credit.

Line No.	Designation of Long-Term Debt (a)	Principal Amount of Debt Issued (b)	Total expense - Premium; Discount; or Debt Issuance Costs (c)	Amortization Period Date From (d)	Amortization Period Date To (e)	Balance at Beginning of Year (f)	Debits During Year (g)	Credits During Year (h)	Balance at End of Year (i)
1	Unamortized Debt Expense (Account 181)								
2	FMBS - SERIES A - 7.53% DUE 05/05/2023	5,500,000	42,712	05/06/1993	05/05/2023	593		593	0
3	FMBS - SERIES A - 7.54% DUE 5/05/2023	1,000,000	7,766	05/07/1993	05/05/2023	108		108	0
4	FMBS - SERIES A - 7.18% DUE 8/11/2023	7,000,000	54,364	08/12/1993	08/11/2023	1,208		1,208	0
5	ADVANCE ASSOCIATED-AVISTA CAPITAL II (ToPRS)	51,547,000	1,296,086	06/03/1997	06/01/2037	203,215		14,015	189,200
6	FMBS - SERIES C - 6.37% DUE 06/18/2028	25,000,000	158,304	06/19/1998	06/19/2028	29,022		5,277	23,745
7	FMBS - 6.25% DUE 12-01-35	150,000,000	2,180,435	11/17/2005	12/01/2035	784,906		60,376	724,530
8	FMBS - 5.70% DUE 07-01-2037	150,000,000	4,924,304	12/15/2006	07/01/2037	2,242,519		153,772	2,088,747
9	5.55% SERIES DUE 12-20-2040	35,000,000	258,834	12/20/2010	12/20/2040	155,305		8,628	146,677
10	4.45% SERIES DUE 12-14-2041	85,000,000	692,833	12/14/2011	12/14/2041	438,975		23,104	415,871
11	SHORT-TERM CREDIT FACILITY	0	16,344,304	12/14/2011	06/08/2028	3,086,430	889,710	750,577	3,225,563
12	4.23% SERIES DUE 11-29-2047	80,000,000	730,833	11/30/2012	11/29/2047	520,412		20,886	499,526
13	4.11% SERIES DUE 12-1-2044	60,000,000	428,205	12/18/2014	12/01/2044	314,208		14,283	299,925
14	4.37% SERIES DUE 12-1-2045	100,000,000	590,761	12/16/2015	12/01/2045	453,134		19,701	433,433
15	3.54% SERIES DUE 2051	175,000,000	1,042,569	12/15/2016	12/01/2051	864,021		29,794	834,227
16	3.91% SERIES DUE 12-1-2047	90,000,000	552,539	12/14/2017	12/01/2047	460,562		18,422	442,140
17	4.35% SERIES DUE 6-1-2048	375,000,000	4,625,198	06/01/2018	06/01/2048	3,599,919		141,174	3,458,745
18	3.43% SERIES DUE 12-1-2049	180,000,000	1,108,340	12/01/2019	12/01/2049	994,748		36,843	957,905
19	3.07% SERIES DUE 9-1-2050	165,000,000	1,074,990	09/30/2020	09/30/2050	1,045,232		37,666	1,007,566
20	2.90% SERIES DUE 10/01/2051	140,000,000	1,083,452	09/28/2021	10/01/2051	1,026,917		22,609	1,004,308
21	4.00% SERIES DUE 4-1-2052	400,000,000	4,723,993	03/17/2022	04/01/2052	4,466,881		152,280	4,314,601
22	5.66% SERIES DUE 04-01-2053	250,000,000	1,444,302	03/29/2023	04/01/2053	0	1,444,302	35,358	1,408,944
23	COLSTRIP 2010A PCRBs DUE 2032	66,700,000	89,915	12/31/2008	10/01/2032	0	89,915	24,655	65,260
24	COLSTRIP 2010B PCRBs DUE 2034	17,000,000	4,721,521	12/30/2009	03/01/2034	0	4,721,521	4,704,888	16,633
25	DEBT STRATEGIES	0	56,760	08/01/2005	08/01/2035	361		28	333
26	Rathrum 2005	0	71,647	09/30/2005	12/01/2035	30,791		2,369	28,422
27	Premium on Long-Term Debt (Account 225)								
28	FMBS - 6.25% DUE 12-01-35	150,000,000	2,180,435	11/17/2005	12/01/2035	115,483	8,883		106,600
29	Discount on Long-Term Debt (Account 226)								
30	FMBS - 6.25% DUE 12-01-35	150,000,000	2,180,435	11/17/2005	12/01/2035	273,972		21,074	252,898
31	FMBS - 5.70% DUE 07-01-2037	150,000,000	4,924,304	12/15/2006	07/01/2037	105,858		7,259	98,599
32	4.35% SERIES DUE 6-1-2048"	375,000,000	4,625,198	06/01/2018	06/01/2048	321,046		12,590	308,456
33	4.00% SERIES DUE 4-1-2052	400,000,000	4,723,993	03/17/2022	04/01/2052	140,410		4,787	135,623

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Unamortized Loss and Gain on Reacquired Debt (Accounts 189, 257)

1. Report under separate subheadings for Unamortized Loss and Unamortized Gain on Reacquired Debt, details of gain and loss, including maturity date, on reacquisition applicable to each class and series of long-term debt. If gain or loss resulted from a refunding transaction, include also the maturity date of the new issue.
2. In column (d) show the principal amount of bonds or other long-term debt reacquired.
3. In column (e) show the net gain or net loss realized on each debt reacquisition as computed in accordance with General Instruction 17 of the Uniform Systems of Accounts.
4. Show loss amounts by enclosing the figures in parentheses.
5. Explain in a footnote any debits and credits other than amortization debited to Account 428.1, Amortization of Loss on Reacquired Debt, or credited to Account 429.1, Amortization of Gain on Reacquired Debt-Credit.

Line No.	Designation of Long-Term Debt (a)	Date of Maturity (b)	Date Reacquired (c)	Principal of Debt Reacquired (d)	Net Gain or Loss (e)	Balance at Beginning of Year (f)	Balance at End of Year (g)
1	Unamortized Loss (Account 189)						
2	Misc Debt Repurchases I		05/10/1993	0	4,695,395	50,397	28,297
3	ADVANCE ASSOCIATED-AVISTA CAPITAL II (ToPRS)	06/01/2037	12/18/2000	10,000,000	0	0	0
4	Misc 2002 Repurchase		12/31/2002	10,000,000	121,847	14,006	11,157
5	Misc 2003 Repurchase		12/31/2003	25,330,000	684,726	38,776	33,059
6	Misc 2005 Repurchase		12/31/2005	26,000,000	1,700,371	391,999	356,995
7	Misc 2008 Repurchase		12/31/2008	0	(43,132)	(2,834)	(139)
8	COLSTRIP 2010A PCRBs DUE 2032	03/01/2032	12/14/2010	66,700,000	3,709,174	1,530,733	1,375,065
9	COLSTRIP 2010B PCRBs DUE 2034	03/01/2034	12/14/2010	17,000,000	1,916,297	920,919	842,019
10	5.55% SERIES DUE 12-20-2040	12/20/2040	12/20/2010	30,000,000	5,263,822	3,158,293	2,982,834
11	4.23% SERIES DUE 11-29-2047	11/29/2047	06/28/2012	4,100,000	105,020	74,765	71,764
12	Unamortized Gain (Account 257)						
13	Misc Debt Repurchases I		05/10/1993	0	0	0	
14	ADVANCE ASSOCIATED-AVISTA CAPITAL II (ToPRS)	06/01/2037	12/18/2000	10,000,000	(1,769,125)	703,583	654,780
15	Misc 2002 Repurchase		12/31/2002	10,000,000	(2,350,000)	270,123	215,183
16	Misc 2003 Repurchase		12/31/2003	25,330,000	(1,000,000)	86,042	72,421
17	Misc 2005 Repurchase		12/31/2005	26,000,000	0	0	
18	Misc 2008 Repurchase		12/31/2008	0	0	0	
19	COLSTRIP 2010A PCRBs DUE 2032	03/01/2032	12/14/2010	66,700,000	0	0	
20	COLSTRIP 2010B PCRBs DUE 2034	03/01/2034	12/14/2010	17,000,000	0	0	
21	5.55% SERIES DUE 12-20-2040	12/20/2040	12/20/2010	30,000,000	0	0	
22	4.23% SERIES DUE 11-29-2047	11/29/2047	06/28/2012	4,100,000	0	0	

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ 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 that files consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be filed, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group members, tax assigned to each group member, and basis of allocation, assignments, or sharing of the consolidated tax among the group members.

Line No.	Details (a)	Amount (b)
1	Net Income for the Year (Page 114)	171,180,214
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	Contributions in Aid of Construction	10,754,152
6	Other	36,360,532
8	Total	47,114,684
9	Deductions Recorded on Books Not Deducted for Return	
10	Book Depreciation	269,272,553
11	Federal Income Tax Expense	(36,924,664)
12	State Income Tax Expense	(31,119)
13	Subsidiary Overheads	360,971
14	Other	16,809,291
13	Total	249,487,032
14	Income Recorded on Books Not Included in Return	
15	Subsidiary Earnings	4,449,671
16	Other	3,328,370
18	Total	7,778,041
19	Deductions on Return Not Charged Against Book Income	
20	Tax Depreciation	234,949,702
21	Plant Basis Adjustments	137,699,340
22	Other	87,001,270
26	Total	459,650,312
27	Federal Tax Net Income	353,577
28	Show Computation of Tax:	
29	Federal Tax at 21%	74,251
30	Business Credits Utilized	(989,812)
31	Prior Year True Ups	1,271,341
32	WA Remand at 35%	(16,263)
33	Total Federal Current Tax Expense	339,517

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report End of: 2023/ Q4

Taxes Accrued, Prepaid and Charged During Year, Distribution of Taxes Charged (Show utility dept where applicable and acct charged)

1. Give 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 the portion of prepaid taxes charged 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 footnote. 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. Show in columns (l) thru (s) how the taxes accounts were distributed. Show both the utility department and number of account charged. For taxes charged to utility plant, show the number of the appropriate balance sheet plant account or subaccount.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.
10. Items under $250,000 may be grouped.
11. Report in column (t) the applicable effective state income tax rate.

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	Tax Jurisdiction (c)	Tax Year (d)	Balance at Beg. of Year Taxes Accrued (e)	Balance at Beg. of Year Prepaid Taxes (f)
1	Income Tax	Federal Tax		2021		
2	Income Tax	Federal Tax		2022		
3	Income Tax	Federal Tax		2023		
4	Subtotal Federal Tax				0	0
5	Property Tax	Property Tax	WA	2022	18,573,985	
6	Property Tax	Property Tax	WA	2023		
7	Property Tax	Property Tax	ID	2022	2,857,137	
8	Property Tax	Property Tax	ID	2023		
9	Property Tax	Property Tax	MT	2022	4,840,427	
10	Property Tax	Property Tax	MT	2023		
11	Property Tax	Property Tax	OR	2022		4,517,894
12	Property Tax	Property Tax	OR	2023		
13	Subtotal Property Tax				26,271,549	4,517,894
14	Excise Tax	Excise Tax	WA	2022	3,980,660	
15	Excise Tax	Excise Tax	WA	2023		
16	Corp Activities Tax-CAT	Excise Tax	OR	2022		
17	Corp Activities Tax-CAT	Excise Tax	OR	2023		
18	Subtotal Excise Tax				3,980,660	0
19	Natural Gas Use Tax	Sales And Use Tax	WA	2022	46,608	
20	Use Tax	Sales And Use Tax	WA	2023		
21	Use Tax	Sales And Use Tax	WA	2022	210,812	
22	Use Tax	Sales And Use Tax	WA	2023		
23	Use Tax	Sales And Use Tax	ID	2022	31,762	
24	Use Tax	Sales And Use Tax	ID	2023		
25	Subtotal Sales And Use Tax				289,182	0
26	Municipal Occupation Tax	Local Tax	WA	2022	4,001,655	
27	Municipal Occupation Tax	Local Tax	WA	2023		
28	Subtotal Local Tax				4,001,655	0
29	KWH Tax	Other Taxes	ID	2022	24,554	
30	KWH Tax	Other Taxes	ID	2023		
31	KWH Tax	Other Taxes	MT	2022	239,401	
32	KWH Tax	Other Taxes	MT	2023		
33	WA Renewable Energy Credits	Other Taxes	WA	2023		
34	Subtotal Other Taxes				263,955	0
35	Income Tax	State Tax	ID	2022		

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	Tax Jurisdiction (c)	Tax Year (d)	Balance at Beg. of Year Taxes Accrued (e)	Balance at Beg. of Year Prepaid Taxes (f)
36	Income Tax	State Tax	ID	2023		
37	Income Tax	State Tax	MT	2022		
38	Income Tax	State Tax	MT	2023		
39	Income Tax	State Tax	OR	2022		
41	Income Tax	State Tax	OR	2023		
42	Income Tax	State Tax	MISC	2022		
43	Subtotal State Tax				0	0
44	Payroll Taxes	Payroll Tax	ID	2022	6,943	
45	Payroll Taxes	Payroll Tax	ID	2023		
46	Payroll Taxes	Payroll Tax	MT	2022	528	
47	Payroll Taxes	Payroll Tax	MT	2023		
48	Payroll Taxes	Payroll Tax	OR	2022	14,255	
49	Payroll Taxes	Payroll Tax	OR	2023		
50	Payroll Taxes	Payroll Tax	WA	2022	72,315	
51	Payroll Taxes	Payroll Tax	WA	2023		
52	Payroll Taxes	Payroll Tax	Misc	2022		
53	Payroll Taxes	Payroll Tax	MISC	2023		
54	Payroll Taxes	Payroll Tax	FED	2021		
55	Payroll Taxes	Payroll Tax	FED	2022	796,213	
56	Payroll Taxes	Payroll Tax	FED	2023		
57	Subtotal Payroll Tax				890,254	0
58	Franchise Tax	Franchise Tax	ID	2022	1,285,869	
59	Franchise Tax	Franchise Tax	ID	2023		
60	Franchise Tax	Franchise Tax	OR	2022	1,537,313	
61	Franchise Tax	Franchise Tax	OR	2023		
62	Subtotal Franchise Tax				2,823,182	0
63	Consumer Council Fee	Other License And Fees Tax	MT	2022	8	
64	Consumer Council Fee	Other License And Fees Tax	MT	2023		
65	Public Commission Fee	Other License And Fees Tax	MT	2022	42	
66	Public Commission Fee	Other License And Fees Tax	MT	2023		
67	Subtotal Other License And Fees Tax				50	0
40	Total				38,520,487	4,517,894

Line No.	Kind of Tax (See Instruction 5) (a)	Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	Balance at End of Year Taxes Accrued (Account 236) (j)	Balance at End of Year Prepaid Taxes (Included in Acct 165) (k)
1	Income Tax		-800,000	-800,000	0	
2	Income Tax	1271339	238,248	-1,033,091	0	
3	Income Tax	-1007626	-1,679,000	-671,374	0	
4	Subtotal Federal Tax	263713	-2,240,752	-2,504,465	0	0
5	Property Tax	-2685052	15,889,288	355	0	
6	Property Tax	14235079	1,405	-354	14,233,320	
7	Property Tax	-1236	2,857,841	1,940	0	
8	Property Tax	4149832	2,099,678	-1,940	2,048,214	
9	Property Tax	243	4,840,669	-1	0	
10	Property Tax	7382564	3,707,034		3,675,530	
11	Property Tax	4517893		1	0	
12	Property Tax	4233758	8,467,363	-64,328	0	4,297,933
13	Subtotal Property Tax	31833081	37,863,278	-64,327	19,957,064	4,297,933
14	Excise Tax	78882	4,059,542		0	
15	Excise Tax	34977642	31,016,843		3,960,799	
16	Corp Activities Tax-CAT	-5020		5,020	0	
17	Corp Activities Tax-CAT	799999	700,000	-99,999	0	
18	Subtotal Excise Tax	35851503	35,776,385	-94,979	3,960,799	0
19	Natural Gas Use Tax	709	47,318	1	0	
20	Use Tax	100177	94,352	-1	5,824	
21	Use Tax	-7910	202,902		0	
22	Use Tax	1830363	1,588,474		241,889	
23	Use Tax		31,761	-1	0	
24	Use Tax	166826	114,132	1	52,695	
25	Subtotal Sales And Use Tax	2090165	2,078,939		300,408	0
26	Municipal Occupation Tax	48832	4,050,487		0	
27	Municipal Occupation Tax	29728805	25,905,105		3,823,700	
28	Subtotal Local Tax	29777637	29,955,592		3,823,700	0
29	KWH Tax	1573	26,126	-1	0	
30	KWH Tax	317428	295,205	1	22,224	
31	KWH Tax		239,401		0	
32	KWH Tax	1009062	789,685		219,377	
33	WA Renewable Energy Credits	664254	664,254		0	
34	Subtotal Other Taxes	1992317	2,014,671		241,601	0
35	Income Tax				0	
36	Income Tax	60		-60	0	
37	Income Tax				0	
38	Income Tax	50	50		0	
39	Income Tax				0	
41	Income Tax	100000	100,000		0	
42	Income Tax	975	975		0	
43	Subtotal State Tax	101085	101,025	-60	0	0
44	Payroll Taxes		2,310	-4,633	0	
45	Payroll Taxes	46448	42,701		3,747	
46	Payroll Taxes		350	-178	0	
47	Payroll Taxes	9910	9,671		239	
48	Payroll Taxes		1,249	-13,006	0	
49	Payroll Taxes	63273	52,444		10,829	
50	Payroll Taxes		89,303	16,988	0	
51	Payroll Taxes	1119287	1,244,525		-125,238	
52	Payroll Taxes				0	
53	Payroll Taxes	2877	2,157		720	
54	Payroll Taxes		-14,004	-14,004	0	
55	Payroll Taxes	234843	-8,879	-1,039,935	0	
56	Payroll Taxes	17276344	17,277,550	1,054,060	1,052,854	
57	Subtotal Payroll Tax	18752982	18,699,377	-708	943,151	0
58	Franchise Tax	646	1,286,515		0	
59	Franchise Tax	5621364	4,248,584		1,372,780	

Line No.	Kind of Tax (See Instruction 5) (a)	Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	Balance at End of Year Taxes Accrued (Account 236) (j)	Balance at End of Year Prepaid Taxes (Included in Acct 165) (k)
60	Franchise Tax	-107	1,537,207	1	0	
61	Franchise Tax	5733816	4,454,171	-1	1,279,644	
62	Subtotal Franchise Tax	11355719	11,526,477		2,652,424	0
63	Consumer Council Fee		7	-1	0	
64	Consumer Council Fee	35	26	1	10	
65	Public Commission Fee		42		0	
66	Public Commission Fee	215	165		50	
67	Subtotal Other License And Fees Tax	250	240		60	0
40	Total	132018452	135,775,232	-2,664,539	31,879,207	4,297,933

Line No.	Kind of Tax (See Instruction 5) (a)	Electric (Account 408.1, 409.1) (l)	Gas (Account 408.1, 409.1) (m)	Other Utility Dept. (Account 408.1, 409.1) (n)	Other Income and Deductions (Account 408.2, 409.2) (o)	Extraordinary Items (Account 409.3) (p)
1	Income Tax					
2	Income Tax	730,140	459,236		81,963	
3	Income Tax	-8,445,193	9,674,985		-2,237,418	
4	Subtotal Federal Tax	-7,715,053	10,134,221	0	-2,155,455	0
5	Property Tax	-2,115,275	-617,068		47,291	
6	Property Tax	10,920,067	3,175,017		139,995	
7	Property Tax				-1,236	
8	Property Tax	3,177,624	957,043		15,165	
9	Property Tax	243				
10	Property Tax	7,382,564				
11	Property Tax	1,866,618	2,651,275			
12	Property Tax	1,690,101	2,543,657			
13	Subtotal Property Tax	22,921,942	8,709,924	0	201,215	0
14	Excise Tax	81,744	4,288		-7,150	
15	Excise Tax	24,313,394	10,513,082		151,166	
16	Corp Activities Tax-CAT		-5,020			
17	Corp Activities Tax-CAT		799,999			
18	Subtotal Excise Tax	24,395,138	11,312,349	0	144,016	0
19	Natural Gas Use Tax	709				
20	Use Tax	3,022				
21	Use Tax					
22	Use Tax					
23	Use Tax					
24	Use Tax					
25	Subtotal Sales And Use Tax	3,731	0	0	0	0
26	Municipal Occupation Tax	44,370	4,462			
27	Municipal Occupation Tax	20,889,865	8,838,940			
28	Subtotal Local Tax	20,934,235	8,843,402	0	0	0
29	KWH Tax	1,573				
30	KWH Tax	317,428				
31	KWH Tax					
32	KWH Tax	1,009,062				
33	WA Renewable Energy Credits					
34	Subtotal Other Taxes	1,328,063	0	0	0	0
35	Income Tax					
36	Income Tax	51	9			
37	Income Tax					
38	Income Tax	50				
39	Income Tax					
41	Income Tax	20,000	80,000			
42	Income Tax	123	52		800	
43	Subtotal State Tax	20,224	80,061	0	800	0
44	Payroll Taxes					
45	Payroll Taxes	16,098	6,524		286	
46	Payroll Taxes					
47	Payroll Taxes	3,435	1,392		61	
48	Payroll Taxes					
49	Payroll Taxes	21,929	8,887		389	
50	Payroll Taxes					
51	Payroll Taxes	387,927	157,204		6,886	
52	Payroll Taxes					
53	Payroll Taxes	997	404		18	
54	Payroll Taxes					
55	Payroll Taxes	81,393	32,984		1,445	
56	Payroll Taxes	5,987,700	2,426,463		106,282	
57	Subtotal Payroll Tax	6,499,479	2,633,858	0	115,367	0
58	Franchise Tax	665	-19			
59	Franchise Tax	3,800,945	1,820,419			
60	Franchise Tax		-107			
61	Franchise Tax		5,733,816			
62	Subtotal Franchise Tax	3,801,610	7,554,109	0	0	0
63	Consumer Council Fee					

Line No.	Kind of Tax (See Instruction 5) (a)	Electric (Account 408.1, 409.1) (l)	Gas (Account 408.1, 409.1) (m)	Other Utility Dept. (Account 408.1, 409.1) (n)	Other Income and Deductions (Account 408.2, 409.2) (o)	Extraordinary Items (Account 409.3) (p)
64	Consumer Council Fee	35				
65	Public Commission Fee					
66	Public Commission Fee	215				
67	Subtotal Other License And Fees Tax	250	0	0	0	0
40	Total	72,189,619	49,267,924	0	-1,694,057	0

Line No.	Kind of Tax (See Instruction 5) (a)	Other Utility Opn. Income (Account 408.1, 409.1) (q)	Adjustment to Ret. Earnings (Account 439) (r)	Other (s)	State/Local Income Tax Rate (t)
1	Income Tax				
2	Income Tax				
3	Income Tax				
4	Subtotal Federal Tax	0	0	0	
5	Property Tax				
6	Property Tax				
7	Property Tax				
8	Property Tax				
9	Property Tax				
10	Property Tax				
11	Property Tax				
12	Property Tax				
13	Subtotal Property Tax	0	0	0	
14	Excise Tax				
15	Excise Tax				
16	Corp Activities Tax-CAT				
17	Corp Activities Tax-CAT				
18	Subtotal Excise Tax	0	0	0	
19	Natural Gas Use Tax				
20	Use Tax			97,155	
21	Use Tax			-7,910	
22	Use Tax			1,830,363	
23	Use Tax				
24	Use Tax			166,826	
25	Subtotal Sales And Use Tax	0	0	2,086,434	
26	Municipal Occupation Tax				
27	Municipal Occupation Tax				
28	Subtotal Local Tax	0	0	0	
29	KWH Tax				
30	KWH Tax				
31	KWH Tax				
32	KWH Tax				
33	WA Renewable Energy Credits			664,254	
34	Subtotal Other Taxes	0	0	664,254	
35	Income Tax				
36	Income Tax				
37	Income Tax				
38	Income Tax				
39	Income Tax				
41	Income Tax				
42	Income Tax				
43	Subtotal State Tax	0	0	0	
44	Payroll Taxes				
45	Payroll Taxes			23,540	
46	Payroll Taxes				
47	Payroll Taxes			5,022	
48	Payroll Taxes				
49	Payroll Taxes			32,068	
50	Payroll Taxes				
51	Payroll Taxes			567,270	
52	Payroll Taxes				
53	Payroll Taxes			1,458	
54	Payroll Taxes				
55	Payroll Taxes			119,021	
56	Payroll Taxes			8,755,899	
57	Subtotal Payroll Tax	0	0	9,504,278	
58	Franchise Tax				
59	Franchise Tax				
60	Franchise Tax				
61	Franchise Tax				
62	Subtotal Franchise Tax	0	0	0	
63	Consumer Council Fee				
64	Consumer Council Fee				

Line No.	Kind of Tax (See Instruction 5) (a)	Other Utility Opn. Income (Account 408.1, 409.1) (q)	Adjustment to Ret. Earnings (Account 439) (r)	Other (s)	State/Local Income Tax Rate (t)
65	Public Commission Fee				
66	Public Commission Fee				
67	Subtotal Other License And Fees Tax	0	0	0	
40	Total	0	0	12,254,966	

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Miscellaneous Current and Accrued Liabilities (Account 242)

1. Describe and report the amount of other current and accrued liabilities at the end of year.
2. Minor items (less than $250,000) may be grouped under appropriate title.

Line No.	Item (a)	Balance at End of Year (b)
1	MISC LIAB-PAID TIME OFF	31,632,754
2	MISC LIAB - CCA EMISSION OBLIGATION ST	19,080,689
3	CURRENT PORTION-BENEFIT LIAB	14,082,143
4	CUSTOMER ACCOUNTS	9,720,576
5	ACCTS PAYABLE EXPENSE ACCRUAL-SC	5,979,564
6	MISC LIAB-MT LEASE PAYMENTS	5,912,000
7	ACCTS PAY - SOFTWARE LICENSES - ST	3,622,744
8	MISC LIAB-MARGIN CALL DEPOSIT	2,768,852
9	MISC LIAB-FOREST USE PERMITS	2,096,466
10	WORKERS COMP LIABILITY	1,930,165
11	MISC LIAB-FERC ADMIN FEE ACC	730,075
12	MISC LIAB - SUA JPMORGAN CHASE	568,946
13	ACCTS PAYABLE INVENTORY ACCRUALS-SC	553,930
14	CLEARING ACCOUNTS	396,745
15	MISC LIAB UNDER $250k	669,247
45	Total	99,744,896

Other Deferred Credits (Account 253)

1. Report below the details called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (less than $250,000) may be grouped by classes.

Line No.	Description of Other Deferred Credits (a)	Balance at Beginning of Year (b)	Debit Contra Account (c)	Debit Amount (d)	Credits (e)	Balance at End of Year (f)
1	[(a)] Deferred Gas Exchange	1,406,250	495	5,625,000	5,625,000	1,406,250
2	Bills Pole Rentals	694,497	454	1,360,857	1,332,721	666,361
3	Defer Comp Active Execs	7,540,648	128	1,417,983	1,671,243	7,793,908
4	Unbilled Revenue	3,568,598	908	26,788,651	27,874,080	4,654,027
5	[(b)] Decoupling Deferred Credits	23,415,084	182, 456, 495	18,690,227	3,741,826	8,466,683
6	[(c)] Reg Liability-COVID-19 Deferral	7,749,100				7,749,100
7	[(d)] WA REC Deferrals	868,759	186, 431	1,107,117	238,358	
8	Misc. Deferred Credits	47,742	186, 903, 242	156,225	115,403	6,920
9	Timber Harvest	226,796				226,796
10	[(e)] Other Def Cr - FISERV	791,667	903	416,667	495,702	870,702
11	[(f)] Accts Pay - Software Licenses - LT	2,093,461	242	1,658,850	642,885	1,077,496
45	TOTAL	48,402,602		57,221,577	41,737,218	32,918,243

FOOTNOTE DATA

(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
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.
(c) 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.
(d) Concept: DescriptionOfOtherDeferredCredits
WA Docket UE-190334, Schedule 98.
(e) Concept: DescriptionOfOtherDeferredCredits
Other Deferred Credit-Fiserv
(f) Concept: DescriptionOfOtherDeferredCredits
Deferred Liability for Software Licenses

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Accumulated Deferred Income Taxes-Other Property (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to property not subject to accelerated amortization.
2. At Other (Specify), include deferrals relating to other income and deductions.
3. Provide in a footnote a summary of the type and amount of deferred income taxes reported in the beginning-of-year and end-of-year balances for deferred income taxes that the respondent estimates could be included in the development of jurisdictional recourse rates.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Changes During Year Amounts Debited to Account 410.1 (c)	Changes During Year Amounts Credited to Account 411.1 (d)	Changes During Year Amounts Debited to Account 410.2 (e)	Changes During Year Amounts Credited to Account 411.2 (f)	Adjustments Debits Account No. (g)	Adjustments Debits Amount (h)	Adjustments Credits Account No. (i)	Adjustments Credits Amount (j)	Balance at End of Year (k)
1	Account 282										
2	Electric	422,767,286	13,309,876	645,700			182.3	3,767,273			439,198,735
3	Gas	152,279,809	2,154,316	1,414,058			182.3	4,017,114			157,037,181
4	Other (Define)	61,774,590	(5,499,651)	167,210			182.3	876,225			56,983,954
5	Total (Total of lines 2 thru 4)	636,821,685	9,964,541	2,226,968				8,660,612		0	653,219,870
6	Other (Specify)	0									0
7	TOTAL Account 282 (Total of lines 5 thru 6)	636,821,685	9,964,541	2,226,968				8,660,612		0	653,219,870
8	Classification of TOTAL										
9	Federal Income Tax	636,821,685	9,964,541	2,226,968				8,660,612			653,219,870
10	State Income Tax	0									0
11	Local Income Tax	0									0

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ 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. At Other (Specify), include deferrals relating to other income and deductions.
3. Provide in a footnote a summary of the type and amount of deferred income taxes reported in the beginning-of-year and end-of-year balances for deferred income taxes that the respondent estimates could be included in the development of jurisdictional recourse rates.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Changes During Year Amounts Debited to Account 410.1 (c)	Changes During Year Amounts Credited to Account 411.1 (d)	Changes During Year Amounts Debited to Account 410.2 (e)	Changes During Year Amounts Credited to Account 411.2 (f)	Adjustments Debits Account No. (g)	Adjustments Debits Amount (h)	Adjustments Credits Account No. (i)	Adjustments Credits Amount (j)	Balance at End of Year (k)
1	Account 283										
2	Electric	46,111,868	5,624,777	796,200	96,298	19,353			182/254	861,711	50,155,679
3	Gas	29,349,984	129,174	8,267,349	1,093,165	4,840			182/254	166,602	22,133,532
4	Other (Define)	209,660,847	803,918	3,215,328	73,800				182/254	22,901,733	184,421,504
5	Total (Total of lines 2 thru 4)	285,122,699	6,557,869	12,278,877	1,263,263	24,193				23,930,046	256,710,715
6	Other (Specify)										
7	TOTAL Account 283 (Total of lines 5 thru 6)	285,122,699	6,557,869	12,278,877	1,263,263	24,193				23,930,046	256,710,715
8	Classification of TOTAL										
9	Federal Income Tax	285,122,699	6,557,869	12,278,877	1,263,263	24,193				23,930,046	256,710,715
10	State Income Tax										
11	Local Income Tax										

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Other Regulatory Liabilities (Account 254)

1. Report below the details called for concerning other regulatory liabilities which are created through the ratemaking actions of regulatory agencies (and not includable in other amounts).
2. For regulatory liabilities being amortized, show period of amortization in column (a).
3. Minor items (5% of the Balance at End of Year for Account 254 or amounts less than $250,000, whichever is less) may be grouped by classes.
4. Provide in a footnote, for each line item, the regulatory citation where the respondent was directed to refund the regulatory liability (e.g. Commission Order, state commission order, court decision).

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	Written off during Quarter/Period Account Credited (c)	Written off During Period Amount Refunded (d)	Written off During Period Amount Deemed Non-Refundable (e)	Credits (f)	Balance at End of Current Quarter/Year (g)
1	[a] Idaho Investment Tax Credit	10,038,667		2,933,191		0	7,105,476
2	[b] Interest Rate Swaps	24,204,062	427, 175	8,321,364		7,868,930	23,751,628
3	Nez Perce	462,284		22,008			440,276
4	Idaho Earnings Test	686,970		114,495			572,475
5	[c] Decoupling Rebate	8,378,370	495, 182	19,020,610		28,640,582	17,998,342
6	[d] WA ERM	5,269,902		5,269,902		0	0
7	[e] Deferred Federal ITC - Varies	7,538,104		333,802		0	7,204,302
8	[f] Plant Excess Deferred	323,181,031		21,561,802		0	301,619,229
9	Reg Liability MDM System	678,843		678,843		0	0
10	[g] DSM Tariff Rider	11,581,998	182, 431, 908	17,700,901		11,105,947	4,987,044
11	[h] Low Income Energy Assistance	7,940,357	242, 908	28,801,667		26,595,334	5,734,024
12	[i] Reg Liability - OR Tax Strategy Deferral	1,283,006	254, 407	757,068		43,628	569,566
13	[j] Reg Liability - Tax Reform Amortization	184,460	407, 431	50,873		5,718	139,305
14	[k] Reg Liability - WA Rev Def of Power Supply	971,669		990,053		18,384	0
15	[l] Reg Liability - Energy Efficiency Assistance	986,890	254	285,347		13,055	714,598
16	[m] Reg Liability - COVID-19 Deferral	4,124,859	254, 407	1,718,235		400,750	2,807,374
17	[n] Reg Liability - Tax Customer Credit	107,138,114	190, 410	60,737,909		9,853,658	56,253,863
18	[o] CS2 Insurance Proceeds Deferral	804,403	254	0		62,834	867,237
19	[p] Regulatory Liabilities - Other	9,869,668	190	0		1,277,935	11,147,603
20	[q] Reg Liability - CCA	0	254	0		37,231,122	37,231,122
21	[r] Insurance Balancing Account	0	182, 407	14,256		29,110	14,854
22	Misc. Regulatory Liabilities	85,888	143, 411	1,571,925		1,561,634	75,597
45	Total	525,409,545		170,884,251	0	124,708,621	479,233,915

FOOTNOTE DATA

(a) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Not amortized.

(b) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Mark-to-Market gains and losses for interest rate swap derivatives. Upon settlement, amortization or 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

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

(h) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

WA Docket No UE-190912, UG-190920

ID Docket No AVU-E-18-12, AVU-G-18-08

OR RG 81, Docket No ADV 1063 (Advice No. 19-10-G)

(i) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

OR Docket No UM 2124. Deferral of associated state tax savings.

(j) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

WA Docket No. UG-170486

ID Docket No. AVU-E-23-01

(k) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Deferred liability for over-collection of authorized power supply cost revenue from Washington retail customers.

(l) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Avista's contribution in the Energy Assistance Fund as per ID Settlement Stipulation Case # AVU-E-19-04

(m) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

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

(n) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

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

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

(o) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Insurance proceeds for failed transformer at Coyote Springs per WA Order UE-210893 Order 01.

(p) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

State inome tax NOL carryforward will reverse over the period in which we are able to utilize the loss to offset taxable income on the ID, MT, and OR tax returns.

(q) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

To defer costs of compliance with the Climate Commitment Act in accordance with WAC 480-100-203(3) and WAC 480-90-203(3). WA Docket No UG-220803.

(r) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

To defer costs above or below the baseline in accordance with Order No 10/04 Docket Nos UE-220053, UE-210854, and UG-220054.

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Gas Operating Revenues

1. Report below natural gas operating revenues for each prescribed account total. The amounts must be consistent with the detailed data on succeeding pages.
2. Revenues in columns (b) and (c) include transition costs from upstream pipelines.
3. Other Revenues in columns (f) and (g) include reservation charges received by the pipeline plus usage charges, less revenues reflected in columns (b) through (e). Include in columns (f) and (g) revenues for Accounts 480-495.
4. If increases or decreases from previous year are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. On Page 108, include information on major changes during the year, new service, and important rate increases or decreases.
6. Report the revenue from transportation services that are bundled with storage services as transportation service revenue.

Line No.	Title of Account (a)	Revenues for Transition Costs and Take-or-Pay Amount for Current Year (b)	Revenues for Transaction Costs and Take-or-Pay Amount for Previous Year (c)	Revenues for GRI and ACA Amount for Current Year (d)	Revenues for GRI and ACA Amount for Previous Year (e)	Other Revenues Amount for Current Year (f)	Other Revenues Amount for Previous Year (g)	Total Operating Revenues Amount for Current Year (h)	Total Operating Revenues Amount for Previous Year (i)	Dekatherm of Natural Gas Amount for Current Year (j)	Dekatherm of Natural Gas Amount for Previous Year (k)
1	(480) Residential Sales					325,631,612	284,451,821	325,631,612	284,451,821	22,566,453	24,245,248
2	(481) Commercial and Industrial Sales					181,362,883	150,394,400	181,362,883	150,394,400	16,379,078	16,683,100
3	(482) Other Sales to Public Authorities					0	0	0	0	0	0
4	(483) Sales for Resale					68,247,032	136,750,007	68,247,032	136,750,007	27,083,664	28,525,973
5	(484) Interdepartmental Sales					441,326	506,375	441,326	506,375	41,323	61,769
6	(485) Intracompany Transfers					0	0	0	0		
7	(487) Forfeited Discounts					0	0	0	0		
8	(488) Miscellaneous Service Revenues					67,247	31,750	67,247	31,750		
9	(489.1) Revenues from Transportation of Gas of Others Through Gathering Facilities					0	0	0	0	0	0
10	(489.2) Revenues from Transportation of Gas of Others Through Transmission Facilities					0	0	0	0	0	0
11	(489.3) Revenues from Transportation of Gas of Others Through Distribution Facilities					8,171,615	8,627,257	8,171,615	8,627,257	17,475,829	17,933,683
12	(489.4) Revenues from Storing Gas of Others					0	0	0	0	0	0
13	(490) Sales of Prod. Ext. from Natural Gas					0	0	0	0		
14	(491) Revenues from Natural Gas Proc. by Others					0	0	0	0		
15	(492) Incidental Gasoline and Oil Sales					0	0	0	0		
16	(493) Rent from Gas Property					12,000	11,791	12,000	11,791		
17	(494) Interdepartmental Rents					0	0	0	0		
18	(495) Other Gas Revenues					35,532,787	4,939,464	35,532,787	4,939,464		
19	Subtotal:	0	0	0	0	619,466,502	585,712,865	619,466,502	585,712,865		
20	(496) (Less) Provision for Rate Refunds					0	0	0	0		
21	TOTAL	0	0	0	0	619,466,502	585,712,865	619,466,502	585,712,865		

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Other Gas Revenues (Account 495)

Report below transactions of $250,000 or more included in Account 495, Other Gas Revenues. Group all transactions below $250,000 in one amount and provide the number of items.

Line No.	Description of Transaction (a)	Amount (in dollars) (b)
1	Commissions on Sale or Distribution of Gas of Others	
2	Compensation for Minor or Incidental Services Provided for Others	
3	Profit or Loss on Sale of Material and Supplies not Ordinarily Purchased for Resale	
4	Sales of Stream, Water, or Electricity, including Sales or Transfers to Other Departments	
5	Miscellaneous Royalties	
6	Revenues from Dehydration and Other Processing of Gas of Others except as provided for in the Instructions to Account 495	
7	Revenues for Right and/or Benefits Received from Others which are Realized Through Research, Development, and Demonstration Ventures	
8	Gains on Settlements of Imbalance Receivables and Payables	
9	Revenues from Penalties earned Pursuant to Tariff Provisions, including Penalties Associated with Cash-out Settlements	
10	Revenues from Shipper Supplied Gas	
11	Other revenues (Specify):	
12	Misc Bills Revenue	470,863
13	CCA Allowance Revenue	36,896,188
14	Deferred Exchange Revenue	5,625,000
15	Deferred Decoupling Revenue	(7,520,456)
40	TOTAL	35,471,595

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Gas Operation and Maintenance Expenses

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. PRODUCTION EXPENSES		
2	A. Manufactured Gas Production		
3	Manufactured Gas Production (Submit Supplemental Statement)		
4	B. Natural Gas Production		
5	B1. Natural Gas Production and Gathering		
6	Operation		
7	750 Operation Supervision and Engineering	0	0
8	751 Production Maps and Records	0	0
9	752 Gas Well Expenses	0	0
10	753 Field Lines Expenses	0	0
11	754 Field Compressor Station Expenses	0	0
12	755 Field Compressor Station Fuel and Power	0	0
13	756 Field Measuring and Regulating Station Expenses	0	0
14	757 Purification Expenses	0	0
15	758 Gas Well Royalties	0	0
16	759 Other Expenses	0	0
17	760 Rents	0	0
18	TOTAL Operation (Total of lines 7 thru 17)	0	0
19	Maintenance		
20	761 Maintenance Supervision and Engineering	0	0
21	762 Maintenance of Structures and Improvements	0	0
22	763 Maintenance of Producing Gas Wells	0	0
23	764 Maintenance of Field Lines	0	0
24	765 Maintenance of Field Compressor Station Equipment	0	0
25	766 Maintenance of Field Measuring and Regulating Station Equipment	0	0
26	767 Maintenance of Purification Equipment	0	0
27	768 Maintenance of Drilling and Cleaning Equipment	0	0
28	769 Maintenance of Other Equipment	0	0
29	TOTAL Maintenance (Total of lines 20 thru 28)	0	0
30	TOTAL Natural Gas Production and Gathering (Total of lines 18 and 29)	0	0
31	B2. Products Extraction		
32	Operation		
33	770 Operation Supervision and Engineering	0	0
34	771 Operation Labor	0	0
35	772 Gas Shrinkage	0	0
36	773 Fuel	0	0
37	774 Power	0	0
38	775 Materials	0	0
39	776 Operation Supplies and Expenses	0	0
40	777 Gas Processed by Others	0	0
41	778 Royalties on Products Extracted	0	0
42	779 Marketing Expenses	0	0
43	780 Products Purchased for Resale	0	0
44	781 Variation in Products Inventory	0	0
45	(Less) 782 Extracted Products Used by the Utility-Credit	0	0
46	783 Rents	0	0
47	TOTAL Operation (Total of lines 33 thru 46)	0	0
48	Maintenance		
49	784 Maintenance Supervision and Engineering	0	0
50	785 Maintenance of Structures and Improvements	0	0
51	786 Maintenance of Extraction and Refining Equipment	0	0
52	787 Maintenance of Pipe Lines	0	0
53	788 Maintenance of Extracted Products Storage Equipment	0	0

54	789 Maintenance of Compressor Equipment	0	0
55	790 Maintenance of Gas Measuring and Regulating Equipment	0	0
56	791 Maintenance of Other Equipment	0	0
57	TOTAL Maintenance (Total of lines 49 thru 56)	0	0
58	TOTAL Products Extraction (Total of lines 47 and 57)	0	0
59	C. Exploration and Development		
60	Operation		
61	795 Delay Rentals	0	0
62	796 Nonproductive Well Drilling	0	0
63	797 Abandoned Leases	0	0
64	798 Other Exploration	0	0
65	TOTAL Exploration and Development (Total of lines 61 thru 64)	0	0
66	D. Other Gas Supply Expenses		
67	Operation		
68	800 Natural Gas Well Head Purchases	0	0
69	800.1 Natural Gas Well Head Purchases, Intracompany Transfers	0	0
70	801 Natural Gas Field Line Purchases	0	0
71	802 Natural Gas Gasoline Plant Outlet Purchases	0	0
72	803 Natural Gas Transmission Line Purchases	0	0
73	804 Natural Gas City Gate Purchases	287,111,521	360,823,227
74	804.1 Liquefied Natural Gas Purchases	0	0
75	805 Other Gas Purchases	0	0
76	(Less) 805.1 Purchases Gas Cost Adjustments	(5,546,259)	29,908,569
77	TOTAL Purchased Gas (Total of lines 68 thru 76)	292,657,780	330,914,658
78	806 Exchange Gas	0	0
79	Purchased Gas Expenses		
80	807.1 Well Expense-Purchased Gas	0	0
81	807.2 Operation of Purchased Gas Measuring Stations	0	0
82	807.3 Maintenance of Purchased Gas Measuring Stations	0	0
83	807.4 Purchased Gas Calculations Expenses	0	0
84	807.5 Other Purchased Gas Expenses	0	0
85	TOTAL Purchased Gas Expenses (Total of lines 80 thru 84)	0	0
86	808.1 Gas Withdrawn from Storage-Debit	36,449,990	47,412,672
87	(Less) 808.2 Gas Delivered to Storage-Credit	25,933,582	56,596,703
88	809.1 Withdrawals of Liquefied Natural Gas for Processing-Debit	0	0
89	(Less) 809.2 Deliveries of Natural Gas for Processing-Credit	0	0
90	Gas used in Utility Operation-Credit		
91	810 Gas Used for Compressor Station Fuel-Credit	0	0
92	811 Gas Used for Products Extraction-Credit	597,452	1,153,772
93	812 Gas Used for Other Utility Operations-Credit	0	0
94	TOTAL Gas Used in Utility Operations-Credit (Total of lines 91 thru 93)	597,452	1,153,772
95	813 Other Gas Supply Expenses	46,258,884	1,796,463
96	TOTAL Other Gas Supply Exp. (Total of lines 77,78,85,86 thru 89,94,95)	348,835,620	322,373,318
97	TOTAL Production Expenses (Total of lines 3, 30, 58, 65, and 96)	348,835,620	322,373,318
98	2. NATURAL GAS STORAGE, TERMINALING AND PROCESSING EXPENSES		
99	A. Underground Storage Expenses		
100	Operation		
101	814 Operation Supervision and Engineering	0	(3)
102	815 Maps and Records	0	0
103	816 Wells Expenses	0	0
104	817 Lines Expense	0	0
105	818 Compressor Station Expenses	0	0
106	819 Compressor Station Fuel and Power	0	0
107	820 Measuring and Regulating Station Expenses	0	0
108	821 Purification Expenses	0	0
109	822 Exploration and Development	0	0
110	823 Gas Losses	0	0
111	824 Other Expenses	1,035,406	931,044

112	825 Storage Well Royalties	0	0
113	826 Rents	0	0
114	TOTAL Operation (Total of lines of 101 thru 113)	1,035,406	931,041
115	Maintenance		
116	830 Maintenance Supervision and Engineering	0	0
117	831 Maintenance of Structures and Improvements	0	0
118	832 Maintenance of Reservoirs and Wells	0	0
119	833 Maintenance of Lines	0	0
120	834 Maintenance of Compressor Station Equipment	0	0
121	835 Maintenance of Measuring and Regulating Station Equipment	0	0
122	836 Maintenance of Purification Equipment	0	0
123	837 Maintenance of Other Equipment	2,107,953	2,253,989
124	TOTAL Maintenance (Total of lines 116 thru 123)	2,107,953	2,253,989
125	TOTAL Underground Storage Expenses (Total of lines 114 and 124)	3,143,359	3,185,030
126	B. Other Storage Expenses		
127	Operation		
128	840 Operation Supervision and Engineering	0	0
129	841 Operation Labor and Expenses	0	0
130	842 Rents	0	0
131	842.1 Fuel	0	0
132	842.2 Power	0	0
133	842.3 Gas Losses	0	0
134	TOTAL Operation (Total of lines 128 thru 133)	0	0
135	Maintenance		
136	843.1 Maintenance Supervision and Engineering	0	0
137	843.2 Maintenance of Structures	0	0
138	843.3 Maintenance of Gas Holders	0	0
139	843.4 Maintenance of Purification Equipment	0	0
140	843.5 Maintenance of Liquefaction Equipment	0	0
141	843.6 Maintenance of Vaporizing Equipment	0	0
142	843.7 Maintenance of Compressor Equipment	0	0
143	843.8 Maintenance of Measuring and Regulating Equipment	0	0
144	843.9 Maintenance of Other Equipment	0	0
145	TOTAL Maintenance (Total of lines 136 thru 144)	0	0
146	TOTAL Other Storage Expenses (Total of lines 134 and 145)	0	0
147	C. Liquefied Natural Gas Terminaling and Processing Expenses		
148	Operation		
149	844.1 Operation Supervision and Engineering	0	0
150	844.2 LNG Processing Terminal Labor and Expenses	0	0
151	844.3 Liquefaction Processing Labor and Expenses	0	0
152	844.4 Liquefaction Transportation Labor and Expenses	0	0
153	844.5 Measuring and Regulating Labor and Expenses	0	0
154	844.6 Compressor Station Labor and Expenses	0	0
155	844.7 Communication System Expenses	0	0
156	844.8 System Control and Load Dispatching	0	0
157	845.1 Fuel	0	0
158	845.2 Power	0	0
159	845.3 Rents	0	0
160	845.4 Demurrage Charges	0	0
161	(less) 845.5 Wharfage Receipts-Credit	0	0
162	845.6 Processing Liquefied or Vaporized Gas by Others	0	0
163	846.1 Gas Losses	0	0
164	846.2 Other Expenses	0	0
165	TOTAL Operation (Total of lines 149 thru 164)	0	0
166	Maintenance		
167	847.1 Maintenance Supervision and Engineering	0	0
168	847.2 Maintenance of Structures and Improvements	0	0
169	847.3 Maintenance of LNG Processing Terminal Equipment	0	0

170	847.4 Maintenance of LNG Transportation Equipment	0	0
171	847.5 Maintenance of Measuring and Regulating Equipment	0	0
172	847.6 Maintenance of Compressor Station Equipment	0	0
173	847.7 Maintenance of Communication Equipment	0	0
174	847.8 Maintenance of Other Equipment	0	0
175	TOTAL Maintenance (Total of lines 167 thru 174)	0	0
176	TOTAL Liquefied Nat Gas Terminaling and Proc Exp (Total of lines 165 and 175)	0	0
177	TOTAL Natural Gas Storage (Total of lines 125, 146, and 176)	3,143,359	3,185,030
178	3. TRANSMISSION EXPENSES		
179	Operation		
180	850 Operation Supervision and Engineering	0	0
181	851 System Control and Load Dispatching	0	0
182	852 Communication System Expenses	0	0
183	853 Compressor Station Labor and Expenses	0	0
184	854 Gas for Compressor Station Fuel	0	0
185	855 Other Fuel and Power for Compressor Stations	0	0
186	856 Mains Expenses	0	0
187	857 Measuring and Regulating Station Expenses	0	0
188	858 Transmission and Compression of Gas by Others	0	0
189	859 Other Expenses	0	0
190	860 Rents	0	0
191	TOTAL Operation (Total of lines 180 thru 190)	0	0
192	Maintenance		
193	861 Maintenance Supervision and Engineering	0	0
194	862 Maintenance of Structures and Improvements	0	0
195	863 Maintenance of Mains	0	0
196	864 Maintenance of Compressor Station Equipment	0	0
197	865 Maintenance of Measuring and Regulating Station Equipment	0	0
198	866 Maintenance of Communication Equipment	0	0
199	867 Maintenance of Other Equipment	0	0
200	TOTAL Maintenance (Total of lines 193 thru 199)	0	0
201	TOTAL Transmission Expenses (Total of lines 191 and 200)	0	0
202	4. DISTRIBUTION EXPENSES		
203	Operation		
204	870 Operation Supervision and Engineering	3,333,244	3,506,427
205	871 Distribution Load Dispatching	0	0
206	872 Compressor Station Labor and Expenses	0	0
207	873 Compressor Station Fuel and Power	0	0
208	874 Mains and Services Expenses	10,210,439	6,833,128
209	875 Measuring and Regulating Station Expenses-General	253,322	321,528
210	876 Measuring and Regulating Station Expenses-Industrial	20,590	7,256
211	877 Measuring and Regulating Station Expenses-City Gas Check Station	91,988	74,155
212	878 Meter and House Regulator Expenses	739,668	1,016,919
213	879 Customer Installations Expenses	9,861,398	3,207,078
214	880 Other Expenses	5,244,257	3,283,339
215	881 Rents	(1,461)	(10,147)
216	TOTAL Operation (Total of lines 204 thru 215)	29,753,445	18,239,683
217	Maintenance		
218	885 Maintenance Supervision and Engineering	96,313	66,321
219	886 Maintenance of Structures and Improvements	0	0
220	887 Maintenance of Mains	1,670,494	2,119,174
221	888 Maintenance of Compressor Station Equipment	0	0
222	889 Maintenance of Measuring and Regulating Station Equipment-General	650,541	719,497
223	890 Maintenance of Meas. and Reg. Station Equipment-Industrial	60,613	59,278
224	891 Maintenance of Meas. and Reg. Station Equip-City Gate Check Station	145,290	202,013
225	892 Maintenance of Services	1,897,884	2,159,017
226	893 Maintenance of Meters and House Regulators	2,469,855	3,028,150
227	894 Maintenance of Other Equipment	631,912	422,064

228	TOTAL Maintenance (Total of lines 218 thru 227)	7,622,902	8,775,514
229	TOTAL Distribution Expenses (Total of lines 216 and 228)	37,376,347	27,015,197
230	5. CUSTOMER ACCOUNTS EXPENSES		
231	Operation		
232	901 Supervision	124,466	119,956
233	902 Meter Reading Expenses	613,160	724,640
234	903 Customer Records and Collection Expenses	8,017,053	7,698,054
235	904 Uncollectible Accounts	1,747,971	20,023
236	905 Miscellaneous Customer Accounts Expenses	255,262	238,056
237	TOTAL Customer Accounts Expenses (Total of lines 232 thru 236)	10,757,912	8,800,729
238	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
239	Operation		
240	907 Supervision	0	0
241	908 Customer Assistance Expenses	22,364,969	20,063,471
242	909 Informational and Instructional Expenses	786,208	882,657
243	910 Miscellaneous Customer Service and Informational Expenses	210,546	114,436
244	TOTAL Customer Service and Information Expenses (Total of lines 240 thru 243)	23,361,723	21,060,564
245	7. SALES EXPENSES		
246	Operation		
247	911 Supervision	0	0
248	912 Demonstrating and Selling Expenses	260	0
249	913 Advertising Expenses	0	0
250	916 Miscellaneous Sales Expenses	(5)	431
251	TOTAL Sales Expenses (Total of lines 247 thru 250)	255	431
252	8. ADMINISTRATIVE AND GENERAL EXPENSES		
253	Operation		
254	920 Administrative and General Salaries	13,189,888	12,185,266
255	921 Office Supplies and Expenses	1,667,382	1,751,120
256	(Less) 922 Administrative Expenses Transferred-Credit	19,248	17,277
257	923 Outside Services Employed	6,089,644	5,477,135
258	924 Property Insurance	964,898	811,113
259	925 Injuries and Damages	2,758,757	2,472,303
260	926 Employee Pensions and Benefits	11,106,187	13,942,568
261	927 Franchise Requirements	0	0
262	928 Regulatory Commission Expenses	2,834,410	2,037,288
263	(Less) 929 Duplicate Charges-Credit	0	0
264	930.1General Advertising Expenses	15	(5,308)
265	930.2Miscellaneous General Expenses	2,496,206	2,387,723
266	931 Rents	215,230	173,076
267	TOTAL Operation (Total of lines 254 thru 266)	41,303,369	41,215,007
268	Maintenance		
269	932 Maintenance of General Plant	5,542,623	5,744,286
270	TOTAL Administrative and General Expenses (Total of lines 267 and 269)	46,845,992	46,959,293
271	TOTAL Gas O&M Expenses (Total of lines 97,177,201,229,237,244,251, and 270)	470,321,208	429,394,562

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Gas Used in Utility Operations

1. Report below details of credits during the year to Accounts 810, 811, and 812.
2. If any natural gas was used by the respondent for which a charge was not made to the appropriate operating expense or other account, list separately in column (c) the Dth of gas used, omitting entries in column (d).

Line No.	Purpose for Which Gas Was Used (a)	Account Charged (b)	Natural Gas Gas Used Dth (c)	Natural Gas Amount of Credit (in dollars) (d)
1	810 Gas Used for Compressor Station Fuel - Credit		1,905,858	0
2	811 Gas Used for Products Extraction - Credit		[a]39,381,019	597,452
3	Gas Shrinkage and Other Usage in Respondent's Own Processing - Credit			
4	Gas Shrinkage, etc. for Respondent's Gas Processed by Others - Credit			
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25	Total		41,286,877	597,452

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: QuantityOfNaturalGasDeliveredByRespondentGasUsedForProductsExtraction
Represents the amount of processed gas run through the plant.

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Other Gas Supply Expenses (Account 813)

1. Report other gas supply expenses by descriptive titles that clearly indicate the nature of such expenses. Show maintenance expenses, revaluation of monthly encroachments recorded in Account 117.4, and losses on settlements of imbalances and gas losses not associated with storage separately. Indicate the functional classification and purpose of property to which any expenses relate. List separately items of $250,000 or more.

Line No.	Description (a)	Amount (in dollars) (b)
1	Gas Resource Management Labor	1,176,409
2	Gas Resource Management Overhead	294,444
3	Gas Resource Management Other Expenses (professional services, travel, transportation, supplies, training)	165,000
4	Regulatory Affairs Other Expenses (Gas Technical Institute)	179,147
5	Climate Commitment Act Obligations	44,443,884
25	Total	46,258,884

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Miscellaneous General Expenses (Account 930.2)

1. Provide the information requested below on miscellaneous general expenses.
2. For Other Expenses, show the (a) purpose, (b) recipient and (c) amount of such items. List separately amounts of $250,000 or more however, amounts less than $250,000 may be grouped if the number of items of so grouped is shown.

Line No.	Description (a)	Amount (b)
1	Industry association dues.	611,891
2	Experimental and general research expenses	
2a	a. Gas Research Institute (GRI)	
2b	b. Other	
3	Publishing and distributing information and reports to stockholders, trustee, registrar, and transfer agent fees and expenses, and other expenses of servicing outstanding securities of the respondent	293,643
4	Board of Director Activities	749,459
5	Education, Information & Training	288,552
6	Community Relations	215,113
7	Misc Employee Expenses	47,719
8	Misc Legal, Professional & General Services	78,810
9	Misc Transportation	82,848
10	Other Misc Expenses <$5,000	2,635
11	Misc. Labor	125,536
25	TOTAL	2,496,206

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Depreciation, Depletion and Amortization of Gas Plant (Accts 403, 404.1, 404.2, 404.3, 405) (Except Amortization of Acquisition Adjustments)

1. Report in Section A the amounts of depreciation expense, depletion and amortization for the accounts indicated and classified according to the plant functional groups shown.
2. Report in Section B, column (b) all depreciable or amortizable plant balances to which rates are applied and show a composite total. (If more desirable, report by plant account, subaccount or functional classifications other than those pre-printed in column (a). Indicate in a footnote the manner in which column (b) balances are obtained. If average balances are used, state the method of averaging used. For column (c) report available information for each plant functional classification listed in column (a). If composite depreciation accounting is used, report available information called for in columns (b) and (c) on this basis. Where the unit-of-production method is used to determine depreciation charges, show in a footnote any revisions made to estimated gas reserves.
3. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state in a footnote the amounts and nature of the provisions and the plant items to which related.
4. Add rows as necessary to completely report all data. Number the additional rows in sequence as 2.01, 2.02, 3.01, 3.02, etc.

Section A. Summary of Depreciation, Depletion, and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Amortization Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization and Depletion of Producing Natural Gas Land and Land Rights (Account 404.1) (d)	Amortization of Underground Storage Land and Land Rights (Account 404.2) (e)	Amortization of Other Limited-term Gas Plant (Account 404.3) (f)	Amortization of Other Gas Plant (Account 405) (g)	Total (b to g) (h)
1	Intangible plant					260,280		260,280
2	Production plant, manufactured gas							
3	Production and Gathering Plant							
4	Products extraction plant							
5	Underground Gas Storage Plant (footnote details)	896,739						896,739
6	Other storage plant							
7	Base load LNG terminaling and processing plant							
8	Transmission Plant							
9	Distribution plant	35,293,681						35,293,681
10	General Plant (footnote details)	1,709,189						1,709,189
11	Common plant-gas	7,439,661				15,241,072		22,680,733
12	Total	45,339,270				15,501,352		60,840,622

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Depreciation, Depletion and Amortization of Gas Plant (Accts 403, 404.1, 404.2, 404.3, 405) (Except Amortization of Acquisition Adjustments)

1. Report in Section A the amounts of depreciation expense, depletion and amortization for the accounts indicated and classified according to the plant functional groups shown.
2. Report in Section B, column (b) all depreciable or amortizable plant balances to which rates are applied and show a composite total. (If more desirable, report by plant account, subaccount or functional classifications other than those pre-printed in column (a). Indicate in a footnote the manner in which column (b) balances are obtained. If average balances are used, state the method of averaging used. For column (c) report available information for each plant functional classification listed in column (a). If composite depreciation accounting is used, report available information called for in columns (b) and (c) on this basis. Where the unit-of-production method is used to determine depreciation charges, show in a footnote any revisions made to estimated gas reserves.
3. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state in a footnote the amounts and nature of the provisions and the plant items to which related.
4. Add rows as necessary to completely report all data. Number the additional rows in sequence as 2.01, 2.02, 3.01, 3.02, etc.

Section B. Factors Used in Estimating Depreciation Charges

Line No.	Functional Classification (a)	Plant Bases (in thousands) (b)	Applied Depreciation or Amortization Rates (percent) (c)
1	Production and Gathering Plant		
2	Offshore (footnote details)		
3	Onshore (footnote details)		
4	Underground Gas Storage Plant (footnote details)		
5	Transmission Plant		
6	Offshore (footnote details)		
7	Onshore (footnote details)		
8	General Plant (footnote details)		
9			
10			
11			
12			
13			
14			
15			

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Particulars Concerning Certain Income Deductions and Interest Charges Accounts

Report the information specified below, in the order given, for the respective income deduction and interest charges accounts.

a. Miscellaneous Amortization (Account 425)-Describe the nature of items included in this account, the contra account charged, the total of amortization charges for the year, and the period of amortization.
b. Miscellaneous Income Deductions-Report the nature, payee, and amount of other income deductions for the year as required by Accounts 426.1, Donations; 426.2, Life Insurance; 426.3, Penalties; 426.4, Expenditures for Certain Civic, Political and Related Activities; and 426.5, Other Deductions, of the Uniform System of Accounts. Amounts of less than $250,000 may be grouped by classes within the above accounts.
c. Interest on Debt to Associated Companies (Account 430)-For each associated company that incurred interest on debt during the year, indicate the amount and interest rate respectively for (a) advances on notes, (b) advances on open account, (c) notes payable, (d) accounts payable, and (e) other debt, and total interest. Explain the nature of other debt on which interest was incurred during the year.
d. Other Interest Expense (Account 431) - Report details including the amount and interest rate for other interest charges incurred during the year.

Line No.	Item (a)	Amount (b)
1	Account 425 - Miscellaneous Amortization	
2	Items under $250,000	5,616
3	TOTAL Account 425 - Miscellaneous Amortization	5,616
4	Account 426.1 - Donations	
5	Items under $250,000	2,755,476
6	TOTAL Account 426.1 - Donations	2,755,476
7	Account 426.2 - Life Insurance	
8	Officers Life Insurance	156,937
9	SERP	2,009,654
10	Officer Life cash value and interest - net	386,254
11	Items Under $250,000	108,219
12	TOTAL Account 426.2 - Life Insurance	2,661,064
13	Account 426.3 - Penalties	
14	Items Under $250,000	25,450
15	TOTAL Account 426.3 - Penalties	25,450
16	Account 426.4 Expenditures for Certain Civic, Political, and Related Activities	
17	Items Under $250,000	1,775,518
18	Total Account 426.4 - Expenditues for Certain Civic, Political, and Related Activities	1,775,518
19	Account 426.5 - Other Deductions	
20	Executive Deferred Compensation	472,330
21	Items Under $250,000	937,971
22	TOTAL Account 426.5 - Other Deductions	1,410,301
23	Account 430 - Interest on Debt to Associated Companies	
24	Avista Capital II (Long Term Debt) (Variable rate ranged from 5.64 to 6.55 percent)	2,503,671
25	TOTAL Account 430 - Interest on Debt to Associated Companies	2,503,671
26	Account 431 - Other Interest Expense	
27	Interest on Electric Deferrals	2,087,182
28	Interest on Natural Gas Deferrals	1,245,416
29	Interest on ST Borrowings	17,947,850
30	Interest on South Lake CDA	(354,295)
31	Interest on Transmissions Deposits	451,984
32	Items under $250,000	57,470
33	TOTAL Account 431 - Other Interest Expense	21,435,607

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Regulatory Commission Expenses (Account 928)

1. Report below details of regulatory commission expenses incurred during the current year (or in previous years, if being amortized) relating to formal cases before a regulatory body, or cases in which such a body was a party.
2. In column (b) and (c), indicate whether the expenses were assessed by a regulatory body or were otherwise incurred by the utility.
3. Show in column (k) any expenses incurred in prior years that are being amortized. List in column (a) the period of amortization.
4. Identify separately all annual charge adjustments (ACA).
5. List in column (f), (g), and (h) expenses incurred during year which were charges currently to income, plant, or other accounts.
6. Minor items (less than $250,000) may be grouped.

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 to Date (d)	Deferred in Account 182.3 at Beginning of Year (e)	Expenses Incurred During Year Charged Currently To Department (f)	Expenses Incurred During Year Charged Currently To Account No. (g)	Expenses Incurred During Year Charged Currently To Amount (h)	Expenses Incurred During Year Deferred to Account 182.3 (i)	Amortized During Year Contra Account (j)	Amortized During Year 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	3,651,398	200,949	3,852,347		Electric	928	3,852,347				0
2	Washington Utilities and Transportation Commission			0								0
3	Electric - Includes annual fee and various other electric dockets	2,376,954	488,941	2,865,895		Electric	928	2,865,895	1,264,383	407		1,264,383
4	Gas - Includes annual fee and various other natural gas dockets	887,457	143,367	1,030,824		Gas	928	1,030,824	571,217	407		571,217
5	Idaho Public Utilities Commission			0								0
6	Electric - Includes annual fee and various other electric dockets	578,031	312,522	890,553		Electric	928	890,553				0
7	Gas - Includes annual fee and various other natural gas dockets	179,872	71,625	251,497		Gas	928	251,497				0
8	Public Utility Commission of Oregon			0								0
9	Includes annual fees and various other natural gas dockets	903,979	306,869	1,210,848	98,369	Gas	928	1,210,848	100,648	407	119,201	79,816
10	Not directly assigned Electric		778,751	778,751		Electric	928	778,751				0
11	Not directly assigned Natural Gas		341,241	341,241		Gas	928	341,241				0
25	TOTAL	8,577,691	2,644,265	11,221,956	98,369			11,221,956	1,936,248		119,201	1,915,416

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Employee Pensions and Benefits (Account 926)

1. Report below the items contained in Account 926, Employee Pensions and Benefits.

Line No.	Expense (a)	Amount (in dollars) (b)
1	Pensions - defined benefit plans	9,327,324
2	Pensions - other	
3	Post-retirement benefits other than pensions (PBOP)	4,464,398
4	Post-employment benefit plans	
5	Health Insurance and Benefits	33,752,657
6	401(K) Savings Plan	15,716,073
7	Employee Education	1,965,811
8	Other	763,401
9	Allocated to Electric and other expense accounts	(54,883,477)
40	Total	11,106,187

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ 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. Salaries and wages billed to the Respondent by an affiliated company must be assigned to the particular operating function(s) relating to the expenses.

In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used. When reporting detail of other accounts, enter as many rows as necessary numbered sequentially starting with 75.01, 75.02, etc.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Payroll Billed by Affiliated Companies (c)	Allocation of Payroll Charged for Clearing Accounts (d)	Total (e)
1	Electric				
2	Operation				
3	Production	15,180,372			15,180,372
4	Transmission	5,610,502			5,610,502
5	Distribution	12,299,941			12,299,941
6	Customer Accounts	6,507,117			6,507,117
7	Customer Service and Informational	422,600			422,600
8	Sales	0			0
9	Administrative and General	29,427,473		9,629,046	39,056,519
10	TOTAL Operation (Total of lines 3 thru 9)	69,448,005		9,629,046	79,077,051
11	Maintenance				
12	Production	4,713,472			4,713,472
13	Transmission	1,001,293			1,001,293
14	Distribution	4,725,477			4,725,477
15	Administrative and General	0			0
16	TOTAL Maintenance (Total of lines 12 thru 15)	10,440,242			10,440,242
17	Total Operation and Maintenance				
18	Production (Total of lines 3 and 12)	19,893,844			19,893,844
19	Transmission (Total of lines 4 and 13)	6,611,795			6,611,795
20	Distribution (Total of lines 5 and 14)	17,025,418			17,025,418
21	Customer Accounts (line 6)	6,507,117			6,507,117
22	Customer Service and Informational (line 7)	422,600			422,600
23	Sales (line 8)	0			0
24	Administrative and General (Total of lines 9 and 15)	29,427,473		9,629,046	39,056,519
25	TOTAL Operation and Maintenance (Total of lines 18 thru 24)	79,888,247		9,629,046	89,517,293
26	Gas				
27	Operation				
28	Production - Manufactured Gas				
29	Production - Natural Gas(Including Exploration and Development)				
30	Other Gas Supply	1,176,409			1,176,409
31	Storage, LNG Terminaling and Processing				
32	Transmission				0
33	Distribution	9,858,961			9,858,961
34	Customer Accounts	3,088,460			3,088,460
35	Customer Service and Informational	288,019			288,019
36	Sales				
37	Administrative and General	11,927,195		2,737,908	14,665,103
38	TOTAL Operation (Total of lines 28 thru 37)	26,339,044		2,737,908	29,076,952
39	Maintenance				
40	Production - Manufactured Gas				
41	Production - Natural Gas(Including Exploration and Development)				
42	Other Gas Supply				0
43	Storage, LNG Terminaling and Processing				
44	Transmission	2,433,655			2,433,655
45	Distribution	3,689,066			3,689,066
46	Administrative and General				0
47	TOTAL Maintenance (Total of lines 40 thru 46)	6,122,721			6,122,721

49	Total Operation and Maintenance				
50	Production - Manufactured Gas (Total of lines 28 and 40)				
51	Production - Natural Gas (Including Expl. and Dev.) (ll. 29 and 41)				
52	Other Gas Supply (Total of lines 30 and 42)	1,176,409			1,176,409
53	Storage, LNG Terminaling and Processing (Total of ll. 31 and 43)				
54	Transmission (Total of lines 32 and 44)	2,433,655			2,433,655
55	Distribution (Total of lines 33 and 45)	13,548,027			13,548,027
56	Customer Accounts (Total of line 34)	3,088,460			3,088,460
57	Customer Service and Informational (Total of line 35)	288,019			288,019
58	Sales (Total of line 36)				
59	Administrative and General (Total of lines 37 and 46)	11,927,195		2,737,908	14,665,103
60	Total Operation and Maintenance (Total of lines 50 thru 59)	32,461,765		2,737,908	35,199,673
61	Other Utility Departments				
62	Operation and Maintenance				0
63	TOTAL ALL Utility Dept. (Total of lines 25, 60, and 62)	112,350,012		12,366,954	124,716,966
64	Utility Plant				
65	Construction (By Utility Departments)				
66	Electric Plant	53,228,480		8,231,597	61,460,077
67	Gas Plant	15,228,319		2,355,006	17,583,325
68	Other				0
69	TOTAL Construction (Total of lines 66 thru 68)	68,456,799		10,586,603	79,043,402
70	Plant Removal (By Utility Departments)				
71	Electric Plant	2,754,050		219,243	2,973,293
72	Gas Plant	991,983		78,969	1,070,952
73	Other				0
74	TOTAL Plant Removal (Total of lines 71 thru 73)	3,746,033		298,212	4,044,245
75.1	Stores Expense (163)	3,033,814		(3,033,814)	0
75.2	Preliminary Survey and Investigation (183)	0			0
75.3	Small Tool Expense (184)	5,526,184		(5,526,184)	0
75.4	Miscellaneous Deferred Debits (186)	1,274,251			1,274,251
75.5	Non-operating Expenses (417)	743,935			743,935
75.6	Retirement Bonus/SERP/HRA (228)	39,474			39,474
75.7	Other Income Deductions (426)	974,987			974,987
75.8	Employee Incentive Plan (232380)	12,261,080		(12,261,080)	0
75.9	DSM Tariff Rider (242600)	2,430,691		(2,430,691)	0
75.10	Incentive/Stock Compensation (238000)	250,528			250,528
75.11	Payroll Equalization Liability (242700)	29,517,696			29,517,696
76	TOTAL Other Accounts	56,052,640	0	(23,251,769)	32,800,871
77	TOTAL SALARIES AND WAGES	240,605,484	0	0	240,605,484

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Charges for Outside Professional and Other Consultative Services

1. Report the information specified below for all charges made during the year included in any account (including plant accounts) for outside consultative and other professional services. These services include rate, management, construction, engineering, research, financial, valuation, legal, accounting, purchasing, advertising, labor relations, and public relations, rendered for the respondent under written or oral arrangement, for which aggregate payments were made during the year to any corporation partnership, organization of any kind, or individual (other than for services as an employee or for payments made for medical and related services) amounting to more than $250,000, including payments for legislative services, except those which should be reported in Account 426.4 Expenditures for Certain Civic, Political and Related Activities. (a) Name of person or organization rendering services. (b) Total charges for the year.
2. Sum under a description "Other", all of the aforementioned services amounting to $250,000 or less.
3. Total under a description "Total", the total of all of the aforementioned services.
4. Charges for outside professional and other consultative services provided by associated (affiliated) companies should be excluded from this schedule and be reported on Page 358, according to the instructions for that schedule.

Line No.	Description (a)	Amount (in dollars) (b)
1	MICHELS UTILITY SERVICES INC	23,033,035
2	VOLT MANAGEMENT CORP	20,653,229
3	NPL CONSTRUCTION CO	18,296,475
4	ASPLUNDH TREE EXPERT LLC	14,296,211
5	WILSON CONSTRUCTION COMPANY	10,606,127
6	TITAN ELECTRIC INC	8,507,436
7	INTERNATIONAL LINE BUILDERS INC	8,117,451
8	ONE CALL LOCATORS LTD	5,705,412
9	MICHELS PACIFIC ENERGY INC	5,133,045
10	PERFECTION TRAFFIC CONTROL LLC	4,883,817
11	WRIGHT TREE SERVICE INC	4,531,415
12	BOUTEN CONSTRUCTION COMPANY	4,412,342
13	TRAFFIC CONTROL SERVICES LLC	4,258,665
14	KNIGHT CONSTRUCTION & SUPPLY INC	4,068,968
15	IBM CORPORATION	3,253,062
16	POTELCO INC	3,212,994
17	GARCO CONSTRUCTION INC	3,132,140
18	BRENT WOODWARD INC	3,104,556
19	NAGARRO INC	2,700,943
20	MAX J KUNEY COMPANY	2,520,346
21	CASCADE CABLE CONSTRUCTORS INC	2,498,884
22	COLEMAN ENVIRONMENTAL ENGINEERING INC	2,249,139
23	HEATH CONSULTANTS INCORPORATED	2,148,727
24	SPOKANE TRAFFIC CONTROL INC	1,966,188
25	DELOITTE	1,926,400
26	TRAFFICORP	1,902,638
27	HYDROMAX USA LLC	1,885,073
28	UTILITY SOLUTIONS PARTNERS LLC	1,797,645
29	SUNRISE ENGINEERING INC	1,719,717
30	LYDIG CONSTRUCTION INC	1,672,739
31	INTELLITECT	1,647,413
32	POWER ENGINEERS INC	1,598,583
33	CN UTILITY CONSULTING INC	1,575,741
34	PER SE GROUP INC	1,492,457
35	WALKER INDUSTRIES LLC	1,440,389
36	BLACK & VEATCH CORPORATION	1,333,466
37	POE ASPHALT PAVING INC	1,331,848
38	POWER CITY ELECTRIC INC	1,326,151
39	ARBORMETRICS SOLUTIONS LLC	1,307,342
40	CURRY INC	1,292,416
41	ALDEN RESEARCH LABORATORY LLC	1,285,776
42	AAA SWEEPING LLC	1,260,952
43	FIRST AMERICAN TITLE INSURANCE CO	1,260,628
44	SCHNABEL ENGINEERING LLC	1,205,251
45	COEUR D ALENE TRIBE	1,197,607
46	NEAL STRUCTURAL REPAIR LLC	1,176,983
47	COLVICO INC	1,159,514
48	RESSA & SON CONSTRUCTION LLC	1,151,008
49	ASSOCIATED ARBORISTS	1,089,835

50	FUJITSU NORTH AMERICA INC	1,009,401
51	COMMERCIAL GRADING INC	973,896
52	CARPI USA INC	927,717
53	MCKINSTRY COMPANY LLC	847,101
54	INTEC SERVICES INC	812,174
55	PALOUSE POWER LLC	803,804
56	NV5 GEOSPATIAL INC	786,791
57	POWER PLAN INC	775,683
58	STANTEC CONSULTING SERVICES INC	737,387
59	DW EXCAVATING INC	724,279
60	GE RENEWABLES US LLC	689,566
61	LAND EXPRESSIONS	688,147
62	AVANTE PARTNERS	652,779
63	HILL INTERNATIONAL INC	626,553
64	CANNON HILL INDUSTRIES INC	625,799
65	GE PROLEC TRANSFORMERS INC	623,305
66	PAINE HAMBLEN LLP	618,507
67	D W POLEHOLE	605,775
68	FOUST FABRICATION CO	586,854
69	JENSENS TREE SERVICE INC	566,461
70	DXC TECHNOLOGY SERVICES LLC	548,707
71	POWER SYSTEMS CONSULTANTS INC	535,514
72	VENTURE SUM CORPORATION	514,152
73	AIDASH INC	510,867
74	COMMONWEALTH ASSOCIATES INC	509,658
75	UTILITY CONSTRUCTION INSPECTION LLC	504,130
76	IDAHO DEPT OF FISH & GAME	494,674
77	NEELBLUE TECHNOLOGIES CONSULTING INC	488,070
78	WEMCO INC	477,140
79	ACTALENT SERVICES LLC	452,457
80	KASCO OF IDAHO LLC	449,241
81	RANDALL DANSKIN ATTORNEYS	428,127
82	OPEN ENERGY SOLUTIONS INC	420,583
83	HICKEY BROTHERS RESEARCH LLC	416,447
84	GE ENERGY MANAGEMENT SERVICES LLC	416,245
85	LEDFORD CONSTRUCTION COMPANY	411,996
86	BILLS HEATING AND AIR CONDITIONING	407,662
87	HANNA & ASSOCIATES INC	407,364
88	CERIUM NETWORKS	401,885
89	BOYER LAND DEVELOPMENT INC	393,233
90	BIOMARK	390,822
91	PUGET SOUND ENERGY	386,263
92	DHISOFT SOLUTIONS	380,041
93	SLALOM INC	378,970
94	TAILORED SOLUTIONS LLC	378,201
95	BAKER BOTTS LLP	352,480
96	BARNHART CRANE AND RIGGING CO	350,520
97	NUVODIA LLC	347,427
98	TRANSFORMER TECHNOLOGIES LLC	345,952
99	COFFMAN ENGINEERS	342,151
100	WESTERN POWER POOL	336,267
101	GEODIGITAL INTERNATIONAL CORP	334,743
102	AVCO CONSULTING INC	331,280
103	NORTH WEST ELECTRIC SOLUTIONS LLC	322,880
104	LANDAU ASSOCIATES	321,910
105	ABSCO SOLUTIONS	320,506
106	7B BORING LLC	320,466
107	MESA PRODUCTS INC	318,690
108	COMPUNET INC	318,064

109	L & S ELECTRIC INC	316,386
110	PRO MECHANICAL SERVICES INC	293,319
111	WOODS CRUSHING & HAULING	289,160
112	ABREMOD LLC	286,875
113	CIRRUS DESIGN INDUSTRIES INC	284,946
114	BRACEWELL LLP	278,579
115	RTI INTERNATIONAL	276,404
116	STOEL RIVES LLP	274,720
117	NORTH AMERICAN SUBSTATION SERVICES LLC	266,663
118	ABLE CLEAN UP TECHNOLOGIES INC	266,543
119	JIMMYS ROOFING	261,422
120	PRO BUILDING SYSTEMS INC	258,494
121	OTHER <$250,000	37,865,288
122	TOTAL	270,994,742

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Transactions with Associated (Affiliated) Companies

1. Report below the information called for concerning all goods or services received from or provided to associated (affiliated) companies amounting to more than $250,000.
2. Sum under a description “Other”, all of the aforementioned goods and services amounting to $250,000 or less.
3. Total under a description “Total”, the total of all of the aforementioned goods and services.
4. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote the basis of the allocation.

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	Goods or Services Provided by Affiliated Company			
19	TOTAL			
20	Goods or Services Provided for Affiliated Company			
21	Corporate Support	Avista Development	146000	200,750
22	Corporate Support	Avista Capital	146000	65,093
23	Corporate Support	AELP	146000	34,020
24	Corporate Support	AJT Mining	146000	1,561
25	Corporate Support	Avista Edge	146000	160,199
40	TOTAL			461,623

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Gas Storage Projects

1. Report injections and withdrawals of gas for all storage projects used by respondent.

Line No.	Item (a)	Gas Belonging to Respondent (Dth) (b)	Gas Belonging to Others (Dth) (c)	Total Amount (Dth) (d)
	STORAGE OPERATIONS (in Dth)			
1	Gas Delivered to Storage			
2	January	226,529		226,529
3	February	25,786		25,786
4	March	556,917		556,917
5	April	1,331,595		1,331,595
6	May	2,971,354		2,971,354
7	June	2,885,287		2,885,287
8	July	1,162,459		1,162,459
9	August	526,145		526,145
10	September	434,050		434,050
11	October	45,371		45,371
12	November	409,950		409,950
13	December	148,314		148,314
14	TOTAL (Total of lines 2 thru 13)	10,723,757	0	10,723,757
15	Gas Withdrawn from Storage			
16	January	1,385,315		1,385,315
17	February	1,131,783		1,131,783
18	March	1,588,340		1,588,340
19	April	326,395		326,395
20	May	4,093		4,093
21	June	899		899
22	July	508,888		508,888
23	August	207,825		207,825
24	September	176,870		176,870
25	October	212,332		212,332
26	November	622,551		622,551
27	December	960,150		960,150
28	TOTAL (Total of lines 16 thru 27)	7,125,441	0	7,125,441

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Gas Storage Projects

1. On line 4, enter the total storage capacity certificated by FERC.
2. Report total amount in Dth or other unit, as applicable on lines 2, 3, 4, 7. If quantity is converted from Mcf to Dth, provide conversion factor in a footnote.

Line No.	Item (a)	Total Amount (b)
	STORAGE OPERATIONS	
1	Top or Working Gas End of Year	8,528,000
2	Cushion Gas (Including Native Gas)	7,730,668
3	Total Gas in Reservoir (Total of line 1 and 2)	16,258,668
4	Certificated Storage Capacity	
5	Number of Injection - Withdrawal Wells	50
6	Number of Observation Wells	32
7	Maximum Days' Withdrawal from Storage	150,023
8	Date of Maximum Days' Withdrawal	01/31/2023
9	LNG Terminal Companies (in Dth)	
10	Number of Tanks	
11	Capacity of Tanks	
12	**LNG Volume**	
13	Received at "Ship Rail"	
14	Transferred to Tanks	
15	Withdrawn from Tanks	
16	"Boil Off" Vaporization Loss	

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Auxiliary Peaking Facilities

1. Report below auxiliary facilities of the respondent for meeting seasonal peak demands on the respondent's system, such as underground storage projects, liquefied petroleum gas installations, gas liquefaction plants, oil gas sets, etc.
2. For column (c), for underground storage projects, report the delivery capacity on February 1 of the heating season overlapping the year-end for which this report is submitted. For other facilities, report the rated maximum daily delivery capacities.
3. For column (d), include or exclude (as appropriate) the cost of any plant used jointly with another facility on the basis of predominant use, unless the auxiliary peaking facility is a separate plant as contemplated by general instruction 12 of the Uniform System of Accounts.

Line No.	Location of Facility (a)	Type of Facility (b)	Maximum Daily Delivery Capacity of Facility Dth (c)	Cost of Facility (in dollars) (d)	Was Facility Operated on Day of Highest Transmission Peak Delivery? (e)
1	Chehalis, Washington	Underground Natural Gas Storage Field Washington & Idaho Supply	346,667	52,331,227	true
2	Chehalis, Washington	Underground Natural Gas Storage Field Oregon Supply	52,000	7,680,822	true
3	Chehalis, Washington	[(a)] Underground Natural Gas Storage Field Oregon Supply	2,623		true
4	Rock Springs, Wyoming	[(b)] Underground Natural Gas Storage Field Washington & Idaho Supply			false
5	Rock Springs, Wyoming	[(c)] Underground Natural Gas Storage Field Oregon Supply			false

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: AuxiliaryPeakingFacilitiesTypeOfFacility
Avista is a participant in the facilities, not an owner and is charged a fee for demand deliverability and capacity.
(b) Concept: AuxiliaryPeakingFacilitiesTypeOfFacility
Avista does not have firm rights but has interruptible access to it.
(c) Concept: AuxiliaryPeakingFacilitiesTypeOfFacility
Avista does not have firm rights but has interruptible access to it.

Name of Respondent: Avista Corporation	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report:	Year/Period of Report: End of: 2023/ Q4

Gas Account - Natural Gas

1. The purpose of this schedule is to account for the quantity of natural gas received and delivered by the respondent.
2. Natural gas means either natural gas unmixed or any mixture of natural and manufactured gas.
3. Enter in column (c) the year to date Dth as reported in the schedules indicated for the items of receipts and deliveries.
4. Enter in column (d) the respective quarter's Dth as reported in the schedules indicated for the items of receipts and deliveries.
5. Indicate in a footnote the quantities of bundled sales and transportation gas and specify the line on which such quantities are listed.
6. If the respondent operates two or more systems which are not interconnected, submit separate pages for this purpose.
7. Indicate by footnote the quantities of gas not subject to Commission regulation which did not incur FERC regulatory costs by showing (1) the local distribution volumes another jurisdictional pipeline delivered to the local distribution company portion of the reporting pipeline (2) the quantities that the reporting pipeline transported or sold through its local distribution facilities or intrastate facilities and which the reporting pipeline received through gathering facilities or intrastate facilities, but not through any of the interstate portion of the reporting pipeline, and (3) the gathering line quantities that were not destined for interstate market or that were not transported through any interstate portion of the reporting pipeline.
8. Indicate in a footnote the specific gas purchase expense account(s) and related to which the aggregate volumes reported on line No. 3 relate.
9. Indicate in a footnote (1) the system supply quantities of gas that are stored by the reporting pipeline, during the reporting year and also reported as sales, transportation and compression volumes by the reporting pipeline during the same reporting year, (2) the system supply quantities of gas that are stored by the reporting pipeline during the reporting year which the reporting pipeline intends to sell or transport in a future reporting year, and (3) contract storage quantities.
10. Also indicate the volumes of pipeline production field sales that are included in both the company's total sales figure and the company's total transportation figure. Add additional information as necessary to the footnotes.

Line No.	Item (a)	Ref. Page No. of (FERC Form Nos. 2/2-A) (b)	Total Amount of Dth Year to Date (c)	Current Three Months Ended Amount of Dth Quarterly Only (d)
1	Name of System		Avista Storage	
2	GAS RECEIVED			
3	Gas Purchases (Accounts 800-805)		70,594,330	18,742,554
4	Gas of Others Received for Gathering (Account 489.1)	303		
5	Gas of Others Received for Transmission (Account 489.2)	305		
6	Gas of Others Received for Distribution (Account 489.3)	301	17,475,829	4,913,097
7	Gas of Others Received for Contract Storage (Account 489.4)	307		
8	Gas of Others Received for Production/Extraction/Processing (Account 490 and 491)			
9	Exchanged Gas Received from Others (Account 806)	328		
10	Gas Received as Imbalances (Account 806)	328	21,814	68,609
11	Receipts of Respondent's Gas Transported by Others (Account 858)	332		
12	Other Gas Withdrawn from Storage (Explain)		(3,609,033)	1,180,675
13	Gas Received from Shippers as Compressor Station Fuel			
14	Gas Received from Shippers as Lost and Unaccounted for			
15	Other Receipts (Specify) (footnote details)			
16	Total Receipts (Total of lines 3 thru 15)		84,482,940	24,904,935
17	GAS DELIVERED			
18	Gas Sales (Accounts 480-484)		66,070,518	19,375,123
19	Deliveries of Gas Gathered for Others (Account 489.1)	303		
20	Deliveries of Gas Transported for Others (Account 489.2)	305		
21	Deliveries of Gas Distributed for Others (Account 489.3)	301	16,506,564	4,583,143
22	Deliveries of Contract Storage Gas (Account 489.4)	307		
23	Gas of Others Delivered for Production/Extraction/Processing (Account 490 and 491)			
24	Exchange Gas Delivered to Others (Account 806)	328		
25	Gas Delivered as Imbalances (Account 806)	328		
26	Deliveries of Gas to Others for Transportation (Account 858)	332		
27	Other Gas Delivered to Storage (Explain)			
28	Gas Used for Compressor Station Fuel	509	1,905,858	946,669
29	Other Deliveries and Gas Used for Other Operations			
30	Total Deliveries (Total of lines 18 thru 29)		84,482,940	24,904,935
31	GAS LOSSES AND GAS UNACCOUNTED FOR			
32	Gas Losses and Gas Unaccounted For			
33	TOTALS			
34	Total Deliveries, Gas Losses & Unaccounted For (Total of lines 30 and 32)		84,482,940	24,904,935

Name of Respondent	This Report Is:	Date of Report	Year of Report
	(1) [X] An Original	(M, D, Y)	
Avista Corp.	(2) [ ] A Resubmission	April 23, 2024	Dec. 31, 2023

STATE OF OREGON - STATEMENT OF OPERATING INCOME FOR THE YEAR

Line No.	Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)	2	$171,337,357	$177,907,223
3	Operating Expenses			
4	Operation Expenses (401)	4 - 9	115,390,920	123,044,518
5	Maintenance Expenses (402)	4 - 9	4,121,421	4,731,206
6	Depreciation Expense (403)	10	13,508,484	12,695,112
7	Amort. & Depl. of Utility Plant (404-405)	10	4,588,262	4,014,941
8	Amort. of Utility Plant Acq. Adj. (406)(See Note 1)	10		
9	Amort. of Property Losses, Unrecovered Plant and Regulatory Study Costs (407)			
10	Senate Bill 408 (407330/407408/407431)		0	0
11	Reg Debit/Credit ()		91,478	411,730
12	Taxes Other Than Income Taxes (408.1)	11	11,702,315	10,905,643
13	Income Taxes - Federal (409.1)	12	3,920,201	(337,865)
14	- Other (409.1)	13	874,995	846,011
15	Provision for Deferred Income Taxes (410.1) (410.2)	14 - 21	(675,264)	3,094,901
16	(Less) Prov. for Def. Inc. Taxes-Cr. (411.1)	14 - 21	3,987,261	1,633,434
17	Investment Tax Credit Adj. - Net (411.4)	22		
18	(Less) Gains from Disp. of Utility Plant (411.7)			
19	Losses from Disp. of Utility Plant (411.7)			
20	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 18)		149,535,551	157,772,763
21	Net Utility Operating Income Enter Total of Line 2 less Line 19		$21,801,806	$20,134,460

Name of Respondent	This Report Is:	Date of Report (M, Y, D)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	April 23, 2024	Dec. 31, 2023

STATE OF OREGON - GAS OPERATING REVENUES (Account 400)

Line No.	Title of Account (a)	OPERATING REVENUES Current Year (b)	OPERATING REVENUES Previous Year (c)	THERMS OF GAS SOLD Current Year (d)		THERMS OF GAS SOLD Previous Year (e)	AVG. NO. OF GAS CUST. PER MO. Current Year (f)	AVG. NO. OF GAS CUST. PER MO. Previous Year (g)	Line No.
1	GAS SERVICE REVENUES								1
2	(480) Residential Sales	87,918,615 *	80,669,589	53,245,820	**	53,202,783	94,486	93,820	2
3	(481) Commercial and Industrial Sales								3
4	Small (or Comm.) (See Instr. 6)	49,281,567 *	43,449,901	37,990,054	**	37,457,404	12,082	11,998	4
5	Large (or Ind.) (See Instr. 6)	9,004,608 *	4,386,274	14,284,982	**	9,723,755	48	47	5
6	(482) Other Sales to Public Authorities								6
7	(484) Interdepartmental Sales	22,409	22,056	15,347		16,713	11	11	7
8	TOTAL Sales to Ultimate Consumers	146,227,199 *	128,527,821	105,536,203	**	100,400,655	106,627	105,875	8
9	(483) Sales for Resale	28,889,298	46,865,973	78,266,550		81,665,960			9
10	TOTAL Nat. Gas Service Revenues	175,116,497	175,393,793	183,802,753		182,066,615	106,627	105,875	10
11	Revenues from Manufactured Gas								11
12	TOTAL Gas Service Revenues	175,116,497	175,393,793						12
13	OTHER OPERATING REVENUES								13
14	(485) Intracompany Transfers								14
15	(487) Forfeited Discounts								15
16	(488) Misc. Service Revenues	58,068	24,312						16
17	(489) Rev. from Trans. of Gas of Others	2,499,685 *	2,804,561	Notes:					17
18	(490) Sales of Prod. Ext. from Nat. Gas								18
19	(491) Rev. from Nat. Gas Proc. by Others			* Includes unbilled revenues					19
20	(492) Incidental Gasoline and Oil Sales								20
21	(493) Rent from Gas Property	11,000	12,000	** Includes unbilled therms					21
22	(494) Interdepartmental Rents								22
23	(495) Other Gas Revenues	(6,347,893)	(327,443)						23
24	TOTAL Other Operating Revenues	(3,779,140)	2,513,429						24
25	TOTAL Gas Operating Revenues	171,337,357	177,907,223						25
26	(Less) (496) Provision for Rate Refunds	0	0						26
27	TOTAL Gas Operating Revenues Net of Provision for Refunds	171,337,357							27
28	Dis. Type Sales by States (Incl. Main Line Sales to Resid. and Comm. Custrs.)	137,200,182		91,235,874					28
29	Main Line Industrial Sales (Incl. Main Line Sales to Pub. Authorities)	9,004,608		14,284,982					29
30	Sales for Resale	28,889,298		78,266,550					30
31	Other Sales to Pub. Auth. (Local Dist. Only)								31
32	Interdepartmental Sales	22,409		15,347					32
33	TOTAL (Same as Line 10, Columns (b) and (d))	175,116,497		183,802,753					33

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	April 23, 2024	Dec. 31, 2023

STATE OF OREGON - INTERDEPARTMENTAL SALES - NATURAL GAS (Account 484)

Report particulars concerning sales of natural gas included in Account 484

Line No.	Department and Basis of Charges (a)	Point of Delivery (b)	Mcf (14.73 psia at 60• F) (c)	Revenue (d)
1				
2				
3	Natural gas supply for operation	Avista facility	1,480	22,409
4	of Avista's facilities			
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	TOTAL		1,480	22,409

RENT FROM GAS PROPERTY AND INTERDEPARTMENTAL RENTS (Accounts 493 and 494)

1. Report particulars concerning rents received included in Accounts 493 and 494.
2. Minor rents may be entered at the total amount for each class of such rents.
3. If rents are included which were arrived at under an arrangement for apportioning expenses of a joint facility, whereby the amount included in this account represents profit or return on property, depreciation, and taxes, give particulars and the basis of apportionment of such charges to Account 493 or 494.
4. Provide a subheading and total for each account.

Line No.	Name of Lessee or Department (Designate associated companies) (a)	Description of property (b)	Amount of Revenue for Year	
			Natural Gas Property (c)	Manufactured Gas Property (d)
1				
2				
3	Michels Corporation		11,000	
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19	TOTAL		11,000	

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) April 23, 2024	Dec. 31, 2023

STATE OF OREGON - ALLOCATED GAS OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Amount *(a)*	Amount for Current Year *(b)*	Amount for Previous Year *(c)*
1	1. PRODUCTION EXPENSES		
2	A. Manufactured Gas Production	-	-
3	Manufactured Gas Production (Submit Supplemental Statement)		
4	B. Natural Gas Production		
5	B1. Natural Gas Production and Gathering		
6	Operation	-	-
7	750 Operation Supervision and Engineering	-	-
8	751 Production Maps and Records	-	-
9	752 Gas Wells Expenses	-	-
10	753 Field Lines Expenses	-	-
11	754 Field Compressor Station Expenses	-	-
12	755 Field Compressor Station Fuel and Power	-	-
13	756 Field Measuring and Regulating Station Expenses	-	-
14	757 Purification Expenses	-	-
15	758 Gas Well Royalties	-	-
16	759 Other Expenses	-	-
17	760 Rents	-	-
18	TOTAL Operation (Enter Total of lines 7 thru 17)	-	-
19	Maintenance		
20	761 Maintenance Supervision and Engineering	-	-
21	762 Maintenance of Structures and Improvements	-	-
22	763 Maintenance of Producing Gas Wells	-	-
23	764 Maintenance of Field Lines	-	-
24	765 Maintenance of Field Compressor Station Equipment	-	-
25	766 Maintenance of Field Meas. and Reg. Sta. Equipment	-	-
26	767 Maintenance of Purification Equipment	-	-
27	768 Maintenance of Drilling and Cleaning Equipment	-	-
28	769 Maintenance of Other Equipment	-	-
29	TOTAL Maintenance (Enter Total of lines 20 thru 28)	-	-
30	TOTAL Natural Gas Production and Gathering (Total of lines 18 and 29)	-	-
31	B2. Products Extraction		
32	Operation		
33	770 Operation Supervision and Engineering	-	-
34	771 Operation Labor	-	-
35	772 Gas Shrinkage	-	-
36	773 Fuel	-	-
37	774 Power	-	-
38	775 Materials	-	-
39	776 Operation Supplies and Expenses	-	-
40	777 Gas Processed by Others	-	-
41	778 Royalties on Products Extracted	-	-
42	779 Marketing Expenses	-	-
43	780 Products Purchased for Resale	-	-
44	781 Variation in Products Inventory	-	-
45	(Less) 782 Extracted Products Used by the Utility-Credit	-	-
46	783 Rents	-	-
47	TOTAL Operation (Enter Total of Lines 33 thru 46)	-	-

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	April 23, 2024	Dec. 31, 2023

STATE OF OREGON - ALLOCATED GAS OPERATION AND MAINTENANCE EXPENSES

Line No.	Amount *(a)*	Amount for Current Year *(b)*	Amount for Previous Year *(c)*
	B2. Products Extraction (Continued)		
48	Maintenance		
49	784 Maintenance Supervision and Engineering	-	-
50	785 Maintenance of Structures and Improvements	-	-
51	786 Maintenance of Extraction and Refining Equipment	-	-
52	787 Maintenance of Pipe Lines	-	-
53	788 Maintenance of Extracted Products Storage Equipment	-	-
54	789 Maintenance of Compressor Equipment	-	-
55	790 Maintenance of Gas Measuring and Reg. Equipment	-	-
56	791 Maintenance of Other Equipment	-	-
57	TOTAL Maintenance (Enter Total of lines 49 thru 56)	-	-
58	TOTAL Products Extraction (Enter Total of lines 47 and 57)	-	-
59	C. Exploration and Development		
60	Operation		
61	795 Delay Rentals	-	-
62	796 Nonproductive Well Drilling	-	-
63	797 Abandoned Leases	-	-
64	798 Other Exploration	-	-
65	TOTAL Exploration and Development (Enter Total of lines 61 thru 64)	-	-
	D. Other Gas Supply Expenses		
66	Operation		
67	800 Natural Gas Well Head Purchases	-	-
68	800.1 Natural Gas Well Head Purchases, Intracompany Transfers	-	-
69	801 Natural Gas Field Line Purchases	-	-
70	802 Natural Gas Gasoline Plant Outlet Pruchases	-	-
71	803 Natural Gas Transmission Line Purchases	-	-
72	804 Natural Gas City Gate Purchases	74,415,970	97,420,019
73	804.1 Liquefied Natural Gas Purchases	-	-
74	805 Other Gas Purchases	-	-
75	(Less) 805.1 Purchased Gas Cost Adjustments	12,442,036	(1,727,280)
76			
77	TOTAL Purchased Gas (Enter Total of lines 67 to 76)	86,858,006	95,692,739
78	806 Exchange Gas		-
79	Purchased Gas Expenses		
80	807.1 Well Expenses-Purchased Gas		-
81	807.2 Operation of Purchased Gas Measuring Stations		-
82	807.3 Maintenance of Purchased Gas Measuring Stations		-
83	807.4 Purchased Gas Calculations Expenses		-
84	807.5 Other Purchased Gas Expenses		-
85	TOTAL Purchased Gas Expenses (Enter Total of lines 80 thru 84)		-
86	808.1 Gas Withdrawn from Storage-Debit	873,144	-
87	(Less) 808.2 Gas Delivered to Storage-Credit	-	(812,502)
88	809.1 Withdrawals of Liquefied Natural Gas for Processing-Debit	-	-
89	(Less) 809.2 Deliveries of Natural Gas for Processing-Credit	-	-
90	Gas Used in Utility Operations-Credit		
91	810 Gas Used for Compressor Station Fuel-Credit	-	-
92	811 Gas Used for Products Extraction-Credit	(200,884)	(361,616)
93	812 Gas used for Other Utility Operations-Credit	-	-
94	TOTAL Gas Used in Utility Operations-Credit (Total of lines 91 thru 93)	(200,884)	(361,616)
95	813 Other Gas Supply Expenses	600,984	599,736
96	TOTAL Other Gas Supply Exp (Total of lines 77,78,85,86 thru 89,94,95)	88,131,250	95,118,357
97	TOTAL Production Expenses (Enter Total of lines 3,30,58,65, and 96)	88,131,250	95,118,357

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	April 23, 2024	Dec. 31, 2023

STATE OF OREGON - ALLOCATED GAS OPERATION AND MAINTENANCE EXPENSES

Line No.	Amount (a)	Amount for Current Year (b)	Amount for Previous Year (c)
98	2. NATURAL GAS STORAGE, TERMINALING AND PROCESSING EXPENSES		
99	A. Underground Storage Expenses		
100	Operation		
101	814 Operation Supervision and Engineering	-	-
102	815 Maps and Records	-	-
103	816 Wells Expenses	-	-
104	817 Lines Expense	-	-
105	818 Compressor Station Expenses	-	-
106	819 Compressor Station Fuel and Power	-	-
107	820 Measuring and Regulating Station Expenses	-	-
108	821 Purification Expenses	-	-
109	822 Exploration and Development	-	-
110	823 Gas Losses	-	-
111	824 Other Expenses	99,917	89,846
112	825 Storage Well Royalties	-	-
113	826 Rents	-	-
114	TOTAL Operation (Enter Total of lines 101 thru 113)	99,917	89,846
115	Maintenance		
116	830 Maintenance Supervision and Engineering	-	-
117	831 Maintenance of Structures and Improvements	-	-
118	832 Maintenance of Reservoirs and Wells	-	-
119	833 Maintenance of Lines	-	-
120	834 Maintenance of Compressor Station Equipment	-	-
121	835 Maintenance of Measuring and Regulating Station Equipment	-	-
122	836 Maintenance of Purification Equipment	-	-
123	837 Maintenance of Other Equipment	203,417	217,510
124	TOTAL Maintenance (Enter Total of lines 116 thru 123)	203,417	217,510
125	TOTAL Underground Storage Expenses (Total of lines 114 and 124)	303,334	307,356
126	B. Other Storage Expenses		
127	Operation		
128	840 Operation Supervision and Engineering	-	-
129	841 Operation Labor and Expenses	-	-
130	842 Rents	-	-
131	842.1 Fuel	-	-
132	842.2 Power	-	-
133	842.3 Gas Losses	-	-
134	TOTAL Operation (Enter Total of lines 128 thru 133)	-	-
135	Maintenance		
136	843.1 Maintenance Supervision and Engineering	-	-
137	843.2 Maintenance of Structures and Improvements	-	-
138	843.3 Maintenance of Gas Holders	-	-
139	843.4 Maintenance of Purification Equipment	-	-
140	843.5 Maintenance of Liquefaction Equipment	-	-
141	843.6 Maintenance of Vaporizing Equipment	-	-
142	843.7 Maintenance of Compressor Equipment	-	-
143	843.8 Maintenance of Measuring and Regulating Equipment	-	-
144	843.9 Maintenance of Other Equipment	-	-
145	TOTAL Maintenance (Enter Total of lines 136 thru 144)	-	-
146	TOTAL Other Storage Expenses (Enter Total of lines 134 and 145)	-	-

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) April 23, 2024	Dec. 31, 2023

STATE OF OREGON - ALLOCATED GAS OPERATION AND MAINTENANCE EXPENSES

Line No.	Amount *(a)*	Amount for Current Year *(b)*	Amount for Previous Year *(c)*
147	C. Liquefied Natural Gas Terminaling and Processing Expenses		
148	Operation		
149	844.1 Operation Supervision and Engineering	-	-
150	844.2 LNG Processing Terminal Labor and Expenses	-	-
151	844.3 Liquefaction Processing Labor and Expenses	-	-
152	844.4 Liquefaction Transportation Labor and Expenses	-	-
153	844.5 Measuring and Regulating Labor and Expenses	-	-
154	844.6 Compressor Station Labor and Expenses	-	-
155	844.7 Communication System Expenses	-	-
156	844.8 System Control and Load Dispatching	-	-
157	845.1 Fuel	-	-
158	845.2 Power	-	-
159	845.3 Rents	-	-
160	845.4 Demurrage Charges	-	-
161	(Less) 845.5 Wharfage Receipts-Credit	-	-
162	845.6 Processing Liquefied or Vaporized Gas by Others	-	-
163	846.1 Gas Losses	-	-
164	846.2 Other Expenses	-	-
165	TOTAL Operation (Enter Total of lines 149 thru 164)	-	-
166	Maintenance		
167	847.1 Maintenance Supervision and Engineering	-	-
168	847.2 Maintenance of Structures and Improvements	-	-
169	847.3 Maintenance of LNG Processing Terminal Equipment	-	-
170	847.4 Maintenance of LNG Transportation Equipment	-	-
171	847.5 Maintenance of Measuring and Regulating Equipment	-	-
172	847.6 Miantenance of Compressor Station Equipment	-	-
173	847.7 Maintenance of Communication Equipment	-	-
174	847.8 Maintenance of Other Equipment	-	-
175	TOTAL Maintenance (Enter Total of lines 167 thru 174)	-	-
176	TOTAL Liquefied Nat Gas Terminaling and Processing Exp (Lines 165 & 175)	-	-
177	TOTAL Natural Gas storage (Enter Total of lines 125, 146, and 176)	303,334	307,356
178	3. TRANSMISSION EXPENSES		
179	Operation		
180	850 Operation Supervision and Engineering	-	-
181	851 System Control and Load Dispatching	-	-
182	852 Communication System Expenses	-	-
183	853 Compressor Station Labor and Expenses	-	-
184	854 Gas for Compressor Station Fuel	-	-
185	855 Other Fuel and Power for Compressor Stations	-	-
186	856 Mains Expenses	-	-
187	857 Measuring and Regulating Station Expenses	-	-
188	858 Transmission and Compression of Gas by Others	-	-
189	859 Other Expenses	-	-
190	860 Rents	-	-
191	TOTAL Operation (Enter Total of lines 180 thru 190)	-	-

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) April 23, 2024	Dec. 31, 2023

STATE OF OREGON - ALLOCATED GAS OPERATION AND MAINTENANCE EXPENSES

Line No.	Amount *(a)*	Amount for Current Year *(b)*	Amount for Previous Year *(c)*
	3. TRANSMISSION EXPENSES (Continued)		
192	Maintenance		
193	861 Maintenance Supervision and Engineering	-	-
194	862 Maintenance of Structures and Improvements	-	-
195	863 Maintenance of Mains	-	-
196	864 Maintenance of Compressor Station Equipment	-	-
197	865 Maintenance of Measuring and Reg. Station Equipment	-	-
198	866 Maintenance of Communication Equipment	-	-
199	867 Maintenance of Other Equipment	-	-
200	TOTAL Maintenance (Enter Total of lines 193 thru 199)	-	-
201	TOTAL Transmission Expenses (Enter Total of lines 191 and 200)	-	-
202	4. DISTRIBUTION EXPENSES		
203	Operation		
204	870 Operation Supervision and Engineering	936,048	939,820
205	871 Distribution Load Dispatching	-	-
206	872 Compressor Station Labor and Expenses	-	-
207	873 Compressor Station Fuel and Power	-	-
208	874 Mains and Services Expenses	2,522,143	2,173,839
209	875 Measuring and Regulating Station Expenses-General	92,662	155,990
210	876 Measuring and Regulating Station Expenses-Industrial	2,814	1,706
211	877 Measuring and Regulating Station Expenses-City Gate Check Station	7,161	5,949
212	878 Meter and House Regulator Expenses	286,184	303,902
213	879 Customer Installations Expenses	1,263,887	1,296,748
214	880 Other Expenses	1,076,549	885,087
215	881 Rents	(250)	(3,025)
216	TOTAL Operation (Enter Total of lines 204 thru 215)	6,187,198	5,760,016
217	Maintenance		
218	885 Maintenance Supervision and Engineering	42,649	39,863
219	886 Maintenance of Structures and Improvements		
220	887 Maintenance of Mains	446,241	876,499
221	888 Maintenance of Compressor Station Equipment		
222	889 Maintenance of Meas. and Reg. Sta. Equip.-General	385,946	423,667
223	890 Maintenance of Meas. and Reg. Sta. Equip.-Industrial	36,976	35,838
224	891 Maintenance of Meas. and Reg. Sta. Equip.-City Gate Check Station	19,786	20,149
225	892 Maintenance of Services	437,035	482,853
226	893 Maintenance of Meters and House Regulators	566,849	781,681
227	894 Maintenance of Other Equipment	385,480	213,766
228	TOTAL Maintenance (Enter Total of lines 218 thru 227)	2,320,962	2,874,316
229	TOTAL Distribution Expenses (Enter Total of lines 216 and 228)	8,508,160	8,634,332
230	5. CUSTOMER ACCOUNTS EXPENSES		
231	Operation		
232	901 Supervision	35,417	34,032
233	902 Meter Reading Expenses	177,624	231,682
234	903 Customer Records and Collection Expenses	2,502,943	2,440,036
235	904 Uncollectible Accounts	647,079	(93,358)
236	905 Miscellaneous Customer Accounts Expenses	72,635	67,571
237	TOTAL Customer Accounts Expenses (Enter Total of lines 232 thru 236)	3,435,698	2,679,963

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	April 23, 2024	Dec. 31, 2023

STATE OF OREGON - ALLOCATED GAS OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Amount (a)	Amount for Current Year (b)	Amount for Previous Year (c)
238	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
239	Operation		
240	907 Supervision	-	-
241	908 Customer Assistance Expenses	4,075,706	5,615,034
242	909 Informational and Instructional Expenses	238,118	341,568
243	910 Miscellaneous Customer Service and Informational Expenses	59,911	32,482
244	TOTAL Customer Service and Information Expenses (Lines 240 thru 243)	4,373,735	5,989,084
245	7. SALES EXPENSES		
246	Operation		
247	911 Supervision		-
248	912 Demonstrating and Selling Expenses	260	-
249	913 Advertising Expenses	-	-
250	916 Miscellaneous Sales Expenses	-	-
251	TOTAL Sales Expenses (Enter Total of lines 247 thru 250)	260	-
252	8. ADMINISTRATIVE AND GENERAL EXPENSES		
253	Operation		
254	920 Administrative and General Salaries	4,070,956	3,818,419
255	921 Office Supplies and Expenses	516,581	556,371
256	(Less) (922) Administrative Expenses Transferred-Cr.	-	-
257	923 Outside Services Employed	1,824,187	1,676,403
258	924 Property Insurance	296,365	251,236
259	925 Injuries and Damages	846,190	778,336
260	926 Employee Pensions and Benefits	3,463,376	4,405,433
261	927 Franchise Requirements	-	-
262	928 Regulartory Commission Expenses	1,314,031	1,128,832
263	(Less) (929) Duplicate Charges-Cr.	-	-
264	930.1 General Advertising Expenses	4	(1,659)
265	930.2 Miscellaneous General Expenses	770,357	746,489
266	931 Rents	60,815	47,392
267	TOTAL Operation (Enter Total of lines 254 thru 266)	13,162,862	13,407,252
268	Maintenance		
269	935 Maintenance of General Plant	1,597,042	1,639,380
270	TOTAL Administrative and General Exp (Total of lines 267 and 269)	14,759,904	15,046,632
271	TOTAL Gas O. and M. Exp (Lines 97,177,201,229,237,244,251,and 270)	119,512,341	127,775,724
		0.00	0.00

NUMBER OF GAS DEPARTMENT EMPLOYEES

1. The data on number of employees should be reported for the payroll period ending nearest to October 31, or any payroll period ending 60 days before or after October 31.

2. If the respondent's payroll for the reporting period includes any special constrction personnel, include such employees on line 3, and show the number of such special construction employees in a foonote.

3. The number of employees assignable to the gas department from joint function of combination utilities may be determined by estimate, on the basis of employee equivalents. Show the estimated number of equivalent employees attributed to the gas department from joint functions.

1. Payroll Period Ended (Date) December 31, 2023		
2. Total Regular Full-Time Employees	68	66
3. Total Part-Time and Temporary Employees allocation of General Employees	1	1
4. Total Employees	69	67

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	[X] An Original [ ] A Resubmission	April 23, 2024	Dec. 31, 2023

STATE OF OREGON - ALLOCATED DEPRECIATION, DEPLETION AND AMORTIZATION OF GAS PLANT (ACCT 403, 404.1,404.2, 404.3, 405)

(Except Amortization of Acquisition Adjustments)

Report the amounts of depreciation expense, depletion and amortization for the accounts indicated and classify according to the plant functional groups shown.

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Amortization and Depletion of Producing Natural Gas Land & Land Rights (Account 404.1) (c)	Amortization of Underground Storage Land and Land Rights (Account 404.2) (d)	Amortization of Other Limited-Term Gas Plant (Account 404.3) (e)	Amortization of Leasehold Improvements (Account 404.6) (f)	Amortization of Other Gas Plant (Account 405) (g)	Total (h)
1	Intangible plant				74,404			74,404
2	Production plant, manufactured gas							
3	Production and gathering plant, natural gas							
4	Products extraction plant							
5	Undergound gas storage plant	129,752						129,752
6	Other storage plant							
7	Base load LNG terminaling and processing plant							
8	Transmission plant							
9	Distribution plant	11,025,577						11,025,577
10	General plant	186,516						186,516
11	Common plant-gas	2,166,639			4,513,857			6,680,496
12								
13								
14								
15								
16								
17								
18								
19	TOTAL	13,508,484	0	0	4,588,261	0	0	18,096,745

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	April 23, 2024	Dec. 31, 2023

STATE OF OREGON - ALLOCATED TAXES, OTHER THAN INCOME TAXES (Account 408.1)

Line No.	Kind of Tax *(a)*	Amount *(b)*
1		
2		
3	Real and Personal Property Tax	5,215,058
4		
5	Municipal Occupation & License Tax	5,733,709
6		
7	Payroll Taxes	753,548
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
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37		
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41		
42		
43		
44		
45		
46		
47		
48	TOTAL (Must agree with page 1, line 11)	11,702,315

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(M, D, Y) April 23, 2024	Dec. 31, 2023

STATE OF OREGON -
ALLOCATED CALCULATION OF CURRENT FEDERAL INCOME TAX EXPENSE (Account 409.1)

1. Report amounts used to derive current Federal income tax expense, Account 409.1, for the reporting period. If amounts ar shown in thousands, show (000) in the heading for column (b).
2. Show amounts increasing taxable income as positive values and amounts decreasing taxable income as negative
3. Current tax expense on this schedule must match the amount reported on page 1, line 12 of this report. Separately identif adjustments arising from revisions of prior year accruals.
4. Minor amounts of other additions (subtractions) may be grouped

Line No.	Particulars (Details) *(a)*	Amount *(b)*
1		
2	Operating Revenue	171,337,357
3	Operating & Maintenance Expense	(119,512,341)
4	Book Depreciation & Amortization	(18,188,224)
5	Taxes Other than FIT	(12,577,310)
6	Interest Expense	(10,261,258)
7		
8	Net Operating Income Before FIT	10,798,224
9		
10	Schedule M Adjustments	7,869,399
11	Net Operating Loss CF Utilized	(18,667,623)
12		
13	Taxable Net Operating Income (loss)	0
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26	Federal Tax Net Income (loss)	0
27	Show computation of Tax:	
	Tax Rate	21%
	Total Federal Income Tax	0
	Deferred FIT	(4,662,525)
	Total FIT/Deferred FIT	(4,662,525)
	The Federal Income Tax computation is from the Avista Corporation's Results of Operations System. As the "Results" system includes allocations of various indirect revenue and cost elements, the values in th allocation of Federal income taxes will not agree with certain supporting schedules	

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	April 23, 2024	Dec. 31, 2023

STATE OF OREGON -
ALLOCATED CALCULATION OF CURRENT STATE INCOME (EXCISE) TAX EXP. (Account 409.1)

1. Report amounts used to derive current state income (excise) tax expense, Account 409.1, for the reporting period. If amount are shown in thousands, show (000) in the heading for column (b).
2. Show amounts increasing taxable income as positive values and amounts decreasing taxable income as negative
3. Current tax expense on this schedule must match the amount reported on page 1, line 13 of this report. Separately identif adjustments arising from revisions of prior year accruals.
4. Minor amounts of other additions (subtractions) may be grouped

Line No.	Particulars (Details) (a)	Amount (b)
1	Federal Tax Net Income (loss) from page 12	0
2	Add back: State Income Taxes Accrued	0
3		
4	Oregon Taxable Income (Loss)	0
5		
6	Oregon SIT Rate	7.60%
7		
8	Oregon SIT	0
9	Minimum Tax	100,000
10	Greater of Calculated SIT or Minimum Oregon Tax	100,000
11		
12	Oregon Natural Gas Allocation Factor	80.016%
13		
14	Oregon Natural Gas SIT	80,016
15		
16	Oregon Commercial Activity Tax (CAT)	794,979
17		
18	State Income Tax	874,995
19		
20		
21		
22		
23		
24		
25		
26		
27		
28	State Tax Net Income	874,995
29	The Federal Tax Net Income computation is from the Avista Corporation's Results of Operations system The commercial activity tax amount is an estimate based on federal taxable revenues and cost of goods sold	

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	*(M, D, Y)* April 23, 2024	Dec. 31, 2023

STATE OF OREGON - ALLOC. ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. In the space provided:
   (a) Identify, by amount and classification, significant items for which deferred taxes are being provided.

Line No.	Account Subdivisions *(a)*	Balance at Beginning of Year *(b)*	CHANGES DURING YEAR: Amounts Debited to Account 410.1 *(c)*	CHANGES DURING YEAR: Amounts Credited to Account 411.1 *(d)*
1	Electric			
2				
3				
4				
5				
6				
7	Other			
8	TOTAL ELECTRIC			
9	Gas Purchased Gas Adjustment			
10				
11	All Other			
12				
13				
14				
15	Other			
16	TOTAL GAS	N/A	(675,264)	3,987,261
17	Other (Specify)			
18	TOTAL (ACCOUNT 190)			
19	Classification of Totals			
20	Federal Income Tax	N/A	(675,264)	3,987,261
21	State Income Tax			
22	Local Income Tax			

Allocation to balance sheet accounts by state is not available. Total expense/credit to 410.1 and 411.1 is reflected in Account 190 for reporting purposes.

Name of Respondent	This Report Is:	Date of Report	Year of Report
	(1) [X] An Original	*(Mo, Da, Yr)*	
Avista Corp.	(2) [ ] A Resubmission	April 23, 2024	Dec. 31, 2023

STATE OF OREGON - ALLOC. ACCUM. DEF. INCOME TAXES (Acct. 190) (Con't.)

(b) Indicate insignificant amounts under OTHER.

3. Beginning balance may be omitted if not readily available. Report gas utility deferred taxes only.
4. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 *(e)*	Amounts Credited to Account 411.2 *(f)*	Acct. No. *(g)*	Amount *(h)*	Acct. No. *(i)*	Amount *(j)*	Balance at End of Year *(k)*	Line No.
							1
							2
							3
							4
							5
							6
							7
							8
						0	9
							10
						0	11
							12
							13
							14
							15
						N/A	16
							17
							18
							19
						N/A	20
							21
							22

Name of Respondent Avista Corp.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report *(M, D, Y)* April 23, 2024	Year of Report Dec. 31, 2023

STATE OF OREGON - ALLOCATED ACCUMULATED DEFERRED INCOME TAXES

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amortizable property.
2. In the space provided furnish explanations, including the following in columnar order:
   (a) State each certification number with a brief description of property.
   (b) Total and amortizable cost of such property.
   (c) Date amortization for tax purposes commenced.
   (d) "Normal" depreciation rate used in computing the deferred tax.

Line No.	Account Subdivisions *(a)*	Balance at Beginning of Year *(b)*	CHANGES DURING YEAR: Amounts Debited to Account 410.1 *(c)*	CHANGES DURING YEAR: Amounts Credited to Account 411.1 *(d)*
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities			
5	Other			
6				
7				
8	TOTAL Electric (Total of lines 3 thru 7)	0		
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other			
13				
14				
15	Total Gas (Total of lines 10 thru 14)	0		
16	Other (Specify)			
17	Total (Acct 281) (Total of 8, 15 & 16)	0		
18	Classification of TOTAL			
19	Federal Income tax			
20	State Income Tax			
21	Local Income Tax			

Allocation to balance sheet accounts by state is not available. Total expense/credit to 410.1 and 411.1 is reflected in Account 190 for reporting purposes.

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(M, D, Y) April 23, 2024	Dec. 31, 2023

STATE OF OREGON - ALLOC. ACCELERATED AMORTIZATION PROPERTY (Acct. 281) Con't.

(e) Tax rate used to originally defer amounts and the tax rate used during the current year to amortize previous deferrals.

3. Beginning balance may be omitted if not readily available. Report gas utility deferred taxes only.
4. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		Debits		Credits			
Amounts Debited to Account 410.2 *(e)*	Amounts Credited to Account 411.2 *(f)*	Acct. No. *(g)*	Amount *(h)*	Acct. No. *(i)*	Amount *(j)*	*(k)*	
							1
							2
							3
							4
							5
							6
							7
						0	8
							9
							10
							11
							12
							13
							14
						0	15
							16
						0	17
							18
							19
							20
							21

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(M, D, Y) April 23, 2024	Dec. 31, 2023

STATE OF OREGON - ALLOC. ACCUM. DEFERRED INCOME TAXES (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred taxes related to property not subject to accelerated amortization.
2. In the space provided furnish explanations, including the following in columnar order:
   (a) State the general method or methods of liberalized depreciation being used (sum-of-year digits, declining balance, etc.)
   (b) Estimated lives (i.e. useful life, guideline life, guideline class life, etc.)
   (c) Classes of plant to which each method is being applied and date method was adopted

Line No.	Account Subdivisions *(a)*	Balance at Beginning of Year *(b)*	CHANGES DURING YEAR Amounts Debited to Account 410.1 *(c)*	Amounts Credited to Account 411.1 *(d)*
1	Account 282			
2	Electric			
3	Gas			
4	Other (Define)			
5	TOTAL (Lines 2 thru 4)			
6	Other (Specify)			
7	Acquisition Adjustment			
8				
9	TOTAL Account 282 (Lines 5 thru 8)	0	0	
10	Classification of TOTAL			
11	Federal Income Tax			
12	State Income Tax			
13	Local Income Tax			

Allocation to balance sheet accounts by state is not available. Total expense/credit to 410.1 and 411.1 is reflected in Account 190 for reporting purposes.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	April 23, 2024	Dec. 31, 2023

STATE OF OREGON - ALLOCATED OTHER PROPERTY (Acct. 282) (Con't.)

3. Beginning balance may be omitted if not readily available. Report gas utility deferred taxes only.
4. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 *(e)*	Amounts Credited to Account 411.2 *(f)*	Acct. No. *(g)*	Amount *(h)*	Acct. No. *(i)*	Amount *(j)*	Balance at End of Year *(k)*	Line No.
							1
							2
						0	3
							4
						0	5
							6
						0	7
							8
0						0	9
							10
						0	11
						0	12
							13

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(M, D, Y) April 23, 2024	Dec. 31, 2023

STATE OF OREGON - ALLOC. ACCUM. DEF. 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. In the space provided below include amounts relating to insignificant items under Other.

Line No.	Account Subdivisions *(a)*	Balance at Beginning of Year *(b)*	CHANGES DURING YEAR Amounts Debited to Account 410.1 *(c)*	CHANGES DURING YEAR Amounts Credited to Account 411.1 *(d)*
1	Account 283			
2	Electric			
3	Electric			
4				
5				
6				
7				
8	Other			
9	TOTAL Electric (Total Lines 3 thru 8)			
10	Gas			
11	Gas			
12				
13	Deferred Gas Estimate			
14				
15				
16	Other			
17	TOTAL Gas (Total Lines 11 thru 16)	0	0	
18	Other (Specify)			
19	TOTAL Account 283 (Enter Total lines 9, 17 and 18)	0	0	
20	Classification of TOTAL			
21	Federal Income Tax	0	0	
22	State Income Tax			
23	Local Income Tax			

Allocation to balance sheet accounts by state is not available. Total expense/credit to 410.1 and 411.1 is reflected in Account 190 for reporting purposes.

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(M, D, Y) April 23, 2024	Dec. 31, 2023

STATE OF OREGON - ALLOC. ACCUM. DEF. INCOME TAXES - OTHER (Acct. 283) (Con't)

3. Beginning balance may be omitted if not readily available. Report gas utility deferred taxes only.
4. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Acct. No. (g)	Amount (h)	Acct. No. (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
						0	11
							12
						0	13
							14
							15
							16
						0	17
							18
						0	19
							20
						0	21
							22
							23

Name of Respondent Avista Corp.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report ((M, D, Y) April 23, 2024	Year of Report Dec. 31, 2023

STATE OF OREGON - ALLOCATED ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. 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)
			Account No. *(c)*	Amount *(d)*	Account No. (e)	Amount (f)			
1	NONE								
2									
3									
4									
5									
6									
8									
9									
10									
11									
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29									
30									
31									

Name of Respondent Avista Corp.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report ((M, D, Y) April 23, 2024	Year of Report Dec. 31, 2023

STATE OF OREGON - ALLOCATED ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Explain by footnote any correction adjustments to the account balance shown in column (g). Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions *(a)*	Balance at Beginning of Year *(b)*	Deferred for Year: Account No. *(c)*	Deferred for Year: Amount *(d)*	Allocations to Current Year's Income: Account No. (e)	Allocations to Current Year's Income: Amount (f)	Adjustments (g)	Balance at End of Year (h)	Average Period of Allocation to Income (i)
1	Gas Utility								
2	3%								
3	4%								
4	7%								
5	10%								
6	TOTAL	0.00						0.00	
7	Other (List separately and show 3%, 4%, 7%, 10%, and TOTAL)								
8									
9									
10									
11									
12									
13									
14									
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31									

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	[X] An Original [ ] A Resubmission	April 23, 2024	Dec. 31, 2023

STATE OF OREGON - SITUS UTILITY PLANT
SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION

Line No.	Item (a)	Total (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Common (g)
1	UTILITY PLANT						
2	In Service						
3	Plant In Service (Classified)	798,530,776	252,137,710	545,032,321			1,360,745
4	Property Under Capital Leases	0		0			
5	Plant Purchased or Sold						
6	Completed Construction not Classified						
7	Experimental Plant Unclassified						
8	TOTAL (Enter Total of lines 3 thru 7)	798,530,776	252,137,710	545,032,321			1,360,745
9	Leased to Others						
10	Held for Future Use						
11	Construction Work in Progress	2,818,599		2,818,599			
12	Acquisition Adjustments	0		0			
13	TOTAL Utility Plant (Lines 8 thru 12)	801,349,375	252,137,710	547,850,920			1,360,745
14	Accum. Prov. for Depr., Amort., Depl.	258,436,109	102,171,591	155,849,751			414,767
15	Net Utility Plant (Line 13 less 14)	543,277,480	150,111,418	392,220,084			945,978
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION & DEPLETION						
17	In Service:						
18	Depreciation	258,071,895	102,026,292	155,630,836			414,767
19	Amort. & Depl. of Producing Natural Gas Land & Land Rights						
20	Amort. of Underground Storage Land & Land Rights						
21	Amort. of Other Utility Plant	364,214	145,299	218,915			0
22	TOTAL in Service (lines 18 thru 21)	258,436,109	102,171,591	155,849,751			414,767
23	Leased to Others						
24	Depreciation						
25	Amortization and Depletion						
26	TOTAL Leased to Others (Lines 24 & 25)	0	0	0			
27	Held for Future Use						
28	Depreciation						
29	Amortization						
30	TOTAL Held for Future Use (Lines 28 & 29)	0	0	0			
31	Abandonment of Leases (Natural Gas)						
32	Amort. of Plant Acquisition Adj.	0	0				
33	TOTAL Accumulated Provisions (Should agree with line 14) (Lines 22, 26, 30, 31 & 32)	258,436,109	102,171,591	155,849,751			414,767

NOTE: Electric plant represents the Coyote Springs 2 plant, which was placed in service on July 1, 2003. Electric depreciation expense is charged to the states of Washington and Idaho.

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	April 23, 2024	Dec. 31, 2023

STATE OF OREGON - SITUS GAS PLANT IN SERVICE

1. Report below the original cost of gas plant in service according to the prescribed accounts.
2. In addition to Account 101, Gas Plant in Service (Classified), this page and the next include Account 102, Gas Plant Purchased or Sold; Account 103, Experimental Gas Plant Unclassified; and Account 106, Completed Construction Not Classified-Gas.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
5. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) reversals of tentative distributions of prior year unclassified retirements. Attach supplemental statement showing the account 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 the end of the year. (Continued on page 25)

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
1	1. Intangible Plant								1
2	301 Organization						0	301	2
3	302 Franchises and Consents							302	3
4	303 Miscellaneous Intangible Plant	715,049	65,514	0	0	0	780,563	303	4
5	TOTAL Intangible Plant	715,049	65,514	0	0	0	780,563		5
6	2. Production Plant								6
7	Natural Gas Production and Gathering Plant								7
8	325.1 Producing Lands	0					0	325.1	8
9	325.2 Producing Leaseholds							325.2	9
10	325.3 Gas Rights							325.3	10
11	325.4 Rights-of-Way							325.4	11
12	325.5 Other Land and Land Rights							325.5	12
13	326 Gas Well Structures							326	13
14	327 Field Compressor Station Structures							327	14
15	328 Field Meas. and Reg. Sta. Structures							328	15
16	329 Other Structures							329	16
17	330 Producing Gas Wells-Well Construction							330	17
18	331 Producing Gas Wells-Well Equipment							331	18
19	332 Field Lines							332	19
20	333 Field Compressor Station Equipment							333	20
21	334 Field Meas. and Reg. Sta. Equipment							334	21
22	335 Drilling and Clearing Equipment							335	22
23	336 Purification Equipment							336	23
24	337 Other Equipment							337	24
25	338 Unsuccessful Exploration & Devel. Costs							338	25
26	TOTAL Production and Gathering Plant	0	0	0	0	0	0		26
27	Products Extraction Plant								27
28	340 Land and Land Rights							340	28
29	341 Structures and Improvements							341	29
30	342 Extraction and Refining Equipment							342	30
31	343 Pipe Lines							343	31
32	344 Extracted Products Storage Equipment							344	32

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	April 23, 2024	Dec. 31, 2023

STATE OF OREGON - SITUS GAS PLANT IN SERVICE

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

7. For Account 399, state the nature and use of plant included in this account and if substantial in amount, submit a supplementary statement showing subaccount classification of such plant conforming to the requirements of these pages.
8. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchaser, and date of transaction. If proposed journal entires have been filed with the Commission as required by the Uniform System of Accounts, give also date of such filing.

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
33	345 Compressor Equipment							345	33
34	346 Gas Meas. and Reg. Equipment							346	34
35	347 Other Equipment							347	35
36	TOTAL Products Extraction Plant	0	0	0	0	0	0		36
37	TOTAL Nat. Gas Production Plant	0	0	0	0	0	0		37
38	Mfd. Gas Prod. Plant (Submit Suppl. Statement)		0	0	0		0		38
39	TOTAL Production Plant	0	0	0	0	0	0		39
40	3. Natural Gas Storage and Processing Plant								40
41	Underground Storage Plant								41
42	350.1 Land						0	350.1	42
43	350.2 Rights-of-Way						0	350.2	43
44	351 Structures and Improvements						0	351	44
45	352 Wells						0	352	45
46	352.1 Storage Leaseholds and Rights						0	352.1	46
47	352.2 Reservoirs						0	352.2	47
48	352.3 Non-recoverable Natural Gas						0	352.3	48
49	353 Lines						0	353	49
50	354 Compressor Station Equipment						0	354	50
51	355 Measuring and Reg. Equipment						0	355	51
52	356 Purification Equipment						0	356	52
53	357 Other Equipment						0	357	53
54	TOTAL Underground Storage Plant	0	0	0	0	0	0		54
55	Other Storage Plant								55
56	360 Land and Land Rights							360	56
57	361 Structures and Improvements							361	57
58	362 Gas Holders							362	58
59	363 Purification Equipment							363	59
60	363.1 Liquefaction Equipment							363.1	60
61	363.2 Vaporizing Equipment							363.2	61
62	363.3 Compressor Equipment							363.3	62
63	363.4 Meas. and Reg. Equipment							363.4	63
64	363.5 Other Equipment							363.5	64
65	TOTAL Other Storage Plant	0	0	0	0	0	0		65

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
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STATE OF OREGON - SITUS GAS PLANT IN SERVICE

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
66	Base Load Liquefied Natural Gas Terminaling and Processing Plant								66
67	364.1 Land and Land Rights							364.1	67
68	364.2 Structures and Improvements							364.2	68
69	364.3 LNG Processing Terminal Equipment							364.3	69
70	364.4 LNG Transportation Equipment							364.4	70
71	364.5 Measuring and Regulating Equipment							364.5	71
72	364.6 Compressor Station Equipment							364.6	72
73	364.7 Communications Equipment							364.7	73
74	364.8 Other Equipment							364.8	74
75	TOTAL Base Load Liquefied Natural	0	0	0	0	0	0		75
76	Gas, Terminaling and Processing Plant								76
77	TOTAL Nat. Gas Storage and Proc. Plant	0	0	0	0	0	0		77
78	4. Transmission Plant								78
79	365.1 Land and Land Rights							365.1	79
80	365.2 Rights-of-Way							365.2	80
81	366 Structures and Improvements							366	81
82	367 Mains							367	82
83	368 Compressor Station Equipment							368	83
84	369 Measuring and Reg. Sta. Equipment							369	84
85	370 Communication Equipment							370	85
86	371 Other Equipment							371	86
87	TOTAL Transmission Plant	0	0	0	0	0	0		87
88	5. Distribution Plant								88
89	374 Land and Land Rights	864,275	35,262	0		0	899,537	374	89
90	375 Structures and Improvements	678,742	21,081	829		0	698,994		90
91	376 Mains	284,079,054	20,493,817	219,729		0	304,353,142		91
92	377 Compressor Station Equipment	0	0	0		0	0		92
93	378 Meas. and Reg. Sta. Equip. - General	6,345,398	476,959	9,765		0	6,812,592		93
94	379 Meas. and Reg. Sta. Equip. - City Gate	3,297,585	51,676	2,357		0	3,346,904		94
95	380 Services	140,725,649	8,591,579	130,588		0	149,186,640		95
96	381 Meters	59,460,901	4,780,399	148,175		0	64,093,125		96
97	382 Meter Installations	0	0	0		0	0		97
98	383 House Regulators	0	0	0		0	0		98
99	384 House Reg. Installations	0	0	0		0	0		99
100	385 Industrial Meas. and Reg. Sta. Equipment	2,480,737	127,383	6,375		0	2,601,745		100
101	386 Other Prop. on Customers' Premises	0	0	0		0	0	386	101
102	387 Other Equipment	539	0	0		0	539	387	102
103	TOTAL Distribution Plant	497,932,880	34,578,156	517,818	0	0	531,993,218		103

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
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STATE OF OREGON - SITUS GAS PLANT IN SERVICE

Line No.		Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
104		6. General Plant								104
105	389	Land and Land Rights	845,517	0	0		0	845,517	389	105
106	390	Structures and Improvements	4,283,635	177,998	3,712		0	4,457,921	390	106
107	391	Office Furniture and Equipment	12,109	0	0		0	12,109	391	107
108	392	Transportation Equipment	4,840,842	229,310	253,585		(4,241)	4,812,326	392	108
109	393	Stores Equipment	20,792	0	0		0	20,792	393	109
110	394	Tools, Shop, and Garage Equipment	1,064,451	324,247	92,514		0	1,296,184	394	110
111	395	Laboratory Equipment	18,586	0	0		0	18,586	395	111
112	396	Power Operated Equipment	43,834	0	0		0	43,834	396	112
113	397	Communication Equipment	754,627	0	12,448		0	742,179	397	113
114	398	Miscellaneous Equipment	9,092	0	0		0	9,092	398	114
115		Subtotal	11,893,485	731,555	362,259	0	(4,241)	12,258,540		115
116	399	Other Tangible Property							399	116
117		TOTAL General Plant	11,893,485	731,555	362,259	0	(4,241)	12,258,540		117
118		TOTAL (Accounts 101 and 106)	510,541,414	35,375,225	880,077	0	(4,241)	545,032,321		118
119		Gas Plant Purchased (See Instr. 8)								119
120		(Less) Gas Plant Sold (See Instr. 8)								120
121		Experimental Gas Plant Unclassified								121
122		TOTAL Gas Plant in Service	510,541,414	35,375,225	880,077	0	(4,241)	545,032,321		122

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
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STATE OF OREGON - SITUS GAS PLANT IN SERVICE

SUPPLEMENT TO PAGE 25

Line No.	Account *(a)*	Balance at Beginning of Year *(b)*	Additions *(c)*	Retirements *(d)*	Adjustments *(e)*	Transfers *(f)*	Balance at End of Year *(g)*		Line No.
	304 Land and Land Rights	59,923				0	59,923	304	
	305 Structures and Improvements						0	305	
	311 Liquified Petroleum Gas Equipment	0					0	311	
38	Total Mfd. Gas Prod. Plant	59,923	0	0	0	0	59,923		38

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
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STATE OF OREGON - EXPENDITURES TO ANY PERSON OR ORGANIZATION HAVING AN AFFILIATED INTEREST FOR SERVICES, ETC.

1. Report all expenditures to any person or organization having an affiliated interest for service, advice, auditing associating, sponsoring, engineering, managing, operating, financial, legal or other services. See Oregon Revised Statute 757.015 for definition of "affiliated interest."
2. Give reference if such expenditures have in the past been approved by the Commission. Describe the services received and the account or accounts charged. Report whole dollars only.

Line No.	Description *(a)*	Account Number *(b)*	Total Amount *(c)*	Amount Assigned to Oregon *(d)*
1				
2	Please refer to the Annual Affiliated Interest Report			
3	pursuant to OAR 860-27-100.			
4				
5	This report will be filed with the Public Utility			
6	Commission of Oregon in June 2024.			
7				
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Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	April 23, 2024	Dec. 31, 2023

STATE OF OREGON - SITUS GAS PLANT HELD FOR FUTURE USE

1. Report separately each property held for future use at end of the year having an original cost of $100,000 or more. Other items of property held for future use may be grouped provided that the number of properties so grouped is indicated.
2. For property having an original cost of $100,000 or more previously used in utility operations, now held for future use, give, 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)	Dated Expected To Be Used In Utility Service (c)	Balance at End of Year (d)
1				
2	NONE			
3				
4				
5				
6				
7				
8				
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43				
44	TOTALS			

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(M, D, Y) April 23, 2024	Dec. 31, 2023

STATE OF OREGON - SITUS CONSTRUCTION WORK IN PROGRESS - (Account 107)

1. Report below descriptions and balances at end of year of project in process of construction (107).
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstration (see Account 107 of the Uniform System of Accounts).
3. Minor projects may be grouped.

Line No.	Description of Project *(a)*	Construction Work in Progress-Gas (Account 107) *(b)*	Estimated Additional Cost of Project *(c)*
1	Gas Replace-St&Hwy	2,791,835	1,450,000
2	Minor Projects < $1M	1,452,063	3,270,893
3			
4			
5			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18	(1) Minor Projects Under $1,000,000 represents mains and		
19	service replacements, regulator reliability programs, gas		
20	telemetry, etc.		
21			
22			
23			
24			
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38	TOTALS	4,243,898	4,720,893

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	April 23, 2024	Dec. 31, 2023

STATE OF OREGON - SITUS ACC. PROV. FOR DEPR. OF GAS UTILITY PLANT (Acct. 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, line 11, column (c), and that reported for gas plant in service, pages 24-27, column (d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 of the Uniform System of Accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Gas Plant in Service (c)	Gas Plant Held for Future Use (d)	Gas Plant Leased to Others (e)
1	Balance Beginning of Year	146,104,452	146,104,452	0	0
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	11,212,093	11,212,093		
4	(413) Exp. of Gas Plt. Leas. to Others				
5	Transportation Expenses-Clearing	330,662	330,662		
6	Other Clearing Accounts				
7	Other Accounts (Specify):	0			
8					
9	TOTAL Deprec. Prov. for Year (Enter Total of lines 3 thru 8)	11,542,755	11,542,755	0	0
10	Net Charges for Plant Retired:				
11	Book Cost of Plant Retired	880,077	880,077		
12	Cost of Removal	0	0		
13	Salvage (Credit)	0	0		
14	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 11 thru 13)	880,077	880,077	0	0
15	Other Debit or Credit Items (Describe)	(1,136,294)	(1,136,294)		
16	Transfer of Intang Plt & Exclude Comm. Plt.				
17	Balance End of Year (Enter Total of lines 1, 9, 14, 15, and 16)	155,630,836	155,630,836	0	0

Section B. Balances at End of Year According to Functional Classifications

Line No.	Item (a)	Total (c+d+e) (b)	Gas Plant in Service (c)	Gas Plant Held for Future Use (d)	Gas Plant Leased to Others (e)
18	Production-Manufactured Gas				
19	Prod. and Gathering-Natural Gas				
20	Products Extraction-Natural Gas				
21	Underground Gas Storage	0			
22	Other Storage Plant				
23	Base Load LNG Term and Proc. Plt.				
24	Transmission				
25	Distribution	149,690,561	149,690,561		
26	General	5,940,275	5,940,275		
27	TOTAL (Enter Total of lines 18 thru 26)	155,630,836	155,630,836	0	0

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(M, D, Y) April 23, 2024	Dec. 31, 2023

STATE OF OREGON - ALLOCATED
SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION

Line No.	Item (a)	Total (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Common (g)
1	UTILITY PLANT						
2	In Service						
3	Plant In Service (Classified)	70,336,737		10,249,660			60,087,077
4	Property Under Capital Leases	963,648					963,648
5	Plant Purchased or Sold						
6	Completed Construction not Classified						
7	Experimental Plant Unclassified						
8	TOTAL (Enter Total of lines 3 thru 7)	71,300,385		10,249,660			61,050,725
9	Leased to Others						
10	Held for Future Use						
11	Construction Work in Progress	2,906,131		75,217			2,830,914
12	Acquisition Adjustments						
13	TOTAL Utility Plant (Lines 8 thru 12)	74,206,516		10,324,877			63,881,639
14	Accum. Prov. for Depr., Amort., Depl.	28,714,938		2,769,610			25,945,328
15	Net Utility Plant (Line 13 less 14)	45,491,578		7,555,267			37,936,311
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION & DEPLETION						
17	In Service:						
18	Depreciation	12,366,113		2,650,245			9,715,868
19	Amort. & Depl. of Producing Natural Gas Land & Land Rights						
20	Amort. of Underground Storage Land & Land Rights						
21	Amort. of Other Utility Plant	16,348,825		119,365			16,229,460
22	TOTAL in Service (lines 18 thru 21)	28,714,938		2,769,610			25,945,328
23	Leased to Others						
24	Depreciation						
25	Amortization and Depletion						
26	TOTAL Leased to Others (Lines 24 & 25)	0		0			
27	Held for Future Use						
28	Depreciation						
29	Amortization						
30	TOTAL Held for Future Use (Lines 28 & 29)	0		0			
31	Abandonment of Leases (Natural Gas)						
32	Amort. of Plant Acquisition Adj.						
33	TOTAL Accumulated Provisions (Should agree with line 14) (Lines 22, 26, 30, 31 & 32)	28,714,938		2,769,610			25,945,328

NOTE: Property Under Capital Leases is comprised of ROU Assests

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	April 23, 2024	Dec. 31, 2023

STATE OF OREGON - ALLOCATED GAS PLANT IN SERVICE

1. Report below the original cost of gas plant in service according to the prescribed accounts.
2. In addition to Account 101, Gas Plant in Service (Classified), this page and the next include Account 102, Gas Plant Purchased or Sold; Account 103, Experimental Gas Plant Unclassified; and Account 106, Completed Construction Not Classified-Gas.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year
4. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
5. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c) Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) reversals of tentative distributions of prior year unclassified retirements. Attach supplemental statement showing the account 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 the end of the year. (Continued on page 33)

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
1	1. Intangible Plant								1
2	301 Organization						0	301	2
3	302 Franchises and Consents						0	302	3
4	303 Miscellaneous Intangible Plant	131,433	99,852			235,702	466,987	303	4
5	TOTAL Intangible Plant	131,433	99,852	0	0	235,702	466,987		5
6	2. Production Plant								6
7	Natural Gas Production and Gathering Plant								7
8	325.1 Producing Lands						0	325.1	8
9	325.2 Producing Leaseholds						0	325.2	9
10	325.3 Gas Rights						0	325.3	10
11	325.4 Rights-of-Way						0	325.4	11
12	325.5 Other Land and Land Rights						0	325.5	12
13	326 Gas Well Structures						0	326	13
14	327 Field Compressor Station Structures						0	327	14
15	328 Field Meas. and Reg. Sta. Structures						0	328	15
16	329 Other Structures						0	329	16
17	330 Producing Gas Wells-Well Construction						0	330	17
18	331 Producing Gas Wells-Well Equipment						0	331	18
19	332 Field Lines						0	332	19
20	333 Field Compressor Station Equipment						0	333	20
21	334 Field Meas. and Reg. Sta. Equipment						0	334	21
22	335 Drilling and Clearing Equipment						0	335	22
23	336 Purification Equipment						0	336	23
24	337 Other Equipment						0	337	24
25	338 Unsuccessful Exploration & Devel. Costs						0	338	25
26	TOTAL Production and Gathering Plant	0	0	0	0	0	0		26
27	Products Extraction Plant								27
28	340 Land and Land Rights						0	340	28
29	341 Structures and Improvements						0	341	29
30	342 Extraction and Refining Equipment						0	342	30
31	343 Pipe Lines						0	343	31
32	344 Extracted Products Storage Equipment						0	344	32

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	April 23, 2024	Dec. 31, 2023

STATE OF OREGON - ALLOCATED GAS PLANT IN SERVICE

6. Show in column (f) reclassifications or transfers within utility plant acounts. Include also in column (f) the additions or reductions of primary account classifications arising fror distribution of amounts initially recorded in Account 102. In showing the clearance o Account 102, include in column (e) the amounts with respect to accumulated provision fo 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

7. 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 requirements of these page:

8. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold name of vendor or purchaser, and date of transaction. If proposed journal entires have been filed with the Commissio as required by the Uniform System of Accounts, give also date of such filing

Line No.	Account (a)	Balance at Beginning of Yea (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
33	345 Compressor Equipment						0	345	33
34	346 Gas Meas. and Reg. Equipment						0	346	34
35	347 Other Equipment						0	347	35
36	TOTAL Products Extraction Plant	0	0	0	0	0	0		36
37	TOTAL Nat. Gas Production Plant	0	0	0	0				37
38	Mfd. Gas Prod. Plant (Submit Suppl. Statement)	59,923				0	59,923		38
39	TOTAL Production Plant	59,923	0	0	0	-	59,923		39
40	3. Natural Gas Storage and Processing Plant								40
41	Underground Storage Plant								41
42	350.1 Land	87,585				0	87,585	350.1	42
43	350.2 Rights-of-Way	669				0	669	350.2	43
44	351 Structures and Improvements	179,069				36,904	215,973	351	44
45	352 Wells	3,390,349				36,893	3,427,242	352	45
46	352.1 Storage Leaseholds and Rights	0				0	0	352.1	46
47	352.2 Reservoirs	0				0	0	352.2	47
48	352.3 Non-recoverable Natural Gas	0				0	0	352.3	48
49	353 Lines	170,745				0	170,745	353	49
50	354 Compressor Station Equipment	3,281,269				36,894	3,318,163	354	50
51	355 Measuring and Reg. Equipment	196,984				36,894	233,878	355	51
52	356 Purification Equipment	15,106				0	15,106	356	52
53	357 Other Equipment	174,569				36,893	211,462	357	53
54	TOTAL Underground Storage Plant	7,496,345	0	0	0	184,478	7,680,823		54
55	Other Storage Plant								55
56	360 Land and Land Rights						0	360	56
57	361 Structures and Improvements						0	361	57
58	362 Gas Holders						0	362	58
59	363 Purification Equipment						0	363	59
60	363.1 Liquefaction Equipment						0	363.1	60
61	363.2 Vaporizing Equipment						0	363.2	61
62	363.3 Compressor Equipment						0	363.3	62
63	363.4 Meas. and Reg. Equipment						0	363.4	63
64	363.5 Other Equipment						0	363.5	64
65	TOTAL Other Storage Plant	0	0	0	0	0	0		65

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
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STATE OF OREGON - ALLOCATED GAS PLANT IN SERVICE

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
66	Base Load Liquefied Natural Gas Terminaling and Processing Plant								66
67	364.1 Land and Land Rights						0	364.1	67
68	364.2 Structures and Improvements						0	364.2	68
69	364.3 LNG Processing Terminal Equipment						0	364.3	69
70	364.4 LNG Transportation Equipment						0	364.4	70
71	364.5 Measuring and Regulating Equipment						0	364.5	71
72	364.6 Compressor Station Equipment						0	364.6	72
73	364.7 Communications Equipment						0	364.7	73
74	364.8 Other Equipment						0	364.8	74
75	TOTAL Base Load Liquefied Natural	0	0	0	0	0	0		75
76	Gas, Terminaling and Processing Plant						0		76
77	TOTAL Nat. Gas Storage and Proc. Plant	7,496,345	0	0	0	184,478	7,680,823		77
78	4. Transmission Plant								78
79	365.1 Land and Land Rights						0	365.1	79
80	365.2 Rights-of-Way						0	365.2	80
81	366 Structures and Improvements						0	366	81
82	367 Mains						0	367	82
83	368 Compressor Station Equipment						0	368	83
84	369 Measuring and Reg. Sta. Equipment						0	369	84
85	370 Communication Equipment						0	370	85
86	371 Other Equipment						0	371	86
87	TOTAL Transmission Plant	0	0	0	0	0	0		87
88	5. Distribution Plant								88
89	374 Land and Land Rights						0	374	89
90	375 Structures and Improvements						0	375	90
91	376 Mains						0	376	91
92	377 Compressor Station Equipment						0	377	92
93	378 Meas. and Reg. Sta. Equip. - General						0	378	93
94	379 Meas. and Reg. Sta. Equip. - City Gate						0	379	94
95	380 Services						0	380	95
96	381 Meters						0	381	96
97	382 Meter Installations						0	382	97
98	383 House Regulators						0	383	98
99	384 House Reg. Installations						0	384	99
100	385 Industrial Meas. and Reg. Sta. Equipment		0			0	0	385	100
101	386 Other Prop. on Customers' Premises	0					0	386	101
102	387 Other Equipment	0					0	387	102
103	TOTAL Distribution Plant	0	0	0	0	0	0		103

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
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STATE OF OREGON - ALLOCATED GAS PLANT IN SERVICE

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
104	6. General Plant								104
105	389 Land and Land Rights	0	0	0		0	0	389	105
106	390 Structures and Improvements	0	0	0		0	0	390	106
107	391 Office Furniture and Equipment	53,358	0	0		(511)	52,847	391	107
108	392 Transportation Equipment	30,385	34,856	15,748		(19,399)	30,094	392	108
109	393 Stores Equipment	0	0	0		0	0	393	109
110	394 Tools, Shop, and Garage Equipment	1,801,973	7,896	5,856		7,360	1,811,373	394	110
111	395 Laboratory Equipment	72,696	0	0		(695)	72,001	395	111
112	396 Power Operated Equipment	0	0	0		0	0	396	112
113	397 Communication Equipment	76,065	0	0		(728)	75,337	397	113
114	398 Miscellaneous Equipment	278	0	0		(3)	275	398	114
115	Subtotal	2,034,755	42,752	21,604	0	(13,976)	2,041,927		115
116	399 Other Tangible Property	0					0	399	116
117	TOTAL General Plant	2,034,755	42,752	21,604	0	(13,976)	2,041,927		117
118	TOTAL (Accounts 101 and 106)	9,722,456	142,604	21,604	0	406,204	10,249,660		118
119	Gas Plant Purchased (See Instr. 8)								119
120	(Less) Gas Plant Sold (See Instr. 8)								120
121	Experimental Gas Plant Unclassified								121
122	TOTAL Gas Plant in Service	9,722,456	142,604	21,604	0	406,204	10,249,660		122

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	April 23, 2024	Dec. 31, 2023

STATE OF OREGON - ALLOCATED GAS 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 $100,000 or more. Other items of property held for future use may be grouped provided that the number of properties so grouped is indicatec
2. For property having an original cost of $100,000 or more previously used in utility operations, now held for future use, give, ir addition to other required information, the date that utility use of such property was discontinued, and the date the origina 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				
2	NONE			
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
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43				
44	TOTALS			

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	April 23, 2024	Dec. 31, 2023

STATE OF OREGON - ALLOCATED CONSTRUCTION WORK IN PROGRESS - (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 Demonstration (see Account 107 of the Uniform System of Accounts).
3. Minor projects may be grouped.

Line No.	Description of Project (a)	Construction Work in Progress-Gas (Account 107) (b)	Estimated Additional Cost of Project (c)
1	Minor Projects Under $1,000,000:	2,693,816	2,251,058
2			
3			
4			
5			
6			
7			
8			
9			
10			
11			
12			
13			
14			
15	(1) Minor Projects Under $1,000,000 represents mains and		
16	service replacements, regulator reliability programs, gas		
17	telemetry, facilities and ET projects, etc.		
18			
19			
20			
21			
22			
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24			
25			
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37			
38	Totals	2,693,816	2,251,058

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	April 23, 2024	Dec. 31, 2023

STATE OF OREGON - ALLOC. ACC. PROV. FOR DEPR. OF GAS UTILITY PLANT (Acct. 119)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, line 11, column (c), and that reported for gas plant in service, pages 32-35, column (d), excluding retirements of non-depreciable property.
3. The provisions of Account 119 in the Uniform System of Accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Gas Plant in Service (c)	Gas Plant Held for Future Use (d)	Gas Plant Leased to Others (e)
1	Balance Beginning of Year	2,415,832	2,415,832	0	0
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	239,802	239,802		
4	(413) Exp. of Gas Plt. Leas. to Others				
5	Transportation Expenses-Clearing	0			
6	Other Clearing Accounts				
7	Other Accounts (Specify):	0	0		
8					
9	TOTAL Deprec. Prov. for Year (Enter Total of lines 3 thru 8)	239,802	239,802	0	0
10	Net Charges for Plant Retired:				
11	Book Cost of Plant Retired	0	0		
12	Cost of Removal	0	0		
13	Salvage (Credit)	0	0		
14	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 11 thru 13)	0	0	0	0
15	Other Debit or Credit Items (Describe):	(5,389)	(5,389)		
16					
17	Balance End of Year (Enter Total of lines 1, 9, 14, 15, and 16)	2,650,245	2,650,245	0	0

Section B. Balances at End of Year According to Functional Classifications

Line No.	Item	Total (c+d+e)	Gas Plant in Service	Gas Plant Held for Future Use	Gas Plant Leased to Others
18	Production-Manufactured Gas				
19	Prod. and Gathering-Natural Gas				
20	Products Extraction-Natural Gas				
21	Underground Gas Storage	1,773,512	1,773,512		
22	Other Storage Plant				
23	Base Load LNG Term and Proc. Plt.				
24	Transmission				
25	Distribution	0	0		
26	General	876,733	876,733		
27	TOTAL (Enter Total of lines 18 thru 26)	2,650,245	2,650,245	0	0

Name of Respondent	This Report Is:	Date of Report (M,D,Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	April 23, 2024	Dec. 31, 2023

STATE OF OREGON - GAS STORED (117, 164.1, 164.2, AND 164.3)

1. Report below the information called for concerning inventories of gas stored
2. The Uniform System of Accounts provides that inventory cost records be maintained on a consolidated basis for all storage projects with separate records showing the Mcf of inputs and withdrawals and balance for each project, except under specified circumstances. If the respondent's inventory cost records are not maintained on a consolidated basis for all storage projects, furnish an explanation of the accounting followed and reason for any deviation from the general basis provided by the Uniform System of Accounts. Separate schedules on this schedule form should be furnished for each group of storage projects for which separate inventory cost records are maintained.
3. If during the year adjustment was made of the stored gas inventory, such as to correct for cumulative inaccuracies of gas measurements, furnish an explanation of the reason for the adjustment, the Mcf and dollar amount of adjustment and account charged or credited.
4. Give a concise statement of the facts and the accounting performed with respect to any encroachment of withdrawals during the year, or restoration of previous encroachment, upon native gas constituting the "gas cushion" of any storage reservoir.
5. If the respondent uses a "base stock" in connection with its inventory accounting, give a concise statement of the basis of establishing such "base stock" and the inventory basis and the accounting performed with respect to any encroachment of withdrawals on "base stock", or restoration of previous encroachment, including brief particulars of any such accounting during the year
6. If respondent has provided accumulated provision for stored gas which may not eventually be fully recovered from any storage project furnish a statement showing: (a) date of Commission authorization of such accumulated provision (b) explanation of circumstances requiring such provision (c) basis of provision and factors of calculation (d) estimated ultimate accumulated provision accumulation (e) a summary showing balance of accumulated provision and entries during year
7. Pressure base of gas volume reported in this schedule is 14.73 psia at 60° F

Line No.	Description	Noncurrent (Account 117) (a)	Current (Account 164.1) (b)	LNG (Account 164.2) (e)	LNG (Account 164.3) (d)	Total (e)
1	Balance, beginning of year	1,261,012	2,727,910	0	0	3,988,922
2	Gas delivered to storage		2,527,065			2,527,065
3	(contra account)					
4	Gas withdrawn from storage		3,400,209			3,400,209
5	(contra account)					
6	Other debits and credits net		0			0
7						
8						
9						
10						
11						
12	Balance, end of year	1,261,012	1,854,766	0	0	3,115,778
13	Therm	2,259,880	8,015,870			10,275,750
14	Amount per Mcf	$5.58	$2.31			$3.03
15	State basis of segregation of inventory between current and noncurrent portions.					
16	Current portion is gas expected to be sold within a 24-month period. All other gas is considered non-current.					
17	Gas delivered to storage:			Current	LNG	
18	Therm			10,502,920		
19	Amount per therm			$0.24		
20	Cost basis of gas delivered to storage:					
21	Specify: Own production (give production area, see				Average Cost	
22	uniform system of accounts); average system purchases;					
23	specific purchases (state which purchases).					
24	Does cost of gas delivered to storage include any expenses					
25	for use of respondent's transmission, storage or other					
26	facilities? If so, give particulars and date of Commision			No		
27	approval of accounting.					
28						
29	Gas withdrawn from storage:					
30	Therm			6,619,930		
31	Amount per therm			$0.51		
32	Cost basis of withdrawal					
33	Specify: average cost, lifo, fifo, (Explain any change in				Average Cost	
34	inventory basis during year and give date of Commission					
35	approval of the change or approval of an inventory basis					
36	different from that referred to in uniform system of accounts)					
37						
38						
39						
40						

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	April 23, 2024	Dec. 31, 2023
Conversion Factor to MCF .9756	0.976		

STATE OF OREGON - GAS PURCHASES (Accounts 800, 801,803, 804, 804.1 and 805)

Line No.	Name of Seller (Designate Associated Companies) (a)	Name of Producing Field or Gasoline Plant (b)	Net Rate Effective December 31 (c)
1	Refer to Note (1)		
2	Note (1) The following are the major gas suppliers for the State of Oregon		
3	BP Canada Energy Marketing, Corp.		
4	BP Energy Company		
5	Castleton Commodities Merchant Trading L.P.		
6	CIMA Energy, Ltd		
7	Citadel Energy Marketing LLC		
8	Concord Energy, LLC		
9	ConocoPhillips Canada Resources Corp.		
10	ConocoPhillips Company		
11	EDF Trading North America, LLC		
12	FortisBC Energy Inc.		
13	Freepoint Commodities LLC		
14	ICE NGX Canada Inc.		
15	Idaho Power Company		
16	IGI Resources Inc.		
17	J. Aron & Company LLC		
18	Koch Energy Services, LLC		
19	Macquarie Energy Canada Ltd		
20	Macquarie Energy LLC		
21	Mercuria Commodities Canada Corporation		
22	Mercuria Energy America, LLC		
23	MIECO LLC		
24	Morgan Stanley Capital Group Inc.		
25	National Bank of Canada		
26	Nevada Power Company		
27	Portland General Electric Company		
28	Powerex		
29	Puget Sound Energy, Inc.		
30	Sacramento Municipal Utility District		
31	Sequent Energy Management LLC		
32	Sequent Energy Management, L.P.		
33	Shell Energy North America (US) L.P.		
34	Sierra Pacific Power Company		
35	Spotlight Energy, LLC		
36	Summit Energy LLC		
37	TD Energy Trading Inc.		
38	Tenaska Marketing Ventures		
39	Twin Eagle Resource Management, LLC		
40	Ultra Resources, Inc.		
41	United Energy Trading LLC		
42	Vitol Inc.		
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Name of Respondent	This Report is	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(M, D, Y) April 23, 2024	Dec. 31, 2023

STATE OF OREGON - GAS PURCHASES (Accounts 800, 801, 802, 803, 804, 804.1 and 805) (Con't)

Seller Code (d)	State Code (e)	Count Code (f)	Schedule No. (g)	Schedule Suffix (h)	Date of Contract (i)	Approx BTU Per CU FT (j)	Gas Purchased - Mcf (14.73 PSIA 60°) (k)	Cost of Gas (l)	Cost Per Mcf (Dollars) (m)	Line No.
Refer to Note (1)					Various		17,968,720	$ 74,415,968.00	$4.14	1
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Name of Respondent Avista Corp.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (M, D, Y) April 23, 2024	Year of Report Dec. 31, 2023

STATE OF OREGON - GAS USED IN UTILITY OPERATIONS - CREDIT (Accounts 810, 811, 812)

1. Report below particulars of credits during the year to Accounts 810, 811 and 812, which offset charges to operating expenses or other accounts or the cost of gas from the respondent's own supply.
2. Natural gas means either natural gas unmixed, or any mixture of natural and manufactured gas.
3. If the reported MCF for any use is an estimated quantity, state such fact.
4. If any natural gas was used by the respondent for which charge was not made to the appropriate operating expense or other account, list separately in column (c) the MCF of gas so used, omitting entries in columns (d) and (e).
5. Pressure base of measurement, to be reported in columns (c) and (f) is 14.73 psia at 60° F.

			Natural Gas			Manufactured Gas	
Line No.	Purpose for Which Gas was Used (a)	Account Charged (b)	MCF of Gas Used (14.73 PSIA at 60°F) (c)	Amount of Credit (d)	Amount Per MCF (Cents) (e)	MCF of Gas Used (14.73 PSIA at 60°) (f)	Amount of Credit (g)
1	810 Gas used for Compressor Station Fuel- Credit						
2	811 Gas used for Products Extraction - Credit		12,914,355	$200,884	$0.02		
3	(a) Gas shrinkage & other usage in respondent's own processing						
4	(b) Gas shrinkage, etc. for respondent's gas processed by others						
5	812 Gas used for Other Utility Operations - Credit						
6	(Report separately for each principal use. Group minor uses.)						
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Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	April 23, 2024	Dec. 31, 2023
Year: 201212			

STATE OF OREGON - GAS ACCOUNT - NATURAL GAS

1. The purpose of this schedule is to account for the quantity of natural gas received and delivered by the respondent taking into consideration differences in pressure bases used in measuring MCF of natural gas received and delivered.
2. Natural gas means either natural gas unmixed or any mixture of natural and manufactured gas.
3. Enter in column (c) the MCF as reported in the schedules indicated for the respective items of receipts and deliveries.

Line No.	Item *(a)*	Ref. Page No. *(b)*	Therms *(c)*
1	GAS RECEIVED		
2	Natural Gas Produced		
3	LPG Gas Produced and Mixed with Natural Gas		
4	Manufactured Gas Produced and Mixed with Natural Gas		
5	Purchased Gas		
6	Wellhead		
7	Field Lines		
8	Gasoline Plants		
9	Transmission Line		
10	City Gate Under FERC Rate Schedules		184,181,220
11	LNG		
12	Other (imbalances)		218,140
13	TOTAL GAS PURCHASED		184,399,360
14	Gas of Others Received for Transportation		31,565,750
15	Receipts of Respondents' Gas Transported or Compressed by Others		
16	Exchange Gas Received		
17	Gas Withdrawn from Underground Storage		6,619,930
18	Gas Received from LNG Storage		
19	Gas Received from LNG Processing		
20	Other Receipts (Specify): Storage Injections		
	TOTAL RECEIPTS		222,585,040

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	April 23, 2024	Dec. 31, 2023

STATE OF OREGON - GAS ACCOUNT - NATURAL GAS (Con't)

4. In a footnote report the volumes of gas from respondent's own production delivered to respondent's transmission system and included in natural gas sale.
5. If the respondent operates two or more systems which are not interconnected, separate schedules should be submitted. Insert pages should be used for this purpose.

Line No.	Item *(a)*	Ref. Page No. *(b)*	Amount of Therms *(c)*
	GAS DELIVERED		
22	Natural Gas Sales		
23	a. Field Sales		
24	(i) To Interstate Pipeline Companies for Resale		
25	Pursuant to FERC Rate Schedules		
26	(ii) Retail Industrial Sales		
27	(iii) Other Field Sales		
28	TOTAL FIELD SALES		0
29	b. Transmission Systems Sales		
30	(i) To Interstate Pipeline Co. for Resale Under FERC Rate Schedules		
31	(ii) To Intrastate Pipeline Co. and Gas Utilities for resale under		
32	FERC rate schedules		
33	(iii) Mainline Industrial Sales Under FERC Certification		
34	(iv) Other Mainline Industrial Sales		
35	(v) Other Transmission System Sales		
36	TOTAL TRANSMISSION SYSTEM SALES		0
37	c. Local Distribution by Respondent		
38	(i) Retail Industrial Sales		14,284,982
39	(ii) Other Distribution System Sales		91,235,874
40	TOTAL DISTRIBUTION SYSTEM SALES		105,520,856
41	d. Interdepartmental sales		15,347
42	TOTAL SALES		105,536,203
43			
44	Deliveries of Gas Transported or Compressed for:		
45	a. Other Interstate Pipeline Companies		
46	b. Others		31,565,750
47	TOTAL GAS TRANSPORTED OR COMPRESSED FOR OTHERS		31,565,750
48	Deliveries of Respondent's Gas for Trans. or Compression by Others		
49	Exchange Gas Delivered		
50	Natural Gas Used by Respondent		
51	Natural Gas Delivered to Underground Storage		10,502,920
52	Natural Gas Delivered to LNG Storage		
53	Natural Gas Delivered to LNG Processing		
54	Natural Gas for Franchise Requirements		
55	Other Deliveries (Specify): Sales for Resale		78,266,550
56	TOTAL SALES & OTHER DELIVERIES UNACCOUNTED FOR		225,871,423
57	Production System Losses		
58	Storage Losses		
59	Transmission System Losses		(3,286,383)
60	Distribution System Losses		
61	Other Losses (Specify in so far as possible):		
62	TOTAL UNACCOUNTED FOR		
63	TOTAL SALES, OTHER DELIVERIES, AND UNACCOUNTED FOR		222,585,040

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	April 23, 2024	Dec. 31, 2023

STATE OF OREGON - MISCELLANEOUS GENERAL EXPENSES (Account 930.2)

Report below the information called for concerning items included in miscellaneous general expenses.

Line No.	Items (a)	Total (b)	Amount Applicable to Oregon (c)	Amount Applicable to Other States (d)
1	Industry Association Dues	611,891	187,917	423,974
2	Experimental and General Research Expenses			
3	Publishing and Distributing Information and Reports to Stockholders; Trustee, Registrar and Transfer Agent Fees and Expenses, and Other Expenses of Servicing Outstanding Securities of the Respondent	293,643	90,191	203,452
4	Other Expenses (List items of $5,000 or more in this column showing the (1) purpose, (2) recipient and (3) amount of such items, Group amounts of less than $5,000 by classes if			
5	Community Relations	215,113	68,098	147,015
6	Board of Director Activites	749,459	230,194	519,265
7	Educational - Informational	288,552	88,627	199,925
8	Misc. Employee Expenses	47,719	15,935	31,784
9	Misc. Legal, Professional, and General Services	78,810	24,206	54,604
10	Misc. Transportation	82,848	25,447	57,401
11	Other Misc. Expenses <$5k	2,635	1,184	1,451
12	Misc. Labor	125,536	38,558	86,978
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	TOTAL	2,496,206	770,357	1,725,849

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	April 23, 2024	Dec. 31, 2023

STATE OF OREGON - POLITICAL ADVERTISING

1. List all payments for advertising, the purpose of which is to aid or defeat any measure before the people or to promote or prevent the enactment of any national, state, district or municipal legislation.
2. Give the specific purpose of such advertising, when and where placed, and the account or accounts charged.
3. Report whole dollars only. Provide a total for each account and a grand total.

Line No.	Description (a)	Account Charged (b)	Amount (c)
1			
2			
3	NONE		
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Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	April 23, 2024	Dec. 31, 2023

STATE OF OREGON - POLITICAL CONTRIBUTIONS

1. List all payments or contributions to persons and organizations for the purpose of aiding or defeating any measure before the people or to promote or prevent the enactment of any national, state, district or municipal legislation.
2. The purpose of all contributions or payments should be clearly explained.
3. Report whole dollars only. Provide a total for each account and a grand total.

Line No.	Description *(a)*	Account Charged *(b)*	Amount *(c)*
1	Senator David Brock Smith	426.4	2,500
2	Senator Dick Anderson	426.4	2,500
3	Senator Fred Girod	426.4	2,500
4	Senator Rob Wagner	426.4	1,500
5	Senator Kate Lieber	426.4	1,500
6	Senator Elizabeth Steiner Hayward	426.4	1,500
7	Dan Rayfield	426.4	1,500
8	Vikki Breese Iverson	426.4	2,000
9	Court Boice	426.4	1,000
10	Virgle Osborne	426.4	1,000
11	Lily Morgan	426.4	1,500
12	Christine Goodwin	426.4	1,000
13	Kim Wallan	426.4	1,000
14	Annessa Hartman	426.4	1,000
15	Emerson Levy	426.4	1,500
16	E Werner Reschke	426.4	1,000
17	Emily McIntire	426.4	1,000
18	Greg Smith	426.4	1,000
19	Bobby Levy	426.4	2,000
20	Mark Owens	426.4	1,000
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42	TOTAL		29,500

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	April 23, 2024	Dec. 31, 2023

STATE OF OREGON - DONATIONS AND MEMBERSHIPS

1. List all donations and membership expenditures made by the utility during the year and the amounts charged (items less than $1,000 may be consolidated by category stating the number of organizations included). Give the name, city and state of each organization to whom a donation has been made. Group donations under headings as:
   a. Contributions to and memberships in charitable organizations
   b. Organizations of the utility industry
   c. Technical and professional organizations
   d. Commercial and trade organizations
   e. All other organizations and kinds of donations and contributions

2. List donations by type and group by the accounts charged. Report whole dollars only. Provide a total for each group of donations.

Line No.	Description (a)	Account Number (b)	Total Amount (c)	Amount Assigned To Oregon (d)
1	a. Contributions to and memberships in charitable organizations			
2	a Less than $1,000		15,722	15,722
3	a Greater than $1,000		53,981	53,981
4	a UNION COUNTY EXTENSION		1,301	1,301
	OREGON HUMAN DEVELOPMENT CORP		1,000	1,000
	WALKING TALL SOUTHERN OREGON		1,000	1,000
	PROVIDENCE COMMUNITY HEALTH FOUNDATION		5,000	5,000
	BUILDERS ASSOCIATION SOUTHERN OREGON		4,660	4,660
	SOUTHERN OREGON UNIVERSITY		4,000	4,000
	ASHLAND CHAMBER OF COMMERCE		4,000	4,000
	PEAR BLOSSOM ASSOCIATION		2,500	2,500
	ROSEBURG ROTARY FOUNDATION		2,500	2,500
	CRATERIAN PERFORMANCES		2,500	2,500
	MEDFORD JACKSON COUNTY		2,250	2,250
	MERC		1,550	1,550
	ACCESS INC		1,500	1,500
	EASTERN OREGON LIVESTOCK		1,500	1,500
	GRANTS PASS CHAMBER OF COMMERCE		1,500	1,500
	GRANTS PASS ACTIVE CLUB		1,500	1,500
	CITY OF GRANTS PASS		1,500	1,500
	OREGON BUSINESS CHARITABLE INST		1,170	1,170
	BOARDMAN CHAMBER OF COMMERCE		1,050	1,050
	ROGUE COMMUNITY HEALTH		1,000	1,000
	THE CHAMBER OF MEDFORD / JACKSON COUNTY		1,000	1,000
	FRIENDS OF THE CHILDREN		1,000	1,000
	RIVERBEND LIVE		1,000	1,000
	CASA OF JACKSON COUNTY INC		1,000	1,000
	NON COMMISSIONED OFFICERS ASSN		1,000	1,000
	TIGER BOOSTERS		1,000	1,000
	KCEDA		1,000	1,000
	UNITED COMMUNITY ACTION NETWORK		1,000	1,000
	GRACE CASCADE CHRISTIAN SCHOOL		1,000	1,000
	CITY OF WINSTON		1,000	1,000
	SUTHERLIN ROTARY CLUB		1,000	1,000
5	a Total Contributions to and memberships in charitable orgs	426.1	69,703	69,703
6	d. Commercial and trade organizations			
7	d Less than $1,000		5,704	5,704
8	d Greater than $1,000		15,221	15,221
9	d BUILDERS ASSOCIATION OF SOUTHERN OREGON		1,245	1,745
	KCEDA		5,000	5,000
	SOREDI		2,750	2,500
	UMPQUA ECONOMIC DEVELOPMENT PARTNERSHIP		5,000	5,000
	THE CHAMBER OF MEDFORD / JACKSON COUNTY		1,226	1,226
10	d Total Commercial and Trade Organizations	426.1	20,925	20,925
11				
12				
13	Subtotal	426.1	90,628	90,628
14				
15				
16	Total		90,628	90,628

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(M, D, Y) April 23, 2024	Dec. 31, 2023

STATE OF OREGON - OFFICERS' SALARIES

1. Report below the name, title and salary for the year 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 date change in incumbency was made
3. Utilities which are required to file similar data with the Securities and Exchange Commission, may substitute a copy of Item 4, Regulation S-K, identified as this schedule page. The substituted page(s) should be conformed to the size of this page.

Line No.	Title (a)	Name of Officer (b)	Salary for Year Total (c)	Salary for Year Oregon (d)
	See the attached Executive Compensation Table from Avista Corp.'s Proxy Statement.			

EXECUTIVE COMPENSATION TABLES

Summary Compensation Table—2023

Summary Compensation Table — 2023

Name and Principal Position	Year	Salary[1]	Stock Awards ($)[2]	Non-Equity Incentive Plan Compensation ($)[3]	Change in Pension and Non-Qualified Deferred Compensation Earnings ($)[4]	All Other Compensation ($)[5]	Total Compensation ($)
D. P. Vermillion CEO	2023	$878,769	$2,728,537	$219,692	$1,384,964	$ 18,000	$5,229,962
	2022	$838,077	$2,923,157	$951,228	N/A	$ 32,917	$4,745,379
	2021	$769,038	$1,986,445	$855,587	$ 905,751	$ 60,718	$4,577,539
M. T. Thies[6] Former Executive Vice President, CFO & Treasurer	2023	$272,029	$ 637,549	$ 44,205	N/A	$ 32,969	$ 986,752
	2022	$473,153	$ 852,877	$349,073	N/A	$ 18,300	$1,693,404
	2021	$461,615	$ 653,436	$333,818	$ 197,793	$ 17,400	$1,664,062
K. J. Christie Sr. Vice President, CFO, Treasurer, and Regulatory Affairs Officer	2023	$386,446	$ 565,941	$ 57,967	$ 218,552	$ 14,850	$1,243,756
	2022	$354,307	$ 572,377	$241,286	N/A	$ 13,725	$1,181,695
	2021	$343,461	$ 345,109	$229,269	$ 186,490	$ 13,050	$1,117,379
H. L. Rosentrater President, and Chief Operating Officer	2023	$459,500	$ 561,028	$ 70,361	$ 223,727	$ 14,850	$1,329,466
	2022	$365,858	$ 572,377	$249,152	N/A	$ 13,725	$1,201,111
	2021	$343,462	$ 345,109	$229,269	$ 147,079	$ 13,050	$1,077,969
J. R. Thackston Sr. Vice President and Chief Strategy & Clean Energy Officer	2023	$389,386	$ 418,227	$ 58,408	$ 337,139	$ 17,322	$1,220,482
	2022	$359,936	$ 572,377	$245,119	N/A	$ 16,131	$1,193,563
	2021	$343,463	$ 428,659	$229,270	$ 152,208	$ 15,196	$1,168,796
W. O. Manuel[7] Vice President, Chief Information Officer & Chief Security Officer	2023	$196,616	$ 344,861	$ 36,000	N/A	$331,500	$ 908,977

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	April 23, 2024	Dec. 31, 2023

STATE OF OREGON - DONATIONS OR PAYMENTS FOR SERVICES RENDERED BY PERSONS OTHER THAN EMPLOYEES AND CHARGED TO OREGON OPERATING ACCOUNTS

1. Report for each service rendered (including materials furnished incidental to the service which are impracticable of separation) by recipient and in total the aggregate of all payments made during the year where the aggregate of such payments to a recipient was $25,000 or more including fees, retainers, commissions, gifts, contributions, assessments, bonuses, subscriptions, allowances for expenses or any other form of payments for services, traffic settlements, amounts paid for general services and licenses, accruals paid to trustees of pension and other employee benefit funds, and amounts paid for construction or maintenance of plant to persons other than affiliates) to any one corporation, institution, association, firm, partnership, committee, or person (not an employee of the respondent). Indicate by an asterisk in column (c) each item that includes payments for materials furnished incidental to the service performed. Payments to a recipient by two or more companies within a single system under a cost sharing or other joint arrangement shall be considered a single item for reporting in this schedule and shall be shown in the report of the principal company in the joint arrangement (as measured by gross operating revenues) with references thereto in the reports of the other system companies in the joint arranement.
2. If more convenient, this schedule may be filled out for a group of companies considered as one system and shown only in the report of the principal company in the system, with references thereto in the reports of the other companies.

Line No.	Name of Recipient (a)	Nature of Service (b)	Amount of Payment (c)
1	MICHELS UTILITY SERVICES INC	Professional Services	22,782,010
2	TRAFFIC CONTROL SERVICES LLC	Professional Services	4,253,363
3	VOLT MANAGEMENT CORP	Professional Services	1,606,258
4	ONE CALL LOCATORS LTD	Professional Services	795,244
5	HYDROMAX USA LLC	Professional Services	742,395
6	HEATH CONSULTANTS INCORPORATED	Professional Services	700,927
7	SUNRISE ENGINEERING INC	Professional Services	451,077
8	LEDFORD CONSTRUCTION COMPANY	Professional Services	411,996
9	IBM CORPORATION	Professional Services	298,417
10	BOUTEN CONSTRUCTION COMPANY	Professional Services	211,898
11	WEBB ASPHALT & SEALING INC	Professional Services	171,982
12	NAGARRO INC	Professional Services	149,639
13	UTILITY SOLUTIONS PARTNERS LLC	Professional Services	144,168
14	INTELLITECT	Professional Services	121,124
15	HANNA & ASSOCIATES INC	Professional Services	88,794
16	LYDIG CONSTRUCTION INC	Professional Services	87,747
17	FUJITSU NORTH AMERICA INC	Professional Services	83,963
18	BAKER BOTTS LLP	Professional Services	72,636
19	POWER PLAN INC	Professional Services	71,208
20	SUPERIOR FENCE LLC	Professional Services	66,385
21	SOS PLUMBING & DRAIN SERVICE INC	Professional Services	65,231
22	CASCADE CABLE CONSTRUCTORS INC	Professional Services	61,036
23	AVANTE PARTNERS	Professional Services	54,926
24	DXC TECHNOLOGY SERVICES LLC	Professional Services	48,770
25	NEELBLUE TECHNOLOGIES CONSULTING INC	Professional Services	44,805
26	VINCENT ARCHAEOLOGICAL SERVICES LLC	Professional Services	40,936
27	ONE CALL CONCEPTS INC	Professional Services	38,463
28	MARQUESS & ASSOCIATES INC	Professional Services	37,900
29	CERIUM NETWORKS	Professional Services	36,893
30	DHISOFT SOLUTIONS	Professional Services	36,023
31	NATIONAL COLOR GRAPHICS INC	Professional Services	35,872
32	JANA CORPORATION	Professional Services	35,806
33	RANDALL DANSKIN ATTORNEYS	Professional Services	34,376
34	NUVODIA LLC	Professional Services	31,706
35	DAVIS WRIGHT TREMAINE LLP	Professional Services	31,117
36	NEATHAMER SURVEYING INC	Professional Services	31,043
37	SOUTHERN OREGON UNIVERSITY	Professional Services	28,938
38	QUESTLINE INC	Professional Services	28,530
39	COMPUNET INC	Professional Services	28,487
40	AVCO CONSULTING INC	Professional Services	27,530
45	OTHER <$25,000	Professional Services	1,020,674
			35,110,293

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	April 23, 2024	Dec. 31, 2023

In order to help us with production of our Oregon Utility Statistics publication, please indicate:

Oregon Production Statistics (therms)	
Gas Produced	0
Gas Purchased	184,399,360
Total Receipts	184,399,360
Gas Sales	105,520,856
Gas Used by Company	15,347
Gas Delivered to Storage - Net	3,882,990
Sales for Resale	78,266,550
Losses and billing delay	(3,286,383)
Total Disbursements	184,399,360
Oregon Revenue by Service Class	
Residential Sales	87,918,615
Commercial and Industrial Sales	
Firm Sales	47,487,274
Interruptible Sales	10,798,901
Transportation	2,499,685
Total	148,704,475
Gas Delivered in Therms (Oregon)	
Residential Sales	53,245,820
Commercial and Industrial Sales	
Firm	34,842,515
Interruptible	17,432,521
Transportation	31,565,750
Total	137,086,606
Average Number of Oregon Customers	
Residential Sales	94,092
Commercial and Industrial	
Firm	11,988
Interruptible	46
Transportation	32
Total	106,158

Name of Respondent	This Report Is:	Date of Report (M, D, Y)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	April 23, 2024	Dec. 31, 2023

STATE OF OREGON - Distribution of Salaries and Wages

1. 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. Salaries and wages billed to the Respondent by an affiliated company must be assigned to the particular operating function(s) relating to the expenses.
2. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used. When 'reporting detail of other accounts, enter as many rows as necessary numbered sequentially starting with 75.01, 75.02, etc.

Line No.	Classification *(a)*	Direct Payroll Distribution *(b)*	Allocation of Payroll Charged to Clearing Accounts *(c)*	Total *(d)*
1	Electric			
2	Operation			
3	Production			
4	Transmission			
5	Regional Market			
6	Distribution			
7	Customer Accounts			
8	Customer Service and Informational			
9	Sales			
10	Administrative and General			
11	TOTAL Operation (Total of lines 3 thru 10)			
12	Maintenance			
13	Production			
14	Regional Market			
15	Transmission			
16	Distribution			
17	Administrative and General			
18	TOTAL Maintenance (Total of lines 13 thru 17)			
19	Total Operation and Maintenance			
20	Production (Total of lines 3 and 13)			
21	Transmission (Total of lines 4 and 14)			
22	Regional Market (Total of Lines 5 and 15)			
23	Distribution (Total of lines 6 and 16)			
24	Customer Accounts (line 7)			
25	Customer Service and Informational (line 8)			
26	Sales (line 9)			
27	Administrative and General (Total of lines 10 and 17)			
28	TOTAL Operation and Maintenance (Total of lines 20 thru 27)			
29	Gas			
30	Operation			
31	Production - Manufactured Gas			
32	Production - Natural Gas(Including Exploration and Development)			
33	Other Gas Supply	388,955		388,955
34	Storage, LNG Terminaling and Processing			0
35	Transmission			0
36	Distribution	2,216,083		2,216,083
37	Customer Accounts	1,500,058		1,500,058
38	Customer Service and Informational	155,283		155,283
39	Sales			0
40	Administrative and General	3,779,250		3,779,250
41	TOTAL Operation (Total of lines 31 thru 40)	8,039,629		8,039,629
42	Maintenance			0
43	Production - Manufactured Gas			0
44	Production - Natural Gas(Including Exploration and Development)			0
45	Other Gas Supply			0
46	Storage, LNG Terminaling and Processing			0
47	Transmission	688,476		688,476

48	Distribution	926,897		926,897
49	Administrative and General			0
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	1,615,373		1,615,373
51	Total Operation and Maintenance	9,655,002		9,655,002
52	Other Utility Departments			0
53	Operation and Maintenance			0
54	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)			0
55	Utility Plant			0
56	Construction (By Utility Departments)			0
57	Electric Plant			0
58	Gas Plant	1,932,297		1,932,297
59	Other (provide details in footnote):			0
60	TOTAL Construction (Total of lines 68 thru 70)	1,932,297		1,932,297
61	Plant Removal (By Utility Departments)			0
62	Electric Plant			0
63	Gas Plant			
64	Other (provide details in footnote):			0
65	TOTAL Plant Removal (Total of lines 73 thru 75)			0
66	Other Accounts (Specify, provide details in footnote):			0
67				0
68				0
69	Current & Accrued Liabilities	91,628		91,628
70				0
71				0
72				0
73				0
74	TOTAL Other Accounts	91,628		91,628
75	TOTAL SALARIES AND WAGES	11,678,927		11,678,927

AVISTA

STAYING POWER

2023

ANNUAL REPORT

ON THE COVER:
Tricia Matthews (Apprentice Electrical Mechanic) installs one of two large auto transformers at Avista’s 110kv Lolo Substation in the Lewiston-Clarkston Valley, south of Lewiston, Idaho. In 2023, the facility received a complete upgrade and rebuild to improve transmission performance and reliability for Avista customers.

To Our Shareholders,

As you read this, Avista marks 135 years of service. Talk about staying power. Throughout our history, we've supported our communities by providing the safe and reliable energy they count on to improve their lives and run their businesses.

And we look forward to continuing this legacy into the future. Building on our foundation of clean hydropower, we will continue to be partners in an even cleaner energy future for our region.

To us, staying power means the strength to weather challenging conditions while delivering on our commitments to all our stakeholders. We believe in the core of our business: to provide affordable, reliable, and safe energy. We believe in our people and our ability to plan for the future. We have the staying power to light the way forward and meet the needs of today—and tomorrow.

Staying power with purpose

Our investment of capital across our service territory strengthens our ability to deliver the energy our customers rely on. From hardening our grid to mitigate risk, to maintaining our facilities to ensure their safe operation, to upgrading our infrastructure to improve reliability, we are enhancing our customers' experience.

Just as we continue to invest in our infrastructure for the benefit of our customers, we continue to pursue constructive regulatory outcomes to move us closer to the rate relief we're striving to achieve. With cases just completed in Idaho and Oregon, we filed our next multi-year rate plan in Washington in January, 2024—purposeful steps in the execution of our strategy.

Staying power into the future

Avista is committed to developing leaders and ensuring continued innovation and adaptability—critical components of our staying power today and for years to come.

Heather Rosentrater is now President and COO. This makes her the first female President in the company's 135-year history. Heather's leadership positions our utility to be at the forefront of innovation. She has established a reputation as a thought leader who constantly challenges Avista and our partners to strategically anticipate what's next—a necessity for leadership during this unique, transformational time in the utility industry.

Kevin Christie is our new Senior Vice President, CFO, Treasurer, and Regulatory Affairs Officer. Kevin and his team have built trusted relationships with our state commissions and with the financial community.

The staying power of our innovative spirit

Our innovative spirit sparks many opportunities for collaboration and partnership that add value to our company and position us well for future growth and transformation.

Building on our vision of energy innovation with the Catalyst building and Eco-District, Avista and our subsidiary Edo hosted a Department of Energy (DOE) Connected Communities Regional Summit at the Scott Morris Center for Energy Innovation. Connected Communities grant recipients from the western region gathered in Spokane to share information, introduce their projects, meet with DOE representatives and partners, and seek project synergies.

And we are partnering with General Electric to implement an Advanced Distribution Management System (ADMS) to replace our existing outage management tool. Design and data modeling work is already underway. The new ADMS will help address business needs, including enabling shorter windows for estimated restoration times for customers during power outages.

Staying power through adaptation

Transforming how we work has a powerful impact.

For the first time in 2023, Avista used special equipment called a "spider" to install transmission line poles. The "spider" reduces the environmental impact of this work by eliminating the need for access roads and construction pads on steep terrain as well as subsequent restoration of the area to its original state.

We also received Chartwell's Bronze Best Practices Award in Outage Operations for our Weather & Incident Forecasting Tool. This innovative tool utilizes a variety of data to generate outage predictions, allowing us to proactively plan and prepare for potential weather events and significantly extending our planning horizon and improving response times.

Staying power under pressure

The risk of wildfire affects how we deliver energy safely and reliably. We demonstrate our staying power by wildfire prevention through grid hardening and other resiliency efforts. Our Fire Safety Mode enhances customer safety through monitoring of wildfire conditions. We've made significant progress in implementing our 10-year Wildfire Resiliency Plan. In 2023, we invested $28 million under our Plan.

In addition to grid hardening, the Plan includes enhanced vegetation management, smart grid intelligence, and augmented operations and emergency response capability. Mitigating our wildfire risk will transform electric service reliability and safety for Avista's most highly impacted customers and communities—we've already seen these results.

We also launched the Safe Tree Program, which allows residents to easily report vegetation that could pose a threat to utility lines. Avista contracts with local arborists to assess and remove problematic vegetation, and even replant the area with utility-friendly species.

Staying power to advance clean energy

From our founding on clean hydropower to today, collaborating toward a clean energy future has been part of our company values. This past year marked the 40th anniversary of our Kettle Falls Generating Station. This biomass plant was the first utility-owned electric generating station of its kind in the United States. Its sole purpose is to produce electricity from wood waste. Then and now, biomass is an important part of

Dennis Vermillion, CEO
Heather Rosentrater, President and COO

our diverse energy portfolio. The renewable energy generated at Kettle Falls helps us continue to provide reliable, responsible energy while meeting environmental mandates and being good stewards of both our customers' energy dollars and the environment in which we live and operate.

We completed a 30-year agreement for 100 megawatts of clean wind energy in Montana. That agreement, and the addition of Avista's recent hydroelectric agreements with Chelan County PUD and Columbia Basin Hydro, results in more than 70 percent of our peak generating capability coming from non-emitting resources by 2026.

We also announced three renewable natural gas (RNG) contracts. The RNG projects contribute to our aspirational clean energy goals within our natural gas operations.

These agreements move us closer to achieving our clean energy goals and our Washington Clean Energy Implementation Plan, as well as meeting our customers' needs now and into the future.

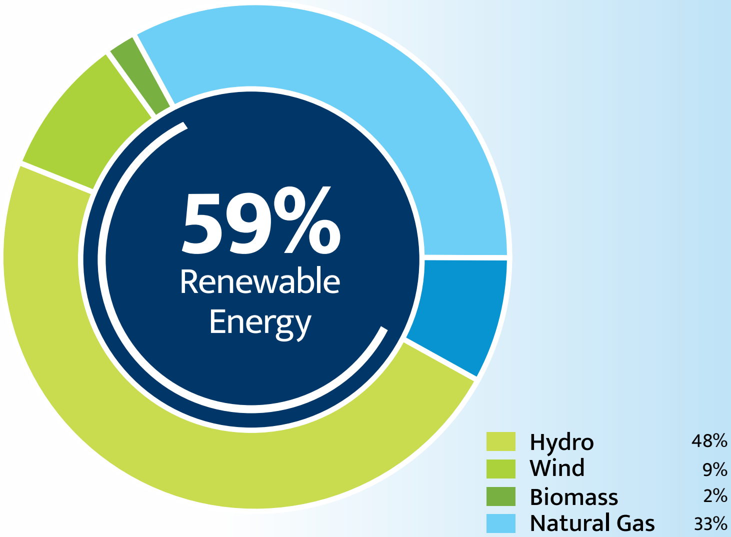
Avista is well-positioned to adapt to the challenges that surround us. We have the staying power to deliver on our commitments to our customers, our communities, our employees, and you—our shareholders.

Dennis Vermillion
Chief Executive Officer

Financial and Operating Highlights

Electricity Generation Resource Mix

As of Dec. 31, 2023 - Excludes AEL&P



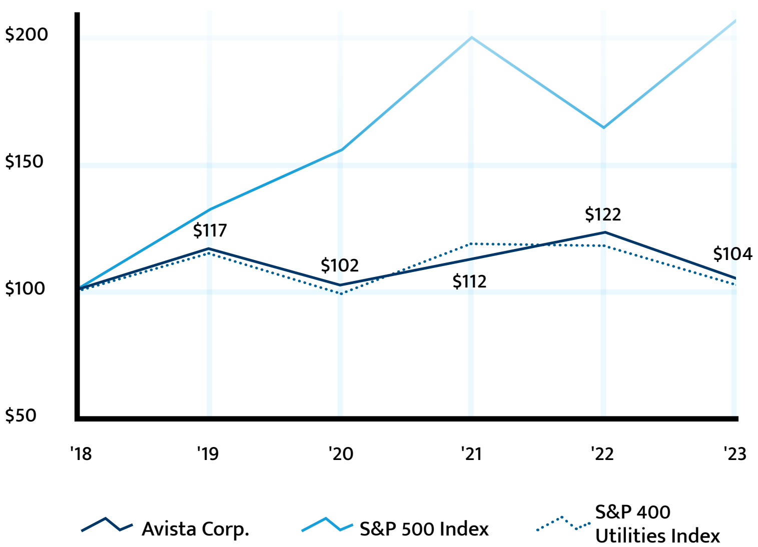
Clean Energy Goals

Avista has set goals to serve its customers with 100% clean electricity and to be carbon-neutral in its natural gas operations by 2045.

Avista was founded on clean, renewable hydro power in 1889, and the company has a long-standing history of providing clean, reliable and affordable energy to the customers and communities it serves.

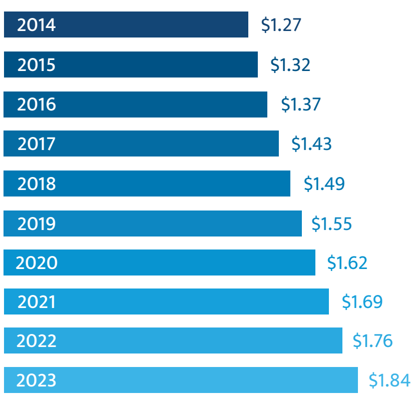
Total Shareholder Return

Assumes $100 was invested in Avista Corp. and each index on Dec. 31, 2018, and that all dividends were reinvested when paid.



Common Stock Dividends Paid by Avista Corp.

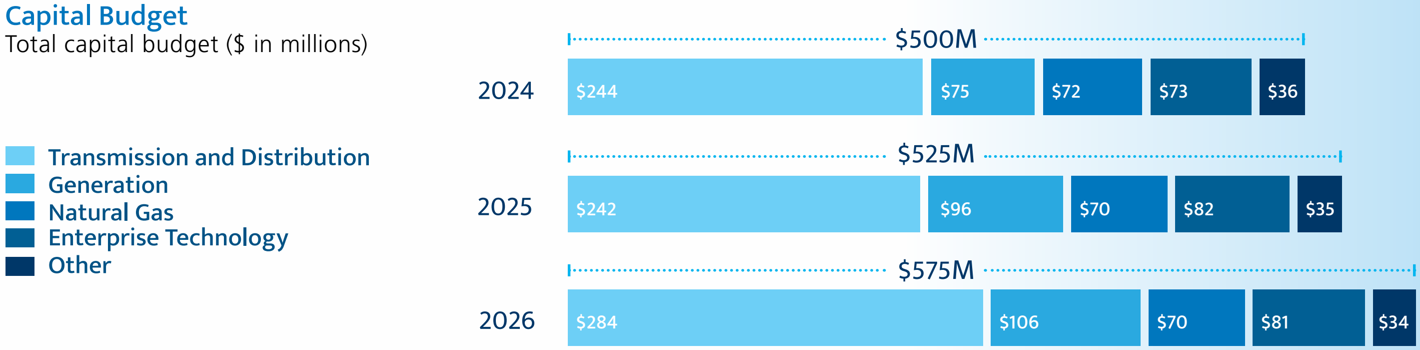
Annualized Dividend (paid in dollars)



Avista Corp.'s board of directors raised the dividend in each of the last 21 years, reflecting their confidence in the financial strength of the company.

Capital Budget

Total capital budget ($ in millions)



(dollars in thousands except statistics and per share amounts or as otherwise indicated)

	2023	2022	2021
Financial Results			
Operating revenues	$ 1,751,554	$ 1,710,207	$ 1,438,936
Operating expenses	1,493,864	1,519,965	1,210,704
Income from operations	257,690	190,242	228,232
Net income	171,180	155,176	147,334
Total earnings per common share—diluted	2.24	2.12	2.10
Dividends paid per common share	1.84	1.76	1.69
Book value per common share	$ 31.83	$ 31.15	$ 30.14
Average common shares outstanding	76,396	72,989	69,951
Return on average stockholders' equity	7.1 %	6.9 %	7.1 %
Common stock closing price	$ 35.74	$ 44.34	$ 42.49
Operating Results			
Avista Utilities			
Retail electric revenues	$ 886,446	$ 868,702	$ 835,118
Retail kWh sales (in millions)	8,868	9,071	8,796
Retail electric customers at year-end	416,329	410,641	405,622
Wholesale electric revenues	$ 249,847	$ 179,316	$ 89,768
Wholesale kWh sales (in millions)	3,468	3,094	2,461
Sales of fuel	$ (25,926)	$ 84,256	$ 63,673
Other electric revenues	49,235	46,319	36,288
Decoupling (electric)	12,419	(31,844)	(19,525)
Deferrals and amortizations for rate refunds to customers	149	74	1,730
Retail natural gas revenues	$ 506,994	$ 434,846	$ 330,020
Wholesale natural gas revenues	55,295	133,235	113,277
Transportation and other natural gas revenues	14,945	16,783	15,872
Decoupling (natural gas)	(7,520)	(1,513)	12,890
Deferrals and amortizations for rate refunds to customers	876	134	1,254
Total therms delivered (in thousands)	817,123	861,840	901,279
Retail natural gas customers at year-end	381,002	377,420	372,025
Net income	$ 167,016	$ 117,901	$ 125,558
Alaska Electric Light and Power Company			
Revenues	$ 48,139	$ 45,704	$ 45,366
Retail kWh sales (in millions)	411	404	404
Retail electric customers at year-end	17,688	17,577	17,428
Net income	8,937	7,545	7,224
Other			
Revenues	$ 558	$ 688	$ 571
Net income (loss)	(4,773)	29,730	14,552
Financial Condition			
Total assets	$ 7,702,477	$ 7,417,350	$ 6,853,583
Long-term debt and leases (including current portion)	2,640,902	2,408,876	2,267,554
Long-term debt to affiliated trusts	51,547	51,547	51,547
Total stockholders' equity	2,485,323	2,334,668	2,154,744

In 2023, Avista crews replaced 32 wood poles with Corten steel structures, increasing transmission reliability in the event of field or wildfires south of Rockford, Washington.

(bottom right) In Priest River, Idaho, a contract crew wraps wood distribution poles with fire-retardant mesh as part of Avista's wildfire resiliency plan.

Board of Directors

Julie A. Bentz, 59
Principal, HOMR LLC
Scio, Oregon
Director since 2021

Donald C. Burke, 63
Langhorne, Pennsylvania
Director since 2011

Kevin B. Jacobsen, 57
Executive Vice President & CFO,
The Clorox Company
Danville, California
Director since 2023

Rebecca A. Klein, 58
Principal, Klein Energy, LLC
Austin, Texas
Director since 2010

Sena M. Kwawu, 55
President, In-Home Services
Bellevue, Washington
Director since 2021

Scott H. Maw, 56
Seattle, Washington
Director since 2016

Scott L. Morris, 66
Chairman of the Board,
Avista Corp.
Spokane, Washington
Director since 2007

Jeffry L. Philipps, 68
Spokane, Washington
Director since 2019

Heidi B. Stanley, 67
Co-owner & Chair,
Empire Bolt & Screw Inc.
Spokane, Washington
Director since 2006

Dennis P. Vermillion, 62
CEO, Avista Corp.
Spokane, Washington
Director since 2018

Janet D. Widmann, 57
San Francisco, California
Director since 2014

Board Committees

Governance & Corporate Responsibility Committee
Donald C. Burke
Scott H. Maw
Heidi B. Stanley
Janet D. Widmann — Chair

Executive Committee
Donald C. Burke
Scott L. Morris — Chair
Heidi B. Stanley
Dennis P. Vermillion

Audit Committee
Donald C. Burke (Financial Expert) — Chair
Kevin B. Jacobsen
Jeffry L. Philipps
Heidi B. Stanley

Compensation & Organization Committee
Rebecca A. Klein
Scott H. Maw - Chair
Jeffry L. Philipps

Finance Committee
Julie A. Bentz
Sena M. Kwawu — Chair
Scott L. Morris
Janet D. Widmann

Environmental, Technology & Operations Committee
Julie A. Bentz
Kevin B. Jacobsen
Rebecca A. Klein — Chair
Sena M. Kwawu

Corporate & Business Unit Officers

Dennis P. Vermillion, 62
CEO

Heather L. Rosentrater, 46
President & COO

Kevin J. Christie, 56
Senior Vice President, CFO, Treasurer & Regulatory Affairs Officer

Bryan A. Cox, 54
Senior Vice President, Safety & Chief People Officer

Gregory C. Hesler, 46
Senior Vice President, General Counsel, Corporate Secretary & Chief Ethics/Compliance Officer

Jason R. Thackston, 54
Senior Vice President, Chief Strategy & Clean Energy Officer

Joshua D. DiLuciano, 43
Vice President, Energy Delivery

Latisha D. Hill, 45
Vice President, Community Affairs & Chief Customer Officer

Scott J. Kinney, 55
Vice President, Energy Resources

Ryan L. Krasselt, 54
Vice President, Controller & Principal Accounting Officer

Wayne O. Manuel, 51
Vice President, CIO & Chief Security Officer

David J. Meyer, 70
Vice President & Chief Counsel for Regulatory & Governmental Affairs

Alec J. Mesdag, 44
President & CEO, Alaska Electric Light & Power Co.

AVISTA CORP: (AVA)

FORM 10-K

FILED: FEBRUARY 20, 2024 (PERIOD: DECEMBER 31, 2023)
ANNUAL REPORT WHICH PROVIDES A COMPREHENSIVE OVERVIEW OF THE COMPANY FOR THE PAST YEAR.

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE FISCAL YEAR ENDED **DECEMBER 31, 2023** OR

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE TRANSITION PERIOD FROM ______________ TO ______________

Commission file number 001-03701

AVISTA CORPORATION

(Exact name of Registrant as specified in its charter)

WA	91-0462470
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1411 East Mission Avenue, Spokane, WA 99202-2600

(Address of principal executive offices, including zip code)

Registrant's telephone number, including area code: 509-489-0500

Website: http://www.avistacorp.com

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Trading Symbol(s)	Name of Each Exchange on Which Registered
Common Stock	AVA	NYSE

Securities registered pursuant to Section 12(g) of the Act:

Title of Class

Preferred Stock, Cumulative, Without Par Value

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act.
Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days: Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files).
Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer	☒	Accelerated Filer	☐	Non-accelerated Filer	☐
Smaller reporting company	☐	Emerging growth company	☐		

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act):
Yes ☐ No ☒

The aggregate market value of the Registrant's outstanding Common Stock, no par value (the only class of voting stock), held by non-affiliates is $3,005,104,706 based on the last reported sale price thereof on the consolidated tape on June 30, 2023.

As of January 31, 2024, 78,161,596 shares of Registrant's Common Stock, no par value (the only class of common stock), were outstanding.

Documents Incorporated By Reference

Document	Part of Form 10-K into Which Document is Incorporated
Proxy Statement to be filed in connection with the annual meeting of shareholders to be held May 1, 2024. Prior to such filing, the Proxy Statement was filed in connection with the annual meeting of shareholders held on May 11, 2023.	Part III, Items 10, 11, 12, 13 and 14

INDEX

Part I

Part II

** = not an applicable item in the 2023 calendar year for Avista Corp.*

ACRONYMS AND TERMS

(The following acronyms and terms are found in multiple locations within the document)

Acronym/Term	Meaning
aMW	– Average Megawatt—a measure of the average rate at which a particular generating source produces energy over a period of time
AEL&P	– Alaska Electric Light and Power Company, the primary operating subsidiary of AERC, which provides electric services in Juneau, Alaska
AERC	– Alaska Energy and Resources Company, the Company's wholly owned subsidiary based in Juneau, Alaska
AFUDC	– Allowance for Funds Used During Construction; represents the cost of both the debt and equity funds used to finance utility plant additions during the construction period
ASC	– Accounting Standards Codification
Avista Capital	– Parent company to the Company's non-utility businesses, with the exception of AJT Mining Properties, Inc., which is a subsidiary of AERC.
Avista Corp.	– Avista Corporation, the Company
Avista Utilities	– Operating division of Avista Corp. (not a subsidiary) comprising the regulated utility operations in Washington, Idaho, Oregon and Montana
BPA	– Bonneville Power Administration
Capacity	– The rate at which a particular generating source is capable of producing energy, measured in kW or MW
Cabinet Gorge	– The Cabinet Gorge Hydroelectric Generating Project, located on the Clark Fork River in Idaho
CCA	– Climate Commitment Act, Washington
CCRs	– Coal Combustion Residuals, also termed coal combustion byproducts or coal ash
CEIP	– Clean Energy Implementation Plan, Washington
CETA	– Clean Energy Transformation Act, Washington
CPP	– Climate Protection Program, Oregon
Colstrip	– The coal-fired Colstrip Generating Plant in southeastern Montana
Cooling degree days	– The measure of the warmness of weather experienced, based on the extent to which the average of high and low temperatures for a day exceeds 65 degrees Fahrenheit (annual degree days above historic indicate warmer than average temperatures)
Coyote Springs 2	– The natural gas-fired combined-cycle Coyote Springs 2 Generating Plant located near Boardman, Oregon
COVID-19	– Coronavirus disease 2019, a respiratory illness that was declared a pandemic in March 2020
CT	– Combustion turbine
Deadband or ERM deadband	– The first $4.0 million in annual power supply costs above or below the amount included in base retail rates in Washington under the ERM in the state of Washington

(The following acronyms and terms are found in multiple locations within the document)

Acronym/Term	Meaning
EIM	– Energy Imbalance Market
Energy	– The amount of electricity produced or consumed over a period of time, measured in kWh or MWh. Also, refers to natural gas consumed and is measured in dekatherms.
EPA	– Environmental Protection Agency
ERM	– The Energy Recovery Mechanism, a mechanism for accounting and rate recovery of certain power supply costs accepted by the utility commission in the state of Washington
FCA	– Fixed Cost Adjustment, the electric and natural gas decoupling mechanism in Idaho
FERC	– Federal Energy Regulatory Commission
GAAP	– Generally Accepted Accounting Principles
GHG	– Greenhouse gas
GS	– Generating station
Heating degree days	– The measure of the coldness of weather experienced, based on the extent to which the average of high and low temperatures for a day falls below 65 degrees Fahrenheit (annual degree days above historic indicate warmer than average temperatures)
IPUC	– Idaho Public Utilities Commission
IRP	– Integrated Resource Plan
Jackson Prairie	– Jackson Prairie Natural Gas Storage Project, an underground natural gas storage field located near Chehalis, Washington
kV	– Kilovolt (1000 volts): a measure of capacity on transmission lines
kW, kWh	– Kilowatt (1000 watts): a measure of generating output or capability. Kilowatt-hour (1000 watt hours): a measure of energy produced
Lancaster Plant	– A natural gas-fired combined-cycle combustion turbine plant located in Idaho
MPSC	– Public Service Commission of the State of Montana
MW, MWh	– Megawatt: 1000 kW. Megawatt-hour: 1000 kWh
NERC	– North American Electricity Reliability Corporation
NorthWestern	– NorthWestern Corporation
Noxon Rapids	– The Noxon Rapids Hydroelectric Generating Project, located on the Clark Fork River in Montana
OPUC	– The Public Utility Commission of Oregon
PCA	– The Power Cost Adjustment mechanism, a procedure for accounting and rate recovery of certain power supply costs accepted by the utility commission in the state of Idaho

ACRONYMS AND TERMS (continued)

(The following acronyms and terms are found in multiple locations within the document)

Acronym/Term	Meaning
PGA	– Purchased Gas Adjustment
PPA	– Power Purchase Agreement
PUD	– Public Utility District
RCA	– The Regulatory Commission of Alaska
REC	– Renewable energy credit
ROE	– Return on equity
ROR	– Rate of return on rate base
ROU	– Right-of-use lease asset
SEC	– U.S. Securities and Exchange Commission
Talen	– Talen Montana, LLC, an indirect subsidiary of Talen Energy Corporation
Therm	– Unit of measurement for natural gas; a therm is equal to approximately one hundred cubic feet (volume) or 100,000 BTUs (energy)
WUTC	– Washington Utilities and Transportation Commission

FORWARD-LOOKING STATEMENTS

From time-to-time, we make forward-looking statements such as statements regarding projected or future:

- financial performance;
- cash flows;
- capital expenditures;
- dividends;
- capital structure;
- other financial items;
- strategic goals and objectives;
- business environment; and
- plans for operations.

These statements are based upon underlying assumptions (many of which are based, in turn, upon further assumptions). Such statements are made both in our reports filed under the Securities Exchange Act of 1934, as amended (including this Annual Report on Form 10-K), and elsewhere. Forward-looking statements are all statements except those of historical fact including, without limitation, those that are identified by the use of words that include "will," "may," "could," "should," "intends," "plans," "seeks," "anticipates," "estimates," "expects," "forecasts," "projects," "predicts," and similar expressions.

Forward-looking statements (including those made in this Annual Report on Form 10-K) are subject to a variety of risks, uncertainties and other factors. Most of these factors are beyond our control and may have a significant effect on our operations, results of operations, financial condition or cash flows, which could cause actual results to differ materially from those anticipated in our statements. Such risks, uncertainties and other factors include, among others:

Utility Regulatory Risk

- state and federal regulatory decisions or related judicial decisions that affect our ability to recover costs and earn a reasonable return including, but not limited to, disallowance or delay in the recovery of capital investments, operating costs, commodity costs, the ordering of refunds to customers and discretion over allowed return on investment;
- the loss of regulatory accounting treatment, which could require the write-off of regulatory assets and the loss of regulatory deferral and recovery mechanisms;

Operational Risk

- weather conditions, which affect both energy demand and electric generating capability, including the impact of precipitation and temperature on hydroelectric resources, the impact of wind patterns on wind-generated power, weather-sensitive customer demand, and similar impacts on supply and demand in the wholesale energy markets;
- wildfires ignited, or allegedly ignited, by our equipment or facilities could cause significant loss of life and property or result in liability for resulting fire suppression costs and/or damages, thereby causing serious operational and financial harm;
- severe weather or natural disasters, including, but not limited to, avalanches, wind storms, wildfires, earthquakes, extreme temperature events, snow and ice storms that could disrupt energy generation, transmission and distribution, as well as the availability and costs of fuel, materials, equipment, supplies and support services;
- political unrest and/or conflicts between foreign nation-states, which could disrupt the global, national and local economy, result in increases in operating and capital costs, impact energy commodity prices or our ability to access energy resources, create disruption in supply chains, disrupt, weaken or create volatility in capital markets, and increase cyber and physical security risks. In addition, any of these factors could negatively impact our liquidity and limit our access to capital, among other implications;
- explosions, fires, accidents, mechanical breakdowns or other incidents that could impair assets and may disrupt operations of our generation facilities, transmission, and electric and natural gas distribution systems or other operations and may require us to purchase replacement power or incur costs to repair our facilities;
- interruptions in the delivery of natural gas by our suppliers, including physical problems with pipelines themselves, can disrupt our service of natural gas to our customers and/or impair our ability to operate gas-fired electric generating facilities;
- explosions, fires, accidents or other incidents arising from or allegedly arising from our operations that could cause injuries to the public or property damage;
- blackouts or disruptions of interconnected transmission systems (the regional power grid);
- terrorist attacks, cyberattacks or other malicious acts that could disrupt or cause damage to our utility assets or to the national or regional economy in general, including effects of terrorism, cyberattacks, ransomware, or vandalism that damage or disrupt information technology systems;
- pandemics, which could disrupt our business, as well as the global, national and local economy, resulting in a decline in customer demand, deterioration in the creditworthiness of our customers, increases in operating and capital costs, workforce shortages, losses or disruptions in our workforce due to vaccine mandates, delays in capital projects, disruption in supply chains, and disruption, weakness and volatility in capital markets. In addition, any of these factors could negatively impact our liquidity and limit our access to capital, among other implications;
- workforce issues, including changes in collective bargaining unit agreements, strikes, work stoppages, the loss of key executives, availability of workers in a variety of skill areas, and our ability to recruit and retain employees;
- changes in the availability and price of purchased power, fuel and natural gas, as well as transmission capacity;
- increasing costs of insurance, more restrictive coverage terms and our ability to obtain insurance;
- delays or changes in construction costs, and/or our ability to obtain required permits and materials for present or prospective facilities;
- increasing health care costs and cost of health insurance provided to our employees and retirees;
- increasing operating costs, including effects of inflationary pressures;
- third party construction of buildings, billboard signs, towers or other structures within our rights of way, or placement of fuel containers within close proximity to our transformers or other equipment, including overbuilding atop natural gas distribution lines;

- the loss of key suppliers for materials or services or other disruptions to the supply chain;
- adverse impacts to our Alaska electric utility (AEL&P) that could result from an extended outage of its hydroelectric generating resources or their inability to deliver energy, due to their lack of interconnectivity to other electrical grids and the availability or cost of replacement power (diesel);
- changing river or reservoir regulation or operations at hydroelectric facilities not owned by us, which could impact our hydroelectric facilities downstream;

Climate Change Risk

- increasing frequency and intensity of severe weather or natural disasters resulting from climate change, that could disrupt energy generation, transmission and distribution, as well as the availability and costs of fuel, materials, equipment, supplies and support services;
- change in the use, availability or abundancy of water resources and/or rights needed for operation of our hydroelectric facilities, including impacts resulting from climate change;
- changes in the long-term climate and weather could materially affect, among other things, customer demand, the volume and timing of streamflows required for hydroelectric generation, costs of generation, transmission and distribution. Increased or new risks may arise from severe weather or natural disasters, including wildfires as well as their increased occurrence and intensity related to changes in climate;

Cybersecurity Risk

- cyberattacks on the operating systems used in the operation of our electric generation, transmission and distribution facilities and our natural gas distribution facilities, and cyberattacks on such systems of other energy companies with which we are interconnected, which could damage or destroy facilities or systems or disrupt operations for extended periods of time and result in the incurrence of liabilities and costs;
- cyberattacks on the administrative systems used in the administration of our business, including customer billing and customer service, accounting, communications, compliance and other administrative functions, and cyberattacks on such systems of our vendors and other companies with which we do business, resulting in the disruption of business operations, the release of private information and the incurrence of liabilities and costs;

Technology Risk

- changes in costs that impede our ability to implement new information technology systems or to operate and maintain current production technology;
- changes in technologies, possibly making some of the current technology we utilize obsolete or introducing new cybersecurity risks and other new risks inherent in the use, by either us or our counterparties, of new technologies in the developmental stage including, without limitation, generative artificial intelligence;
- changes in the use, perception, or regulation of generative artificial intelligence technologies, which could limit our ability to utilize such technology, create risk of enhanced regulatory scrutiny, generate uncertainty around intellectual property ownership, licensing or use, or which could otherwise result in risk of damage to our business, reputation or financial results;
- insufficient technology skills, which could lead to the inability to develop, modify or maintain our information systems;

Strategic Risk

- growth or decline of our customer base due to new uses for our services or decline in existing services, including, but not limited to, the effect of the trend toward distributed generation at customer sites;
- the potential effects of negative publicity regarding our business practices, whether true or not, which could hurt our reputation and result in litigation or a decline in our common stock price;
- changes in our strategic business plans, which could be affected by any or all of the foregoing, including the entry into new businesses and/or the exit from existing businesses and the extent of our business development efforts where potential future business is uncertain;
- wholesale and retail competition including alternative energy sources, growth in customer-owned power resource technologies that displace utility-supplied energy or may be sold back to the utility, and alternative energy suppliers and delivery arrangements;
- non-regulated activities may increase earnings volatility and result in investment losses;
- the risk of municipalization or other forms of service territory reduction;

External Mandates Risk

- changes in environmental laws, regulations, decisions and policies, including, but not limited to, regulatory responses to concerns regarding climate change, efforts to restore anadromous fish in areas currently blocked by dams, more stringent requirements related to air quality, water quality and waste management, present and potential environmental remediation costs and our compliance with these matters;
- the potential effects of initiatives, legislation or administrative rulemaking at the federal, state or local levels, including possible effects on our generating resources, prohibitions or restrictions on new or existing services, or restrictions on greenhouse gas emissions to mitigate concerns over climate changes, including future limitations on the usage and distribution of natural gas;
- political pressures or regulatory practices that could constrain or place additional cost burdens on our distribution systems through accelerated adoption of distributed generation or electric-powered transportation or on our energy supply sources, such as campaigns to halt fossil fuel-fired power generation and opposition to other thermal generation, wind turbines or hydroelectric facilities;
- failure to identify changes in legislation, taxation and regulatory issues that could be detrimental or beneficial to our overall business;
- policy and/or legislative changes in various regulated areas, including, but not limited to, environmental regulation, healthcare regulations and import/export regulations;

Financial Risk

- our ability to obtain financing through the issuance of debt and/or equity securities and access to our funds held with financial institutions, which could be affected by various factors including our credit ratings, interest rates, other capital market conditions and global economic conditions;
- changes in interest rates that affect borrowing costs, variable interest rate borrowing and the extent to which we recover interest costs through retail rates collected from customers;
- volatility in energy commodity markets that affect our ability to effectively hedge energy commodity risks, including cash flow impacts and requirements for collateral;
- volatility in the carbon emissions allowances market that could result in increased compliance costs;
- changes in actuarial assumptions, interest rates and the actual return on plan assets for our pension and other postretirement benefit plans, which could affect future funding obligations, pension and other postretirement benefit expense and the related liabilities;
- the outcome of legal proceedings and other contingencies;
- economic conditions in our service areas, including the economy's effects on customer demand for utility services;
- economic conditions nationally may affect the valuation of our unregulated portfolio companies;
- declining electricity demand related to customer energy efficiency, conservation measures and/or increased distributed generation and declining natural gas demand related to customer energy efficiency, conservation measures and/or increased electrification;
- industry and geographic concentrations which could increase our exposure to credit risks due to counterparties, suppliers and customers being similarly affected by changing conditions;
- deterioration in the creditworthiness of our customers;
- activist shareholders may result in additional costs and resources required in response to activist actions;

Energy Commodity Risk

- volatility and illiquidity in wholesale energy markets, including exchanges, the availability of willing buyers and sellers, changes in wholesale energy prices that could affect operating income, cash requirements to purchase electricity and natural gas, value received for wholesale sales, collateral required of us by individual counterparties and/or exchanges in wholesale energy transactions and credit risk from such transactions, and the market value of derivative assets and liabilities;
- default or nonperformance on the part of parties from whom we purchase and/or sell capacity or energy;
- potential environmental regulations or lawsuits affecting our ability to utilize or resulting in the obsolescence of our power supply resources;
- explosions, fires, accidents, pipeline ruptures or other incidents that could limit energy supply to our facilities or our surrounding territory, which could result in a shortage of commodities in the market that could increase the cost of replacement commodities from other sources;

Compliance Risk

- changes in laws, regulations, decisions and policies at the federal, state or local levels, which could materially impact both our electric and gas operations and costs of operations; and
- the ability to comply with the terms of the licenses and permits for our hydroelectric or thermal generating facilities at cost-effective levels.

Our expectations, beliefs and projections are expressed in good faith. We believe they are reasonable based on, without limitation, an examination of historical operating trends, our records and other information available from third parties. There can be no assurance that our expectations, beliefs or projections will be achieved or accomplished. Furthermore, any forward-looking statement speaks only as of the date on which such statement is made. We undertake no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events. New risks, uncertainties and other factors emerge from time-to-time, and it is not possible to predict all such factors, nor can we assess the effect of each such factor on our business or the extent that any such factor or combination of factors may cause actual results to differ materially from those contained in any forward-looking statement.

AVAILABLE INFORMATION

We file annual, quarterly and current reports and proxy statements with the SEC. The SEC maintains a website that contains these documents at www.sec.gov. We make annual, quarterly and current reports and proxy statements available on our website, https://investor.avistacorp.com, as soon as practicable after electronically filing these documents with the SEC. Except for SEC filings or portions thereof specifically referred to in this report, information contained on these websites is not part of this report.

PART I

ITEM 1. Business

COMPANY OVERVIEW

Avista Corp., incorporated in the territory of Washington in 1889, is primarily an electric and natural gas utility with certain other business ventures. Our mission is to improve our customers' lives through innovative energy solutions, safely, responsibly and affordably. Our corporate headquarters is in Spokane, Washington, the second-largest city in Washington. Spokane serves as the business, transportation, medical, industrial and cultural hub of the Inland Northwest region (eastern Washington and northern Idaho). Regional services include government and higher education, medical services, retail trade and finance. Through our subsidiary AEL&P, we also provide electric utility services in Juneau, Alaska.

As of December 31, 2023, we have two reportable business segments as follows:

- **Avista Utilities**—an operating division of Avista Corp., comprising the regulated utility operations in Washington, Idaho, Oregon and Montana. Avista Utilities provides electric distribution and transmission, and natural gas distribution services in parts of eastern Washington and northern Idaho. Avista Utilities also provides natural gas distribution service in parts of northeastern and southwestern Oregon. Avista Utilities has electric generating facilities in Washington, Idaho, Oregon and Montana. Avista Utilities also supplies electricity to a small number of customers in Montana. Avista Utilities also engages in wholesale purchases and sales of electricity and natural gas as an integral part of energy resource management and its load-serving obligation.
- **AEL&P**—a regulated utility providing electric services in Juneau, Alaska that is a wholly owned subsidiary and the primary operating subsidiary of AERC.

We have other businesses, including venture fund investments, real estate investments, as well as certain other investments made by Avista Capital, which is a direct, wholly owned subsidiary of Avista Corp. These activities do not represent a reportable business segment and are conducted by various direct and indirect subsidiaries of Avista Corp.

Total Avista Corp. shareholders' equity was $2.5 billion as of December 31, 2023, which includes a $145.6 million investment in Avista Capital and a $119.6 million investment in AERC.

See "Note 24 of the Notes to Consolidated Financial Statements" for information with respect to the operating performance of each business segment (and other subsidiaries).

Human Capital

Our approach to people is a critical strategy and the priorities for this strategy include, among other things:

- attracting, developing, and retaining a diverse, engaged and skilled workforce,
- providing opportunities for continuous learning, development, career growth, and movement within the Company,
- supporting and rewarding our employees through competitive pay and benefits,
- encouraging and supporting a community-minded culture, and
- investing in the physical, emotional and financial health and safety of our employees.

The following is an overview of some of our key human capital initiatives intended to foster the overall well-being of our employees and other stakeholders, such as our customers and business partners.

Equity, Inclusion and Diversity

We strive to foster a culture that values trust, and respect based on equity, inclusion and diversity, and offering all employees the opportunity to enrich their lives and careers through challenging and meaningful work—all in an equal opportunity workplace surrounded by a supportive and inclusive environment. Our equity, inclusion, and diversity (EID) initiatives are focused on equity in our systems and processes, employee recruitment, employee training and development, and employee engagement, including participation in employee resource groups. Employee resource groups are voluntary, employee-led groups fostering a diverse and inclusive workplace aligned with our organizational mission, values and goals and business practices. We continued to sponsor employee resource groups in 2023 which include: Women of Avista, Veterans of Avista, Diversity Awareness, Connections, and History of Avista.

Additional employee-focused EID efforts include active engagement in employment system and practice reviews to uncover and correct systemic inequities and/or barriers for a more fulsome approach to EID. Projects include overhauling and updating all job descriptions ensuring equity among similar positions regardless of the department, a pay equity project and developing a robust inclusive recruiting initiative to address direct recruiting activities and processes, recruiting systems and future workforce pipeline development.

On December 31, 2023, Avista Utilities employed 1,858 individuals with an employee profile of:

	Women	Under-Represented Groups [a]
Bargaining Unit	3%	6%
Non-bargaining Unit	45%	11%
Executives [b]	17%	17%
Overall	30%	9%

(a) As defined by our Affirmative Action Plan and through employee self-identification.

(b) Executive is defined as vice president or higher.

Employee data represents all regular full-time and part-time employees, including temporary workers and student interns.

Bargaining Unit employees comprise 36 percent of Avista Utilities' employees.

People Development, Retention and Attraction

We strive to hire and retain talented people who are innovative and skilled so we can continue to provide safe, reliable and affordable service to our customers and advance the Company at the same time. Retention of our talented people is a focal strategy addressed through employee engagement efforts and the pay equity project. In 2022, we held our biennial employee experience survey and prioritized initiatives focusing on enhancing our employee experience.

Continuous learning plays a large part in fostering collaboration and innovation among our employees and is pervasive throughout the Company. Our development opportunities are created to prepare our employees at all levels to ensure they have the skills, knowledge and experience to perform today and well into the future. Keeping our workforce equipped to succeed is imperative to meet the emerging challenges that lay ahead. We develop training that is relevant, necessary and in demand for our organization. Training is delivered through instructor-led courses, self-service topics, computer-based learning modules, and field-based, hands-on workshop models covering the range of our operations. Training programs include craft apprenticeship programs, engineering development programs, leadership development, communication skills, cross-functional learning and EID topics. We also provide opportunities for our employees to attend industry events and certification programs, courses or programs offered through energy-related organizations such as the Western Energy Institute, the American Gas Association and the Edison Electric Institute, as well as through our local colleges and universities.

Workplace Safety

Safety is an essential part of our mission. A variety of programs and initiatives are in place to help employees complete their work safely through heightened vigilance, hazard recognition, defensive strategies, lessons learned, human and organizational performance and other tools intended to ensure resilience in varying and unpredictable conditions. We work with our employees to reinforce personal responsibility regarding safety and health, and to implement measures to create and maintain a safe work environment.

Additional Information

Additional information highlighting our commitment to corporate responsibility, including our commitment to our environment, our people, our customers and communities and ethical governance, is available on our website at www.avistacorp.com/corporate-responsibility/our-commitment. Material on our website is not part of this report.

AVISTA UTILITIES

General

At the end of 2023, Avista Utilities supplied retail electric service to approximately 416,000 customers and retail natural gas service to approximately 381,000 customers across its service territory. Avista Utilities' service territory covers 30,000 square miles with a population of 1.7 million.

Electric Operations

General

Avista Utilities generates, transmits and distributes electricity, serving electric customers in eastern Washington and northern Idaho and a small number of customers in Montana.

Avista Utilities generates electricity from facilities that we own and purchases capacity, energy and fuel for generation under long-term and short-term contracts to meet customer load obligations. We also sell electric capacity and energy, as well as surplus fuel in the wholesale market in connection with our resource optimization activities as described below.

As part of Avista Utilities' resource procurement and management operations in the electric business, we engage in an ongoing process of resource optimization, which involves the selection from available energy resources to serve our load obligations and the use of these resources to capture 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, fuel and fuel transportation. Such transactions are part of the process of matching available resources with load obligations and hedging a portion of the related financial risks. To implement this process, we make continuing projections of:

- electric loads at various points in time (ranging from intra-hour to multiple years) based on, among other things, estimates of customer usage and weather, historical data, contract terms, and emerging trends and climate modeling results, and
- resource availability at these points in time based on, among other things, fuel choices and fuel markets, estimates of snowpack and streamflows, availability of generating units, historic and forward market information, contract terms and experience.

Based on these projections, we make purchases and sales of electric capacity and energy, fuel for electric generation, and related derivative contracts to match expected resources to expected electric load requirements and reduce our exposure to electricity (or fuel) market price changes. The process of resource optimization involves scheduling and dispatching available resources as well as the following:

- purchasing fuel for generation,
- when economical, selling fuel and substituting wholesale electric purchases, and
- other wholesale transactions to capture the value of generating resources, transmission contract rights and fuel delivery (transport) capacity contracts.

This optimization process includes entering into hedging transactions to manage risks. Transactions include both physical energy contracts and related derivative instruments, and the terms range from intra-hour up to multiple years.

Avista Utilities' generation assets are interconnected through the regional transmission system and are operated on a coordinated basis to enhance load-serving capability and reliability. We acquire both long-term and short-term transmission capacity to facilitate our energy and capacity transactions. We provide transmission and ancillary services in eastern Washington, northern Idaho and western Montana.

Electric Requirements

Avista Utilities' peak electric native load requirement for 2023 was 1,809 MW, which occurred on August 15, 2023. In 2022, our peak electric native load was 1,860 MW, which occurred during the winter, and in 2021, it was 1,889 MW, which occurred during the summer.

Electric Resources

Avista Utilities has a diverse electric resource mix of Company-owned and contracted hydroelectric, thermal, wind and solar generation facilities, and other contracts for power purchases and exchanges. As of December 31, 2023, Avista Utilities' electric generation resource mix (including contracts for power purchases) was approximately 48 percent hydroelectric, 43 percent thermal and 9 percent other renewables. See "Item 2. Properties" for detailed information on Company-owned generating facilities.

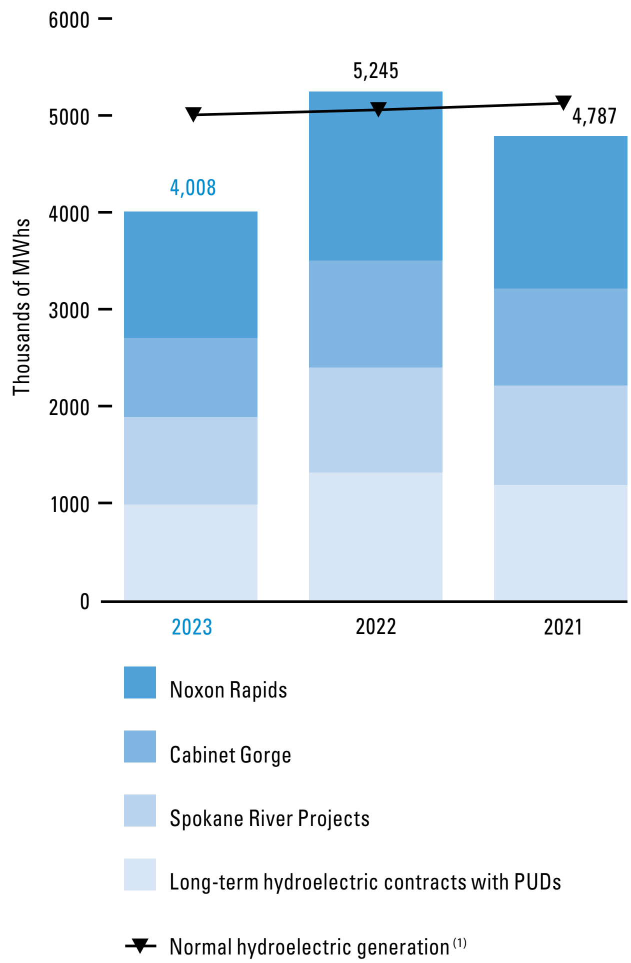
Hydroelectric Resources

Avista Utilities owns and operates Noxon Rapids and Cabinet Gorge on the Clark Fork River and six smaller hydroelectric projects on the Spokane River. Hydroelectric generation is typically our lowest cost source per MWh of electric energy and the availability of hydroelectric generation has a significant effect on total power supply costs. Under normal streamflow and operating conditions, we estimate that we would be able to meet approximately one-half of our total average electric requirements (both retail and long-term wholesale) with the combination of our hydroelectric generation and long-term hydroelectric purchase contracts (including those with certain PUDs in the state of Washington). Our estimate of normal annual hydroelectric generation for 2024 (including resources purchased under long-term hydroelectric contracts with certain PUDs) is 563.1 aMW (or 4.95 million MWhs).

See "Item 2. Properties—Avista Utilities—Generation Properties" for the present generating capabilities of the above hydroelectric resources.

The following graph shows Avista Utilities' hydroelectric generation (in thousands of MWhs) during the year ended December 31:

HYDROELECTRIC GENERATION



(1) Normal hydroelectric generation is determined by reference to the effect of upstream dam regulation on median natural water flow. Natural water flow is the flow of the rivers without the influence of dams, whereas regulated water flow reflects water flow changes from upstream dams due to releasing or holding back water. The calculation of normal varies annually due to the timing of upstream dam regulation throughout the year, as well as changes in PUD contracts.

Thermal Resources

Avista Utilities owns the following thermal generating resources:

- the combined cycle natural gas-fired CT, known as Coyote Springs 2, located near Boardman, Oregon,
- a 15 percent interest in Units 3 & 4 of Colstrip, a coal-fired boiler generating facility located in southeastern Montana. We have an agreement with NorthWestern to transfer our ownership at the end of 2025; see "Note 22 of the Notes to Consolidated Financial Statements" for discussion of our Colstrip transaction with NorthWestern,
- a wood waste-fired boiler generating facility known as the Kettle Falls GS in northeastern Washington,
- a two-unit natural gas-fired CT generating facility in northeastern Spokane (Northeast CT),
- a two-unit natural gas-fired CT generating facility in northern Idaho (Rathdrum CT), and
- two small natural gas-fired generating facilities (Boulder Park GS and Kettle Falls CT).

Coyote Springs 2, which is operated by Portland General Electric Company, is supplied with natural gas under a combination of term contracts and spot market purchases, including transportation agreements with bilateral renewal rights.

Colstrip, which is operated by Talen, is supplied with fuel from adjacent coal reserves under coal supply and transportation agreements. Several of the co-owners of Colstrip, including us, have a coal contract that runs through December 31, 2025. See "Item 7. Management's Discussion and Analysis—Colstrip" for discussion regarding environmental and other issues surrounding Colstrip.

The primary fuel for the Kettle Falls GS is wood waste generated as a by-product and delivered by trucks from forest industry operations within 100 miles of the plant. A combination of long-term contracts and spot purchases has provided, and is expected to meet, fuel requirements for the Kettle Falls GS.

The Northeast CT, Rathdrum CT, Boulder Park GS and Kettle Falls CT generating units are primarily used to meet peaking electric requirements. We also operate these facilities when marginal costs are below prevailing wholesale electric prices. These generating facilities have access to natural gas supplies that are adequate to meet their respective operating needs.

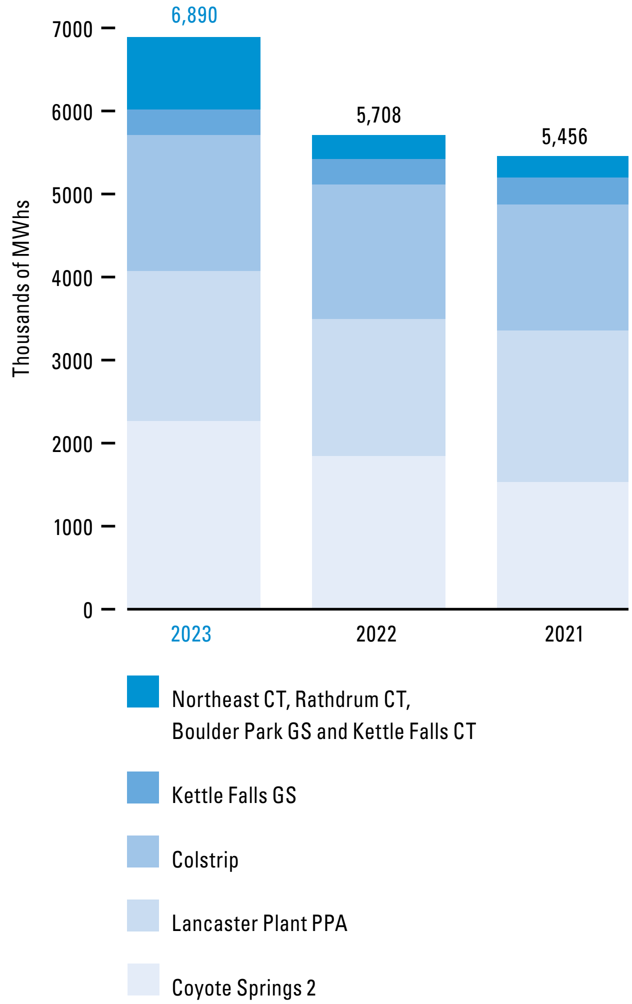
See "Item 2. Properties—Avista Utilities—Generation Properties" for the present generating capabilities of the above thermal resources.

The Lancaster Plant is a 270 MW natural gas-fired combined cycle combustion turbine plant located in northern Idaho, owned by an unrelated third-party. We have a PPA for the output from the Lancaster Plant through December 31, 2041. Under the terms of the PPA, we make the dispatch decisions, provide all natural gas fuel and receive the electric energy output. Therefore, we consider the Lancaster Plant to be a baseload resource. See "Note 5 of the Notes to Consolidated Financial Statements" for further discussion of this PPA.

See "Natural Gas Operations—Natural Gas Supply" for information regarding our supply of natural gas for both fuel and delivery to natural gas customers.

The following graph shows Avista Utilities' thermal generation (in thousands of MWhs) during the year ended December 31:

THERMAL GENERATION



Wind Resources

We have exclusive rights to the capacity of Palouse Wind, a wind generation project developed, owned and managed by an unrelated third-party and located in Whitman County, Washington. Under the PPA, which expires in 2042, we purchase the power and renewable attributes produced by the project at a fixed price per MWh with a fixed escalation of the price over the term of the agreement. The project has a nameplate capacity of 105 MW. We have an annual option to purchase the wind project, which we have not exercised. The purchase price is a fixed price per KW of in-service capacity with a fixed decline in the price per KW over the remaining 20-year term of the PPA.

We have exclusive rights to the capacity of Rattlesnake Flat Wind project developed, owned and managed by an unrelated third party and located in Adams County, Washington. The facility has a nameplate capacity of 144 MW. The 20-year PPA began in December 2020 and we purchase the power and renewable attributes produced by the project at a fixed price per MWh with a fixed escalation of the price over the term of the agreement.

Solar Resources

We have exclusive rights to the capacity of the Lind Solar Farm, a solar generation project developed, owned and managed by an unrelated third-party and located in Lind, Washington. Under a PPA, which expires in 2038, we purchase the power and renewable attributes produced by the project at a fixed price per MWh. The project has a nameplate capacity of 28 MW.

Other Purchases, Exchanges and Sales

In addition to the resources described above, we purchase and sell power under various long-term contracts, and we enter into short-term purchases and sales. Further, pursuant to The Public Utility Regulatory Policies Act of 1978, as amended, we are required to purchase generation from qualifying facilities. This includes, among other resources, hydroelectric projects, cogeneration projects and wind generation projects at rates approved by the WUTC and the IPUC.

See "Avista Utilities Electric Operating Statistics—Electric Operations" below for annual quantities of purchased power, wholesale power sales and power from exchanges in 2023, 2022 and 2021. See "Electric Operations" above for additional information on the use of wholesale purchases and sales as part of our resource optimization process and see "Future Resource Needs" below for the magnitude of these power purchase and sales contracts in future periods.

Regional Capacity Issues

Purchases of capacity and energy at any time are dependent upon the availability of excess capacity in the west region at that time. Many coal-fired electric generating stations throughout the western United States are scheduled for retirement in the next several years. Depending upon a variety of factors, these retirements could have an impact upon the availability and price of purchased power in, and the dynamics of, the market in which we conduct our wholesale purchases and sales. After December 31, 2025, we are prohibited by Clean Energy Transformation Act (CETA) from using energy produced by coal-fired plants to serve our retail customers in Washington. We entered into an agreement with NorthWestern to transfer our interest in Colstrip at the end of 2025. To the extent necessary, we will obtain energy produced by other resources. See "Item 7. Management's Discussion and Analysis—Environmental Matters and Contingencies—Climate Change—Washington Legislation and Regulatory Actions—Clean Energy Transformation Act" and "Colstrip."

In addition to retirement of coal-fired generating stations, some other generation plants in the region are being considered for possible closure due to environmental and other concerns. The reduction of regional generating capacity will have to be offset by the addition of new generating resources and energy storage facilities.

Hydroelectric Licenses

Avista Corp. is a licensee under the Federal Power Act (FPA) as administered by the FERC, which includes regulation of hydroelectric generation resources. Excluding the Little Falls Hydroelectric Generating Project (Little Falls), our other seven hydroelectric plants are regulated by the FERC through two project licenses. The licensed projects are subject to the provisions of Part I of the FPA. These provisions include payment for headwater benefits, condemnation of licensed projects upon payment of just compensation, and take-over by the federal government of such projects after the expiration of the license upon payment of the lesser of "net investment" or "fair value" of the project, in either case, plus severance damages. In the unlikely event that a take-over occurs, it could lead to either the decommissioning of the hydroelectric project or offering the project to another party (likely through sale and transfer of the license).

Cabinet Gorge and Noxon Rapids are under one 45-year FERC license expiring in 2046. This license embodies a settlement agreement relating to project operations and resource protection and mitigation efforts over the license term.

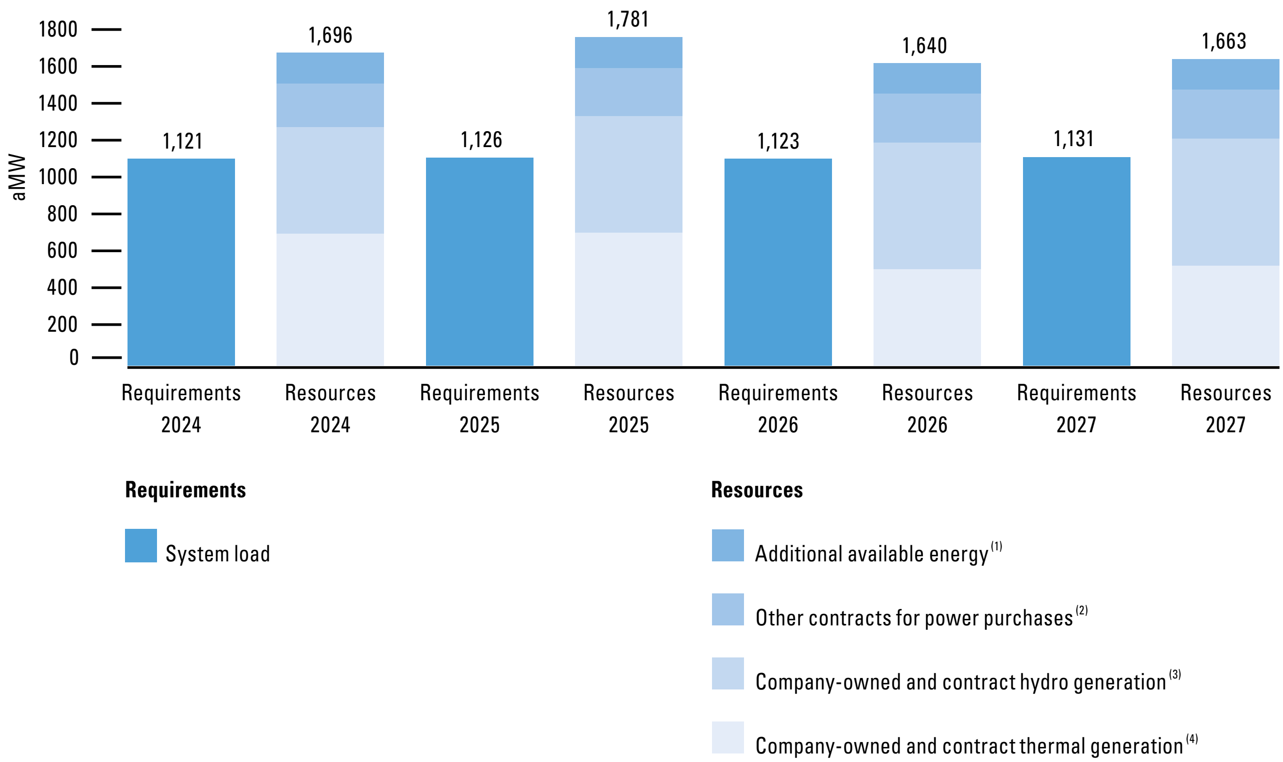
Five of our six hydroelectric projects on the Spokane River (Long Lake, Nine Mile, Upper Falls, Monroe Street and Post Falls) are under one 50-year FERC license expiring in 2059 and are referred to collectively as the Spokane River Project. The license includes numerous natural and cultural resource protection measures that are subject to ongoing regulatory interpretation. The sixth, Little Falls, is operated under separate Congressional authority and is not licensed by the FERC. It is the subject of a 50-year agreement with the Spokane Tribe, expiring in 2044.

Future Resource Needs

Avista Utilities has operational strategies to provide sufficient resources to meet our energy requirements under a range of operating conditions. These operational strategies consider the amount of energy needed, which varies because of the factors that influence demand over intra-hour, hourly, daily, monthly and annual durations. Our average hourly load was 1,115 aMW in 2023, 1,142 aMW in 2022 and 1,113 aMW in 2021.

The following graph shows our forecast of our average annual energy requirements and our available resources for 2024 through 2027:

FORECASTED ELECTRIC ENERGY REQUIREMENTS AND RESOURCES



(1) The combined maximum capacity of Boulder Park GS, Kettle Falls CT, Northeast CT and Rathdrum CT is 278 MW, with estimated available energy production as indicated for each year.

(2) Other contracts for power purchases includes power purchase agreements for solar and wind energy.

(3) The forecast assumes near normal hydroelectric generation.

(4) Includes the Lancaster Plant PPA. Excludes Boulder Park GS, Kettle Falls CT, Northeast CT and Rathdrum CT, as these are considered peaking facilities and are generally not used to meet our base load requirements.

We are required to file an Integrated Resource Plan (IRP) or Washington Progress Report with the WUTC and IPUC every two years. The WUTC and IPUC review the IRP and give the public the opportunity to comment. The WUTC and IPUC do not approve or disapprove of the content in the IRP; rather, they acknowledge that the IRP was prepared in accordance with applicable standards if that is the case. The IRP details projected growth in demand for energy and the new resources needed to serve customers over the next 20 years. We regard the IRP as a tool for resource evaluation, rather than an acquisition plan for a particular project.

In June 2023, we filed our 2023 Electric IRP with the WUTC and the IPUC. We anticipate our next IRP to be filed in 2025.

Highlights of the 2023 Electric IRP include the following expectations and/or assumptions:

- The forecast for growth in energy requirements increased to 0.9 percent per year, from 0.2 percent in the 2021 IRP. Higher growth largely reflects higher residential and commercial electric vehicle forecasts and new building electrification.
- We have entered into PPAs for several renewable resources, and an expected divestiture (Colstrip at the end of 2025) since our 2021 IRP.
- The resource strategy selected in the IRP is designed to achieve an 80 percent reduction in GHG emissions by 2045.
- We need long-duration storage to serve customers in peak hours after 2035.
- We created a Named Community Investment Fund to increase energy-related investments in disadvantaged communities. The fund will increase distributed energy resources such as energy efficiency, small-scale renewables, and energy storage.

We are subject to the Washington State Energy Independence Act, which requires us to obtain a portion of our electricity from qualifying renewable resources or through purchase of RECs and acquiring all cost effective conservation measures. Future generation resource decisions will be affected by legislation for restrictions on greenhouse gas emissions and renewable energy requirements.

See "Item 7. Management's Discussion and Analysis of Financial Condition—Environmental Issues and Contingencies" and "Colstrip" for information related to existing and proposed laws and regulations, and issues relating to Colstrip.

Additional generating resources required will either be owned by us or be owned by other parties who will sell us the capacity and energy under PPAs. The decision as to ownership will be made as to each project at the appropriate time and will depend on, among other things, the type of project and the related economics, including tax and ratemaking treatment.

Electric Clean Energy Goals

We have an aspirational goal to serve our customers with 100 percent clean electricity by 2045. To help achieve this goal and add to our clean electricity portfolio, we have implemented renewable energy projects, including entering into various PPAs for solar, wind and hydroelectric resources. These resources are in addition to our existing clean hydroelectric generation, biomass generation, and additional wind and solar projects.

To achieve our clean energy goals, we expect energy storage and other technologies, which are either not currently available or are not cost-effective under the lowest reasonable cost regulatory standard, will advance to allow us to meet our goals while maintaining reliability and affordability for our customers. If the required technology is not available or not affordable in the future, we may not meet our goals in the desired timeframe. Meeting our clean energy goals may also require accommodation from regulatory agencies. See the discussion under "Electric Resources" for more information on our existing clean electricity sources and efforts to achieve these goals. See "Item 7. Management's Discussion and Analysis of Financial Condition—Environmental Issues and Contingencies" for further discussion on clean energy, including applicable regulations.

Wildfire Resiliency Plan

We are implementing additional measures to enhance our ability to mitigate the potential for, and impact of, wildfires within our service territories. Building on prevention and response strategies in place for many years, in 2020 we created a comprehensive 10-year Wildfire Resiliency Plan that includes improved defense strategies and operating practices for a more resilient system. This plan is periodically updated and informed by observed experience as well as changes in observed landscape and climatic conditions.

We developed the Wildfire Resiliency Plan through a series of internal workshops, industry research and engagement with state and local fire agencies. Improvements to infrastructure and operational practices were identified as key components to the plan. These key components are categorized into the following categories: grid hardening, vegetation management, situational awareness, operations and emergency response, and worker and public safety.

We expect to spend $437 million ($124 million of which was spent through 2023) implementing the plan components over the life of the 10-year plan that began in 2020. The IPUC and WUTC approved deferral of certain costs of the wildfire resiliency plan, and we will continue to seek recovery of costs in future rate filings.

See "Note 22 of the Notes to Consolidated Financial Statements" for further discussion on wildfires.

Natural Gas Operations

General

Avista Utilities provides natural gas distribution services to retail customers in parts of eastern Washington, northern Idaho, and northeastern and southwestern Oregon.

Market prices for natural gas, like other commodities, can be volatile. Our natural gas procurement strategy is to provide a reliable supply to our customers with some level of price certainty. We procure natural gas from various supply basins and over varying time periods. The resulting portfolio is a diversified mix of forward fixed price purchases, index and spot market purchases, and utilizing physical and financial derivative instruments. We also use natural gas storage to support high demand periods and the procurement of natural gas when prices may be lower. Securing prices throughout the year and even into subsequent years provides a level of price certainty and can mitigate price volatility to customers between years.

Weather is a key component of our natural gas customer load. This load is highly variable and daily natural gas loads can differ significantly from the monthly forecasted load projections. We make continuing projections of our natural gas loads and assess available natural gas resources. Based on these projections, we plan and execute a series of transactions to hedge a portion of our customers' projected natural gas requirements through forward market transactions and derivative instruments. These transactions may extend for multiple years into the future. We also leave a portion of our natural gas supply requirements unhedged for purchase in the short-term spot markets.

Our purchase of natural gas supply is governed by our procurement plan and is reviewed and approved annually by the Risk Management Committee (RMC), which is comprised of certain officers and other management personnel. Once approved, the plan is implemented and monitored by our gas supply and risk management groups.

The plan's progress is presented to the WUTC and IPUC staff in semi-annual meetings, and updates are given to the OPUC staff quarterly. The RMC is provided with an update on plan results and changes in their monthly meetings. These activities provide transparency for the natural gas supply procurement plan. Material changes to the plan are documented and communicated to RMC members.

As part of the process of balancing natural gas retail load requirements with resources, we engage in the wholesale purchase and sale of natural gas. We plan for sufficient natural gas delivery capacity to serve our retail customers for a theoretical peak day event. We generally have more pipeline and storage capacity than what is needed during periods other than a peak day. We optimize our natural gas resources by using market opportunities to generate economic value that helps mitigate fixed costs. Wholesale sales are delivered through wholesale market facilities outside of our natural gas distribution system. Natural gas resource 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.

We also provide distribution transportation service to qualified, large commercial and industrial natural gas customers who purchase natural gas through third-party marketers. For these customers, we receive their purchased natural gas from such third-party marketers into our distribution system and deliver it to the customers' premises. These customers generally pay the same rates as other customers in the same class, without charge for the cost of the natural gas delivered.

Optimization transactions that we engage in throughout the year are included in our annual purchased gas cost adjustment filings with the various commissions and are subject to review for prudence during this process.

Natural Gas Clean Energy Goals

We have an aspirational goal for our natural gas operations to be carbon neutral by 2045. Examples of carbon emissions reduction strategies include the following:

- diversify or transition from fossil fuel-based natural gas to renewable natural gas,
- reduce natural gas consumption via conservation, energy efficiency and new technologies, and
- purchase carbon offsets as necessary.

See "Item 7. Management's Discussion and Analysis of Financial Condition—Environmental Issues and Contingencies" for further discussion on clean energy, including applicable regulations.

We have several contracts for RNG, including agreements with Pine Creek RNG to purchase an expected output of approximately 9.7 million therms annually from various projects.

Natural Gas Supply

We purchase natural gas, for both fuel for generation and delivery to natural gas customers, in wholesale markets and are connected to multiple supply basins in the western United States and Canada through firm capacity transportation rights on six different pipeline networks. Access to this diverse portfolio of natural gas resources allows for natural gas procurement decisions that benefit our natural gas customers. These interstate pipeline transportation rights provide the capacity to serve approximately 25 percent of peak natural gas customer demands from domestic sources and 75 percent from Canadian sources. Natural gas prices in the Pacific Northwest are affected by global energy markets, as well as supply and demand factors in other regions of the United States and Canada. Future prices and delivery constraints may cause our resource mix to vary.

Natural Gas Storage

Avista Utilities owns a one-third interest in Jackson Prairie, an underground aquifer natural gas storage field located near Chehalis, Washington. Jackson Prairie has a total peak day deliverability of 12 million therms, with a total working natural gas capacity of 256 million therms. Our share is one-third of the peak day deliverability and total working capacity. We also contract for additional storage capacity and delivery at Jackson Prairie from Northwest Pipeline for a portion of their one-third share of the storage project.

We optimize our natural gas storage capacity throughout the year by executing transactions that capture favorable market price spreads. Natural gas buyers identify opportunities to purchase lower cost natural gas in the immediate term to inject into storage, and then sell the gas in a forward market to be withdrawn later. The reverse of this type of transaction also occurs. These transactions lock in incremental value for customers. Jackson Prairie is also used as a variable peaking resource, and to protect from extreme daily price volatility during cold weather or other events affecting the market.

Future Resource Needs

In March 2023, we filed our 2023 Natural Gas IRP with the WUTC, the IPUC and the OPUC. The IRP details projected growth in demand for energy and the new resources needed to serve customers over the next 20 years. We regard the IRP as a tool for resource evaluation, rather than an acquisition plan for a particular project.

Highlights of the 2023 natural gas IRP include the following expectations and/or assumptions:

- We anticipate having sufficient natural gas resources to meet expected loads with our current transportation contracts for natural gas.
- Customer forecasts are increasingly difficult to model due to a variety of rules and codes.
- Emissions compliance with various environmental laws greatly impact our resource strategy, including the use of renewable natural gas, synthetic methane, and credits or allowances.
- Our Idaho preferred resource strategy continues to utilize a least cost basis.

We monitor these assumptions on an on-going basis and adjust our resource requirements accordingly.

See "Item 7. Management's Discussion and Analysis of Financial Condition—Environmental Issues and Contingencies" for further discussion of environmental laws, including impacts to our business.

We are required to file a natural gas IRP every two years and we anticipate our next IRP to be filed in 2025.

Utility Regulation

General

As a public utility, Avista Corp. is subject to regulation by state utility commissions for retail electric and natural gas rates, accounting, the issuance of securities and other matters. The retail electric and natural gas operations are subject to the jurisdiction of the WUTC, IPUC, OPUC and MPSC. Approval of the issuance of securities is not required from the MPSC. We are subject to the jurisdiction of the FERC for licensing of hydroelectric generation resources, and for electric transmission services and wholesale sales.

Since Avista Corp. is a "holding company" (in addition to being itself an operating utility), we are subject to the jurisdiction of the FERC under the Public Utility Holding Company Act of 2005, which imposes certain reporting and record-keeping requirements on Avista Corp. and its subsidiaries. We and our subsidiaries are required to make books and records available to the FERC and the state utility commissions. In addition, upon the request of any jurisdictional state utility commission, the FERC would have the authority to review assignment of costs of non-power goods and administrative services among us and our subsidiaries. The FERC has the authority generally to require that rates subject to its jurisdiction be just and reasonable and, in this context, would continue to be able to, among other things, review transactions of an affiliated company.

Our rates for retail electric and natural gas services (other than specially negotiated retail rates for industrial or large commercial customers, which are subject to regulatory review and approval) are generally determined on a "cost of service" basis.

Retail rates are designed to provide an opportunity to recover allowable operating expenses and earn a return of and a reasonable return on "rate base." Rate base is generally determined by reference to the original cost (net of accumulated depreciation) of utility plant in service, subject to various adjustments for deferred income taxes and other items. Over time, rate base is increased by additions to utility plant in service and reduced by depreciation and write-offs as authorized by the utility commissions. Our operating expenses and rate base are allocated or directly assigned to five regulatory jurisdictions: electric in Washington and Idaho, and natural gas in Washington, Idaho and Oregon. In general, requests for new retail rates are made based on revenues, operating expenses and net investment for a test year that ended prior to the date of the request, subject to possible adjustments, which differ among the various jurisdictions, designed to reflect the expected revenues, operating expenses and net investment during the period new retail rates will be in effect. The retail rates approved by the state commissions in a rate proceeding may not provide sufficient revenues to provide recovery of costs and a reasonable return on investment for a number of reasons, including, but not limited to, ongoing capital expenditures and unexpected changes in revenues and expenses following the time new retail rates are requested in the rate proceeding (known as "regulatory lag"), the denial by the commission of recovery, or timely recovery, of certain expenses or investment and the limitation by the commission of the authorized return on investment. In 2021, Washington enacted a multi-year rate plan and performance-based rate making regulations. See "Item 7. Management's Discussion and Analysis—Regulatory Matters—General Rate Cases" for further information.

Our rates for wholesale electric sales and electric transmission services, as well as certain natural gas transportation services, are based on either "cost of service" principles or market-based rates as set forth by the FERC. See "Notes 1, 13 and 23 of the Notes to Consolidated Financial Statements" for additional information about regulation (including power cost deferrals, purchased gas adjustments and decoupling mechanisms), depreciation and deferred income taxes.

See "Item 7. Management's Discussion and Analysis—Regulatory Matters" for information on general rate cases.

Federal Laws Related to Wholesale Competition

Federal law promotes practices that foster competition in the electric wholesale energy market. The FERC requires electric utilities to transmit power and energy to or for wholesale purchasers and sellers, and requires electric utilities to enhance or construct transmission facilities to create additional transmission capacity for the purpose of providing these services. Public utilities (through subsidiaries or affiliates) and other entities may participate in the development of independent electric generating plants for sales to wholesale customers.

Public utilities operating under the FPA are required to provide open and non-discriminatory access to their transmission systems to third parties and establish an Open Access Same-Time Information System to provide an electronic means by which transmission customers can obtain information about available transmission capacity and purchase transmission access. The FERC also requires each public utility subject to the rules to operate its transmission and wholesale power merchant operating functions separately and to comply with standards of conduct designed to ensure that all wholesale users, including the public utility's power merchant operations, have equal access to the public utility's transmission system. Our compliance with these standards has not had a substantive impact on the operation, maintenance and marketing of our transmission system or our ability to provide service to customers.

See "Item 7. Management's Discussion and Analysis—Competition" for further information.

Regional Transmission Planning

Beginning with FERC Order No. 888 and continuing with subsequent rulemakings and policies, the FERC has encouraged better coordination and operational consistency aimed to capture efficiencies that might otherwise be gained through the formation of a Regional Transmission Organization or an independent system operator.

We meet our FERC requirements to coordinate transmission planning activities with other regional entities through NorthernGrid. Launched January 1, 2020, NorthernGrid is an association of all major transmission providers throughout the Pacific Northwest and Intermountain West, with facilities in California, Idaho, Montana, Oregon, Utah, Washington and Wyoming. Through our participation in NorthernGrid, we meet the regional transmission planning requirements of FERC Order Nos. 890 and 1000, and follow-on orders. NorthernGrid and its members also work with other western organizations, including WestConnect and the California Independent System Operator (CAISO), to address broader interregional planning. Neither the costs nor requirements of participating in NorthernGrid's coordinated transmission planning activities are expected to materially impact our operations or financial performance.

Regional Energy Markets

The CAISO operates the Western Energy Imbalance Market (EIM) in the western United States. All investor-owned utilities in the Pacific Northwest are participants in the Western EIM. We commenced Western EIM operations in March 2022. The Western EIM, among other things, facilitates regional load balancing by allowing certain generating plants to receive automated dispatch signals from the CAISO in five-minute intervals.

Reliability Standards

Among its other provisions, the U.S. Energy Policy Act provides for the implementation of mandatory reliability standards and authorizes the FERC to assess penalties for non-compliance with these standards and other FERC regulations.

The FERC certified the NERC as the single Electric Reliability Organization authorized to establish and enforce reliability standards and delegate authority to regional entities for the purpose of establishing and enforcing reliability standards, including but not limited to cybersecurity measures. The FERC approves NERC Reliability Standards, including western region standards that make up the set of legally enforceable standards for the United States bulk electric system. We are required to self-certify our compliance with these standards on an annual basis and undergo regularly scheduled periodic reviews by the NERC and its regional entity, the Western Electricity Coordinating Council (WECC). Failure to comply with NERC reliability standards could result in substantial financial penalties. We have a robust internal compliance program in place to manage compliance activities and mitigate the risk of potential noncompliance with these standards. We do not expect the costs associated with compliance with these standards to have a material impact on our financial results.

As both a balancing authority and transmission operator, we must operate under the oversight of a reliability coordinator per

NERC reliability standards. RC West is the reliability coordinator of record for 41 balancing authorities and transmission operators in the Western Interconnection, including Avista Corp. RC West oversees grid compliance with federal and regional grid standards, and can determine measures to prevent or mitigate system emergencies in day-ahead or real-time operations.

Vulnerability to Cyberattack

The energy sector, including electric and natural gas utility companies, have become the subject of cyberattacks and ransomware attacks with increased frequency. Our administrative and operating networks are targeted by hackers on a regular basis.

A successful attack on our administrative networks could compromise the security and privacy of data, including operating, financial and personal information. A successful attack on our operating networks could impair the operation of our electric and/or natural gas utility facilities, possibly resulting in the inability to provide electric and/or natural gas service for extended periods of time.

We continually reinforce and update our defensive systems and comply with the NERC's reliability standards. See "Reliability Standards," "Item 1A. Risk Factors—Cybersecurity Risk Factors" and "Item 1C. Cybersecurity" for further information.

AVISTA UTILITIES ELECTRIC OPERATING STATISTICS

Years Ended December 31,

	2023	2022	2021
Electric Operations			
Operating Revenues (Dollars in Thousands):			
Residential	$ 425,258	$ 414,823	$ 394,717
Commercial	343,523	338,656	326,173
Industrial	109,689	107,740	106,756
Public street and highway lighting	7,976	7,483	7,472
Total retail	886,446	868,702	835,118
Wholesale	249,847	179,316	89,768
Sales of fuel	(25,926)	84,256	63,673
Other	49,235	46,319	36,288
Alternative revenue programs	12,419	(31,844)	(19,525)
Deferrals and amortizations for rate refunds to customers	149	74	1,730
Total electric operating revenues	$ 1,172,170	$ 1,146,823	$ 1,007,052
Energy Sales (Thousands of MWhs):			
Residential	4,020	4,154	3,955
Commercial	3,160	3,201	3,158
Industrial	1,671	1,699	1,666
Public street and highway lighting	17	17	17
Total retail	8,868	9,071	8,796
Wholesale	3,468	3,094	2,461
Total electric energy sales	12,336	12,165	11,257
Energy Resources (Thousands of MWhs):			
Hydro generation (from Company facilities)	3,024	3,930	3,598
Thermal generation (from Company facilities)	5,084	4,055	3,635
Purchased power	5,121	5,065	4,954
Power exchanges	(421)	(385)	(398)
Total power resources	12,808	12,665	11,789
Energy losses and Company use	(472)	(500)	(532)
Total energy resources (net of losses)	12,336	12,165	11,257
Number of Retail Customers (Average for Period):			
Residential	366,450	361,564	356,387
Commercial	45,341	44,550	44,110
Industrial	1,188	1,193	1,205
Public street and highway lighting	690	681	666
Total electric retail customers	413,669	407,988	402,368
Residential Service Averages:			
Annual use per customer (kWh)	10,971	11,487	11,098
Revenue per kWh (in cents)	10.58	9.99	9.98
Annual revenue per customer	$ 1,160	$ 1,147	$ 1,108
Average Hourly Load (aMW)	1,115	1,142	1,113

AVISTA UTILITIES ELECTRIC OPERATING STATISTICS

Years Ended December 31,

	2023	2022	2021
Electric Operations (continued)			
Retail Native Load at time of system peak (MW):			
Winter	1,771	1,860	1,696
Summer	1,809	1,810	1,889
Cooling Degree Days: (1)			
Spokane, WA			
Actual	811	758	946
Historical average	585	568	546
% of average	139%	133%	173%
Heating Degree Days: (2)			
Spokane, WA			
Actual	6,012	6,811	6,124
Historical average	6,557	6,560	6,596
% of average	92%	104%	93%

(1) Cooling degree days are the measure of the warmness of weather experienced, based on the extent to which the average of high and low temperatures for a day exceeds 65 degrees Fahrenheit (annual degree days above historical average indicate warmer than average temperatures).

(2) Heating degree days are the measure of the coldness of weather experienced, based on the extent to which the average of high and low temperatures for a day falls below 65 degrees Fahrenheit (annual degree days below historical averages indicate warmer than average temperatures).

AVISTA UTILITIES NATURAL GAS OPERATING STATISTICS (continued)

Years Ended December 31,

	2023	2022	2021
Natural Gas Operations			
Operating Revenues (Dollars in Thousands):			
Residential	$ 325,631	$ 284,452	$ 221,405
Commercial	164,048	139,923	100,819
Interruptible	12,747	6,474	4,781
Industrial	4,568	3,997	3,015
Total retail	506,994	434,846	330,020
Wholesale	55,295	133,235	113,277
Transportation	8,172	8,627	8,547
Other	6,773	8,156	7,325
Alternative revenue programs	(7,520)	(1,513)	12,890
Deferrals and amortizations for rate refunds to customers	876	134	1,254
Total natural gas operating revenues	$ 570,590	$ 583,485	$ 473,313
Therms Delivered (Thousands of Therms):			
Residential	225,665	242,452	219,835
Commercial	138,719	147,059	130,399
Interruptible	20,158	14,166	16,013
Industrial	4,914	5,606	5,402
Total retail	389,456	409,283	371,649
Wholesale	262,188	280,154	356,891
Transportation	165,066	171,785	172,260
Interdepartmental and Company use	413	618	479
Total therms delivered	817,123	861,840	901,279
Number of Retail Customers (Average for Period):			
Residential	340,655	337,073	332,187
Commercial	37,193	36,753	36,448
Interruptible	50	44	42
Industrial	187	188	190
Total natural gas retail customers	378,085	374,058	368,867
Residential Service Averages:			
Annual use per customer (therms)	662	719	662
Revenue per therm (in dollars)	$ 1.44	$ 1.17	$ 1.01
Annual revenue per customer	$ 956	$ 844	$ 667
Heating Degree Days: [1]			
Spokane, WA			
Actual	6,012	6,811	6,124
Historical average	6,557	6,560	6,596
% of average	92%	104%	93%
Medford, OR			
Actual	4,295	4,408	4,107
Historical average	4,248	4,248	4,254
% of average	101%	104%	97%

(1) Heating degree days are the measure of the coldness of weather experienced, based on the extent to which the average of high and low temperatures for a day falls below 65 degrees Fahrenheit (annual degree days below historic indicate warmer than average temperatures).

ALASKA ELECTRIC LIGHT AND POWER COMPANY

AEL&P is the primary operating subsidiary of AERC, and the sole utility providing electrical energy in Juneau, Alaska. Juneau is a geographically isolated community with no electric interconnections with the transmission facilities of other utilities and no pipeline access to natural gas or other fuels. Juneau's economy is primarily driven by government activities, tourism, commercial fishing, and mining, as well as activities as the commercial hub of southeast Alaska.

AEL&P owns and operates electric generation, transmission and distribution facilities located in Juneau. AEL&P operates five hydroelectric generation facilities with 102.7 MW of hydroelectric generation capacity. AEL&P owns four of these generation facilities (totaling 24.5 MW of capacity) and has a PPA for the output of the Snettisham Hydroelectric Project (totaling 78.2 MW of capacity).

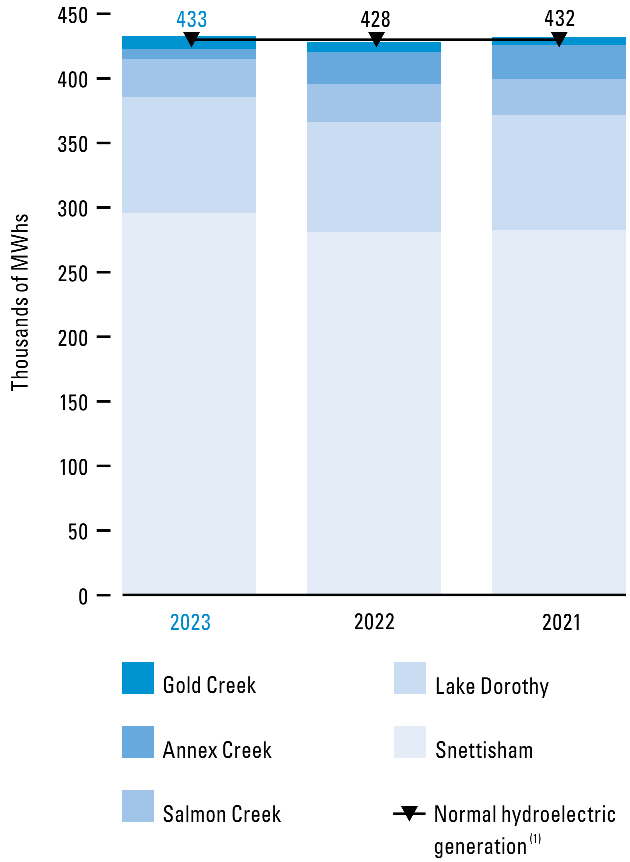
The Snettisham Hydroelectric Project is owned by the Alaska Industrial Development and Export Authority (AIDEA), a public corporation of the State of Alaska. AIDEA issued revenue bonds in 1998 (which were refinanced in 2015) to finance its acquisition of the project. These bonds were outstanding in the amount of $42.5 million at December 31, 2023 and mature in January 2034. AEL&P has a PPA and operating and maintenance agreement with the AIDEA to operate and maintain the facility. This PPA is a take-or-pay obligation, expiring in December 2038. AIDEA's bonds are payable solely out of the revenues received under the PPA. Amounts payable by AEL&P under the PPA are equal to the required debt service on the bonds plus operating and maintenance costs.

This PPA is a finance lease and, as of December 31, 2023, the finance lease obligation was $42.5 million. Snettisham Electric Company, a non-operating subsidiary of AERC, has the option to purchase the Snettisham project at any time for a price equal to the principal amount of the bonds outstanding at that time. See "Note 5 of the Notes to Consolidated Financial Statements" for further discussion of the Snettisham finance lease obligation.

AEL&P has 107.5 MW of diesel generating capacity from four facilities to provide back-up service to firm customers when necessary.

The following graph shows AEL&P's hydroelectric generation (in thousands of MWhs) during the time periods indicated below:

HYDROELECTRIC GENERATION



(1) *Normal hydroelectric generation is defined as the energy output of the plant during a year with average inflows to the reservoir.*

As of December 31, 2023, AEL&P served approximately 17,700 customers. Its primary customers include city, state and federal governmental entities located in Juneau, as well as a mine located in the Juneau area. Most of AEL&P's customers are served on a firm basis while certain of its customers, including its largest customer, are served on an interruptible sales basis. AEL&P maintains separate rate tariffs for each of its customer classes, as well as seasonal rates.

AEL&P's operations are subject to regulation by the RCA with respect to customer rates, standard of service, facilities, accounting and certain other matters, but not with respect to the issuance of securities.

AEL&P is subject to the jurisdiction of the FERC with respect to permits and licenses necessary to operate certain of its hydroelectric facilities. One of these licenses (for the Lake Dorothy hydroelectric project) expires in 2053 while the other (for the Salmon Creek and Annex Creek hydroelectric projects) expires in 2058. Gold Creek is not subject to a FERC license requirement. Since AEL&P has no electric interconnection with other utilities and makes no wholesale sales, it is not subject to general FERC jurisdiction, other than the reporting and other requirements of the Public Utility Holding Company Act of 2005 as an Avista Corp. subsidiary.

The Snettisham Hydroelectric Project is subject to regulation by the State of Alaska with respect to dam safety and certain aspects of its operations. AEL&P is subject to regulation with respect to air and water quality, land use and other environmental matters under both federal and state laws.

AEL&P ELECTRIC OPERATING STATISTICS

Years Ended December 31,

	2023	2022	2021
Electric Operations			
Operating Revenues (Dollars in Thousands):			
Residential	$ 20,232	$ 19,667	$ 18,940
Commercial and government	27,026	25,782	25,861
Public street and highway lighting	267	254	250
Total retail	47,525	45,703	45,051
Other	614	1	315
Total electric operating revenues	$ 48,139	$ 45,704	$ 45,366
Energy Sales (Thousands of MWhs):			
Residential	161	163	160
Commercial and government	249	240	243
Public street and highway lighting	1	1	1
Total electric energy sales	411	404	404
Number of Retail Customers (Average for Period):			
Residential	15,142	15,036	14,919
Commercial and government	2,327	2,305	2,282
Public street and highway lighting	248	236	230
Total electric retail customers	17,717	17,577	17,431
Residential Service Averages:			
Annual use per customer (kWh)	10,633	10,841	10,773
Revenue per kWh (in cents)	12.54	12.07	11.84
Annual revenue per customer	$ 1,336	$ 1,308	$ 1,270
Heating Degree Days: (1)			
Juneau, AK			
Actual	7,550	7,923	8,394
Historical average	8,336	8,337	8,335
% of average	91%	95%	101%

(1) Heating degree days are the measure of the coldness of weather experienced, based on the extent to which the average of high and low temperatures for a day falls below 65 degrees Fahrenheit (annual heating degree days below historical average indicate warmer than average temperatures).

OTHER BUSINESSES

The following table shows our assets related to our other businesses, including intercompany amounts as of December 31 (dollars in thousands):

Entity and Asset Type	2023	2022
Avista Capital		
Equity investments	$ 153,350	$ 147,809
Real estate investments	4,512	7,852
Notes receivable—third parties	20,380	17,954
Other assets	2,452	2,865
Alaska companies (AERC and AJT Mining)	10,971	10,547
Total	$ 191,665	$ 187,027

Avista Capital equity investments are primarily investments in emerging technology and biotechnology companies and venture capital funds, as well as investment in a joint venture focused on local real estate development and economic growth.

Alaska companies includes AERC and AJT Mining, which is a wholly owned subsidiary of AERC and is an inactive mining company holding certain real estate.

ITEM 1A. Risk Factors

RISK FACTORS

The following factors could have a significant impact on our operations, results of operations, financial condition or cash flows. These factors could cause future results or outcomes to differ materially from those discussed in our reports filed with the SEC (including this Annual Report on Form 10-K), and elsewhere. See "Forward-Looking Statements" for additional factors which could have a significant impact on our operations, results of operations, financial condition or cash flows and could cause actual results to differ materially from those anticipated in such statements.

Utility Regulatory Risk Factors

Regulators may not grant rates that provide timely or sufficient recovery of our costs or allow a reasonable rate of return for our shareholders.

Avista Utilities' annual operating expenses and the costs associated with incremental investments in utility assets continue to grow at a faster rate than revenue. Our ability to recover these expenses and capital costs depends on the adequacy and timeliness of retail rate increases allowed by regulatory agencies, as well as managing costs. We expect to periodically file for rate increases with regulatory agencies to recover our expenses and capital costs and provide an opportunity to earn a reasonable rate of return for shareholders. If regulators do not grant rate increases or grant substantially lower rate increases than our requests in the future or if recovery of deferred expenses is disallowed, it could have a negative effect on our financial condition, results of operations or cash flows. See further discussion of regulatory matters in "Item 7. Management's Discussion and Analysis—Regulatory Matters."

In the future, we may no longer meet the criteria for continued application of regulatory accounting principles for all or a portion of our regulated operations.

If we could no longer apply regulatory accounting principles, we could be:

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

See further discussion at "Note 1 of the Notes to Consolidated Financial Statements—Regulatory Deferred Charges and Credits."

Operational Risk Factors

Weather (temperatures, precipitation levels, wind patterns and storms) has a significant effect on our results of operations, financial condition and cash flows. These effects could increase as climate changes occur.

Weather impacts are described in the following subtopics:

- certain retail electricity and natural gas sales,
- the cost of natural gas supply, and
- the cost of power supply.

Wildfires ignited, or allegedly ignited, by Avista Corp. equipment or facilities, could cause significant loss of life and property, thereby causing serious operational and financial harm.

Our equipment may be the ignition source, or alleged cause of ignition, for wildfires and in the event of a fire caused by our equipment, we could potentially be held liable for resulting damages to life and property, as well as fire suppression costs. Also, wildfires could lead to extended operational outages of our equipment while we wait for the wildfire to be extinguished before restoring power, and the cost to implement rapid response or repair to such facilities could be significant. Wildfires caused by our equipment could cause significant damage to our reputation, which could erode shareholder, customer and community satisfaction. In addition, wildfires caused by our equipment could lead to increased litigation and insurance costs, loss of insurance coverage, the need to be self-insured or the need to consider non-traditional insurance coverage or other risk mitigation procedures. Wildfire risks may be exacerbated by increasing temperatures and/or decreasing precipitation due to climate change.

We are subject to various operational and event risks.

Our operations are subject to operational and event risks that include:

- severe weather or natural disasters, including, but not limited to, avalanches, wind storms, wildfires, earthquakes, snow and ice storms, and heat waves due to normal weather variations as well as the impacts of climate change which could disrupt energy generation, transmission and distribution, as well as the availability and costs of materials, equipment, supplies, support services and general business operations,
- blackouts or disruptions of interconnected transmission systems (the regional power grid),
- unplanned outages at generating plants,

- changes in the availability and cost of purchased power, fuel and natural gas, including delivery constraints, which can disrupt service to customers,
- explosions, fires, accidents, or mechanical breakdowns that could occur while operating and maintaining our generation, transmission and distribution systems,
- property damage or injuries to third parties caused by our generation, transmission and distribution systems,
- natural disasters that can disrupt energy generation, transmission and distribution, and general business operations,
- terrorist attacks or other malicious acts that may disrupt or cause damage to our utility assets or the vendors we utilize, and
- increased costs or delay of capital projects associated with the ability of suppliers, vendors or contractors to perform,
- general workforce problems, including decreased employee engagement, which may impact strategy execution and negatively affect retention, ability to attract workers, and result in challenges in collective bargaining, possible work stoppages, and strikes. Retention of employees may also be negatively impacted by early retirements, insufficient remote work opportunities, and higher pay offered by other employers. Attractions of employees to support strategies may be affected by higher pay offered from other companies, more liberal remote work opportunities offered by other employers, and other work-life balance benefits afforded by other companies.

Disasters could affect the general economy, financial and capital markets, specific industries or our ability to conduct business. As protection against operational and event risks, we maintain business continuity and disaster recovery plans, maintain insurance coverage against some, but not all, potential losses and we seek to negotiate indemnification arrangements with contractors for certain event risks. However, insurance or indemnification agreements may not be adequate to protect against liability, extra expenses and operating disruptions from the operational and event risks described above. In addition, we are subject to the risk that insurers and/or other parties will dispute or be unable to perform on their obligations. If insurance or indemnification agreements are unable to adequately protect us or reimburse us for out-of-pocket costs, it could have a material adverse effect on our results of operations, financial condition and cash flows.

Damage to facilities could be caused by severe weather or natural disasters, such as snow, ice, wind storms, wildfires, earthquakes or avalanches. The cost to implement rapid response or repair to such facilities can be significant. Overhead electric lines are most susceptible to damage caused by severe weather and are not covered by insurance.

Physical attacks on our assets could have a negative impact on our business and our results of operations.

Our generation, transmission and distribution assets and the systems that monitor and operate these assets are critical infrastructure for providing service to our customers. Security threats are continuing to evolve, and our industry has been subject to, and will likely continue to be subject to, attempts to disrupt operations. Significant destruction or interruption of these assets and systems could prevent us from fulfilling our critical business functions, including delivering energy to customers. This could result in experiencing a loss of revenues and/or additional costs to replace or restore assets and systems, and may increase costs associated with heightened security requirements.

Adverse impacts to AEL&P could result from an extended outage of its hydroelectric generating resources or its inability to deliver energy, due to its lack of interconnectivity to other electrical grids and the cost of replacement power (diesel).

AEL&P operates several hydroelectric power generation facilities and has diesel generating capacity from multiple facilities to provide backup service to firm customers when necessary; however, a single hydroelectric power generation facility, the Snettisham Hydroelectric Project, provides approximately two-thirds of AEL&P's hydroelectric power generation. Issues that negatively affect AEL&P's ability to generate or transmit power or a decrease in the demand for the power generated by AEL&P could negatively affect our results of operations, financial condition and cash flows.

Climate Change Risk Factors

A trend of increasing average temperatures and its effects could cause significant direct and indirect impacts on our operations and results of operations.

Climate change may exacerbate existing risks related to weather and weather-related events. Potential direct effects of climate change include changes in the timing and magnitude of snowpack and streamflow, impacting hydro generation; timing and magnitude of changes in electric and gas load; increased weather-related stress on, or damage to, energy infrastructure; increased frequency and intensity of extreme weather events that may impact energy generation and delivery.

Indirect impacts associated with climate change may include increased costs to generate electricity or secure natural gas and deliver energy to customers; impacts to the timing or amount of operating revenues; increased costs to maintain or construct energy infrastructure in adaptation to a changing climate; increased costs or inability to obtain insurance coverage; and regional impacts to the demographic makeup, economy or financial conditions of our customers. Indirect impacts also include risks associated with new and emerging laws and regulations, which could have a material adverse impact on our business and results of operations. See further discussion at "Item 7. Management's Discussion and Analysis—Environmental Issues and Contingencies."

Cybersecurity Risk Factors

Cyberattacks, ransomware, terrorism or other malicious acts could disrupt our businesses and have a negative impact on our results of operations and cash flows.

We rely on interconnected technology systems for operation of our generating plants, electric transmission and distribution systems, natural gas distribution systems, customer billing and customer service, accounting and other administrative processes and compliance with various regulations. In addition, in the ordinary course of business, we collect and retain sensitive information including personal information about our customers and employees.

Cyberattacks, ransomware, terrorism or other malicious acts could damage, destroy or disrupt these systems for an extended period of time. The energy sector, including electric and natural gas utility companies have become the subject of cyberattacks with increased frequency. Our administrative and operating networks are targeted by hackers on a regular basis. Additionally, the facilities and systems of clients, suppliers and third party service providers could be vulnerable to the same cyber or terrorism risks as our facilities and systems and such third party systems may be interconnected to our systems both physically and technologically. Therefore, an event caused by cyberattacks, ransomware or other malicious act at an interconnected third party could impact our business and facilities similarly. Any failure, unexpected, or unauthorized use of technology systems could result in the unavailability of such systems, and could result in a loss of operating revenues, an increase in operating expenses and costs to repair or replace damaged assets. Any of the above could also result in the loss or release of confidential customer and/or employee information or other proprietary data that could adversely affect our reputation and competitiveness, could result in costly litigation and negatively impact our results of operations. These cyberattacks have become more common and sophisticated and, as such, we could be required to incur costs to strengthen our systems and respond to emerging concerns.

There are various risks associated with technology systems such as hardware or software failure, communications failure, data distortion or destruction, unauthorized access to data, misuse of proprietary or confidential data, unauthorized control through electronic means, programming mistakes and other deliberate or inadvertent human errors.

Technology Risk Factors

Our technology may become obsolete, development of new technologies could create additional risk, or we may not have sufficient resources to manage our technology.

Our technology may become obsolete before the end of its useful life. In addition, custom or new technology (including potential generative artificial intelligence) that is heavily relied upon may not be maintained and updated appropriately due to resource restraints, or other factors, which could cause technology failures or give rise to additional operational or security risks. Generative artificial intelligence could also create additional regulatory scrutiny and generate uncertainty around intellectual property ownership and/or licensing or use. Technology (including artificial intelligence) is also subject to intentional misuse (by criminals, terrorists or other bad actors). Technology failures or incidents of misuse could result in significant adverse effects on our operations, results of operations, financial condition and cash flows.

We may be adversely affected by our inability to successfully implement certain technology projects.

There are inherent risks associated with replacing and changing systems, which could have a material adverse effect on our results of operations, financial condition and cash flows. Finally, there is the risk that we ultimately do not complete a project and will incur contract cancellation or other costs, which could be significant.

Strategic Risk Factors

Our strategic business plans, which may be affected by the foregoing, may change, including the entry into new businesses and/or the exit from existing businesses and/or the curtailment of our business development efforts where potential future business is uncertain.

Our strategic business plans could be affected by or result in the following:

- disruptive innovations in the marketplace may outpace our ability to compete or manage our risk,
- customers may have a choice in the future over the sources from which to receive their energy and we may not be able to compete,
- potential difficulties in integrating acquired operations and in realizing expected opportunities, diversions of management resources and losses of key employees, challenges with respect to operating new businesses and other unanticipated risks and liabilities,
- non-regulated investments in businesses outside of our core utilities operations may increase earnings volatility,
- market or other conditions that could adversely affect our operations or require changes to our business strategy and could result in reduced assets and net income,
- affordability of electric and/or gas services may be a challenge for customers resulting in increased delayed payment for utility services,
- potential reputational risk arising from repeated general rate case filings, degradation in the quality of service, or from failed strategic investments and opportunities, which could erode shareholder, customer and community satisfaction with the Company, and
- the risk of municipalization or other form of service territory reduction.

External Mandates Risk Factors

External mandate risk involves forces outside the Company, which may include significant changes in customer expectations, disruptive technologies that result in obsolescence of our business model and government action that could impact the Company.

Actions or limitations to address concerns over long-term climate change, both globally and within our utilities' service areas, may affect our operations and financial performance.

Legislative, regulatory and advocacy efforts at the local, state, national and international levels concerning climate change and other environmental issues could have significant impacts on our operations. The electric and natural gas utility industries are frequently affected by proposals to curb greenhouse gas and other air emissions. Various regulatory and legislative proposals have been made to limit or further restrict byproducts of combustion, including that resulting from the use of natural gas by our customers. In addition, regionally, there are regulatory and legislative initiatives that have been passed which are designed to limit greenhouse gas emissions and increase the use of renewable sources of energy. In addition, regulatory and legislative initiatives may restrict customers' access to natural gas and/or require or limit natural gas infrastructure in buildings. Other initiatives may seek to promote social interests expressed as energy equity, environmental justice or similar frameworks. Such legislation could direct and/or restrict the operation and raise the costs of our power generation resources and energy delivery infrastructure as well as the distribution of natural gas to our customers.

We expect continuing legislative and regulatory activity in the future and we are evaluating the extent to which potential changes to environmental laws and regulations may:

- increase the operating costs of generating plants,
- increase the lead time and capital costs for the construction of new generating plants,
- require modification of our existing generating plants,
- require existing generating plant operations to be curtailed or shut down,
- reduce the amount of energy available from our generating plants,
- restrict the types of generating plants that can be built or contracted with,
- require construction of specific types of generation plants at higher cost, and
- increase the cost or limit our ability to distribute natural gas to customers.

See "Item 7. Management's Discussion and Analysis—Environmental Issues and Contingencies" for discussion regarding environmental issues and legislation which may affect our operations.

We have contingent liabilities, including certain matters related to potential environmental liabilities, and cannot predict the outcome of these matters.

In the normal course of our business, we have matters that are the subject of ongoing litigation, mediation, investigation and/or negotiation. We cannot predict the ultimate outcome or potential impact of any issue, including the extent, if any, of insurance coverage or recovery through the ratemaking process. We are subject to environmental regulation by federal, state and local authorities related to our past, present and future operations. See "Note 22 of the Notes to Consolidated Financial Statements" for further details of these matters.

Import tariffs could lead to increased prices on raw materials that are critical to our business.

Tariffs and other restrictions on trade with foreign countries could significantly increase the prices of raw materials that are critical to our business, such as steel poles or wires. In addition, tariffs and trade restrictions could have a similar impact on our suppliers and certain customers, which could have a negative impact on our financial condition, results of operations and cash flows.

See "Item 7. Management's Discussion and Analysis—Environmental Issues and Contingencies" and "Forward-Looking Statements" for discussion of or reference to additional external mandates which could have a material adverse effect on our results of operations, financial condition and cash flows.

Financial Risk Factors

Certain retail electricity and natural gas sales volumes vary directly with changes in temperatures. We normally have our highest retail (electric and natural gas) energy sales during the winter heating season in the first and fourth quarters of the year. We also have high electricity demand for air conditioning during the summer (third quarter). In general, warmer weather in the heating season and cooler weather in the cooling season will reduce our customers' energy demand and our retail operating revenues. The revenue and earnings impact of weather fluctuations is somewhat mitigated by our decoupling mechanisms; however, we could experience liquidity constraints during the period between when decoupling revenue is earned and when it is subsequently collected from customers through retail rates.

The cost of natural gas supply is impacted by both supply-side factors (amount of natural gas production, level of natural gas in storage, volumes of natural gas imports and exports, regulatory restraints or costs on natural gas production and delivery) and demand-side factors (variations in weather, level of economic growth, availability and prices of other fuels). Prices tend to increase with higher demand during periods of cold weather. Inter-regional natural gas pipelines and competition for supply can allow demand-driven price volatility in other regions of North America to affect prices in the Pacific Northwest. Increased costs adversely affect cash flows when we purchase natural gas for retail supply at prices above the amount allowed for recovery in retail rates. We defer differences between actual natural gas supply costs and the amount currently recovered in retail rates and we are generally allowed to recover substantially all of these differences after regulatory review. However, these deferred costs require cash outflows from the time of natural gas purchases until the costs are later recovered through retail sales.

The cost of power supply can be significantly affected by weather, and therefore is subject to trends in climate change. Precipitation (consisting of snowpack, its water content and runoff pattern plus rainfall) and other streamflow conditions (such as regional water storage operations) significantly affect hydroelectric generation capability. Variations in hydroelectric generation inversely affect our reliance on market purchases and thermal generation. To the extent that hydroelectric generation is less than normal, significantly more costly power supply resources must be acquired and the ability to realize net benefits from surplus hydroelectric wholesale sales is reduced. Wholesale prices also vary based on wind patterns as wind generation capacity is material in the Pacific Northwest but its contribution to supply is inconsistent.

The price of power in the wholesale energy markets tends to be higher during periods of high regional demand, such as occurs with temperature extremes. Climate change may increase the frequency and magnitude of temperature extremes. We may need to purchase power in the wholesale market during peak price periods. The price of natural gas as fuel for natural gas-fired electric generation tends to increase during periods of high demand which are often related to temperature extremes. We may need to purchase natural gas fuel in these periods of high prices to meet electric demands. The cost of power supply during peak usage periods may be higher than the retail sales price or the amount allowed in retail rates by our regulators. To the extent that power supply costs are above the amount allowed currently in retail rates, the difference is partially absorbed by the Company in current expense and is partially deferred or shared with customers through regulatory mechanisms. However, these deferred costs require cash outflows from the time of power purchases until the costs are later recovered through retail sales.

The price of power tends to be lower during periods with excess supply, such as the spring when hydroelectric conditions are usually at their maximum and various facilities are required to operate to meet environmental mandates. Oversupply can be exacerbated when intermittent resources such as wind generation are producing output that may be supported by price subsidies. In extreme situations, we may be required to sell excess energy at negative prices.

As a result of these combined factors, our net cost of power supply—the difference between our costs of generation and market purchases, reduced by our revenue from wholesale sales—varies significantly because of weather.

We rely on regular access to financial markets but we cannot assure favorable or reasonable financing terms will be available when we need them.

Access to capital markets is critical to our operations and our capital structure. We have significant capital requirements that we expect to fund, in part, by accessing capital markets. As such, the state of financial markets and credit availability in the global, United States and regional economies impacts our financial condition. We could experience increased borrowing costs or limited access to capital on reasonable terms.

We access long-term capital markets to finance capital expenditures, repay maturing long-term debt and obtain additional working capital, including needs related to power and natural gas purchases and sales, from time-to-time. Our ability to access capital on reasonable terms is subject to numerous factors and market conditions, many of which are beyond our control. If we are unable to obtain capital on reasonable terms, it may limit or prohibit our ability to finance capital expenditures and repay maturing long-term debt. Our liquidity needs could exceed our short-term credit availability and lead to defaults on various financing arrangements. We would also likely be prohibited from paying dividends on our common stock.

Performance of the financial markets could also result in significant declines in the market values of assets held by our pension plan and/or a significant increase in the pension liability (which impacts the funded status of the plan) and could increase future funding obligations and pension expense.

We rely on credit from financial institutions for short-term borrowings. We need adequate levels of credit with financial institutions for short-term liquidity. There is no assurance that we will have access to credit beyond the expiration dates of our committed line of credit agreements. These agreements contain customary covenants and default provisions.

Any default on the lines of credit or other financing arrangements of Avista Corp. or our "significant subsidiaries," if any, could result in cross-defaults to other agreements of such entity, and/or to the line of credit or other financing arrangements of any other of such entities. Defaults could also induce vendors and other counterparties to demand collateral. In the event of any such default, it would be difficult to obtain financing on reasonable terms to pay creditors or fund operations. We would also likely be prohibited from paying dividends on our common stock.

We may hedge a portion of our interest rate risk with financial derivative instruments, which may require the posting of collateral. If market interest rates decrease below the interest rates we have locked in, this will result in a liability related to our interest rate swap derivatives, which can be significant. We may be required to post cash or letters of credit as collateral depending on fluctuations in the fair value of the derivative instruments. Settlement of interest rate swap derivative instruments in a liability position could require a significant amount of cash, which could negatively impact our liquidity and short-term credit availability and increase interest expense over the term of the associated debt.

Downgrades in our credit ratings could impede our ability to obtain financing, adversely affect the terms of financing and impact our ability to transact for or hedge energy resources. If we do not maintain our investment grade credit rating with the major credit rating agencies, we could expect increased debt service costs, limitations on our ability to access capital markets or obtain other financing on reasonable terms, and requirements to provide collateral (in the form of cash or letters of credit) to lenders and counterparties. In addition, credit rating downgrades could reduce the number of counterparties willing to do business with us or result in the termination of outstanding regulatory authorizations for certain financing activities.

Credit risk may be affected by industry concentration and geographic concentration.

We have concentrations of suppliers and customers in the electric and natural gas industries including:

- electric and natural gas utilities,
- electric generators and transmission providers,
- oil and natural gas producers and pipelines,
- financial institutions including commodity clearing exchanges and related parties, and
- energy marketing and trading companies.

We have concentrations of credit risk related to our geographic location in the western United States and western Canada energy markets. These concentrations of counterparties and concentrations of geographic location may affect our overall exposure to credit risk because the counterparties may be similarly affected by changes in conditions.

We are a participant in the EIM, and engage in direct and indirect power purchase and sale transactions in connection with that participation. The EIM collateral posting requirements are based on established credit criteria, but there is no assurance the collateral will be sufficient to cover obligations that counterparties may owe each other in the EIM and credit losses could be allocated among all EIM participants, including us. A significant failure of a participant in the EIM to make payments when due on its obligations could have a ripple effect on our counterparties in the power and gas markets if those counterparties experience ancillary liquidity issues, and could result in a decline in the ability of our counterparties to perform on their obligations.

Activist shareholder actions could have a negative impact on our business and operations.

Shareholder activism can take many forms and arise in a variety of situations. Actions by activist shareholders could include engaging in proxy solicitations, making or advancing shareholder proposals, or otherwise attempting to assert influence on our board of directors and/or management. Response to these actions could result in substantial costs, require significant attention from our board of directors and management, and divert resources from the execution of our strategy and business operations.

Shareholder activism could result in perceived uncertainties, negatively affect our business opportunities, our ability to access capital markets, and relationships with our customers and employees. These actions could have a material adverse effect on our financial condition and results of operations, and could result in significant fluctuations in the trading price of our common stock based on market perceptions or other factors.

Energy Commodity Risk Factors

Energy commodity price changes affect our cash flows and results of operations.

Energy commodity prices can be volatile. We rely on energy markets and other counterparties for energy supply, surplus and optimization transactions and commodity price hedging. A combination of factors exposes our operations to commodity price risks, including:

- our obligation to serve our retail customers at rates set through the regulatory process—we cannot decline to serve our customers and we cannot change retail rates to reflect current energy prices unless and until we receive regulatory approval,
- customer demand, which is beyond our control because of weather, customer choices, prevailing economic conditions and other factors,
- some of our energy supply cost is fixed by the nature of the energy-producing assets or through contractual arrangements (however, a significant portion of our energy resource costs are not fixed), and
- the potential non-performance by commodity counterparties, which could lead to replacement of the scheduled energy or natural gas at higher prices.

Because we must supply the amount of energy demanded by our customers and we must sell it at fixed rates and only a portion of our energy supply costs are fixed, we are subject to the risk of buying energy at higher prices in wholesale energy markets (and the risk of selling energy at lower prices if we are in a surplus position). Electricity and natural gas in wholesale markets are commodities with historically high price volatility. Changes in wholesale energy prices affect, among other things, the cash requirements to purchase electricity and natural gas for retail customers or wholesale obligations and the market value of derivative assets and liabilities.

We hedge a portion of our energy commodity risk with physical and financial derivative instruments that may require the posting of collateral. When we enter into fixed price energy commodity transactions for future delivery, we are subject to credit terms that may require us to provide collateral to wholesale counterparties related to the difference between current prices and the agreed upon fixed prices. These collateral requirements can place significant demands on our cash flows or borrowing arrangements. Price volatility can cause collateral requirements to change quickly and significantly.

Cash flow deferrals related to energy commodities can be significant. We are permitted to collect from customers only amounts approved by regulatory commissions. However, our costs to provide energy service can be much higher or lower than the amounts currently billed to customers. We are permitted to defer income statement recognition and recovery from customers for some of these differences, which are recorded as deferred charges with the opportunity for future recovery through retail rates. These deferred costs are subject to review for prudence and potential disallowance by regulators, who have discretion as to the extent and timing of future recovery or refund to customers.

Power and natural gas costs higher than those recovered in retail rates negatively impact cash flows. Amounts that are not allowed for deferral or which are not approved to become part of customer rates affect our results of operations.

Even if our regulators ultimately allow the recovery of deferred power and natural gas costs, our operating cash flows can be negatively affected until these costs are recovered from customers.

Fluctuating energy commodity prices and volumes in relation to our energy risk management process can cause volatility in our cash flows and results of operations. We engage in active hedging and resource optimization practices to reduce energy cost volatility and economic exposure related to commodity price fluctuations. We routinely enter into contracts to hedge a portion of our purchase and sale commitments for electricity and natural gas, as well as forecasted excess or deficit energy positions and inventories of natural gas. We use physical energy contracts and derivative instruments, such as forwards, futures, swaps and options traded in the over-the-counter markets or on exchanges. If market prices decrease compared to the prices we have locked in with our energy commodity derivatives, this will result in a liability related to these derivatives, which can be significant. As a result of price fluctuations, we may be required to post significant amounts of cash or letters of credit as collateral depending on fluctuations in the fair value of the derivative instruments.

We do not attempt to fully hedge our energy resource assets or our forecasted net positions for various time horizons. To the extent we have positions that are not hedged, or if hedging positions do not fully match the corresponding purchase or sale, fluctuating commodity prices could have a material effect on our operating revenues, resource costs, derivative assets and liabilities, and operating cash flows. In addition, actual loads and resources typically vary from forecasts, sometimes to a significant degree, which require additional transactions or dispatch decisions that impact cash flows.

The hedges we enter into are reviewed for prudence by our various regulators and deferred costs (including those as a result of our hedging transactions) are subject to review for prudence and potential disallowance by regulators.

Generation plants may become obsolete. We rely on a variety of generation and energy commodity market sources to fulfill our obligation to serve customers and meet the demands of our counterparty agreements. Some of our generation sources, such as coal, may become obsolete or be prematurely retired through regulatory action or legislation. This could result in higher commodity costs to replace the lost generation, as well as higher costs to retire the generation source before the end of its expected life. This also includes costs (including replacement of lost generation) associated with our transfer of Colstrip ownership to NorthWestern at the end of 2025. See "Item 7. Management's Discussion and Analysis—Environmental Issues and Contingencies" for discussion regarding environmental and other issues surrounding Colstrip.

Compliance Risk Factors

There have been numerous changes in legislation, related administrative rulemakings, and Executive Orders, including periodic audits of compliance with such rules, which may adversely affect our operational and financial performance.

We expect to continue to be affected by legislation at the national, state and local level, as well as by administrative rules and requirements published by government agencies, including but not limited to the FERC, the EPA and state regulators. We are also subject to NERC and WECC reliability standards. The FERC, the NERC and the WECC perform periodic audits of the Company. Failure to comply with the FERC, the NERC, or the WECC requirements can result in financial penalties.

Future legislation, administrative rules or Executive Orders could have a material adverse effect on our operations, results of operations, financial condition and cash flows.

ITEM 1B. Unresolved Staff Comments

As of the filing date of this Annual Report on Form 10-K, we have no unresolved comments from the staff of the SEC.

ITEM 1C. Cybersecurity

The energy sector, including electric and natural gas utility companies, has become the subject of cyberattacks with increased frequency. Our administrative and operating networks are targeted by hackers on a regular basis. Any failure, unexpected, or unauthorized use of technology systems could result in the unavailability of such systems, and could result in a loss of operating revenues, damage to our brand and reputation, and/or an increase in operating expenses and costs to repair or replace damaged assets. See "Risk Factors—Cyber Risk Factors" for further information.

We consider the management of cybersecurity risk in our overall enterprise risk management program. See "Item 7. Management's Discussion and Analysis—Enterprise Risk Management" for further discussion of the program.

We mitigate cyber risk through trainings and exercises at all levels of the Company. Annual cyber and physical training and testing of employees are included in our enterprise security program. Our enterprise business continuity program facilitates business impact analysis of core functions for development of emergency operating plans and coordinates annual testing and training exercises. In addition, there are independent third party audits of our critical infrastructure security program and our business risk security controls.

The technology department, led by the Vice President, Chief Information Officer, and Chief Security Officer, is responsible for our cybersecurity program. The Vice President, Chief Information Officer and Chief Security Officer has over 20 years of experience, including serving in similar roles leading and overseeing cybersecurity programs at other companies. This program includes maintenance of appropriate cybersecurity measures, such as firewalls, anti-virus, patching, and other zero-trust security protocols, monitoring for intrusion and security events that may include a data breach or an attack on our operations, and working with our supply chain department to ensure contracts with third party service providers include appropriate requirements for the mitigation of cybersecurity risk that might impact our business.

Our data breach response team is comprised of designated members of the technology department, senior management and other appropriate individuals. The team is tasked with assessing, managing and responding to material cybersecurity incidents involving either our systems or the systems of third party service providers. The data breach response team includes subject matter experts within the Company, as well as outside experts who specialize in cybersecurity response. A subset of this team is also responsible for assessing the materiality of cybersecurity incidents, reporting to the Audit Committee of the Board of Directors as appropriate, and ensuring timeline reporting of cybersecurity incidents deemed material to the Company.

The Environmental, Technology and Operations Committee of the Board of Directors oversees our management of cybersecurity risks. This Committee is briefed on security policy, programs and incidents on at least a quarterly basis. The Audit Committee of the Board of Directors provides oversight of required disclosures relating to cybersecurity.

ITEM 2. Properties

AVISTA UTILITIES

Substantially all of Avista Utilities' properties are subject to the lien of Avista Corp.'s mortgage indenture.

Avista Utilities' electric properties, located in the states of Washington, Idaho, Montana and Oregon, include the following:

GENERATION PROPERTIES

	Present Capability (MW) [1]
Hydroelectric Generating Stations (River)	
Washington:	
Long Lake (Spokane)	88.0
Little Falls (Spokane)	48.0
Nine Mile (Spokane)	40.6
Upper Falls (Spokane)	10.2
Monroe Street (Spokane)	15.0
Idaho:	
Cabinet Gorge (Clark Fork) [2]	273.0
Post Falls (Spokane)	11.9
Montana:	
Noxon Rapids (Clark Fork)	562.4
Total Hydroelectric	1,049.1
Thermal Generating Stations (cycle, fuel source)	
Washington:	
Kettle Falls GS (combined-cycle, wood waste) [3]	53.5
Kettle Falls CT (combined-cycle, natural gas) [3]	6.9
Northeast CT (simple-cycle, natural gas)	64.8
Boulder Park GS (simple-cycle, natural gas)	24.6
Idaho:	
Rathdrum CT (simple-cycle, natural gas)	166.5
Montana:	
Colstrip Units 3 & 4 (simple-cycle, coal) [4]	222.0
Oregon:	
Coyote Springs 2 (combined-cycle, natural gas)	322.0
Total Thermal	860.3
Total Generation Properties	1,909.4

(1) Present capability is the maximum capacity of the plant under standard test conditions without exceeding specified limits of temperature, stress and environmental conditions.

(2) For Cabinet Gorge, we have water rights permitting generation up to 265 MW. However, if natural stream flows will allow for generation above our water rights, we are able to generate above our water rights. If natural stream flows only allow for generation at or below 265 MW, we are limited to generation of 265 MW. The present capability disclosed above represents the capability

based on maximum stream flow conditions when we are allowed to generate above our water rights.

(3) These generating stations can operate as separate single-cycle plants or combined-cycle with the natural gas plant providing exhaust heat to the wood boiler to increase efficiency.

(4) Jointly owned; data refers to our 15 percent interest. See "Item 7. Management's Discussion and Analysis of Financial Condition—Colstrip" for information related to Colstrip Units 3 & 4.

Electric Distribution and Transmission Plant

Avista Utilities owns and operates approximately 19,700 miles of primary and secondary electric distribution lines providing service to retail customers. We have an electric transmission system of approximately 700 miles of 230 kV line and approximately 1,600 miles of 115 kV line. We also own an 11 percent interest in approximately 500 miles of a 500 kV line between Colstrip, Montana and Townsend, Montana. Our transmission and distribution systems also include numerous substations with transformers, switches, monitoring and metering devices and other equipment.

The 230 kV lines are the backbone of our transmission grid and are used to transmit power from generation resources, including Noxon Rapids, Cabinet Gorge and the Mid-Columbia hydroelectric projects, to the major load centers in our service area, as well as to transfer power between points of interconnection with adjoining electric transmission systems. These lines interconnect at various locations with the BPA, Grant County PUD, PacifiCorp, NorthWestern and Idaho Power Company and serve as points of delivery for power from generating facilities outside of our service area, including Colstrip, Coyote Springs 2 and the Lancaster Plant.

These lines also provide a means to optimize resources through short-term purchases and sales of power with entities within and outside of the Pacific Northwest.

The 115 kV lines provide for transmission of energy and the integration of smaller generation facilities with our service-area load centers, including the Spokane River hydroelectric projects, the Kettle Falls projects, Rathdrum CT, Boulder Park GS and the Northeast CT. These lines interconnect with the BPA, Chelan County PUD, the Grand Coulee Project Hydroelectric Authority, Grant County PUD, NorthWestern, PacifiCorp and Pend Oreille County PUD. Both the 115 kV and 230 kV interconnections with the BPA are used to transfer energy to facilitate service to each other's customers that are connected through the other's transmission system. We hold a long-term transmission agreement with the BPA that allows us to serve our native load customers that are connected through the BPA's transmission system.

Natural Gas Plant

Avista Utilities has natural gas distribution mains of approximately 3,600 miles in Washington, 2,200 miles in Idaho and 2,400 miles in Oregon. We have natural gas transmission mains of approximately 75 miles in Washington and 15 miles in Oregon. Our natural gas system includes numerous regulator stations, service distribution lines, monitoring and metering devices, and other equipment.

We own a one-third interest in Jackson Prairie, an underground natural gas storage field located near Chehalis, Washington. See "Part I—Item 1. Business—Avista Utilities—Natural Gas Operations" for further discussion of Jackson Prairie.

ALASKA ELECTRIC LIGHT AND POWER COMPANY

Substantially all of AEL&P's utility properties are subject to the lien of the AEL&P mortgage indenture.

AEL&P's utility electric properties, located in Alaska include the following:

GENERATION PROPERTIES AND TRANSMISSION AND DISTRIBUTION LINES

	Present Capability (MW) [1]
Hydroelectric Generating Stations	
Snettisham [2]	78.2
Lake Dorothy	14.3
Salmon Creek	5.0
Annex Creek	3.6
Gold Creek	1.6
Total Hydroelectric	102.7
Diesel Generating Stations	
Lemon Creek	51.8
Auke Bay	25.2
Gold Creek	7.0
Industrial Blvd. Plant	23.5
Total Diesel	107.5
Total Generation Properties	210.2

(1) Present capability is the maximum capacity of the plant under standard test conditions without exceeding specified limits of temperature, stress and environmental conditions.

(2) AEL&P does not own this generating facility but has a PPA under which it has the right to purchase, and the obligation to pay for the capacity and energy of this facility. See further information at "Part 1. Item 1. Business—Alaska Electric Light and Power Company."

In addition to the generation properties above, AEL&P owns 61 miles of transmission lines, which are primarily comprised of 69 kV line, and 184 miles of distribution lines.

ITEM 3. Legal Proceedings

See "Note 22 of Notes to Consolidated Financial Statements" for information with respect to legal proceedings.

ITEM 4. Mine Safety Disclosures

Not applicable.

PART II

ITEM 5. Market for Registrant's Common Equity, Related Stockholder Matters And Issuer Purchases of Equity Securities

AVISTA CORP. MARKET INFORMATION AND DIVIDEND POLICY

Avista Corp.'s common stock is listed on the New York Stock Exchange under the ticker symbol "AVA." As of January 31, 2024, there were 6,110 registered shareholders of our common stock.

Avista Corp.'s Board of Directors considers the level of dividends on our common stock on a recurring basis, taking into account numerous factors including, without limitation:

- our results of operations, cash flows and financial condition,
- the success of our business strategies, and
- general economic and competitive conditions.

Avista Corp.'s net income available for dividends is generally derived from our regulated utility operations (Avista Utilities and AEL&P).

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 (see "Item 7. Management's Discussion and Analysis—Capital Resources" for compliance with these covenants),
- the hydroelectric licensing requirements of section 10(d) of the FPA (see "Note 1 of Notes to Consolidated Financial Statements"), and
- certain requirements under the OPUC approval of the AERC acquisition in 2014. The OPUC's AERC acquisition order requires Avista Utilities 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.

For additional information, see "Notes 1 and 19 of Notes to Consolidated Financial Statements."

For information with respect to securities authorized for issuance under equity compensation plans, see "Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters."

ITEM 6. [Removed and Reserved]

ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

This section of this Annual Report on Form 10-K generally discusses 2023 and 2022 financial statement items and year-to-year comparisons between 2023 and 2022. Discussion of 2021 financial statement items and year-to-year comparisons between 2022 and 2021 not included in this Form 10-K can be found in "Management's Discussion and Analysis of Financial Conditions and Results of Operations" in Part II, Item 7 of the Company's Annual Report on Form 10-K for the year ended December 31, 2022.

BUSINESS SEGMENTS

As of December 31, 2023, we have two reportable business segments, Avista Utilities and AEL&P. We also have other businesses which do not represent a reportable business segment and are conducted by various direct and indirect subsidiaries of Avista Corp. See "Part I, Item 1. Business—Company Overview" for further discussion of our business segments.

The following table presents net income (loss) for each of our business segments and the other businesses, for the year ended December 31 (dollars in thousands):

	2023	2022	2021
Avista Utilities	$ 167,016	$ 117,901	$ 125,558
AEL&P	8,937	7,545	7,224
Other	(4,773)	29,730	14,552
Net income	$ 171,180	$ 155,176	$ 147,334

EXECUTIVE LEVEL SUMMARY

Overall Results

Avista Utilities' net income increased primarily due to increased utility margin, including benefits from our completed general rate cases, lower property taxes, and the recognition of tax customer credits which resulted in higher income tax benefit for 2023. These positive factors to net income were partially offset by increased interest expense, depreciation and amortization expense, and other operating expenses.

AEL&P net income increased, primarily due to higher sales volumes and rate increases.

The decrease in net income at our other businesses was primarily due to net investment losses recognized in 2023, compared to net investment gains recognized in 2022.

More detailed explanations of the fluctuations are provided in the results of operations and business segment discussions (Avista Utilities, AEL&P, and the other businesses).

2023 Hydroelectric Generation

In May and June of 2023, our region experienced historically high temperatures, causing the snowpack to melt more rapidly than expected. The quick runoff had a significant negative impact on our hydrogeneration resources, resulting in one of our worst years for hydroelectric generation. As a result, we increased thermal generation and purchased power to compensate for the decrease in available hydroelectric generation, and our ability to optimize our generation assets was limited compared to the opportunities we originally expected for the year. The decreased availability of hydroelectric generation compared to our expectations had a significant impact on the ERM in Washington, as well as our financial results.

Washington Climate Commitment Act

Effective January 1, 2023, the CCA went into effect in the State of Washington, requiring us to secure carbon allowances to cover our carbon emissions for our natural gas operations over a certain amount each year. Costs associated with the CCA have been deferred, and will be included in natural gas customer rates starting in March 2024. The resulting aggregate increase to customer bills is expected to be approximately 3.8 percent, and will impact customers differently based on revenue class, income level, and the age of a residential customers residence. The CCA is expected to have limited financial impact on our electric operations in its initial years.

See "Environmental Issues and Contingencies" for further discussion of the CCA.

Regulatory Lag

Regulatory "lag" is inherent in utility ratemaking; a result of the delay between the investment in utility plant and/or the increase in costs and the receipt of an order of a public utility commission authorizing an increase in rates sufficient to recover such investment or costs. Regulatory lag can be mitigated to some extent by the incorporation of reasonably expected forward-looking information into an authorization of increased rates. However, there is no protection against unexpected inflation and increased interest rates, as experienced in 2022 and 2023. While we believe our recent general rate settlements are helpful, some increases in our operating expenses and interest costs will have to be addressed in future rate cases, including our 2024 Washington general rate cases. See "Regulatory Matters" for additional discussion of the general rate cases.

Operational Events

In November 2023, we had the largest natural gas outage in our Company's history. Nearly 37,000 natural gas customers were impacted when a third party damaged a pipeline that transports natural gas to our system. Natural gas service was restored to every impacted customer in less than one week. We filed petitions for regulatory accounting orders with the WUTC and IPUC and received approval to defer $10.3 million of costs of the incident for recovery to be addressed in a future regulatory proceeding.

In mid-January 2024, there were two operational issues impacting our gas distribution system, as well as the natural gas transportation system in the Pacific Northwest. These challenges, combined with very cold temperatures, resulted in high commodity prices. The first issue involved a mechanical problem with a third party transmission pipeline that delivers natural gas to our service territory. The second issue involved a mechanical problem with Jackson Prairie. These issues reduced the capacity of natural gas that could be delivered to our natural gas distribution system, as well as natural gas fuel for electric generation. We made operational decisions and contingency plans in response to the issues and we did not experience any disruptions in service to customers. We experienced higher energy commodity prices and an increased need to purchase energy, which will be accounted for under the ERM, PCA and PGAs.

REGULATORY MATTERS

General Rate Cases

We regularly review the need for electric and natural gas rate changes in each state in which we provide service. We will continue to file for rate adjustments to:

- seek recovery of operating costs and capital investments, and
- seek the opportunity to earn reasonable returns as allowed by regulators.

The assessment of our need for rate relief and the development of rate case plans takes into consideration short-term and long-term needs, as well as specific factors that can affect the timing of rate filings. Such factors include, but are not limited to, in-service dates of major capital investments and the timing of changes in major revenue and expense items.

Avista Utilities

Washington General Rate Cases

2022 General Rate Cases

In January 2022, we filed multi-year electric and natural gas general rate cases with the WUTC. In December 2022, the WUTC issued an order approving the multi-party settlement agreement filed in June 2022. The approved rates were designed to increase annual base electric revenues by $38.0 million, or 6.9 percent, effective in December 2022, and $12.5 million, or 2.1 percent, effective in December 2023. The approved rates were also designed to increase annual base natural gas revenues by $7.5 million, or 6.5 percent, effective in December 2022, and $1.5 million, or 1.2 percent, effective in December 2023.

To mitigate the overall impact of the revenue increases on customers, part of the 2022 base rate increase was offset with tax customer credits. The total estimated benefits of these credits, $27.6 million for electric customers and $12.5 million for natural gas customers, are being returned over a two-year period from December 2022 to December 2024.

In addition, the order approved a separate tracking mechanism and tariff for purposes of recovering existing and prospective Colstrip costs.

The WUTC approved an ROR of 7.03 percent, but the settlement does not specify an explicit ROE, cost of debt or capital structure.

These general rate cases require a subsequent review of additions to utility plant included in rates and a refund of revenues if capital expenditures are less than the level contemplated in the rate case. The review of 2022 capital was completed in 2023, and no refunds were required.

2024 General Rate Cases

On January 18, 2024, we filed multi-year electric and natural gas general rate cases with the WUTC. If approved, new rates would be effective in December 2024 and December 2025.

The proposed rates are designed to increase annual base electric revenues by $77.1 million, or 13.0 percent, effective in December 2024, and $53.7 million, or 11.7 percent, effective in December 2025.

For natural gas, the proposed rates are designed to increase annual base natural gas revenues by $17.3 million, or 13.6 percent, effective in December 2024, and $4.6 million, or 3.2 percent, effective in December 2025.

The proposed electric and natural gas revenue increase requests are based on a 10.4 percent return on equity with a common equity ratio of 48.5 percent and a rate of return on rate base of 7.61 percent. Increasing power supply costs, operating and maintenance costs, and ongoing capital investments (including clean energy hydroelectric projects, continued investment in the wildfire resiliency plan, replacement of natural gas distribution pipe and technology upgrades) were the main drivers of proposed increases.

In the second year of the proposed electric multi-year rate plan, in compliance with Washington's CETA, we have removed from customers' rates the costs associated with generation from Colstrip.

As a part of the electric rate case, we proposed certain updates to power supply costs. The updated power supply costs included as a part of the first rate year, accounts for $18.5 million of our overall electric request. For electric rate year 2, the net effect of increasing base power supply costs (primarily to make up for the loss of Colstrip from our generation portfolio), offset by reductions in customer rates through the removal of Colstrip rate base and expenses, accounts for $35.1 million of our overall $53.7 million request.

Additionally, we are proposing changes to the ERM. Under the present construct, the ERM consists of a $4 million deadband, and then an asymmetric sharing band between $4 million and $10 million. All costs above $10 million are shared on a 90 percent customer, 10 percent company basis. As part of this rate case, we are proposing moving the entire mechanism to a 95 percent customer, 5 percent company sharing of power supply cost above or below the authorized level.

If the multi-year rate plans are approved, we would not file new general rate cases for new rate plans to be effective prior to December 2026.

The WUTC has up to eleven months to review the general rate case filings and issue a decision.

Idaho General Rate Cases

2021 General Rate Cases

In January 2021, we filed multi-year electric and natural gas general rate cases with the IPUC. In September 2021, the IPUC approved the all party settlement agreement designed to increase annual base electric revenues by $10.6 million, or 4.3 percent, effective September 1, 2021, and $8.0 million, or 3.1 percent, effective September 1, 2022. For natural gas, the settlement agreement was designed to decrease annual base natural gas revenues by $1.6 million, or 3.7 percent, effective September 1, 2021, and increase annual base revenues by $0.9 million, or 2.2 percent, effective September 1, 2022. The parties agreed to use the tax customer credits, related to flow through of certain tax items, included in our original filing to offset overall proposed changes to rates over the two-year plan.

The settlement was based on a 9.4 percent ROE with a common equity ratio of 50 percent and an ROR of 7.05 percent.

2023 General Rate Cases

In February 2023, we filed multi-year electric and natural gas general rate cases with the IPUC. In August 2023, the IPUC approved the multi-party settlement agreement designed to increase annual base electric revenues by $22.1 million, or 8.0 percent, effective in September 2023, and $4.3 million, or 1.4 percent, effective in September 2024. The agreement was designed to increase annual base natural gas revenues by $1.3 million, or 2.7 percent, effective in September 2023, and a negligible increase effective in September 2024.

The settlement was based on an ROE of 9.4 percent, with a common equity ratio of 50 percent, and an ROR of 7.19 percent.

Oregon General Rate Cases

2021 General Rate Case

In October 2021, we filed a natural gas general rate case with the OPUC. In January 2022, a partial settlement stipulation addressing cost of capital issues was filed with the OPUC in our natural gas general rate case filed in October 2021. The parties agreed to an ROR of 7.05 percent based on a 50 percent common equity ratio and ROE of 9.4 percent.

In March 2022, a second settlement stipulation was filed with the OPUC that addressed, and resolved, all other remaining issues, and was subsequently approved by the OPUC. The settlement is designed for an overall revenue increase of $1.6 million, effective August 22, 2022. The agreement was a "black box", with the only component of the revenue requirement explicitly stated is the previously-agreed upon cost of capital. The parties also agreed that certain tax credits of approximately $3.0 million will be passed through to customers to mitigate the base revenue increase.

2023 General Rate Case

In March 2023, we filed a natural gas general rate case with the OPUC. In October 2023, the OPUC approved the all party settlement agreement filed in August 2023. The approved rates are designed to increase annual base natural gas revenues by $7.2 million, or 9.4 percent. The OPUC approved an ROR of 7.24 percent, a common equity ratio of 50 percent, and an ROE of 9.5 percent. New rates were effective on January 1, 2024.

Alaska Electric Light and Power Company

2022 General Rate Case

In August 2023, the RCA issued a final order related to AEL&P's electric general rate case, which was originally filed in July 2022.

The order reflects an ROE of 11.45 percent, a common equity ratio of 60.7 percent, and an ROR of 8.79 percent. The order results in an approved base electric revenue increase of 6.0 percent (designed to increase annual electric revenues by $2.1 million), and makes non-refundable the interim rate increase of 4.5 percent that was approved by the RCA in August 2022 and took effect in September 2022. The final increase to rates was effective in October 2023.

Avista Utilities

Purchased Gas Adjustments

PGAs are designed to pass through changes in natural gas costs to customers with no change in utility margin (operating revenues less resource costs) or net income.

The following PGAs went into effect in our various jurisdictions during 2021 through 2023:

Jurisdiction	PGA Effective Date	Percentage Increase / (Decrease) in Billed Rates
Washington	November 1, 2021	10.6%
	July 1, 2022	12.6%
	November 1, 2022	12.3%
	November 1, 2023	(3.0)%
Idaho	September 1, 2021	13.5%
	February 1, 2022	8.1%
	July 1, 2022	10.5%
	November 1, 2022	12.7%
	November 1, 2023	5.0%
Oregon	November 1, 2021	9.6%
	November 1, 2022	16.9%
	November 1, 2023	(14.8)%

Power Cost Deferrals, Decoupling, Earnings Sharing Mechanisms, and Purchased Gas Adjustments

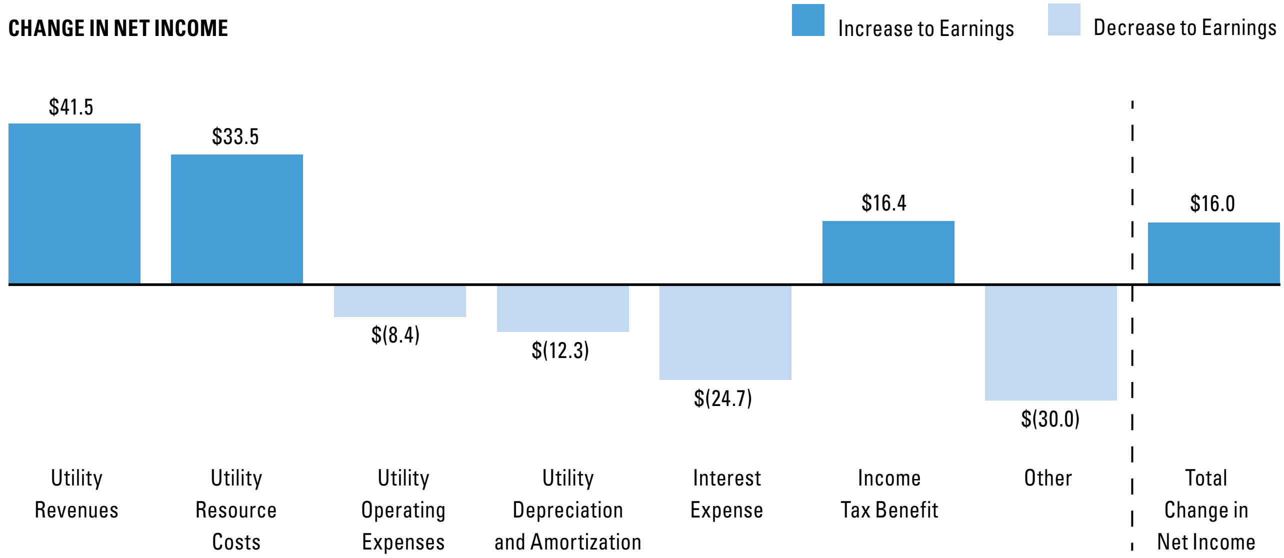
See "Note 23 of the Notes to Consolidated Financial Statements" for discussion of these regulatory mechanisms.

RESULTS OF OPERATIONS—OVERALL

The following provides an overview of changes in our Consolidated Statements of Income. More detailed explanations are provided, particularly for operating revenues and operating expenses, in the business segment discussions (Avista Utilities, AEL&P and the other businesses) that follow this section.

2023 compared to 2022

The following graph shows the total change in net income for 2023 to 2022, as well as the various factors that caused such change (dollars in millions):



Utility revenues increased at Avista Utilities primarily due to increased retail rates (including natural gas PGAs), increased electric wholesale sales prices and volumes, and increased electric decoupling revenues. These increases were partially offset by decreased natural gas wholesale prices, as well as financial losses from our fuel sale hedging activities that are netted with revenues.

Utility resource costs decreased at Avista Utilities primarily due to decreased market prices for natural gas and lower fuel costs for power generation, as well as financial gains related to our hedging activities that are netted with our expenses. These decreases were partially offset by increased purchased power and increased net deferrals and amortizations under regulatory mechanisms. The change related to regulatory mechanisms represents a reduction in deferred costs as well as an increase in amortizations of previously deferred power and natural gas costs.

The increase in utility operating expenses was primarily due to increased labor costs, insurance costs, as well as increased amortizations of previously deferred costs now included in customer rates (resulting in no impact to net income). These increases were partially offset by a decrease due to the $4.0 million write off of Dry Ash Disposal System assets in 2022.

Utility depreciation and amortization increased primarily due to additions to utility plant.

Interest expense increased due to higher interest rates, as well as increased borrowings outstanding during the period. Borrowings increased due to capital expenditures, higher deferred resource costs, and additional requirements for cash collateral.

Income tax benefit increased primarily due to the tax customer credits offsetting the bill impact of rate increases included in our 2021 Washington and Idaho GRCs, and the 2022 Washington GRC. Our effective tax rate for 2023 was negative 24.4 percent. See "Note 13 of the Notes to Consolidated Financial Statements" for further details and a reconciliation of our effective tax rate.

The decrease in other was primarily related to net investment losses recognized in 2023 compared to net investment gains recognized in 2022. See "Note 7 of the Notes to Consolidated Financial Statements" for further details of our investment gain and losses. The decrease related to net investment losses was partially offset by increased interest income, as well as decreased non-utility operating expenses and property taxes in 2023 compared to 2022.

NON-GAAP FINANCIAL MEASURES

The following discussion for Avista Utilities includes two financial measures that are considered "non-GAAP financial measures," electric utility margin and natural gas utility margin. In the AEL&P section, we include a discussion of utility margin, which is also a non-GAAP financial measure.

Generally, a non-GAAP financial measure is a numerical measure of a company's financial performance, financial position or cash flows that excludes (or includes) amounts that are included (excluded) in the most directly comparable measure calculated and presented in accordance with GAAP. Electric utility margin is electric operating revenues less electric resource costs, while natural gas utility margin is natural gas operating revenues less natural gas resource costs. The most directly comparable GAAP financial measure to electric and natural gas utility margin is utility operating revenues as presented in "Note 24 of the Notes to Consolidated Financial Statements."

The presentation of electric utility margin and natural gas utility margin is intended to enhance understanding of our operating performance. We use these measures internally and believe they provide useful information to investors in their analysis of how changes in loads (due to weather, economic or other conditions), rates, supply costs and other factors impact our results of operations. Changes in loads, as well as power and natural gas supply costs, are generally deferred and recovered from customers through regulatory accounting mechanisms. Accordingly, the analysis of utility margin generally excludes most of the change in revenue resulting from these regulatory mechanisms. We present electric and natural gas utility margin separately below for Avista Utilities since each portion of our business has different cost sources, cost recovery mechanisms and jurisdictions, so we believe that separate analysis is beneficial. These measures are not intended to replace utility operating revenues as determined in accordance with GAAP as an indicator of operating performance. Reconciliations of operating revenues to utility margin are set forth below.

RESULTS OF OPERATIONS—AVISTA UTILITIES

Resource Optimization

We engage in resource optimization, which involves the selection from available energy resources to serve our load obligations and the use of these resources to capture economic value through wholesale market transactions, which is ultimately intended to lower net power and natural gas supply costs. Our resource optimization transactions can take the form of physical sales and purchases of electric capacity and energy and fuel for electric generation, as well as financial derivative contracts related to capacity, energy, fuel and fuel transportation. See Item 1. "Business—Avista Utilities—Electric Operations—General."

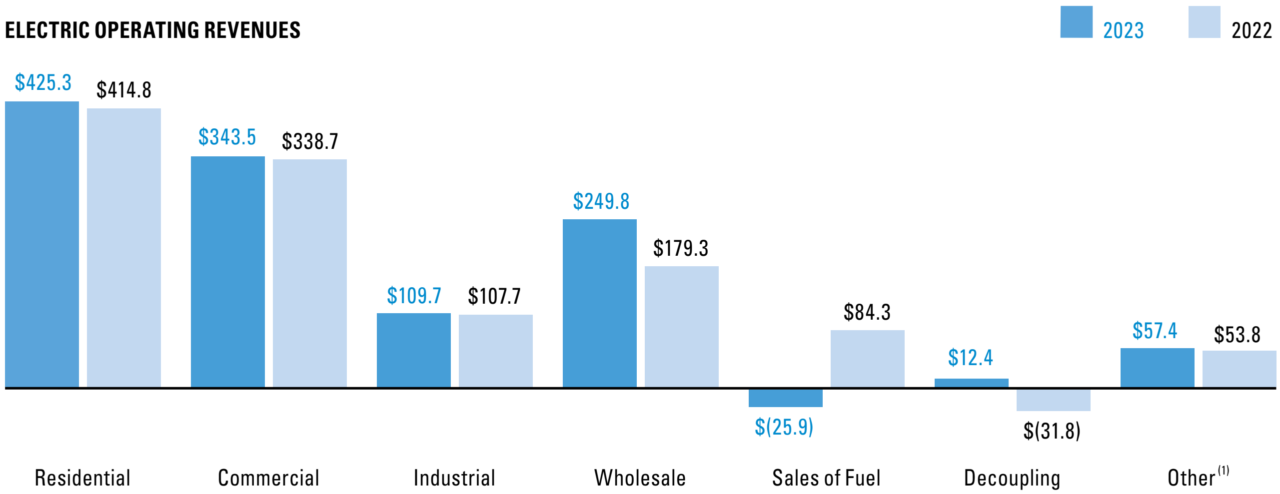
We typically enter into multiple transactions simultaneously to capture value. Even though these transactions are considered together when determining the net impact, they are recorded in separate items within components of utility operating revenue and resource costs and can cause fluctuations in each item. This was experienced in 2023, which included gains and losses on financial derivative contracts in certain line items below (such as wholesale sales and purchases of power and natural gas, sales of fuel, and other fuel costs). The ERM, PCA and PGAs are based on net supply costs and consider all transactions related to resource procurement and optimization (both physical and financial).

2023 compared to 2022

Utility Operating Revenues

The following graphs present Avista Utilities' electric operating revenues and MWh sales for 2023 and 2022, respectively (dollars in millions and MWhs in thousands):

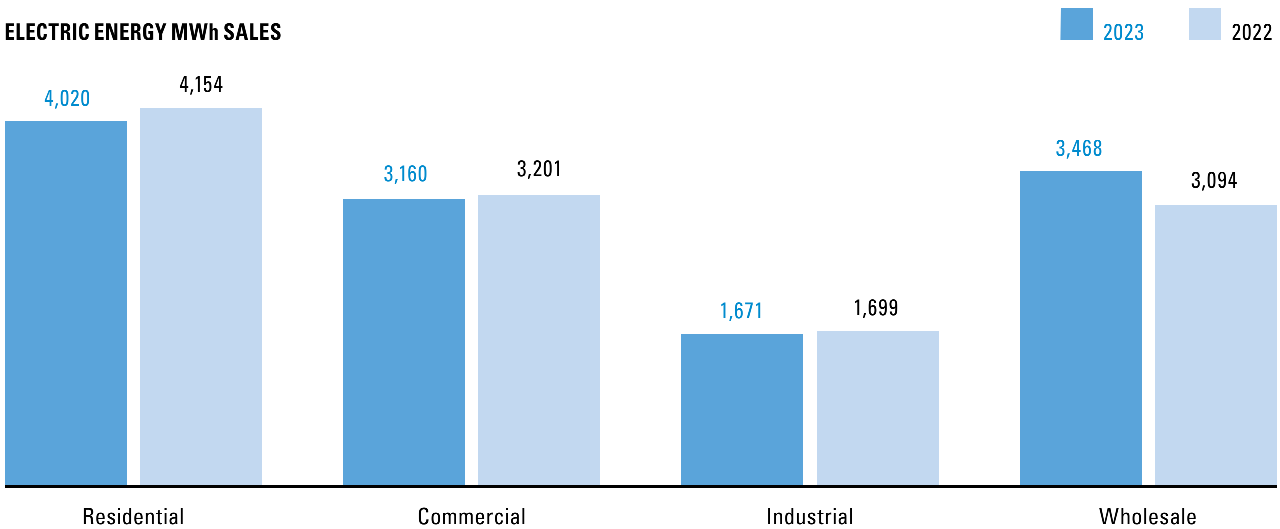
ELECTRIC OPERATING REVENUES



(1) This balance includes public street and highway lighting, which is considered part of retail electric revenues, and deferrals/amortizations to customers related to federal income tax law changes.

Total electric operating revenues in the graph above include intracompany sales of $6.5 million and $11.7 million for 2023 and 2022, respectively.

ELECTRIC ENERGY MWh SALES



The following table presents the current year deferrals and the amortization of prior year decoupling balances reflected in utility electric operating revenues for the years ended December 31 (dollars in thousands):

	Electric Decoupling Revenues	
	2023	2022
Current year decoupling deferrals [(a)]	$ (3,278)	$ (24,943)
Amortization of prior year decoupling deferrals [(b)]	15,697	(6,901)
Total electric decoupling revenue	$ 12,419	$ (31,844)

(a) Positive amounts are increases in decoupling revenue in the current year and will be surcharged to customers in future years. Negative amounts are decreases in decoupling revenue in the current year and will be rebated to customers in future years.

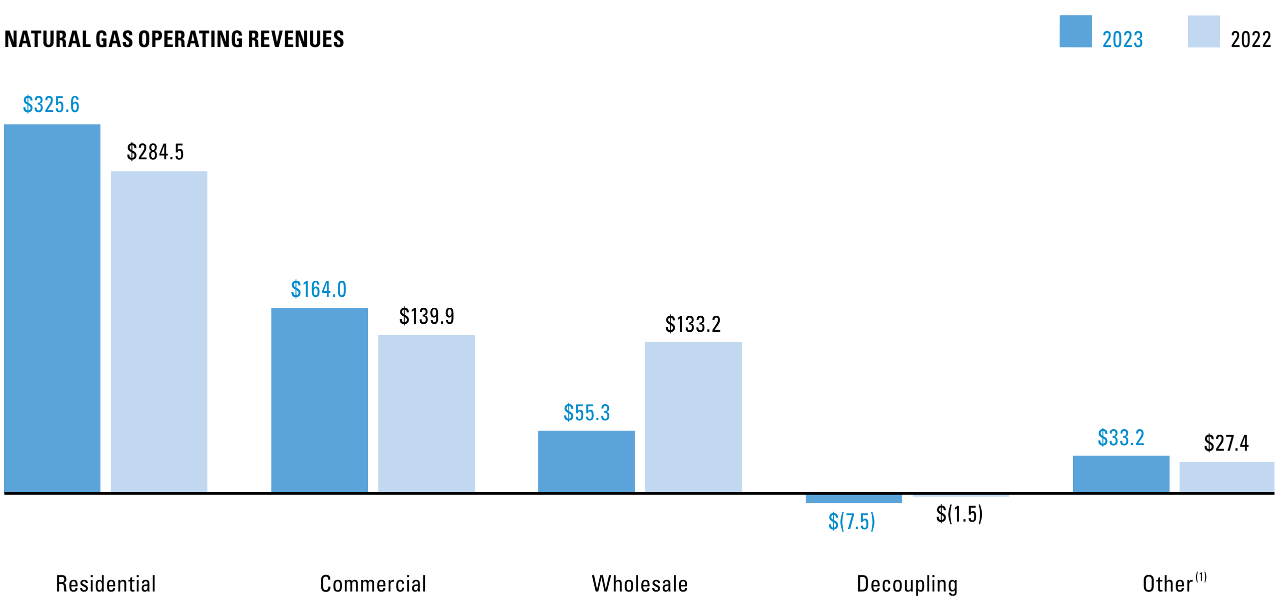
(b) Positive amounts are increases in decoupling revenue in the current year and are related to the amortization of rebate balances that resulted in prior years and are being refunded to customers (causing a corresponding decrease in retail revenue from customers) in the current year. Negative amounts are decreases in decoupling revenue in the current year and are related to the amortization of surcharge balances that resulted in prior years and are being surcharged to customers (causing a corresponding increase in retail revenue from customers) in the current year.

Total electric revenues increased $25.3 million for 2023 as compared to 2022. The primary differences in the results for these periods were as follows:

- a $17.7 million increase in retail electric revenues due to an increase in revenue per MWh (increased revenues $38.0 million), partially offset by a decrease in total MWhs sold (decreased revenues $20.3 million).
  - The decrease in total retail MWhs sold was primarily the result of decreased customer use in the winter months due to weather that was warmer than the prior year. Heating degree days in Spokane during 2023 were 8 percent below historical average, compared to 4 percent above historical average in 2022. This was partially offset by increased usage in summer months as the weather was warmer than the prior year, with Spokane cooling degree days at 39 percent above historical average compared to 33 percent above historical average in the prior year. Compared to 2022, total use per residential customer decreased 4.5 percent, and total use per commercial customer decreased 3.0 percent.
  - The increase in revenue per MWh was primarily due to our general rate cases, as well as the ERM surcharge to customers that started in 2023.
- a $70.5 million increase in wholesale electric revenues due to an increase in sales prices (increased revenues $43.6 million), and an increase in sales volumes (increased revenues $26.9 million). The increase in volumes was due to resource optimization activities.
- a $110.2 million decrease in sales of fuel due to thermal generation resource optimization activities, including net financial losses on derivative instruments resulting from commodity price volatility early in the year.
- a $44.3 million increase in electric decoupling revenue. Rebates decreased in 2023 due to lower usage by residential customers compared to the prior year, and amortizations of the prior year rebate balances in 2023 compared to amortizing a surcharge balance in 2022 increased revenues.

The following graphs present Avista Utilities' natural gas operating revenues and therms delivered for 2023 and 2022, respectively (dollars in millions and therms in thousands):

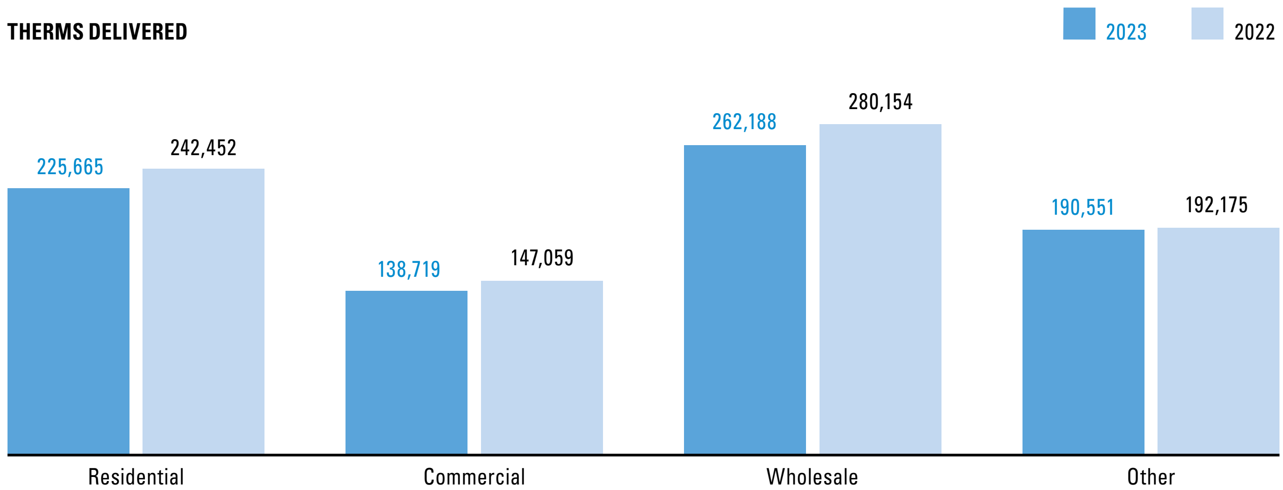
NATURAL GAS OPERATING REVENUES



(1) This balance includes interruptible and industrial revenues, which are considered part of retail natural gas revenues, and deferrals/amortizations to customers related to federal income tax law changes.

Total natural gas operating revenues in the graph above include intracompany sales of $33.4 million and $54.8 million for 2023 and 2022, respectively.

THERMS DELIVERED



The following table presents the current year deferrals and the amortization of prior year decoupling balances reflected in natural gas operating revenues for the years ended December 31 (dollars in thousands):

	Natural Gas Decoupling Revenues	
	2023	**2022**
Current year decoupling deferrals [a]	$ (456)	$ 2,493
Amortization of prior year decoupling deferrals [b]	(7,064)	(4,006)
Total natural gas decoupling revenue	$ (7,520)	$ (1,513)

(a) Positive amounts are increases in decoupling revenue in the current year and will be surcharged to customers in future years. Negative amounts are decreases in decoupling revenue in the current year and will be rebated to customers in future years.

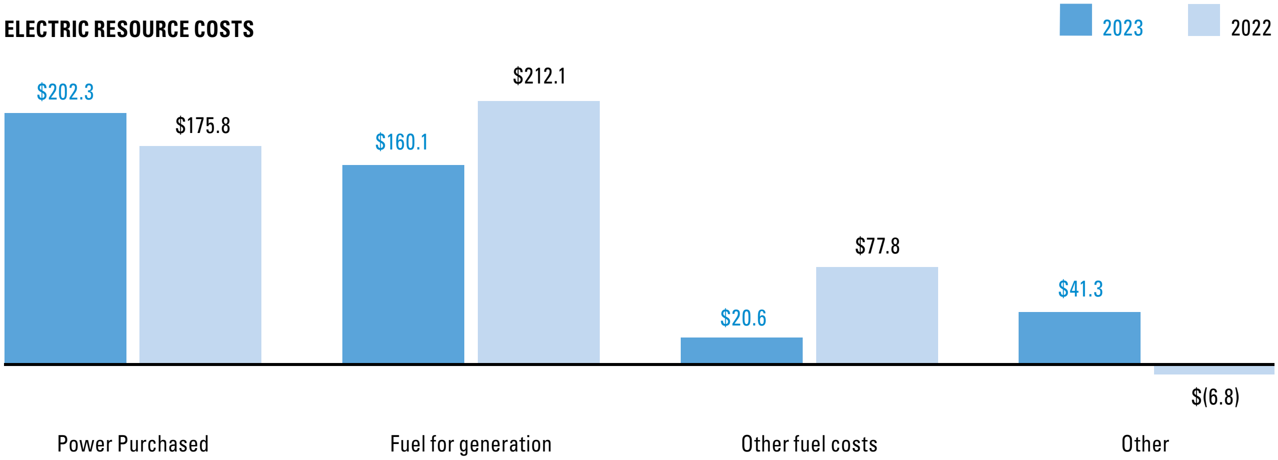
(b) Positive amounts are increases in decoupling revenue in the current year and are related to the amortization of rebate balances that resulted in prior years and are being refunded to customers (causing a corresponding decrease in retail revenue from customers) in the current year. Negative amounts are decreases in decoupling revenue in the current year and are related to the amortization of surcharge balances that resulted in prior years and are being surcharged to customers (causing a corresponding increase in retail revenue from customers) in the current year.

Total natural gas revenues decreased $12.9 million for 2023 as compared to 2022. The primary differences in the results for these periods were as follows:

- a $72.1 million increase in retail natural gas revenues (including industrial, which is included in other) due to increased retail rates (increased revenues $97.9 million), partially offset by decreased sales volumes (decreased revenues $25.8 million).
  - Retail rates increased due to PGA rate increases (which do not impact utility margin), as well as the effects of our general rate cases.
  - Retail natural gas sales decreased primarily due to lower residential and commercial usage due to warmer weather. Compared to 2022, residential use per customer decreased 7.9 percent and commercial use per customer decreased 6.8 percent. Heating degree days in Spokane during 2023 were 8 percent below historical average, compared to 4 percent above historical average in 2022.
- a $77.9 million decrease in wholesale natural gas revenues due to a decrease in prices (decreased revenues $74.1 million) and a decrease in volumes (decreased revenues $3.8 million). The decrease in prices includes the impact of losses on financial derivative instruments associated with our hedging activities, which nets with our wholesale revenues. Differences between revenues and costs from sales of resources in excess of retail load requirements and from resource optimization are accounted for through the PGA mechanisms.
- a $6.0 million decrease in decoupling revenues due to a rebate recognized in 2023 related to increased customer usage during the first quarter of 2023, compared to a surcharge recognized in 2022. In 2023 we also recognized higher amortizations of previous surcharges balances.

Utility Resource Costs

The following graph presents Avista Utilities' electric resource costs for 2023 and 2022, respectively (dollars in millions):

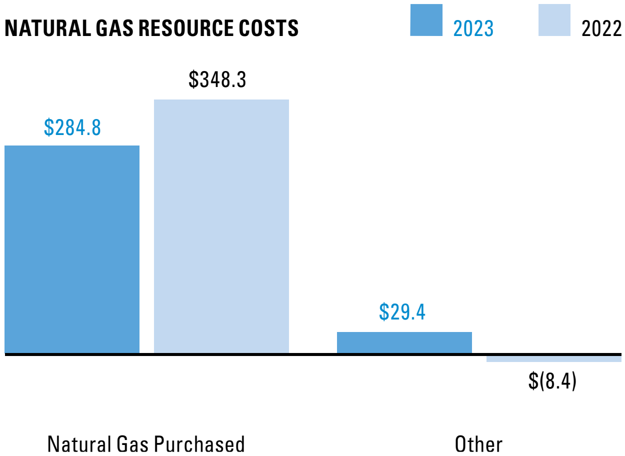


Total electric resource costs in the graph above include intracompany resource costs of $33.4 million and $54.8 million for 2023 and 2022, respectively.

Total electric resource costs decreased $34.6 million for 2023 as compared to 2022. The primary differences in the results for these periods were as follows:

- a $26.5 million increase in power purchased due to an increase in wholesale prices (increased costs by $25.6 million), and an increase in the volume of power purchases (increased costs by $0.9 million).
- a $52.0 million decrease in fuel for generation primarily due to decreased natural gas prices. This was partially offset by an increase in thermal generation volumes due in part to decreased hydroelectric generation during the year.
- a $57.2 million decrease in other fuel costs, including gains on financial derivative instruments associated with our hedging activities. This represents fuel and the related derivative instruments that were purchased for generation but later sold when conditions indicated that it was more economical to sell the fuel as part of the resource optimization process. When the fuel or related derivative instruments are sold, that revenue is included in sales of fuel.
- a $48.1 million increase in other electric resource costs, primarily related to a decrease in the deferral of power supply costs above those authorized under the ERM and PCA mechanisms, as well as increased amortizations of surcharge balances.

The following graph presents Avista Utilities' natural gas resource costs for 2023 and 2022, respectively (dollars in millions):



Total natural gas resource costs in the graph at left include intracompany resource costs of $6.5 million and $11.7 million for 2023 and 2022, respectively.

Total natural gas resource costs decreased $25.7 million for 2023 as compared to 2022. The primary differences in the results for these periods were as follows:

- a $63.5 million decrease in natural gas purchased due to a decrease in the price of natural gas (decreased costs by $47.0 million) and a decrease in total therms purchased (decreased costs $16.5 million).
- a $37.8 million increase in other costs, primarily due to the amortization of previously deferred costs.

Utility Margin

The following table reconciles Avista Utilities' operating revenues, as presented in "Note 24 of the Notes to Consolidated Financial Statements" to the Non-GAAP financial measure utility margin for the years ended December 31 (dollars in thousands):

	Electric		Natural Gas		Intracompany		Total	
	2023	2022	2023	2022	2023	2022	2023	2022
Operating revenues	$ 1,172,170	$ 1,146,823	$ 570,590	$ 583,485	$ (39,903)	$ (66,493)	$ 1,702,857	$ 1,663,815
Resource costs	424,278	458,905	314,171	339,886	(39,903)	(66,493)	698,546	732,298
Utility margin	$ 747,892	$ 687,918	$ 256,419	$ 243,599	$ —	$ —	$ 1,004,311	$ 931,517

Electric utility margin increased $60.0 million and natural gas utility margin increased $12.8 million.

Electric utility margin increased primarily due to our general rate cases, as well as customer growth. A small portion of the increase was due to lower net power supply costs. In 2023, we had a $8.4 million pre-tax expense under the ERM, compared to a $10.9 million pre-tax expense in 2022.

Natural gas utility margin increased primarily due to customer growth and our general rate cases.

Intracompany revenues and resource costs represent purchases and sales of natural gas between our natural gas distribution operations and our electric generation operations (as fuel for our generation plants). These transactions are eliminated in the presentation of total results for Avista Utilities and in the consolidated financial statements but are included in the separate results for electric and natural gas presented above.

RESULTS OF OPERATIONS—ALASKA ELECTRIC LIGHT AND POWER COMPANY

2023 compared to 2022

Net income for AEL&P was $8.9 million for the year ended December 31, 2023, compared to $7.5 million for 2022.

The following table presents AEL&P's operating revenues, resource costs and resulting utility margin for the years ended December 31 (dollars in thousands):

	Electric	
	2023	2022
Operating revenues	$ 48,139	$ 45,704
Resource costs	3,826	3,564
Utility margin	$ 44,313	$ 42,140

Utility margin increased for 2023 primarily due to higher sales volumes and rate increases.

RESULTS OF OPERATIONS—OTHER BUSINESSES

2023 compared to 2022

Our other businesses had a net loss of $4.8 million for 2023 compared to net income of $29.7 million for 2022. The decrease in net income primarily relates to decreases in the fair value of our investments in 2023, compared to net investment gains related to fair value increases in 2022. In 2022, a significant portion of the net income resulted from an increase in the fair value of our investment in a biotechnology company, which stems from an investment originally focused on the development of biofuels. See "Note 18 of the Notes to the Consolidated Financial Statements" for further discussion of our equity investment fair value.

ACCOUNTING STANDARDS TO BE ADOPTED IN 2024

We are not expecting the adoption of accounting standards to have a material impact on our financial condition, results of operations and cash flows in 2024. For more information on accounting standards expected to be adopted in future periods, see "Note 2 of the Notes to the Consolidated Financial Statements."

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of our consolidated financial statements in conformity with GAAP requires the use of estimates and assumptions that affect amounts reported in the consolidated financial statements. Changes in these estimates and assumptions are considered reasonably possible and may have a material effect on our consolidated financial statements and thus actual results could differ from the amounts reported and disclosed herein. The following accounting policies represent those that our management believes are particularly important to the consolidated financial statements and require the use of estimates and assumptions:

- **Regulatory accounting,** in accordance with ASC Topic 980, Regulated Operations, among other things, requires that costs and/or obligations that, in our judgement, are probable of recovery through rates charged to customers, but are not yet reflected in rates, not be reflected in our Consolidated Statements of Income until the period in which they are reflected in rates and matching revenues are recognized. Meanwhile, these costs and/or obligations are deferred and reflected on our Consolidated Balance Sheets as regulatory assets or liabilities. We generally receive regulatory orders before deferring costs as regulatory assets and liabilities; however, in certain instances in which we have regulatory precedent, we may not request an order before deferring the costs. If we no longer met the criteria to apply regulatory accounting or no longer allowed recovery of these costs, we would be required to recognize significant write-offs of regulatory assets and liabilities in the Consolidated Statements of Income. See "Notes 1, 4 and 23 of the Notes to Consolidated Financial Statements" for further discussion of our regulatory accounting policy and mechanisms.
- **Pension plans and other postretirement benefit plans,** discussed in further detail below.
- **Equity investments,** specifically valuations performed to determine the fair value of certain investment holdings, require judgement in the selection of assumptions used to estimate fair value of investments for which there is not a quoted active market

price. We primarily use a market approach to determine fair value of an investment, and transactions involving comparable securities may need to be adjusted to estimate our investment's fair value. See "Notes 7 and 18 of the Notes to Consolidated Financial Statements" for further discussion of our equity investments and method for determining their fair value.

- **Contingencies,** related to unresolved regulatory, legal and tax issues as to which there is inherent uncertainty for the ultimate outcome of the respective matter. We accrue a loss contingency if it is probable that an asset is impaired or a liability has been incurred and the amount of the loss or impairment can be reasonably estimated. To the extent material, we also disclose losses that do not meet these conditions for accrual, if there is a reasonable possibility that a potential loss may be incurred. For all material contingencies, we have made a judgment as to the probability of a loss occurring and as to whether or not the amount of the loss can be reasonably estimated. However, no assurance can be given as to the ultimate outcome of any contingency. See "Notes 1 and 22 of the Notes to Consolidated Financial Statements" for further discussion of our commitments and contingencies.

Pension Plans and Other Postretirement Benefit Plans—Avista Utilities

We have a defined benefit pension plan covering substantially all regular full-time employees at Avista Utilities hired prior to January 1, 2014. For substantially all regular non-union full-time employees at Avista Utilities hired on or after January 1, 2014, a defined contribution 401(k) plan replaced the defined benefit pension plan. Union employees hired between January 1, 2014 and December 31, 2023 are covered under the defined benefit pension plan. Effective January 1, 2024, the plan is closed to new union employees. See "Note 12 of the Notes to Consolidated Financial Statements" for further discussion of these individual plans.

Pension costs (including the SERP) were $9.3 million for 2023, $22.8 million for 2022 and $19.3 million for 2021. Included in our 2022 pension costs is $11.8 million of settlement costs, which were deferred as a regulatory asset and therefore did not impact our net income in 2022. See "Note 12 of the Notes to Consolidated Financial Statements" for further discussion of pension settlement accounting treatment.
Of our pension costs (excluding the SERP), approximately 60 percent are expensed and 40 percent are capitalized consistent with labor charges. The costs related to the SERP are expensed. Our costs for the pension plan are determined in part by actuarial formulas that are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience.

Pension costs are affected by among other things:

- employee demographics (including age, compensation and length of service by employees),
- the amount of cash contributions to the pension plan,
- the actual return on pension plan assets,
- expected return on pension plan assets,
- discount rate used in determining the projected benefit obligation and pension costs,
- assumed rate of increase in employee compensation,
- life expectancy of participants and other beneficiaries, and
- expected method of payment (lump sum or annuity) of pension benefits.

We make estimates and assumptions as to many of these factors. In accordance with accounting standards, changes in pension plan obligations associated with these factors may not be immediately recognized as pension costs in our Consolidated Statements of Income, but we generally recognize the change in future years over the remaining average service period of pension plan participants. As such, our costs recorded in a period may not reflect the actual level of cash benefits provided to pension plan participants.

We revise the key assumption of the discount rate each year.In selecting a discount rate, we consider yield rates at the end of the year for highly rated corporate bond portfolios with cash flows from interest and maturities similar to the expected payout of pension benefits.

The expected long-term rate of return on plan assets is reset or confirmed annually based on past performance and economic forecasts for the types of investments held by our plan.

The following chart reflects the assumptions used each year for the pension discount rate (exclusive of the SERP), the expected long-term return on plan assets and the actual return on plan assets and their impacts to the pension plan associated with the change in assumption (dollars in millions):

	2023	2022	2021
Discount rate (exclusive of SERP)			
Pension discount rate	5.86%	6.10%	3.39%
Increase/(decrease) to projected benefit obligation	$ 14.0	$ (198.3)	$ (15.6)
Return on plan assets [(a)]			
Expected long-term return on plan assets	8.30%	5.80%	5.40%
Increase/(decrease) to pension costs	$ (13.1)	$ (3.0)	$ 0.7
Actual return on plan assets—net of fees	15.00%	(21.80)%	7.10%
Actual gain (loss) on plan assets	$ 78.8	$ (163.9)	$ 50.4

(a) The SERP has no plan assets. The plan assets in this disclosure are for the pension plan only.

The following chart reflects the sensitivities associated with a change in certain actuarial assumptions by the indicated percentage (dollars in millions):

Actuarial Assumption	Change in Assumption	Effect on Projected Benefit Obligation	Effect on Pension Cost
Expected long-term return on plan assets	(0.5)%	$ —*	$ 2.6
Expected long-term return on plan assets	0.5%	—*	(2.6)
Discount rate	(0.5)%	31.4	2.5
Discount rate	0.5%	(28.5)	(2.5)

** Changes in the expected return on plan assets would not affect our projected benefit obligation.*

We provide certain health care and life insurance benefits for substantially all of our retired employees. We accrue the estimated cost of postretirement benefit obligations during the years that employees provide service.

LIQUIDITY AND CAPITAL RESOURCES

OVERALL LIQUIDITY

Avista Corp.'s consolidated operating cash flows are primarily derived from the operations of Avista Utilities. The primary source of operating cash flows for Avista Utilities is revenues from sales of electricity and natural gas. Significant uses of cash flows from Avista Utilities include the purchase of power, fuel and natural gas, and payment of other operating expenses, taxes and interest, with any excess being available for other corporate uses such as capital expenditures and dividends.

We design operating and capital budgets to control operating costs and to direct capital expenditures to projects that support immediate and long-term strategies, particularly for our regulated utility operations. In addition to operating expenses, we have continuing commitments for capital expenditures for construction and improvement of utility facilities.

Our annual net cash flows from operating activities usually do not fully support the amount required for annual utility capital expenditures. As such, from time-to-time, we need to access capital markets to fund these needs as well as fund maturing debt. See further discussion at "Capital Resources."

We regularly file for rate adjustments for recovery of operating costs and capital investments and to seek the opportunity to earn reasonable returns.

We have regulatory mechanisms in place that provide for the deferral and recovery of the majority of power and natural gas supply costs. However, when power and natural gas costs exceed the levels currently recovered from customers, net cash flows are negatively affected. Factors that could cause purchased power and natural gas costs to exceed the levels currently recovered from customers under base rates include, but are not limited to, higher prices in wholesale markets and/or an increased need to purchase power in the wholesale markets, and a lack of regulatory approval for higher authorized net power supply costs. Factors beyond our control that could result in an increased need to purchase power in the wholesale markets include, but are not limited to:

- increases in demand (due to either weather or customer growth),
- reduced snowpack or lower streamflows (due to weather) for hydroelectric generation,
- unplanned outages at generating facilities, and
- failure of third parties to deliver on energy or capacity contracts.

In addition to the above, we enter into derivative instruments to hedge exposure to certain risks, including fluctuations in commodity prices, foreign exchange rates and interest rates (for purposes of issuing long-term debt in the future). These derivative instruments periodically require the posting of collateral (in the form of cash or letters of credit) or other credit enhancements or to reduce or terminate a portion of the contract through cash settlement, in the event of a downgrade in our credit ratings or changes in market prices. In periods of price volatility, the level of exposure can change significantly. As a result, sudden and significant demands may be made against our cash on hand and credit facilities. See "Enterprise Risk Management—Credit Risk Liquidity Considerations" below.

Material contractual obligations that demand cash arise in the normal course of business including energy purchase contracts and contractual obligations related to generation facilities and transmission and distributions services. See "Note 14 of the Notes to Consolidated Financial Statements" for additional information related to these contractual obligations.

Additional demands for cash include payments of borrowings and interest payments (see "Notes 15–17 of the Notes to Consolidated Financial Statements"), lease obligations (see "Note 5 of the Notes to Consolidated Financial Statements"), pension and other postretirement benefit plan contributions (see "Note 12 of the Notes to Consolidated Financial Statements") and investment fund commitments (see "Note 6 of the Notes to Consolidated Financial Statements").

See discussion in "Capital Resources" below for available liquidity under our credit facilities. With our available liquidity under these agreements, we believe that we have adequate liquidity to meet our needs for the next 12 months.

REVIEW OF CONSOLIDATED CASH FLOW STATEMENT

2023 compared to 2022

Consolidated Operating Activities

Net cash provided by operating activities was $447.1 million for 2023 compared to $124.2 million for 2022. The increase in net cash provided by operating activities primarily relates to a decrease in cash collateral posted for derivative investments, which was returned and increased cash flows by $129.2 million in 2023 compared to decreasing cash flows by $141.0 million in 2022. During 2023 we also had an increase to cash flows of $7.1 million resulting from net amortizations of power and natural gas cost deferrals, while the net deferral decreased cash flows by $78.4 million in 2022. Receipts of outstanding accounts receivable balances increased operating cash flows by $92.9 million compared to 2022.

These increases in operating cash flows were partially offset by a decrease in our outstanding accounts payable balance, which decreased operating cash flows by $132.1 million compared to 2022, as well as increased inventory purchases (primarily CCA emissions allowances) resulting in a decrease to operating cash flows of $29.4 million.

Consolidated Investing Activities

Net cash used in investing activities was $510.4 million for 2023, an increase compared to $460.2 million for 2022. During 2023, we paid $498.6 million for utility capital expenditures, compared to $452.0 million for 2022.

Consolidated Financing Activities

Net cash provided by financing activities was $84.9 million for 2023 compared to $327.3 million for 2022. The decrease in financing cash flows was primarily the result of a decrease in short-term borrowings of $114.0 million in 2023, compared to an increase of $179.0 million in 2022. We issued $250.0 million of long term debt and repaid $13.5 million of maturing long term debt in 2023, compared to issuing $400.0 million and repaying $250.0 million in 2022.

CAPITAL RESOURCES

Capital Structure

Our consolidated capital structure, including the current portion of long-term debt and short-term borrowings consisted of the following as of December 31, 2023 and 2022 (dollars in thousands):

	2023		2022	
	Amount	Percent of Total	Amount	Percent of Total
Current portion of long-term debt and leases	$ 22,890	0.4%	$ 21,084	0.4%
Short-term borrowings	349,000	6.3	463,000	8.8
Long-term debt to affiliated trusts	51,547	0.9	51,547	1.0
Long-term debt and leases	2,618,012	47.4	2,387,792	45.4
Total debt	3,041,449	55.0	2,923,423	55.6
Total Avista Corporation shareholders' equity	2,485,323	45.0	2,334,668	44.4
Total	$ 5,526,772	100.0%	$ 5,258,091	100.0%

Our shareholders' equity increased $150.7 million during 2023 primarily due to net income and the issuance of common stock, partially offset by dividends paid.

We need to finance capital expenditures and acquire additional funds for operations from time-to-time. The cash requirements needed to service our indebtedness, both short-term and long-term, reduce the amount of cash flow available to fund capital expenditures, purchased power, fuel and natural gas costs, dividends and other requirements.

Short-Term Borrowings

Avista Corp.

Avista Corp. has a committed line of credit in the total amount of $500 million and an expiration date of June 2028, with the option to extend for an additional one year period (subject to customary conditions). Avista Corp. also has a continuing letter of credit agreement in the aggregate amount of $50 million, and either party may terminate the agreement at any time.

In December 2022, we entered into an additional revolving credit agreement in the amount of $100 million, which was terminated in June 2023.

In December 2022, we entered into a term loan, in the amount of $150 million with a maturity date of March 30, 2023. In March 2023, we repaid the $150 million outstanding balance on the term loan.

The following table summarizes the balances outstanding and available liquidity as of December 31, 2023 (dollars in thousands):

	Aggregate Amount	Amount Outstanding	Letters of Credit Outstanding (1)	Available Liquidity
Line of credit expiring June 2028	$ 500,000	$ 349,000	$ 4,700	$ 146,300
Letter of credit facility	50,000	N/A	20,000	30,000
Total	$ 550,000	$ 349,000	$ 24,700	$ 176,300

(1) Letters of credit are not reflected on the Consolidated Balance Sheets. If a letter of credit were drawn upon by the holder, we would have an immediate obligation to reimburse the bank that issued that letter.

The Avista Corp. credit facilities contain customary covenants and default provisions, including a change in control (as defined in the agreements). The events of default under each of the credit facilities also include a cross default from other indebtedness (as defined) and in some cases other obligations. Some of these agreements also include a covenant which does not permit our ratio of "consolidated total debt" to "consolidated total capitalization" to be greater than 65 percent at any time. As of December 31, 2023, we complied with this covenant with a ratio of 55.0 percent.

Balances outstanding and interest rates on borrowings (excluding letters of credit) under Avista Corp.'s lines of credit were as follows as of and for the year ended December 31 (dollars in thousands):

	2023	2022
$500 million line of credit, expiring June 2028		
Maximum balance outstanding during the year	$ 357,000	$ 345,000
Average balance outstanding during the year	246,337	205,947
Average interest rate during the year	6.06%	3.06%
Average interest rate at end of year	6.46%	5.31%
$100 million line of credit, terminated June 2023		
Maximum balance outstanding during the period (1)	$ 15,000	77,000
Average balance outstanding during the period (1)	283	15,656
Average interest rate during the period (1)	7.75%	7.56%
Average interest rate at end of year	N/A	N/A

(1) Amounts for each period are from entering the agreement in December 2022 to the termination in June 2023.

AEL&P

AEL&P has a $25 million committed line of credit with an expiration date in June 2028. As of December 31, 2023, there was $25.0 million of available liquidity under this line of credit.

The AEL&P credit facility contains customary covenants and default provisions including a covenant which does not permit the ratio of "consolidated total debt at AEL&P" to "consolidated total capitalization at AEL&P," (including the impact of the Snettisham obligation) to be greater than 67.5 percent at any time. As of December 31, 2023, AEL&P complied with this covenant with a ratio of 48.8 percent.

As of December 31, 2023, Avista Corp. and its subsidiaries complied with the covenants of their financing agreements, and none of Avista Corp.'s subsidiaries constituted a "significant subsidiary" as defined in Avista Corp.'s committed line of credit.

Long-Term Debt

In March 2023, Avista Corp. issued and sold $250 million of 5.66 percent first mortgage bonds due in 2053 with institutional investors in the private placement market. A portion of the net proceeds from the sale of these bonds was used for the construction or improvement of utility facilities, and a portion was used to refinance existing indebtedness, including the repayment of Avista Corp.'s $150 million term loan. In connection with the pricing of the first mortgage bonds in March 2023, we cash settled four interest rate swap derivatives (notional aggregate amount of $40 million) and received a net amount of $7.5 million, which will be amortized over the life of the debt. The effective interest cost of the first mortgage bonds is 5.50 percent, including the effects of the settled interest rate swap derivatives and issuance costs.

Common Stock

We issued common stock in 2023 for total net proceeds of $112.3 million. Most of these issuances came through our sales agency agreements under which the sales agents may offer and sell new shares of our common stock from time-to-time, with the balance related to compensation plans. In 2023, 3.0 million shares were issued under these agreements resulting in total net proceeds of $111.8 million.

2024 Liquidity Expectations

During 2024, we expect to issue up to $85 million of long-term debt and $70 million of common stock to fund planned capital expenditures.

After considering the expected issuances of long-term debt and common stock during 2024, we expect net cash flows from operating activities, together with cash available under our credit facilities, to provide adequate resources to fund capital expenditures, dividends, and other contractual commitments.

Limitations on Issuances of Preferred Stock and First Mortgage Bonds

We are restricted under our Restated Articles of Incorporation, as amended, as to the additional preferred stock we can issue. As of December 31, 2023, we could issue $1.6 billion of preferred stock at an assumed dividend rate of 7.25 percent. We are not planning to issue preferred stock.

Under the Avista Corp. and the AEL&P Mortgages and Deeds of Trust securing Avista Corp.'s and AEL&P's first mortgage bonds (including Secured Medium-Term Notes), respectively, each entity may issue additional first mortgage bonds in an aggregate principal amount equal to the sum of:

- 66⅔ percent of the cost or fair value to the company (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.

However, Avista Corp. and AEL&P may not individually 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 respective Mortgages) 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 that entity's 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, 2023, property additions and retired bonds would have allowed, and the net earnings test would not have prohibited, the issuance of $1.2 billion in aggregate principal amount of additional first mortgage bonds at Avista Corp. and $51.4 million at AEL&P, at an assumed interest rate of 8 percent in each case. We believe that we have adequate capacity to issue first mortgage bonds to meet our financing needs over the next several years.

UTILITY CAPITAL EXPENDITURES

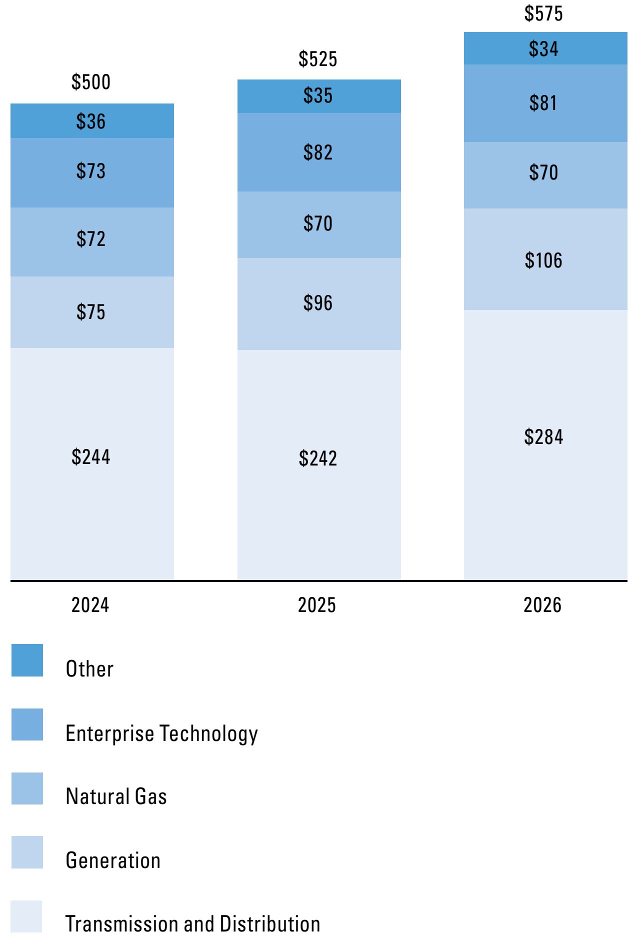
We make capital investments at our utilities to enhance service and system reliability for our customers and replace aging infrastructure.

The following table summarizes our actual and expected capital expenditures as of and for the year ended December 31, 2023 (dollars in thousands):

	Avista Utilities	AEL&P
2023 Actual capital expenditures		
Capital expenditures (per the Consolidated Statement of Cash Flows)	$ 484,716	$ 13,921
Expected total annual capital expenditures (by year)		
2024	$ 500,000	$ 21,000
2025	525,000	10,000
2026	575,000	12,000

The following graph shows Avista Utilities' expected capital expenditures for 2024–2026 by category (in millions):

CAPITAL BUDGET



These estimates of capital expenditures are subject to continuing review and adjustment. Actual expenditures may vary from our estimates due to factors such as changes in business conditions, construction schedules and environmental requirements.

NON-REGULATED INVESTMENTS AND CAPITAL EXPENDITURES

We make investments and capital expenditures at our other businesses including those related to economic development projects in our service territory that demonstrate the latest energy and environmental building innovations and house several local college degree programs. In addition, we make investments in emerging technology companies, venture capital funds, and other business ventures.

The following table summarizes our actual and expected investments and capital expenditures at our other businesses as of and for the year ended December 31, 2023 (dollars in thousands):

		Other
2023 Actual investments and capital expenditures		
Investments and capital expenditure	$	16,805
Expected total annual investments and capital expenditures (by year)		
2024	$	22,000
2025		17,000
2026		14,000

These estimates of investments and capital expenditures are subject to continuing review and adjustment. Actual expenditures may vary from our estimates due to factors such as changes in business conditions or strategic plans.

See "Liquidity" for information regarding other material cash requirements for 2024 and thereafter.

PENSION PLAN

We contributed $10.0 million to the pension plan in 2023. We expect to contribute a total of $50.0 million to the pension plan in the period 2024 through 2028, with an annual contribution of $10.0 million.

The final determination of pension plan contributions for future periods is subject to multiple variables, most of which are beyond our control, including changes to the fair value of pension plan assets, changes in actuarial assumptions (in particular the discount rate used in determining the benefit obligation), or changes in federal legislation. We may change our pension plan contributions in the future depending on changes to any variables, including those listed above.

See "Note 12 of the Notes to Consolidated Financial Statements" for additional information regarding the pension plan.

CREDIT RATINGS

Our access to capital markets and our cost of capital are directly affected by our credit ratings. In addition, many of our contracts for the purchase and sale of energy commodities contain terms dependent upon our credit ratings. See "Enterprise Risk Management—Credit Risk Liquidity Considerations" and "Note 8 of the Notes to Consolidated Financial Statements."

The following table summarizes our credit ratings as of February 20, 2024:

	Standard & Poor's (1)	Moody's (2)
Corporate/Issuer rating	BBB	Baa2
Senior Secured Debt	A-	A3
Senior Unsecured Debt	BBB	Baa2

(1) Standard & Poor's lowest "investment grade" credit rating is BBB-.

(2) Moody's lowest "investment grade" credit rating is Baa3.

A security rating is not a recommendation to buy, sell or hold securities. Each security rating is subject to revision or withdrawal at any time by the assigning rating organization. Each security rating agency has its own methodology for assigning ratings, and, accordingly, each rating should be considered in the context of the applicable methodology, independent of all other ratings. The rating agencies provide ratings at the request of Avista Corp. and charge fees for their services.

DIVIDENDS

See "Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities" for a detailed discussion of our dividend policy and the factors which could limit the payment of dividends.

COMPETITION

Our electric and natural gas distribution utility business has historically been recognized as a natural monopoly. In each regulatory jurisdiction, our rates for retail electric and natural gas services (other than specially negotiated retail rates for industrial or large commercial customers, which are subject to regulatory review and approval) are generally determined on a "cost of service" basis. In theory, rates are designed to provide, after recovery of allowable operating expenses and capital investments, an opportunity to earn a reasonable return on investment as allowed by our regulators.

In retail markets, we compete with various rural electric cooperatives and public utility districts in and adjacent to our service territories in the provision of service to new electric customers. We have service territory agreements with certain rural electric cooperatives and public utility districts, approved in applicable jurisdictions, to set forth conditions under which one or the other utility will provide service to customers. Alternative energy technologies, including customer-sited solar, wind or geothermal generation, and energy storage, may also compete for sales to existing customers. Advances in power generation, energy efficiency, energy storage and other alternative energy technologies could lead to more wide-spread usage of these technologies, thereby reducing customer demand for the energy supplied by us. This reduction in usage and demand would reduce our revenue and negatively impact our financial condition including possibly leading to our inability to fully recover our investments in generation, transmission and distribution assets. Similarly, our natural gas distribution operations compete with other energy sources including heating oil, propane and other fuels.

Certain natural gas customers could bypass our natural gas system, reducing both revenues and recovery of fixed costs. To reduce the potential for such bypass, we price natural gas services, including transportation contracts, competitively and have varying degrees of flexibility to price transportation and delivery rates by means of individual contracts. These individual contracts are subject to regulatory review and approval. We have long-term transportation contracts with several of our largest industrial customers under which the customer acquires its own commodity while using our infrastructure for delivery. Such contracts reduce the risk of these customers bypassing our system in the foreseeable future and minimizes the impact on our earnings.

Customers may have a choice in the future over the sources from which to receive their energy. To effectively compete for our customers in the future, we continue to strive to create value through product and service offerings. We are also attempting to enhance the effectiveness and ease of our customer interactions by tailoring internal initiatives to focus on choices for customers to increase their overall satisfaction with the Company.

Also, non-utility businesses are developing new technologies and services to help energy consumers manage energy in new ways that may improve productivity and could alter demand for the energy we sell.

In wholesale markets, competition for available electric supply is influenced by the:

- localized and system-wide demand for energy,
- type, capacity, location and availability of generation resources, and
- variety and circumstances of market participants.

These wholesale markets are regulated by the FERC, which requires electric utilities to transmit power and energy to or for wholesale purchasers and sellers, enlarge or construct additional transmission capacity for the purpose of providing these services, and transparently price and offer transmission services without favor to any party, including the merchant functions of the utility.

Participants in the wholesale energy markets include:

- other utilities,
- federal power marketing agencies,
- energy marketing and trading companies,
- independent power producers,
- financial institutions, and
- commodity brokers.

UTILITY CUSTOMER AND LOAD GROWTH

We develop customer and load growth forecasts for the next five years. For 2024-2028, we expect electric and natural gas customer growth of approximately 1.3 percent and 0.6 percent, respectively. Expected load growth for the same period is approximately 0.4 percent for both electric and natural gas. These forecasts incorporate the new building codes in Washington (see “Environmental Issues and Contingencies”).

In addition to Washington building code updates, emerging legislation with potential restrictions to new connections does create further uncertainty when forecasting natural gas customer and load growth, with additional potential impacts to our electric customer and load growth from resulting electrification efforts. See further discussion regarding regulations impacting our natural gas operations as included in “Environmental Issues and Contingencies.”

The forward-looking statements set forth above regarding retail load growth are based, in part, upon purchased economic forecasts and publicly available population and demographic studies. The expectations regarding retail load growth are also based upon various assumptions, including:

- assumptions relating to weather and economic and competitive conditions,
- internal analysis of company-specific data, such as energy consumption patterns,
- internal business plans,
- an assumption that we will incur no material loss of retail customers due to self-generation or retail wheeling, and
- an assumption that demand for electricity and natural gas as a fuel for mobility will for now be immaterial.

Changes in actual experience can vary significantly from our projections.

See also “Competition” above for a discussion of competitive factors that could affect our results of operations in the future.

ENVIRONMENTAL ISSUES AND CONTINGENCIES

We are subject to environmental regulation by federal, state and local authorities. The generation, transmission, distribution, service and storage facilities in which we have ownership interests or which we may need to acquire or develop are subject to environmental laws, regulations and rules relating to construction permitting, air emissions, water quality, fisheries, wildlife, endangered species, avian interactions, wastewater and stormwater discharges, waste handling, natural resource protection, historic and cultural resource protection, and other similar activities. These laws and regulations require the Company to make substantial investments in compliance activities and to acquire and comply with a wide variety of environmental licenses, permits, approvals and settlement agreements. These items are enforceable by public officials and private individuals. Some of these regulations are subject to ongoing interpretation, whether administratively or judicially, and are often in the process of being modified. We conduct periodic reviews and audits of pertinent facilities and operations to enhance compliance and to respond to or anticipate emerging environmental issues. The Company’s Board of Directors has established a committee to oversee environmental issues and to assess and manage environmental risk.

We monitor legislative and regulatory developments at different levels of government for environmental issues, particularly those with the potential to impact the operation of our generating plants and other assets, and our ability to provide service to natural gas customers. We continue to be subject to increasingly stringent or expanded application of environmental and related regulations from all levels of government.

Environmental laws and regulations may restrict or impact our business activities in many ways, including, but not limited to, by:

- increasing the operating costs of generating plants and other assets,
- increasing the lead time and capital costs for the construction of new generating plants and other assets,
- requiring modification of existing generating plants,

- requiring existing generating plant operations to be curtailed or shut down,
- reducing the amount of energy available from generating plants,
- restricting the types of generating plants that can be built or contracted with,
- requiring construction of specific types of generation plants at higher cost, and
- increasing costs of distributing, or limiting our ability to distribute, electricity and/or natural gas.

Compliance with environmental laws and regulations could result in increases to capital expenditures and operating expenses. We intend to seek recovery of such costs through the ratemaking process.

Policies and Other Impacts Related to Climate Change

Legal and policy changes responding to concerns about climate changes, and the potential impacts of such changes, could have a significant effect on our business. Direct impacts of climate changes include, without limitation, variations in the amount and timing of energy demand throughout the year, variations in the level and timing of precipitation throughout the year, as well as variations in temperature, and the resulting impact on the availability of hydroelectric resources at times of peak demand as well as an increased risk of wildfire. Indirect impacts include, without limitation, changes in laws and regulations intended to mitigate the risk of, or alter, climate changes, including restrictions on the operation of our power generation resources and obligations or limitations imposed on the sale of natural gas. When direct or indirect impacts of climate change lead to increased operational costs or capital investments, we intend to recover such costs through the ratemaking process.

Washington Legislation and Regulatory Actions

Clean Energy Transformation Act

In 2019, the Washington State Legislature passed the CETA, which requires Washington utilities to eliminate the costs and benefits associated with coal-fired resources from their retail electric sales by December 31, 2025. This requirement effectively prohibits sales of energy produced by coal-fired generation to Washington retail customers after December 31, 2025. In addition, the CETA establishes the policy of Washington State that retail sales of electricity to Washington customers must be carbon-neutral by January 1, 2030 and requires that each electric utility demonstrate compliance with this standard by using electricity from renewable and other non-emitting resources for 100 percent of the utility's retail electric load over consecutive multi-year compliance periods; provided, however, that through December 31, 2044 the utility may satisfy up to 20 percent of this requirement with specified payments, credits and/or investments in qualifying energy transformation projects.

The law has direct, specific impacts on Colstrip, which are unique to those owners of Colstrip who serve Washington customers. See "Colstrip" section and "Note 22 of the Notes to Consolidated Financial Statements" for further details on the impacts of the CETA on Colstrip and our plans to exit Colstrip through an agreement with NorthWestern. Our hydroelectric and biomass generation facilities can be used to comply with the CETA's clean energy standards. We intend to seek recovery of costs associated with the clean energy legislation and regulations through the regulatory process.

As required under the CETA, in October 2021 we filed our first CEIP. Our CEIP is a road map of specific actions we proposed to take over the first four years (2022-2025) to show the progress being made toward clean energy goals and the equitable distribution of benefits and burdens to all customers as established by the CETA.

In June 2022, our CEIP was approved by the WUTC.

Some highlights of our approved plan include:

- Beginning in 2022, serving 40 percent of our Washington retail customer demand with renewable (or zero carbon) energy, then increase this target to 62.5 percent by the end of 2025.
- Energy efficiency targets to reduce Washington retail customer load by approximately 2 percent over the next four years through incentives and programs to lower energy use without impacting the customer.
- A set of 14 Customer Benefit Indicators to ensure the equitable distribution of energy and non-energy benefits and reduction of burden to all customers and named communities.
- A Named Communities Investment Fund that will invest up to $5 million annually in projects, programs and initiatives that directly benefit customers residing in historically disadvantaged and vulnerable communities.

While the CEIP represented our objectives when filed, it is subject to change in the future as circumstances warrant including direct input from the WUTC. We are required to file a CEIP every four years.

Emissions Performance Standard

Washington applies a GHG emissions performance standard to electric generation facilities used to serve retail loads, whether the facilities are located within Washington or elsewhere. The emissions performance standard prevents utilities from constructing or purchasing generation facilities, or entering into power purchase agreements of five years or longer duration to purchase energy produced by plants that have emission levels higher than 925 pounds of GHG per MWh. The Washington State Department of Commerce reviews the standard every five years. We intend to seek recovery of costs related to ongoing and new requirements through the ratemaking process.

Washington Climate Commitment Act

The CCA, and its implementing regulations, established a cap and trade program to reduce GHG emissions and achieve the GHG limits previously established under state law. The final rules implement a cap on emissions, provide mechanisms for the sale and tracking of tradable emissions allowances and establish additional compliance and accountability measures. The state issues allowances necessary to serve our Washington retail electric load; off-system wholesale sales may result in additional obligation costs. The CCA also has direct impacts on our Idaho electric operations as it applies to power that is delivered in Washington but is allocated to Idaho customers (wholesale sales) or power generated in Washington that is ultimately delivered to Idaho customers. In May 2023, a model was approved for use in calculating the allowances needed for compliance that assumes hydroelectric generation is first used for wholesale sales, therefore reducing the number of allowances required. As a result, the CCA is expected to have limited financial impact on our electric operations in its initial years. For our Washington natural gas operations, we expect additional financial burdens associated with compliance which will be deferred in accordance with our regulatory accounting order in Washington (see "Executive Level Summary" for discussion of the CCA). In March 2023, we filed a request with the IPUC for an accounting order to include CCA compliance costs in the PCA. In December 2023, the IPUC denied our request.

In December 2023, PacifiCorp filed suit in the United States District Court for the Western District of Washington challenging the CCA as in violation of the dormant commerce clause of the United States Constitution. In its complaint, PacifiCorp seeks declaratory and injunctive relief. In January 2024, PacifiCorp filed a motion for injunctive relief to enjoin the Washington Department of Ecology from enforcing portions of the CCA. Both the proceeding and the motion remain pending.

Washington State Building Codes

In April 2022, the Washington State Building Code Council (SBCC) approved a revised energy code requiring most new commercial buildings and large multifamily buildings to install all-electric space heating. An amendment to the code allows for natural gas to supplement electric heat pumps. In addition, in November 2022, the SBCC approved new building and energy codes for residential housing, requiring new residential buildings in Washington to use electricity as the primary heat source.

Both the commercial and residential building and energy codes were the subject of legal challenges in both Washington State Superior Court (the State Action) and in the Federal District Court for the Eastern District of Washington (the Federal Action). In the Federal Action, to which the Company was a party, the plaintiffs challenged the amendments on the grounds that they were preempted by the federal Energy Policy and Conservation Act (EPCA), citing the Ninth Circuit's decision in California Restaurant Association v. Berkeley (the Berkeley Decision), which involved similar restrictions on the use of natural gas in new construction in Berkeley, California.

In May 2023, the SBCC voted to delay the effective date of the code amendments and commenced an emergency rulemaking process to evaluate additional amendments to the code in light of the Berkeley decision. As a result of this action, in July 2023, the Federal District Court declined to issue a preliminary injunction to prevent the amendments from taking effect. The plaintiffs in the Federal Action subsequently dismissed the action, without prejudice to their ability to refile after the SBCC rulemaking process is complete.

The SBCC has since voted to approve revised residential and commercial energy regulations that continue to require new residential and commercial buildings in Washington to use electricity as the primary heat source. In light of this action, the plaintiffs in the State Action amended their complaint to challenge the new regulations. The State Action remains pending.

Oregon Legislation and Regulatory Actions

Climate Protection Plan

In March 2020, Oregon Governor Kate Brown issued Executive Order No. 20-04, "Directing State Agencies to Take Actions to Reduce and Regulate Greenhouse Gas Emissions." The Executive Order launched rulemaking proceedings for every Oregon agency with jurisdiction over GHG-related matters, with the aim of reducing Oregon's overall GHG emissions to 80 percent below 1990 levels by 2050. This Executive Order led to the Oregon Department of Environmental Quality developing cap and reduce rules known as the CPP. The CPP, which became effective in January 2022, outlines GHG emissions reduction goals of 50 percent by 2035 and 90 percent by 2050 from the 1990 baseline. The first three-year compliance period is 2022 through 2024.

In March 2022, we, along with the utilities NW Natural and Cascade Natural Gas, filed a lawsuit requesting judicial review of the CPP. This action was subsequently consolidated with a lawsuit filed by several other parties. In December 2023, the Oregon Court of Appeals issued a decision declaring the CPP regulations invalid. The Oregon Department of Environmental Quality did not appeal the decision, and indicated that it will go back through the rulemaking process to reinstate the program. We are monitoring and will engage in any rulemaking process that is commenced.

Emissions Performance Standard

Oregon applies a GHG emissions performance standard to electric generation facilities, requiring that new baseload natural gas plant, non-base load natural gas plant, and non-generating facility reduce its net carbon dioxide emissions 17 percent below what the Oregon Facility Siting Council identifies as the most efficient combustion-turbine plant in the United States. The Oregon Energy Facility Siting Council issues rules periodically to update the standard, as more efficient power plants are built. The standard can be met by combination of efficiency, cogeneration, and offsets from carbon dioxide mitigation measures. We have thermal generation located in Oregon, and as such this standard applies to that facility. We intend to seek recovery of costs related to requirements through the ratemaking process.

Clean Air Act (CAA)

The CAA creates numerous requirements for our thermal generating plants. Colstrip, Kettle Falls GS, Coyote Springs and Rathdrum CT all require CAA Title V operating permits. The Boulder Park GS, Northeast CT and other operations require minor source permits or simple source registration permits. We have secured these permits and certify our compliance with Title V permits on an annual basis. These requirements can change over time as the CAA or applicable implementing regulations are amended and new permits are issued. We actively monitor legislative, regulatory and other program developments of the CAA that may impact our facilities.

Other

For other environmental issues and other contingencies see "Note 22 of the Notes to Consolidated Financial Statements."

Colstrip

Colstrip is a coal-fired generating plant in southeastern Montana that includes four units and which is owned by six separate entities. We have a 15 percent ownership interest in Units 3 & 4. The owners of Units 3 & 4 share operating and capital costs pursuant to the terms of an operating agreement among them (the Ownership and Operation Agreement). In January 2023, we entered into an agreement with NorthWestern under which, subject to the terms and conditions specified in the agreement, we will transfer our ownership of Colstrip. See "Note 22 of the Notes to Consolidated Financial Statements" for further discussion of the agreement.

Coal Ash Management/Disposal

In 2015, the EPA issued a final rule regarding coal combustion residuals (CCRs), also termed coal combustion byproducts or coal ash (Colstrip produces this byproduct). The CCR rule has been the subject of ongoing litigation. In August 2018, U.S. Court of Appeals for the D.C. Circuit struck down provisions of the rule. In December 2019, a proposed revision to the rule was published in the Federal Register to address the D.C. Circuit's decision. The rule includes technical requirements for CCR landfills and surface impoundments under Subtitle D of the Resource Conservation and Recovery Act, the nation's primary law for regulating solid waste. The Colstrip owners developed a multi-year compliance plan to address the CCR requirements along with existing state obligations expressed through the 2012 Administrative Order on Consent (AOC) with Montana Department of Environmental Quality (MDEQ). These requirements continue despite the 2018 federal court ruling.

The AOC requires MDEQ to review Remedy and Closure plans for all parts of the Colstrip plant through an ongoing public process. The AOC also requires the Colstrip owners to provide financial assurance, primarily in the form of surety bonds, to secure each owner's pro rata share of various anticipated closure and remediation obligations. We are responsible for our share of two major areas: the Plant Site Area and the Effluent Holding Pond Area. Generally, the plans include the removal of boron, chloride, and sulfate from the groundwater, closure of the existing ash storage ponds, and installation of a new water treatment system to convert the facility to a dry ash storage. Our share of the posted surety bonds is $16.8 million. This amount is updated annually, with expected obligations decreasing over time as remediation activities are completed.

Colstrip Coal Contract

Colstrip is supplied with fuel from adjacent coal reserves under coal supply and transportation agreements. Several of the co-owners of Colstrip, including us, have a coal contract that runs through December 31, 2025.

Colstrip Arbitration, Litigation, and Other Contingencies

See "Note 22 of the Notes to Consolidated Financial Statements" for disputes, arbitration, litigations and other contingencies related to Colstrip. We intend to seek recovery of costs associated with Colstrip through the ratemaking process.

ENTERPRISE RISK MANAGEMENT

The material risks to our businesses are discussed in "Item 1A. Risk Factors," "Forward-Looking Statements," as well as "Environmental Issues and Contingencies." The following discussion focuses on our mitigation processes and procedures to address these risks.

We consider the management of these risks an integral part of managing our core businesses and a key element of our approach to corporate governance.

Risk management includes identifying and measuring various forms of risk that may affect the Company. We have an enterprise risk management process for managing risks throughout the organization. Our Board of Directors and its Committees take an active role in the oversight of risk affecting the Company. We collect risk information across the Company, and senior management reviews the Company's major risks and risk mitigation measures. Each area identifies risks and implements the related mitigation measures. The enterprise risk process supports management in identifying, assessing, quantifying, managing and mitigating the risks. Despite all risk mitigation measures, however, risks are not eliminated.

Our primary identified categories of risk exposure are:

- Utility regulatory
- Operational
- Climate Change
- Cybersecurity
- Technology
- Strategic
- External mandates
- Financial
- Energy commodity
- Compliance

Our primary categories of risks are described in "Item 1A. Risk Factors."

Utility Regulatory Risk

Regulatory risk is mitigated through a separate regulatory group which communicates with commission regulators and staff regarding the Company's business plans and concerns. The regulatory group also considers the regulator's priorities and rate policies and makes recommendations to senior management on regulatory strategy for the Company. Oversight of our regulatory strategies and policies is performed by senior management and the Board of Directors. See "Regulatory Matters" for further discussion of regulatory matters affecting the Company.

Operational Risk

To manage operational and event risks, we maintain emergency operating plans, business continuity and disaster recovery plans, maintain insurance coverage against some, but not all, potential losses and seek to negotiate indemnification arrangements with contractors for certain event risks. In addition, we design and follow detailed vegetation management and asset management inspection plans, which help mitigate wildfire and storm event risks, as well as identify utility assets which may be failing and in need of repair or replacement. We also have an Emergency Operating Center, which is a team of employees that plan for and train to deal with potential emergencies or unplanned outages at our facilities, resulting from natural disasters or other events. To prevent unauthorized access to our facilities, we have both physical and cyber security in place.

To address the risk related to fuel cost, availability and delivery restraints, we have an energy resources risk policy, which includes a wholesale energy markets credit policy and control procedures to manage energy commodity price and credit risks. Development of the energy resources risk policy includes planning for sufficient capacity to meet our customer and wholesale energy delivery obligations. See further discussion of the energy resources risk policy below.

Oversight of the operational risk management process is performed by the Environmental, Technology and Operations Committee of the Board of Directors and from senior management with input from each operating department.

Climate Change Risk

Multiple departments work to mitigate risks related to climate change. Climate change adds uncertainty to existing risks that we have historically managed and mitigated. These efforts are reflected in electric and gas operations, investments in assets and asset reliability and resiliency across our operations.

Power Supply staff monitor items such as snowpack and broader precipitation conditions, patterns and modeled or predicted climate change. These and other assessments are incorporated into our IRP processes. Environmental Affairs, Governmental Affairs and other departments monitor policy and regulatory developments that may relate to climate change to engage these efforts constructively and prepare for compliance matters.

Our Wildfire Resiliency Plan was also developed to mitigate the increased wildfire risk associated with climate change. See "Item 1. Business—Wildfire Resiliency Plan" for further discussion of the program.

We have four councils that are centered around our primary focus areas: our customers, our people, perform and invent. The Perform Council is an interdisciplinary team of management and other employees which regularly meets to discuss, assess and manage issues associated with our performance. A key area of focus for the Perform Council is potential risks and opportunities associated with long-term climate change. Among other things, the Perform Council:

- facilitates internal and external communications regarding climate change and related issues,
- analyzes policy effects, anticipates opportunities and evaluates strategies,
- develops recommendations on climate related policy positions and action plans, and
- provides direction and oversight with respect to our clean energy goals.

In addition, issues concerning climate-related risk and our clean energy goals are reviewed and regularly discussed by the Board of Directors. The Board's Environmental, Technology and Operations Committee regularly reviews and discusses environmental and climate related risks, and advises the full Board on critical or emerging risks and/or related policies. Likewise, the Audit Committee provides oversight of climate-related disclosures.

Cybersecurity Risk

See "Item 1C.—Cybersecurity" for discussion of Cybersecurity risk and processes for mitigation.

Technology Risk

Technology governance is led by senior management, and includes new technology strategy, risk planning and major project planning and approval. Oversight of technology risk is performed by the Board's Environmental, Technology and Operations Committee. We are dedicated to securing, maintaining and evaluating and developing our information technology systems. We evaluate our technology for obsolescence and upgrade or replace systems as necessary. The technology project management office and enterprise capital planning group provide project cost, timeline and schedule oversight.

Strategic Risk

Oversight of strategic risk is performed by the Board of Directors and senior management. We have a Senior Vice President, Chief Strategy and Clean Energy Officer who leads strategic initiatives, searches for and evaluates opportunities and makes recommendations to other members of senior management and the Board of Directors. We not only focus on whether opportunities are financially viable, but also consider whether these opportunities fall within our core policies and our core business strategies. We mitigate reputational risk primarily through a focus on adherence to our core policies, including our Code of Conduct, maintaining an appropriate culture and tone at the top, and through communication and engagement with external stakeholders.

External Mandates Risk

Oversight of external mandate risk mitigation strategies is performed by the Environmental, Technology and Operations Committee of the Board of Directors and senior management. We have a Perform Council that meets internally to assess the potential impacts of climate policy to our business and to identify strategies to plan for change. Our Environmental, Social and Governance program creates a framework that is intended to attract investment, enhancement of our brand, and promotion of sustainable long-term growth. We also have employees dedicated to actively engage and monitor federal, state and local government positions and legislative actions that may affect us or our customers.

To prevent the threat of municipalization, we work to build strong relationships with the communities we serve through, among other things:

- communicating and being involved with local business leaders and community organizations,
- providing customers with a multitude of limited income initiatives, including energy fairs, senior outreach, low income workshops, mobile outreach strategy and a Low Income Rate Assistance Plan,
- tailoring internal company initiatives to focus on choices for customers, to increase their overall satisfaction with the Company, and
- engaging in the legislative process in a manner that fosters the interests of our customers and the communities we serve.

Financial Risk

Financial risk is impacted by many factors. Several of these risks include regulation and rates, weather risk, access to capital markets, interest rate risk, credit risk, and foreign exchange risk. We have a Treasury department that monitors our daily cash position and future cash flow needs, as well as monitoring market conditions to determine the appropriate course of action for capital financing strategies. Oversight of financial risk mitigation strategies is performed by senior management and the Finance Committee of the Board of Directors.

Regulation and Rates

The Regulatory Affairs department is critical in mitigation of financial risk as they have regular communications with state commission regulators and staff and they monitor and develop rate strategies. Rate strategies, such as decoupling, help mitigate the impacts of revenue fluctuations due to weather, conservation or the economy.

Weather Risk

To partially mitigate the risk of financial under-performance due to weather-related factors, we developed decoupling rate mechanisms that were approved by the Washington, Idaho and Oregon commissions. Decoupling mechanisms are designed to break the link between a utility's revenues and consumers' energy usage and instead provide revenue based on the number of customers, thus mitigating a large portion of the risk associated with lower customer loads. See "Note 23 of the Notes to Consolidated Financial Statements" for further discussion of our decoupling mechanisms.

Access to Capital Markets

Our capital requirements rely to a significant degree on regular access to capital markets. We actively engage with rating agencies, banks, investors and state public utility commissions to understand and address the factors that support access to capital markets on reasonable terms. We manage our capital structure to maintain a financial risk profile that we believe these parties will deem prudent. We forecast cash requirements to determine liquidity needs, including sources and variability of cash flows that may arise from spending plans or from external forces, such as changes in energy prices or interest rates. Our financial and operating forecasts consider various metrics that affect credit ratings. Our regulatory strategies include working with state public utility commissions and filing for rate changes as appropriate to meet financial performance expectations.

Interest Rate Risk

Uncertainty about future interest rates causes risk related to a portion of existing debt, future borrowing requirements, and pension and other postretirement benefit obligations. We manage debt interest rate risk by limiting variable rate debt to a percentage of total capitalization, monitoring market conditions when timing the issuance of long-term debt and optional debt redemptions and establishing fixed rate long-term debt with varying maturities. We may hedge a portion of our interest rate risk with financial derivative instruments, particularly to manage risk associated with significant concentrations of forecasted debt issuances. The Finance Committee of the Board of Directors periodically reviews and discusses interest rate risk management processes and the steps management has undertaken to control interest rate risk. Our Risk Management Committee (RMC) also reviews interest rate risk management plan.

Our interest rate swap derivatives are considered economic hedges against the future forecasted interest rate payments of long-term debt. Interest rates on our long-term debt are generally set based on underlying U.S. Treasury rates plus credit spreads, which are based on our credit ratings and prevailing market prices for debt. The interest rate swap derivatives hedge against changes in the U.S. Treasury rates but do not hedge the credit spread.

Through regulatory accounting practices similar to energy commodity derivatives, interim mark-to-market gains or losses are offset by regulatory assets and liabilities. See "Energy Commodity Risk." Upon settlement of interest rate swap derivatives, the cash payments made or received are recorded as a regulatory asset or liability and (after a prudency review through a general rate case) are subsequently amortized as a component of interest expense over the life of the associated debt. The settled interest rate swap derivatives are included as a part of the cost of debt calculation for ratemaking purposes.

The following table summarizes interest rate swap derivatives outstanding as of December 31, 2023 and December 31, 2022 (dollars in thousands):

	2023	2022
Number of agreements	3	5
Notional amount	$ 30,000	$ 50,000
Mandatory cash settlement dates	2024 to 2025	2023 to 2024
Short-term derivative assets [1]	$ 3,667	$ 8,536
Long-term derivative assets [1]	—	2,648
Short-term derivative liability [1]	—	(52)
Long-term derivative liability [1]	(182)	—

(1) There are offsetting regulatory assets and liabilities for these items on the Consolidated Balance Sheets in accordance with regulatory accounting practices.

We estimate that a 10 basis point increase in forward variable interest rates as of December 31, 2023 would increase the interest rate swap derivative net liability by $0.5 million, while a 10 basis point decrease would decrease the interest rate swap derivative net liability by $0.5 million.

We estimated that a 10 basis point increase in forward variable interest rates as of December 31, 2022 would have increased the interest rate swap derivative net liability by $1.0 million, while a 10 basis point decrease would decrease the interest rate swap derivative net liability by $0.7 million.

The interest rate on $51.5 million of long-term debt to affiliated trusts is adjusted quarterly, reflecting current market rates. Amounts borrowed under our committed line of credit agreements have variable interest rates.

The following table shows long-term debt (including current portion) and related weighted-average interest rates, by expected maturity dates as of December 31, 2023 (dollars in thousands):

	2024	2025	2026	2027	2028	Thereafter	Total	Fair Value
Fixed rate long-term debt [1]	$ 15,000	$ —	$ —	$ —	$ 25,000	$ 2,510,000	$ 2,550,000	$ 2,135,405
Weighted-average interest rate	3.44%	—	—	—	6.37%	4.33%	4.35%	
Variable rate long-term debt to affiliated trusts	—	—	—	—	—	$ 51,547	$ 51,547	$ 46,098
Weighted-average interest rate	—	—	—	—	—	6.51%	6.51%	

(1) These balances include the fixed rate long-term debt of Avista Corp., AEL&P and AERC.

Our pension plan is exposed to interest rate risk because the value of pension obligations and other postretirement obligations varies directly with changes in the discount rates, which are derived from end-of-year market interest rates. In addition, the value of pension investments and potential income on pension investments is partially affected by interest rates because a portion of pension investments are in fixed income securities. Oversight of pension plan investment strategies is performed by the Finance Committee of the Board of Directors, which approves investment and funding policies, objectives and strategies that seek an appropriate return for the pension plan. We manage interest rate risk associated with pension and other postretirement benefit plans by investing a targeted amount of pension plan assets in fixed income investments that have maturities with similar profiles to future projected benefit obligations. See "Note 12 of the Notes to Consolidated Financial Statements" for further discussion of our investment policy associated with the pension plan assets.

Credit Risk

Counterparty Non-Performance Risk

We enter into bilateral transactions with various counterparties. We also trade energy and related derivative instruments through clearinghouse exchanges.

Counterparty non-performance risk relates to potential losses that we would incur due to non-performance of contractual obligations by counterparties to deliver energy or make financial settlements.

Changes in market prices may dramatically alter the size of credit risk with counterparties, even when we establish conservative credit limits. Should a counterparty fail to perform, we may be required to honor the underlying commitment or to replace existing contracts with contracts at then-current market prices.

We seek to mitigate credit risk by:

- transacting through clearinghouse exchanges,
- entering into bilateral contracts that specify credit terms and protections against default,
- applying credit limits and duration criteria to existing and prospective counterparties,
- actively monitoring credit exposures,
- asserting collateral rights with counterparties, and
- carrying out transaction settlements timely and effectively.

The extent of transactions conducted through exchanges has increased, as many market participants have shown a preference toward exchange trading and have reduced bilateral transactions. We actively monitor the collateral required by such exchanges to effectively manage capital requirements.

Our exposure to risks attributable to counterparties' credit profile is dynamic in normal markets and may change significantly in more volatile markets. The amount of potential default risk from each counterparty depends on the extent of forward contracts, unsettled transactions, interest rates and market prices. There is a risk that we do not obtain sufficient additional collateral from counterparties that are unable or unwilling to provide it.

Credit Risk Liquidity Considerations

To address the impact on our operations of energy market price volatility, our hedging practices for electricity (including fuel for generation) and natural gas extend beyond the current operating year. Executing this extended hedging program may increase our credit risk and demands on us for collateral. Our credit risk management process is designed to mitigate such credit risks through limit setting, contract protections and counterparty diversification, among other practices.

Credit risk affects demands on our capital. We are subject to limits and credit terms that counterparties may assert to enter into transactions with them and maintain acceptable credit exposures. Many of our counterparties allow unsecured credit at limits prescribed by agreements or their discretion. Capital requirements for certain transaction types involve a combination of initial margin and market value margins without unsecured credit threshold. Counterparties may seek assurances of performance in the form of letters of credit, prepayment or cash deposits.

Credit exposure can change significantly in periods of commodity price and interest rate volatility. As a result, sudden and significant demands may be made against our credit facilities and cash. We actively monitor the exposure to possible collateral calls and take steps to minimize capital requirements.

As of December 31, 2023, we had cash deposited as collateral of $43.1 million and letters of credit of $20.0 million outstanding related to energy contracts. Price movements and/or a downgrade in our credit ratings or other established credit criteria could impact further the amount of collateral required. See "Credit Ratings" for further information.

For example, in addition to limiting our ability to conduct transactions, if our credit ratings were lowered to below "investment grade" based on positions outstanding at December 31, 2023 (including contracts that are considered derivatives and those that are considered non-derivatives), we would potentially be required to post the following additional collateral (dollars in thousands):

		2023
Additional collateral taking into account		
contractual thresholds (1)	$	17,500
Additional collateral without contractual thresholds		34,320

(1) This amount is different from the amount disclosed in "Note 8 of the Notes to Consolidated Financial Statements" because, while this analysis includes contracts that are not considered derivatives in addition to the contracts considered in Note 8, this analysis also takes into account contractual threshold limits that are not considered in Note 8.

Under the terms of interest rate swap derivatives that we enter into periodically, we may be required to post cash or letters of credit as collateral depending on fluctuations in the fair value of the instrument. As of December 31, 2023, we had interest rate swap agreements outstanding with a notional amount totaling $30.0 million and we had deposited no cash as collateral for these interest rate swap derivatives.

If our credit ratings were lowered to below "investment grade" based on interest rate swap derivatives outstanding at December 31, 2023, we would potentially be required to post the following additional collateral (dollars in thousands):

		2023
Additional collateral taking into account		
contractual thresholds	$	182
Additional collateral without contractual thresholds		182

Foreign Currency Risk

A significant portion of our utility natural gas supply (including fuel for electric generation) is obtained from Canadian sources. Most of those transactions are executed in U.S. dollars, which avoids foreign currency risk. A portion of 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 typically settled within sixty days with U.S. dollars. We hedge a portion of the foreign currency risk by purchasing Canadian currency exchange derivatives when such commodity transactions are initiated. This risk has not had a material effect on our 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.

Further information for derivatives and fair values is disclosed at "Note 8 of the Notes to Consolidated Financial Statements" and "Note 18 of the Notes to Consolidated Financial Statements."

Energy Commodity Risk

We mitigate energy commodity risk primarily through our energy resources risk policy, which includes oversight from the RMC and oversight from the Audit Committee and the Environmental, Technology and Operations Committee of the Board of Directors. In conjunction with the oversight committees, our management team develops hedging strategies, detailed resource procurement plans, resource optimization strategies and long-term integrated resource planning to mitigate some of the risk associated with energy commodities. The various plans and strategies are monitored daily and developed with quantitative methods.

Our energy resources risk policy includes a wholesale energy markets credit policy and control procedures to manage energy commodity price and credit risks. Nonetheless, adverse changes in commodity prices, generating capacity, customer loads, regulation and other factors may result in losses of earnings, cash flows and/or fair values.

We measure the volume of monthly, quarterly and annual energy imbalances between projected power loads and resources. The measurement process is based on expected loads at fixed prices (including those subject to retail rates) and expected resources to the extent costs are essentially fixed by virtue of known fuel supply costs or projected hydroelectric conditions. To the extent expected costs are not fixed, either because of volume mismatches between loads and resources or because fuel cost is not locked in through fixed price contracts or derivative instruments, our risk policy guides the process to manage this open forward position over a period of time. Normal operations result in seasonal mismatches between power loads and available resources. We vary the operation of generating resources to match parts of intra-hour, hourly, daily and weekly load fluctuations. We use the wholesale power markets, including the natural gas market as it relates to power generation fuel, to sell projected resource surpluses and obtain resources when deficits are projected. We buy and sell fuel for thermal generation facilities based on comparative power market prices and marginal costs of fueling and operating available generating facilities and the relative economics of substitute market purchases for generating plant operation.

To address the impact on our operations of energy market price volatility, our hedging practices for electricity (including fuel for generation) and natural gas extend beyond the current operating year. Executing this extended hedging program may increase credit risks. Our credit risk management process is designed to mitigate such credit risks through limit setting, contract protections and counterparty diversification, among other practices.

Projected retail natural gas loads and resources are regularly reviewed by operating management and the RMC. To manage the impacts of volatile natural gas prices, we procure natural gas through a diversified mix of spot market purchases and forward fixed price purchases from various supply basins and time periods. We have an active hedging program that extends into future years with the goal of reducing price volatility in natural gas supply costs. We use natural gas storage capacity to support high demand periods and to procure natural gas when price spreads are favorable. Securing prices throughout the year and even into subsequent years mitigates potential adverse impacts of significant purchase requirements in a volatile price environment.

The following table presents energy commodity derivative fair values as a net asset or (liability) as of December 31, 2023 that are expected to settle in each respective year (dollars in thousands). There are no expected deliveries of energy commodity derivatives after 2026:

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical (1)	Financial (1)
2024	$ 746	$ —	$ (7,485)	$ (50,899)	$ 6,990	$ 1,502	$ (3,495)	$ 1,222
2025	—	—	(5,781)	(5,166)	—	295	(4,349)	(1,348)
2026	—	—	(940)	(431)	—	—	—	—

The following table presents energy commodity derivative fair values as a net asset or (liability) as of December 31, 2022 that were expected to settle in each respective year (dollars in thousands). There were no expected deliveries of energy commodity derivatives after 2025:

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical (1)	Financial (1)
2023	$ 1,120	$ —	$ (33,150)	$ 62,753	$ (2,374)	$ (20,018)	$ 17,166	$ (137,585)
2024	—	—	162	(3,879)	—	—	(4,968)	(5,790)
2025	—	—	135	(220)	—	—	(2,924)	(701)

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

See "Item 1. Business—Electric Operations" and "Item 1. Business—Natural Gas Operations," for additional discussion of the risks associated with Energy Commodities.

Compliance Risk

Compliance risk is mitigated through separate Regulatory and Environmental Compliance departments that monitor legislation, regulatory orders and actions to determine the overall potential impact and develop strategies for complying with the various rules and regulations. We also engage outside attorneys and consultants, when necessary, to help ensure compliance with laws and regulations. Oversight of compliance risk strategy is performed by senior management, including the Chief Compliance Officer, and the Environmental, Technology and Operations Committee and the Audit Committee of the Board of Directors.

See "Item 1. Business, Regulatory Issues" through "Item 1. Business, Reliability Standards" and "Environmental Issues and Contingencies" for further discussion of compliance issues that impact our Company.

ITEM 7A. Quantitative and Qualitative Disclosures About Market Risk

The information required by this item is set forth in the Enterprise Risk Management section of "Item 7. Management's Discussion and Analysis" and is incorporated herein by reference.

ITEM 8. Financial Statements and Supplementary Data

The Report of Independent Registered Public Accounting Firm and Financial Statements begin on the next page.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of Avista Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Avista Corporation and subsidiaries (the "Company") as of December 31, 2023 and 2022, the related consolidated statements of income, comprehensive income, equity, and cash flows, for each of the three years in the period ended December 31, 2023, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2023 and 2022, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2023, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 20, 2024, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current-period audit of the financial statements that were communicated or required to be communicated to the audit committee and that (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Regulatory Matters—Refer to Notes 1, 22, and 23 to the financial statements

Critical Audit Matter Description

The Company accounts for its regulated operations in accordance with Financial Accounting Standards Board Accounting Standards Codification Topic 980, Regulated Operations ("ASC 980"). The provisions of this accounting guidance require, among other things, that financial statements of a rate-regulated enterprise reflect the actions of regulators, where appropriate. These actions may result in the recognition of revenues and expenses in time periods that are different than non-rate-regulated enterprises. When this occurs, costs are deferred as assets in the balance sheet (regulatory assets) and recorded as expenses when those amounts are reflected in rates. Also, regulators can impose liabilities upon a regulated company for amounts previously collected from customers and for recovery of costs that are expected to be incurred in the future (regulatory liabilities).

The Company is subject to regulation by the Washington Utilities and Transportation Commission, the Idaho Public Utilities Commission, the Public Utility Commission of Oregon, the Public Service Commission of the State of Montana and the Regulatory Commission of Alaska (collectively, the "Commissions"), which have jurisdiction with respect to, among other things, the rates of electric and natural gas distribution companies in Washington, Idaho, Oregon, Montana, and Alaska, respectively. Accounting for the economics of rate regulation has an impact on certain financial statement line items and disclosures.

The Company's rates are subject to the rate-setting processes of the Commissions and, in certain jurisdictions, annual earnings oversight. Rates are determined and approved in regulatory proceedings based on analyses of the Company's costs to provide utility service and are designed to recover the Company's prudently incurred investments in the utility business and provide a return thereon. Decisions to be made by the Commissions in the future will impact the accounting for regulated operations under ASC 980 as described above. While the Company has indicated that it expects to recover costs from customers through regulated rates, there is a risk that the Commissions will not approve (1) full recovery of the costs of providing utility service or (2) full recovery of all amounts invested in the utility business and a reasonable return on that investment.

We identified the impact of rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about affected account balances and disclosures and the high degree of subjectivity involved in assessing the impact of future regulatory orders on the financial statements. Management judgments include assessing the likelihood of (1) recovery in future rates of incurred costs, (2) a disallowance of part of the cost of recently completed plant or plant under construction and (3) refunds to customers. Given that management's accounting judgments are based on assumptions about the outcome of future decisions by the Commissions, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of future decisions by the Commissions included the following procedures, among others:

- We tested the effectiveness of management's controls over the evaluation of the likelihood of (1) the recovery in future rates of costs incurred and deferred as regulatory assets and (2) a refund or a future reduction in rates that should be reported as regulatory liabilities. We also tested the effectiveness of management's controls over the initial recognition of amounts as property, plant and equipment; regulatory assets or liabilities; and the monitoring and evaluation of regulatory developments that may affect the likelihood of recovering costs in future rates or of a future reduction in rates.
- We evaluated the Company's disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments.
- We read relevant regulatory orders issued by the Commissions for the Company and other public utilities in the Company's jurisdictions, regulatory statutes, interpretations, procedural memorandums, filings made by interveners, and other publicly available information to assess the likelihood of recovery in future rates or of a future reduction in rates based on the precedents of the Commissions' treatment of similar costs under similar circumstances. We evaluated the external information and compared it to management's recorded regulatory asset and liability balances for completeness.
- We inspected the Company's filings with the Commissions and the filings with the Commissions by intervenors that may impact the Company's future rates, evaluating the evidence in relation to management's assertions, as applicable.
- We inquired of management about property, plant, and equipment that may be abandoned. We inspected the capital-projects budget and construction-work-in-process listings and inquired of management to identify projects that are designed to replace assets that may be retired prior to the end of their useful life. We inspected minutes of the Board of Directors and regulatory orders and other filings with the Commissions, evaluating the evidence in relation to management's assertions, as applicable, regarding probability of an abandonment.
- We obtained an analysis from management regarding probability of recovery for regulatory assets or probability of either refund or future reduction in rates for regulatory liabilities not yet addressed in a regulatory order in order to assess management's assertion that amounts are probable of recovery and/or that a future refund or reduction in rates is not probable.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 20, 2024

We have served as the Company's auditor since 1933.

CONSOLIDATED STATEMENTS OF INCOME

Avista Corporation

For the Years Ended December 31,

Dollars in thousands, except per share amounts

	2023	2022	2021
Operating Revenues:			
Utility revenues:			
Utility revenues, exclusive of alternative revenue programs	$ 1,746,097	$ 1,742,876	$ 1,445,000
Alternative revenue programs	4,899	(33,357)	(6,635)
Total utility revenues	1,750,996	1,709,519	1,438,365
Non-utility revenues	558	688	571
Total operating revenues	1,751,554	1,710,207	1,438,936
Operating Expenses:			
Utility operating expenses:			
Resource costs	702,372	735,862	497,123
Other operating expenses	413,608	405,165	366,125
Depreciation and amortization	265,329	253,017	231,915
Taxes other than income taxes	109,715	114,193	109,353
Non-utility operating expenses	2,840	11,728	6,188
Total operating expenses	1,493,864	1,519,965	1,210,704
Income from operations	257,690	190,242	228,232
Interest expense	140,795	117,634	105,731
Interest expense to affiliated trusts	2,504	1,058	421
Capitalized interest	(3,633)	(3,718)	(3,987)
Other income—net	(19,526)	(62,717)	(33,298)
Income before income taxes	137,550	137,985	159,365
Income tax expense (benefit)	(33,630)	(17,191)	12,031
Net income	$ 171,180	$ 155,176	$ 147,334
Weighted-average common shares outstanding (thousands)—basic	76,396	72,989	69,951
Weighted-average common shares outstanding (thousands)—diluted	76,495	73,093	70,085
Earnings per common share:			
Basic	$ 2.24	$ 2.13	$ 2.11
Diluted	$ 2.24	$ 2.12	$ 2.10

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Avista Corporation

For the Years Ended December 31,

Dollars in thousands

	2023	2022	2021
Net income:	$ 171,180	$ 155,176	$ 147,334
Other Comprehensive Income:			
Change in unfunded benefit obligation for pension and other postretirement benefit plans—net of taxes of $452, $2,387 and $888, respectively	1,701	8,981	3,339
Total other comprehensive income	1,701	8,981	3,339
Comprehensive income	$ 172,881	$ 164,157	$ 150,673

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED BALANCE SHEETS

Avista Corporation
As of December 31,
Dollars in thousands

	2023	2022
Assets:		
Current Assets:		
Cash and cash equivalents	$ 35,003	$ 13,428
Accounts and notes receivable—net	216,744	255,746
Inventory	159,984	107,674
Regulatory assets	146,327	193,787
Other current assets	103,784	151,167
Total current assets	661,842	721,802
Net utility property	5,700,056	5,444,709
Goodwill	52,426	52,426
Non-current regulatory assets	894,168	833,328
Other property and investments—net and other non-current assets	393,985	365,085
Total assets	$ 7,702,477	$ 7,417,350
Liabilities and Equity:		
Current Liabilities:		
Accounts payable	$ 143,262	$ 202,954
Current portion of long-term debt	15,000	13,500
Short-term borrowings	349,000	463,000
Regulatory liabilities	76,007	95,665
Other current liabilities	191,936	189,415
Total current liabilities	775,205	964,534
Long-term debt	2,515,358	2,281,013
Long-term debt to affiliated trusts	51,547	51,547
Pensions and other postretirement benefits	89,830	93,901
Deferred income taxes	718,318	674,995
Non-current regulatory liabilities	856,666	840,837
Other non-current liabilities and deferred credits	210,230	175,855
Total liabilities	5,217,154	5,082,682
Commitments and Contingencies (See Notes to Consolidated Financial Statements)		
Equity:		
Common stock, no par value; 200,000,000 shares authorized; 78,074,587		
and 74,945,948 shares issued and outstanding, respectively	1,644,327	1,525,185
Accumulated other comprehensive loss	(357)	(2,058)
Retained earnings	841,353	811,541
Total equity	2,485,323	2,334,668
Total liabilities and equity	$ 7,702,477	$ 7,417,350

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Avista Corporation

For the Years Ended December 31,

Dollars in thousands

	2023	2022	2021
Operating Activities:			
Net income	$ 171,180	$ 155,176	$ 147,334
Non-cash items included in net income:			
Depreciation and amortization	265,409	253,142	232,176
Provision for deferred income taxes	(36,837)	(18,231)	11,224
Power and natural gas cost amortizations (deferrals)—net	7,122	(78,350)	(51,847)
Amortization of debt expense	2,935	1,974	2,606
Stock-based compensation expense	8,442	8,717	4,713
Equity-related AFUDC	(6,886)	(6,704)	(7,004)
Pension and other postretirement benefit expense	14,283	32,173	29,077
Other regulatory assets and liabilities	(34,189)	(15,129)	4,445
Other non-current assets and liabilities	26,207	(5,280)	(3,769)
Change in decoupling regulatory deferral	(3,328)	33,469	6,056
Realized and unrealized losses (gains) on assets and investments	3,369	(50,006)	(23,187)
Other	(6,066)	11,957	(2,859)
Contributions to defined benefit pension plan	(10,000)	(42,000)	(42,000)
Cash paid on settlement of interest rate swap agreements	(409)	(17,035)	(17,568)
Cash received on settlement of interest rate swap agreements	7,869	—	324
Changes in certain current assets and liabilities:			
Accounts and notes receivable	36,855	(56,007)	(46,107)
Inventory	(52,309)	(22,941)	(17,282)
Collateral posted for derivative instruments	129,226	(141,014)	(17,564)
Income taxes receivable	1,506	(1,125)	20,199
Other current assets	(26,037)	(6,613)	930
Accounts payable	(66,144)	65,928	33,369
Other current liabilities	14,881	22,106	4,074
Net cash provided by operating activities	447,079	124,207	267,340
Investing Activities:			
Utility property capital expenditures (excluding equity-related AFUDC)	(498,637)	(451,995)	(439,939)
Issuance of notes receivable	(3,425)	(2,745)	(1,841)
Equity and property investments	(13,380)	(10,642)	(16,001)
Proceeds from sale of investments	3,200	1,000	8,306
Other	1,853	4,144	4,559
Net cash used in investing activities	$ (510,389)	$ (460,238)	$ (444,916)

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)

Avista Corporation

For the Years Ended December 31,

Dollars in thousands

	2023	2022	2021
Financing Activities:			
Net increase (decrease) in short-term borrowings	$ (114,000)	$ 179,000	$ 81,000
Proceeds from issuance of long-term debt	250,000	399,856	140,000
Maturity of long-term debt and finance leases	(16,735)	(253,085)	(2,935)
Issuance of common stock, net of issuance costs	112,308	137,778	89,998
Cash dividends paid	(140,923)	(129,061)	(118,211)
Other	(5,765)	(7,197)	(4,304)
Net cash provided by financing activities	84,885	327,291	185,548
Net increase (decrease) in cash and cash equivalents	21,575	(8,740)	7,972
Cash and cash equivalents at beginning of year	13,428	22,168	14,196
Cash and cash equivalents at end of year	$ 35,003	$ 13,428	$ 22,168
Supplemental Cash Flow Information:			
Cash paid (received) during the year:			
Interest	$ 131,522	$ 107,468	$ 98,592
Income taxes paid	2,501	2,251	3,652
Income tax refunds	(800)	(86)	(22,330)
Non-cash financing and investing activities:			
Accounts payable for capital expenditures	33,691	27,708	23,938

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED STATEMENTS OF EQUITY

Avista Corporation

For the Years Ended December 31,

Dollars in thousands, except per share amounts

	2023	2022	2021
Common Stock, Shares:			
Shares outstanding at beginning of year	74,945,948	71,497,523	69,238,901
Shares issued through equity compensation plans	117,450	123,631	93,806
Shares issued through Employee Investment Plan	11,943	14,306	14,480
Shares issued through sales agency agreements	2,999,246	3,310,488	2,150,336
Shares outstanding at end of year	78,074,587	74,945,948	71,497,523
Common Stock, Amount:			
Balance at beginning of year	$ 1,525,185	$ 1,380,152	$ 1,286,068
Equity compensation expense	7,144	7,567	5,180
Issuance of common stock through equity compensation plans	1,298	1,150	931
Issuance of common stock through Employee Investment Plan	460	605	610
Issuance of common stock through sales agency agreements—net of issuance costs	111,848	137,173	88,457
Payment of minimum tax withholdings for share-based payment awards	(1,497)	(1,462)	(993)
Other	(111)	—	(101)
Balance at end of year	1,644,327	1,525,185	1,380,152
Accumulated Other Comprehensive Loss:			
Balance at beginning of year	(2,058)	(11,039)	(14,378)
Other comprehensive income	1,701	8,981	3,339
Balance at end of year	(357)	(2,058)	(11,039)
Retained Earnings:			
Balance at beginning of year	811,541	785,631	758,036
Net income	171,180	155,176	147,334
Dividends on common stock	(141,368)	(129,266)	(119,739)
Balance at end of year	841,353	811,541	785,631
Total Equity	$ 2,485,323	$ 2,334,668	$ 2,154,744
Dividends declared per common share	$ 1.84	$ 1.76	$ 1.69

The Accompanying Notes are an Integral Part of These Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Business

Avista Corp. is primarily an electric and natural gas utility with certain other business ventures. Avista Utilities is an operating division of Avista Corp., comprising its regulated utility operations in the Pacific Northwest. Avista Utilities provides electric distribution and transmission, and natural gas distribution services in parts of eastern Washington and northern Idaho. Avista Utilities also provides natural gas distribution service in parts of northeastern and southwestern Oregon. Avista Utilities has electric generating facilities in Washington, Idaho, Oregon and Montana. Avista Utilities also supplies electricity to a small number of customers in Montana.

AERC is a wholly owned subsidiary of Avista Corp. The primary subsidiary of AERC is 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 the subsidiary companies in the non-utility businesses, except AJT Mining Properties, Inc., which is a subsidiary of AERC. See Note 24 for business segment information.

Basis of Reporting

The consolidated financial statements include the assets, liabilities, revenues and expenses of the Company and its subsidiaries and other majority owned subsidiaries and variable interest entities for which the Company or its subsidiaries are the primary beneficiaries. Intercompany balances were eliminated in consolidation. The accompanying consolidated financial statements include the Company's proportionate share of utility plant and related operations associated with its interests in jointly owned plants (see Note 9).

Use of Estimates

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

- determining the market value of energy commodity derivative assets and liabilities,
- pension and other postretirement benefit plan obligations,
- contingent liabilities,
- goodwill impairment testing,
- fair value of equity investments,
- 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 consolidated financial statements and thus actual results could differ from the amounts reported and disclosed herein.

Regulation

The Company is subject to state regulation in Washington, Idaho, Montana, Oregon and Alaska. The Company is 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:

	2023	2022	2021
Avista Utilities	3.52%	3.50%	3.54%
Alaska Electric Light and Power Company	2.78%	2.78%	2.77%

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

	Avista Utilities	Alaska Electric Light and Power Company
Electric thermal/other production	26	41
Hydroelectric production	79	42
Electric transmission	50	43
Electric distribution	40	39
Natural gas distribution property	44	N/A
Other shorter-lived general plant	8	18

Allowance for Funds Used During Construction

AFUDC represents the cost of both the debt and equity funds used to finance utility plant additions during the construction period. 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 Consolidated Statements of Income in the line item "capitalized interest." The equity component of AFUDC is included in the Consolidated 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 Utilities 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 Utilities capitalizes the excess as a regulatory asset. The regulatory asset associated with plant in service is amortized over the average useful life of Avista Utilities' 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:

	2023	2022	2021
Avista Utilities	7.03%	7.12%	7.19%
Alaska Electric Light and Power Company	8.61%	8.08%	8.90%

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 consolidated 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 has elected to account for transferable tax credits as a component of the income tax provision. The Company recognizes the benefit of production tax credits as a reduction of income tax expense in the period the credit is generated, which corresponds to the period the energy production occurs. The Company applies the deferral method of accounting for investment tax credits (ITCs). Under this method, ITCs are amortized as a reduction to income tax expense over the estimated useful lives of the underlying property that gave rise to the credit.

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 penalties on income tax positions in 2023, 2022 or 2021. The Company would recognize interest accrued related to income tax positions as interest expense or interest income and penalties incurred as other operating expense.

Stock-Based Compensation

The Company issues three types of stock-based compensation awards—restricted shares, market-based awards and performance-based awards. 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 Consolidated Statements of Income of the following amounts for the years ended December 31 (dollars in thousands):

	2023	2022	2021
Stock-based compensation expense	$ 7,144	$ 7,567	$ 4,713
Income tax benefits	1,500	1,589	990
Excess tax benefits (expenses) on settled share-based employee payments	84	(19)	(909)

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 have vested 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 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 incorporating the probability of meeting the market targets based on historical returns relative to a peer group. CEPS awards are valued at the close of market of the Company's common stock on the grant date.

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:

	2023	2022	2021
Restricted Shares			
Shares granted during the year	76,806	115,746	62,594
Shares vested during the year	75,007	44,829	34,854
Unvested shares at end of year	152,140	157,860	96,127
Unrecognized compensation expense at end of year (in thousands)	$ 3,477	$ 3,923	$ 2,215
TSR Awards			
TSR shares granted during the year	34,912	69,814	64,910
TSR shares vested during the year	61,456	43,730	77,174
TSR shares earned based on market metrics	44,863	48,890	58,652
Unvested TSR shares at end of year	96,915	130,567	107,854
Unrecognized compensation expense at end of year (in thousands)	$ 2,235	$ 3,533	$ 2,653
CEPS Awards			
CEPS shares granted during the year	104,685	69,814	64,910
CEPS shares vested during the year	61,456	43,730	38,590
CEPS shares earned based on performance metrics	33,801	—	26,627
Unvested CEPS shares at end of year	161,235	130,567	107,854
Unrecognized compensation expense at end of year (in thousands)	$ 2,439	$ 2,471	$ 1,223

Outstanding restricted, TSR and CEPS share awards include a dividend component 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, 2023 and 2022, the Company had recognized a liability of $2.2 million and $1.7 million, respectively, related to the dividend equivalents payable on the outstanding and unvested share grants.

Other Income—Net

Other income—net consisted of the following items for the years ended December 31 (dollars in thousands):

	2023	2022	2021
Interest income	$ 5,949	$ 1,957	$ 1,943
Interest on regulatory deferrals	8,713	1,914	1,206
Equity-related AFUDC	6,886	6,704	7,004
Non-service portion of pension and other postretirement benefit expenses	630	3,037	(1,386)
Earnings (losses) on investments	(3,227)	48,492	21,402
Other income	575	613	3,129
Total	$ 19,526	$ 62,717	$ 33,298

Earnings per Common Share

Basic earnings per common share is computed by dividing net income by the weighted-average number of common shares outstanding for the period. Diluted earnings per common share is calculated by dividing net income by diluted weighted-average common shares outstanding during the period, including common stock equivalent shares outstanding using the treasury stock method, unless such shares are anti-dilutive. Common stock equivalent shares include shares issuable under contingent stock awards. See Note 21 for earnings per common share calculations.

Cash and Cash Equivalents

For the purposes of the Consolidated 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.

The following table presents the activity in the allowance for doubtful accounts during the years ended December 31 (dollars in thousands):

	2023	2022	2021
Allowance as of the beginning of the year	$ 6,473	$ 10,465	$ 11,387
Additions expensed during the year	6,865	149	9,279
Net deductions [1]	(8,351)	(4,141)	(10,201)
Allowance as of the end of the year	$ 4,987	$ 6,473	$ 10,465

(1) The higher balance in 2021 is related to COVID-19 forgiveness program. The Company received support from various government agencies in 2023 and 2022 in the amounts of $1.5 million and $6.1 million, respectively, which were applied to overdue customer accounts.

Utility Plant in Service

The cost of additions to utility plant in service, including an allowance for funds used during construction and replacements of units of property and improvements, is capitalized. The cost of depreciable units of property retired plus the cost of removal less salvage is charged to accumulated depreciation.

Asset Retirement Obligations

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 11 for further discussion of the Company's AROs).

The Company recovers certain asset retirement costs through rates charged to customers as a portion of its depreciation expense for which the Company has not recorded asset retirement obligations.

The Company records the amount of estimated retirement costs collected from customers (that do not represent legal or contractual obligations) and includes them as a non-current regulatory liability on the Consolidated Balance Sheets in the following amounts as of December 31 (dollars in thousands):

	2023	2022
Regulatory liability for utility plant retirement costs	$ 417,027	$ 376,817

Goodwill

Goodwill arising from acquisitions represents the future economic benefit arising from other assets acquired in a business combination not individually identified and separately recognized. In 2023, the Company evaluated goodwill for impairment using a qualitative analysis (Step 0). The Company completed its annual evaluation of goodwill for potential impairment as of November 30, 2023 and determined goodwill was not impaired at that time. No events or circumstances occurred between November 30, 2023 and December 31, 2023 that would more likely than not reduce the fair values of the reporting units below their carrying amounts. As of December 31, 2023 and December 31, 2022, the carrying amount of goodwill was $52.4 million. There are no accumulated impairment losses recognized to date.

Derivative Assets and Liabilities

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

The WUTC and the 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 PGAs, the ERM in Washington, the PCA mechanism in Idaho, and periodic general rate cases. The resulting regulatory assets associated with energy commodity derivative instruments are 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 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 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 allowing 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 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 Consolidated 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, some equity investments, as well as derivatives related to interest rate swaps and foreign currency exchange contracts, are reported at estimated fair value on the Consolidated Balance Sheets. See Note 18 for the Company's fair value disclosures.

Regulatory Deferred Charges and Credits

The Company prepares its consolidated 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 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), to be reflected as deferred charges or credits on the Consolidated Balance Sheets. These costs and/or obligations are not reflected in the Consolidated Statements of Income until the period during which matching revenues are recognized. The Company also has decoupling revenue deferrals. See Note 4 for discussion on decoupling revenue deferrals.

If at some point in the future the Company determines 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.

See Note 23 for further details of regulatory assets and liabilities.

Unamortized Debt Expense

Unamortized debt expense includes debt issuance costs that are amortized over the life of the related debt. These costs are recorded as an offset to Long-Term Debt on the Consolidated Balance Sheets.

Unamortized Debt Repurchase Costs

Premiums paid or discounts received to repurchase debt are amortized over the remaining life of the original debt repurchased or, if new debt is issued in connection with the repurchase, these costs are amortized over the life of the new debt. These costs are recovered 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 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):

	2023	2022
Appropriated retained earnings	$ 59,118	$ 57,231

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, 2023, the Company has not recorded significant amounts related to unresolved contingencies. See Note 22 for further discussion of the Company's commitments and contingencies.

NOTE 2. NEW ACCOUNTING STANDARDS

ASU 2022-03 "Fair Value Measurement of Equity Securities Subject to Contractual Sale Restrictions"

In June 2022, the FASB issued ASU 2022-03, *Fair Value Measurement (Topic 820): Fair Value Measurement of Equity Securities Subject to Contractual Sale Restrictions*. The purpose of this guidance is to clarify that a contractual restriction on the ability to sell an equity security is not considered part of the unit of account of the equity security, and therefore should not be considered when measuring the equity security's fair value. Additionally, an entity cannot separately recognize and measure a contractual sale restriction. This guidance also adds specific disclosures related to equity securities subject to contractual sale restrictions, including (i) the fair value of equity securities subject to contractual sale restrictions reflected in the balance sheet, (ii) the nature and remaining duration of the restrictions and (iii) the circumstances that could cause a lapse in the restrictions. The amendments are effective on January 1, 2024, with early adoption permitted. The amendments must be applied using a prospective approach with adjustments from the adoption of the amendments recognized in earnings and disclosed upon adoption. The Company expects these amendments to only affect its disclosure requirements.

ASU 2023-06 "Disclosure Improvements—Codification Amendments in Response to the SEC's Disclosure Update and Simplification Initiative"

In October 2023, the FASB issued ASU 2023-06, which incorporates a variety of SEC required disclosures into the FASB Accounting Standards Codification (ASC). For entities subject to SEC's existing disclosure requirements, the effective date for each amendment will be the date on which the SEC removes the related disclosure from Regulation S-X or Regulation S-K, with early adoption permitted. If the SEC has not removed the applicable requirement from Regulation S-X or Regulation S-K by June 30, 2027, the disclosure requirements will be removed from the Codification. The requirements of the ASU will not have a material impact on the Company's financial statements.

ASU 2023-07 "Segment Reporting (Topic 280)—Improvements to Reportable Segment Disclosures"

In November 2023, the FASB issued ASU 2023-07, requiring additional disclosures around reportable segment information. The additional required disclosures include significant segment expenses, an amount for other segment activity not included in the disaggregated segment amounts and a description of the activity, and the title and position of the chief operating decision maker and an explanation of how they use the reported measures of segment profit or loss in assessing segment performance and allocating resources. The ASU is effective for fiscal years beginning after December 15, 2023 and interim periods beginning after December 15, 2024, and early adoption is permitted. The Company is in the process of evaluating the impact of the ASU; however, it has determined it will not early adopt as of December 31, 2023.

ASU 2023-09 "Income Taxes (Topic 740)—Improvements to Income Tax Disclosures"

In December 2023, the FASB issued ASU 2023-09, requiring additional income tax disclosures. The additional disclosures include prescribed items presented in the income tax rate reconciliation, and further disaggregation of income taxes paid amounts between federal, state and foreign taxes. The ASU is effective for fiscal years beginning after December 15, 2024 and early adoption is permitted. The Company is in the process of evaluating the impact of the ASU; however, it has determined it will not early adopt as of December 31, 2023.

NOTE 3. BALANCE SHEET COMPONENTS

Inventory

Inventories of materials and supplies, emissions allowances, stored natural gas and fuel stock are recorded at average cost and consisted of the following as of December 31 (dollars in thousands):

	2023	2022
Materials and supplies	$ 81,651	$ 75,766
Emission allowances	56,097	—
Stored natural gas	16,272	26,788
Fuel stock	5,964	5,120
Total	$ 159,984	$ 107,674

Other Current Assets

Other current assets consisted of the following as of December 31 (dollars in thousands):

	2023	2022
Collateral posted for derivative instruments after netting with outstanding derivative liabilities	$ —	$ 66,142
Prepayments	52,752	30,201
Income taxes receivable	29,234	30,740
Derivative assets—net of collateral	11,821	18,198
Other	9,977	5,886
Total	$ 103,784	$ 151,167

Other Property and Investments—Net and Other Non-Current Assets

Other property and investments—net and other non-current assets consisted of the following as of December 31 (dollars in thousands):

	2023	2022
Equity investments	$ 153,350	$ 147,809
Operating lease ROU assets	67,585	68,238
Finance lease ROU assets	36,414	40,056
Non-utility property	33,813	25,401
Notes receivable	15,287	17,954
Long-term prepaid license fees	19,448	17,936
Pension assets	32,997	13,382
Investment in affiliated trust	11,547	11,547
Deferred compensation assets	7,794	7,541
Other	15,750	15,221
Total	$ 393,985	$ 365,085

Other Current Liabilities

Other current liabilities consisted of the following as of December 31 (dollars in thousands):

	2023	2022
Accrued taxes other than income taxes	$ 31,928	$ 38,568
Employee paid time off accruals	32,072	29,279
Accrued interest	23,539	20,863
Pensions and other postretirement benefits	14,082	15,625
Derivative liabilities	17,217	26,910
Climate Commitment Act obligations	19,081	—
Deferred wholesale revenue	—	8,481
Other	54,017	49,689
Total	$ 191,936	$ 189,415

Other Non-Current Liabilities and Deferred Credits

Other non-current liabilities and deferred credits consisted of the following as of December 31 (dollars in thousands):

	2023	2022
Operating lease liabilities	$ 63,559	$ 64,284
Finance lease liabilities	39,095	42,495
Deferred investment tax credits	28,233	28,784
Climate Commitment Act obligations	26,026	—
Asset retirement obligations	18,058	15,783
Derivative liabilities	17,902	7,892
Other	17,357	16,617
Total	$ 210,230	$ 175,855

NOTE 4. REVENUE

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. Since 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. Since all revenue recognition criteria are met upon the delivery of energy to customers, revenue is recognized at that time.

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

Unbilled Revenue from Contracts with Customers

The determination of the volume of energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month (once per month for each individual customer). At the end of each calendar month, the amount of energy delivered to customers since the date of the last meter reading is estimated and the corresponding unbilled revenue is estimated and recorded. The Company's estimate of unbilled revenue is based on:

- the number of customers,
- tariff 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 meter reading and customer billing occurs.

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

	2023	2022
Unbilled accounts receivable	$ 78,531	$ 81,691

Non-Derivative Wholesale Contracts

The Company has certain wholesale contracts that are not accounted for as derivatives and are 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 alternative revenue programs are contracts between an entity and a regulator of utilities, not a contract between an entity and a customer. GAAP requires the presentation of revenue arising from alternative revenue programs separately from revenues arising from contracts with customers on the Consolidated 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 Consolidated 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 an 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 Consolidated Statements of Income. 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 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 Consolidated 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 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 transactions 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 excluded from revenue from contracts with customers, 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

Revenues and resource costs from Avista Utilities' settled energy contracts "booked out" (not physically delivered) are reported on a net basis as part of derivative revenues.

Utility-related taxes collected from customers (primarily state excise taxes and city utility taxes) are imposed on Avista Utilities as opposed to being imposed on customers; therefore, Avista Utilities 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). The utility-related taxes collected from customers at AEL&P are imposed on the customers rather than AEL&P; therefore, the customers are the taxpayers and AEL&P is acting as their agent. As such, these transactions at AEL&P are presented on a net basis within revenue from contracts with customers.

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

	2023	2022	2021
Utility-related taxes	$ 75,404	$ 69,931	$ 62,736

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 has one capacity agreement where the customer makes payments throughout the year. As of December 31, 2023, the Company estimates it had unsatisfied capacity performance obligations of $7.4 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 segment and source for the years ended December 31 (dollars in thousands):

	2023	2022	2021
AVISTA UTILITIES			
Revenue from contracts with customers	$ 1,485,510	$ 1,400,027	$ 1,233,904
Derivative revenues	199,133	286,309	152,590
Alternative revenue programs	4,899	(33,357)	(6,635)
Deferrals and amortizations for rate refunds to customers	1,026	207	2,984
Other utility revenues	12,289	10,629	10,156
Total Avista Utilities	1,702,857	1,663,815	1,392,999
AEL&P			
Revenue from contracts with customers	47,525	45,703	45,051
Deferrals and amortizations for rate refunds to customers	—	(614)	(190
Other utility revenues	614	615	505
Total AEL&P	48,139	45,704	45,366
Other			
Revenue from contracts with customers	—	—	2
Other revenues	558	688	569
Total Other	558	688	571
Total operating revenues	$ 1,751,554	$ 1,710,207	$ 1,438,936

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):

	2023 Avista Utilities	2023 AEL&P	2023 Total Utility	2022 Avista Utilities	2022 AEL&P	2022 Total Utility	2021 Avista Utilities	2021 AEL&P	2021 Total Utility
ELECTRIC OPERATIONS									
Revenue from contracts with customers									
Residential	$ 425,258	$ 20,232	$ 445,490	$ 414,823	$ 19,667	$ 434,490	$ 394,717	$ 18,940	$ 413,657
Commercial and governmental	343,523	27,026	370,549	338,656	25,782	364,438	326,173	25,861	352,034
Industrial	109,689	—	109,689	107,740	—	107,740	106,756	—	106,756
Public street and highway lighting	7,976	267	8,243	7,483	254	7,737	7,472	250	7,722
Total retail revenue	886,446	47,525	933,971	868,702	45,703	914,405	835,118	45,051	880,169
Transmission	32,941	—	32,941	32,307	—	32,307	21,005	—	21,005
Other revenue from contracts with customers	45,332	—	45,332	49,920	—	49,920	33,870	—	33,870
Total revenue from contracts with customers	$ 964,719	$ 47,525	$1,012,244	$ 950,929	$ 45,703	$ 996,632	$ 889,993	$ 45,051	$ 935,044

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):

	2023 Avista Utilities	2022 Avista Utilities	2021 Avista Utilities
NATURAL GAS OPERATIONS			
Revenue from contracts with customers			
Residential	$ 325,631	$ 284,452	$ 221,405
Commercial	164,048	139,923	100,819
Industrial and interruptible	17,315	10,471	7,796
Total retail revenue	506,994	434,846	330,020
Transportation	8,172	8,627	8,547
Other revenue from contracts with customers	5,625	5,625	5,344
Total revenue from contracts with customers	$ 520,791	$ 449,098	$ 343,911

NOTE 5. LEASES

The core principle of lease accounting is that an entity should recognize the ROU assets and liabilities 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 consolidated financial statements to assess the amount, timing, and uncertainty of cash flows from leases.

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. Operating and finance 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 and finance lease ROU assets also includes 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 the Company will exercise that option. Lease expense is recognized on a straight-line basis over the lease term. The 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. In addition, the State of Montana and Avista Corp. were engaged in litigation regarding lease terms, including how much money, if any, the State of Montana should return to Avista Corp.; however, that litigation was dismissed as premature pending the outcome of the ongoing litigation between the State of Montana and NorthWestern. Any reduction in future lease payments or the return to Avista Corp. of amounts previously paid will be included in the future ratemaking process.

In addition to the lease with the State of Montana, the Company 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 70 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 material residual value guarantees or material restrictive covenants.

In March 2023, the Company entered into an agreement with Rathdrum Power, LLC amending and restating a PPA for the output of the Lancaster Plant. The restated PPA meets the accounting definition of a lease, and all payments are variable in nature, based on capacity, usage, or performance of the plant. Therefore, there is no lease obligation or corresponding ROU asset recorded by the Company related to this agreement. The variable lease costs related to this agreement are included in resource costs on the Consolidated Statements of Income.

Avista Corp. does not record leases with a term of 12 months or less in the Consolidated Balance Sheets. Total short-term lease costs for the year ended December 31, 2023 are immaterial.

Finance Lease

AEL&P has a PPA which is a finance lease for accounting purposes related to the Snettisham Hydroelectric Project, which expires in 2034. For ratemaking purposes, this lease is an operating lease with a constant level of annual rental expense (straight line rent expense). Because of this regulatory treatment, differences between the operating lease expense for ratemaking purposes and the expenses recognized under GAAP (interest expense and amortization of the finance lease ROU asset) are recorded as a regulatory asset and amortized during the later years of the lease when the finance lease expense is less than the operating lease expense included in base rates. The amortization of the ROU asset is included in depreciation and amortization and the interest associated with the lease liability is included in interest expense on the Consolidated Statements of Income.

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

	2023	2022	2021
Operating lease cost:			
Fixed lease cost (Other operating expenses)	$ 5,096	$ 4,986	$ 4,970
Variable lease cost (Other operating expenses and resource costs)	24,628	1,567	1,180
Total operating lease cost	$ 29,724	$ 6,553	$ 6,150
Finance lease cost:			
Amortization of ROU asset (Depreciation and amortization)	$ 3,641	$ 3,641	$ 3,641
Interest on lease liabilities (Interest expense)	2,221	2,375	2,522
Total finance lease cost	$ 5,862	$ 6,016	$ 6,163

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

	2023	2022	2021
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash outflows:			
Operating lease payments	$ 4,960	$ 4,828	$ 4,805
Interest on finance lease	2,221	2,375	2,522
Total operating cash outflows	$ 7,181	$ 7,203	$ 7,327
Finance cash outflows:			
Principal payments on finance lease	$ 3,235	$ 3,085	$ 2,935

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

	December 31, 2023	December 31, 2022
Operating Leases		
Operating lease ROU assets (Other property and investment—net and other non-current assets)	$ 67,585	$ 68,238
Other current liabilities	$ 4,490	$ 4,349
Other non-current liabilities and deferred credits	63,559	64,284
Total operating lease liabilities	$ 68,049	$ 68,633
Finance Leases		
Finance lease ROU assets (Other property and investments—net and other non-current assets)	$ 36,414	$ 40,056
Other current liabilities	$ 3,400	$ 3,235
Other non-current liabilities and deferred credits	39,095	42,495
Total finance lease liabilities	$ 42,495	$ 45,730
Weighted-Average Remaining Lease Term		
Operating leases	22.28 years	23.28 years
Finance leases	4.53 years	5.42 years
Weighted-Average Discount Rate		
Operating leases	4.29%	4.28%
Finance leases	3.77%	4.07%

Maturities of lease liabilities (including principal and interest) were as follows as of December 31, 2023 (dollars in thousands):

	Operating Leases	Finance Leases
2024	$ 4,988	$ 5,459
2025	4,984	5,454
2026	4,981	5,456
2027	5,007	5,458
2028	4,992	5,456
Thereafter	83,532	27,292
Total lease payments	$ 108,484	$ 54,575
Less: imputed interest	(40,435)	(12,080)
Total	$ 68,049	$ 42,495

Maturities of lease liabilities (including principal and interest) were as follows as of December 31, 2022 (dollars in thousands):

	Operating Leases	Finance Leases
2023	$ 4,850	$ 5,456
2024	4,877	5,459
2025	4,884	5,454
2026	4,869	5,456
2027	4,880	5,458
Thereafter	86,991	32,748
Total lease payments	$ 111,351	$ 60,031
Less: imputed interest	(42,718)	(14,301)
Total	$ 68,633	$ 45,730

NOTE 6. VARIABLE INTEREST ENTITIES

Under GAAP, a limited partnership or similar legal entity that is the functional equivalent of a limited partnership is considered a VIE regardless of whether it otherwise qualifies as a voting interest entity unless a simple majority or lower threshold of the "unrelated" limited partners (i.e., parties other than the general partner, entities under common control with the general partner, and other parties acting on behalf of the general partner) have substantive kick-out rights (including liquidation rights) or participating rights.

The Company has investments in limited partnerships (or the functional equivalent) where Avista Corp. is a limited partner investor in an investment fund where the general partner makes all of the investment and operating decisions with regards to the partnership and fund. To remove the general partner from any of the funds, approval from greater than a simple majority of the limited partners is required. As such, the limited partners do not have substantive kick-out rights and these investments are considered VIEs. Consolidation of these VIEs by Avista Corp. is not required because the Company does not have majority ownership in any of the funds, it does not have the power to direct activities of the funds, and it does not have the power to appoint executive leadership, including the board of directors.

Avista Corp. participates in profits and losses of the investment funds based on its ownership percentage and its losses are capped at its total initial investment in the funds. Equity investments in VIEs are accounted for under the equity method (see Note 7). As of December 31, 2023, Avista Corp. has invested $73.3 million in these investment funds, with an additional commitment of $17.7 million remaining to be invested. The Company is not allowed to withdraw capital contributions from an investment fund until after that fund expiration date and all liabilities of that fund are settled. The expiration dates range from 2025 to 2036, with some investments having no termination date (as they are perpetual). As of December 31, 2023, the Company has a total carrying amount of $88.1 million in these VIEs, including $78.5 million of equity investments and $9.6 million of notes receivable.

NOTE 7. EQUITY INVESTMENTS

The Company has equity investment holdings that are accounted for under the equity method, at fair value, or using the fair value measurement alternative provided for in ASC 321, adjusting cost for impairment and observable price changes.

The following table summarizes Avista Corp.'s equity investments, which are included in "Other property and investments—net and other non-current assets" on the Consolidated Balance Sheets as of December 31 (dollars in thousands):

	2023	2022
Equity method investments	$ 78,513	$ 70,196
Investments without readily determinable fair value		
Non-recurring fair value	24,583	23,329
Recurring fair value	50,254	54,284
Total	$ 153,350	$ 147,809

Equity Method Investments

The Company has investments in limited partnerships (or the functional equivalent) where Avista Corp. is a limited partner investor in an investment fund. Holdings in these investment funds are accounted for under the equity method. Underlying investments held by the funds are recorded at fair value by the fund, and Avista Corp. recognizes its share of the fund's profits and losses based on its ownership percentage.

The Company also has ownership in joint ventures with underlying holdings in real estate, which are accounted for under the equity method.

The Company's earnings and losses related to equity method investments are included in "Other income—net" on the Consolidated Statements of Net Income.

Investments Without Readily Determinable Fair Value

The Company has investments that do not qualify for equity method treatment, and for which fair value is not readily determinable. The Company has elected the measurement alternative for a majority of these investments, adjusting the recorded value on a non-recurring basis as a result of observable transactions involving the underlying asset. The observable transaction indicates an updated fair value, and the Company adjusts carrying value to fair value at this point in time. The fair value of these assets is determined using the market approach, and these assets are considered level 2 on the fair value hierarchy (see Note 18 for a description of the fair value hierarchy).

The Company has elected to record two investments at fair value on a recurring basis. These equity investments are considered Level 3 on the fair value hierarchy. See further discussion of Level 3 equity investments, including valuation methods and significant inputs, as included in Note 18.

Realized and unrealized gains or losses in equity investments are included in net income.

The following table summarizes net unrealized gains (losses) related to investments without readily determinable fair value held as of the end of the respective period for the years ended December 31 (dollars in thousands):

	2023	2022	2021
Investments recorded at non-recurring fair value	$ —	$ 12,285	$ 8,761
Investments recorded at recurring fair value	(4,323)	33,382	—
Total	$ (4,323)	$ 45,667	$ 8,761

Net unrealized gains recorded related to investments recorded at non-recurring fair value result from identified observable transactions. On a cumulative basis, the Company has recognized a net gain of $14.8 million for fair value adjustments to investments recorded at non-recurring fair value held at December 31, 2023.

NOTE 8. 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 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, Avista Corp. engages in an ongoing process of resource optimization, which involves the economic selection from available energy resources to serve Avista Corp.'s load obligations and 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. Based on 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, 2023 expected to be delivered in each respective year (in thousands of MWhs and mmBTUs):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
	Physical [1]	Financial [1]	Physical [1]	Financial [1]	Physical [1]	Financial [1]	Physical [1]	Financial [1]
Year	MWh	MWh	mmBTUs	mmBTUs	MWh	MWh	mmBTUs	mmBTUs
2024	9	—	22,747	74,596	472	510	1,723	12,038
2025	—	—	12,505	19,590	11	96	1,115	1,125
2026	—	—	5,570	3,940	—	—	—	—

As of December 31, 2023, there are no expected deliveries of energy commodity derivatives after 2026.

The following table presents the underlying energy commodity derivative volumes as of December 31, 2022 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	
	Physical [1]	Financial [1]	Physical [1]	Financial [1]	Physical [1]	Financial [1]	Physical [1]	Financial [1]
Year	MWh	MWh	mmBTUs	mmBTUs	MWh	MWh	mmBTUs	mmBTUs
2023	5	—	19,140	79,253	136	1,011	4,145	29,473
2024	—	—	533	30,658	—	—	1,370	9,668
2025	—	—	450	4,895	—	—	1,115	1,125

As of December 31, 2022, there are 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 recovered 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 outstanding as of December 31 (dollars in thousands):

	2023	2022
Number of contracts	5	19
Notional amount (in United States dollars)	$ 81	$ 8,563
Notional amount (in Canadian dollars)	109	11,659

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. may hedge a portion of its interest rate risk with financial derivative instruments, including interest rate swap derivatives. These interest rate swap derivatives 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 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, 2023	2	$ 20,000	2024
	1	10,000	2025
December 31, 2022	4	$ 40,000	2023
	1	10,000	2024

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 Consolidated Balance Sheets as of December 31, 2023 and December 31, 2022 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 Consolidated Balance Sheets as of December 31, 2023 (dollars 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				
Other current assets	$ 2	$ —	$ —	$ 2
Interest rate swap derivatives				
Other current assets	3,667	—	—	3,667
Other non-current liabilities and deferred credits	—	(182)	—	(182)
Energy commodity derivatives				
Other current assets	8,531	(379)	—	8,152
Other current liabilities	19,510	(79,082)	42,355	(17,217)
Other non-current liabilities and deferred credits	2,913	(20,633)	—	(17,720)
Total derivative instruments recorded on the balance sheet	$ 34,623	$ (100,276)	$ 42,355	$ (23,298)

The following table presents the fair values and locations of derivative instruments recorded on the Consolidated Balance Sheets as of December 31, 2022 (dollars 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				
Other current assets	$ 43	$ —	$ —	$ 43
Other current liabilities	—	(3)	—	(3)
Interest rate swap derivatives				
Other current assets	8,536	—	—	8,536
Other property and investments—net and other non-current assets	2,648	—	—	2,648
Other current liabilities	—	(52)	—	(52)
Energy commodity derivatives				
Other current assets	32,257	(22,638)	—	9,619
Other property and investments—net and other non-current assets	312	(16)	—	296
Other current liabilities	107,902	(229,607)	94,850	(26,855)
Other non-current liabilities and deferred credits	6,049	(24,530)	10,589	(7,892)
Total derivative instruments recorded on the balance sheet	$ 157,747	$ (276,846)	$ 105,439	$ (13,660)

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 changes in market prices or a downgrade in Avista Corp.'s credit ratings or other established credit criteria, 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 (dollars in thousands):

	2023	2022
Energy commodity derivatives		
Cash collateral posted	$ 43,095	$ 171,581
Letters of credit outstanding	20,000	49,425
Balance sheet offsetting (cash collateral against net derivative positions)	42,355	105,439

There were no letters of credit outstanding related to interest rate swap derivatives as of December 31, 2023 and December 31, 2022.

Certain of Avista Corp.'s derivative instruments contain provisions requiring 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 in a liability position and the amount of additional collateral Avista Corp. could be required to post as of December 31 (dollars in thousands):

	2023
Interest rate swap derivatives	
Liabilities with credit-risk-related contingent features	$ 182
Additional collateral to post	182
Energy commodity derivatives	
Liabilities with credit-risk-related contingent features	$ 18,016
Additional collateral to post	15,125

NOTE 9. JOINTLY OWNED ELECTRIC FACILITIES

The Company has a 15 percent ownership interest in Units 3 & 4 of Colstrip, 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 Consolidated 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):

	2023	2022
Utility plant in service	$ 394,398	$ 390,852
Accumulated depreciation	(334,338)	(315,223)

See Note 11 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).

In January 2023, the Company entered into an agreement with NorthWestern to transfer its ownership in Colstrip Units 3 & 4. The Company will retain responsibility for remediation obligations in existence at the time the transaction closes. See further discussion of the transaction within Note 22.

NOTE 10. PROPERTY, PLANT AND EQUIPMENT

Net Utility Property

Net utility property consisted of the following as of December 31 (dollars in thousands):

	2023	2022
Utility plant in service	$ 7,799,481	$ 7,561,688
Construction work in progress	179,527	164,147
Total	7,979,008	7,725,835
Less: Accumulated depreciation		
and amortization	2,278,952	2,281,126
Total net utility property	$ 5,700,056	$ 5,444,709

Gross Property, Plant and Equipment

The gross balances of the major classifications of property, plant and equipment are detailed in the following table as of December 31 (dollars in thousands):

	2023	2022
Avista Utilities:		
Electric production	$ 1,498,398	$ 1,593,795
Electric transmission	1,059,389	994,709
Electric distribution	2,383,201	2,236,376
Electric construction work-in-progress (CWIP) and other	394,711	376,981
Electric total	5,335,699	5,201,861
Natural gas underground storage	59,994	58,072
Natural gas distribution	1,539,467	1,452,637
Natural gas CWIP and other	91,492	88,264
Natural gas total	1,690,953	1,598,973
Common plant (including CWIP)	759,498	744,173
Total Avista Utilities	7,786,150	7,545,007
AEL&P:		
Electric production	118,817	106,390
Electric transmission	22,827	22,856
Electric distribution	32,322	29,269
Electric CWIP and other	8,552	12,295
Electric total	182,518	170,810
Common plant	10,340	10,018
Total AEL&P	192,858	180,828
Total gross utility property	7,979,008	7,725,835
Other (1)	6,425	16,631
Total	$ 7,985,433	$ 7,742,466

(1) Included in other property and investments—net and other non-current assets on the Consolidated Balance Sheets. Accumulated depreciation was less than $0.1 million as of December 31, 2023 and $2.4 million as of December 31, 2022 for the other businesses.

NOTE 11. 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 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):

	2023	2022	2021
Asset retirement obligation at beginning of year	$ 15,783	$ 17,142	$ 17,194
Liabilities incurred	1,927	—	825
Liabilities settled	(232)	(1,964)	(1,541)
Accretion expense	580	605	664
Asset retirement obligation at end of year	$ 18,058	$ 15,783	$ 17,142

NOTE 12. PENSION PLANS AND OTHER POSTRETIREMENT BENEFIT PLANS

The pension and other postretirement benefit plans described below only relate to Avista Utilities. AEL&P 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 Utilities

The Company has a defined benefit pension plan covering the majority of regular full-time non-union employees at Avista Utilities hired prior to January 1, 2014 and regular full-time union employees that were hired prior to January 1, 2024. 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 and union employees hired on or after January 1, 2024 participate in a defined contribution 401(k) plan in lieu of a defined benefit pension plan. The Company's funding policy is to contribute at least the minimum amounts required to be funded under the Employee Retirement Income Security Act, but not more than the maximum amounts currently deductible for income tax purposes. The Company contributed $10.0 million in cash to the pension plan in 2023, and $42.0 million in 2022 and 2021. The Company expects to contribute $10.0 million in cash to the pension plan in 2024.

In 2022, the defined benefit pension plan lump sum payments exceeded the annual service and interest costs for the plan. This resulted in a partial settlement of the plan, and the Company recorded a settlement loss of $11.8 million for the previously unrecognized losses in the year ended December 31, 2022. This loss was deferred as a regulatory asset and is being amortized over 12 years in accordance with regulatory accounting orders.

The Company has a SERP providing additional pension benefits to certain executive officers and certain key employees of the Company. The SERP provides 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 benefit payments under the pension plan and the SERP will total (dollars in thousands):

	2024	2025	2026	2027	2028	Total 2029–2033
Expected benefit payments	$ 41,562	$ 42,123	$ 42,941	$ 43,517	$ 44,700	$ 232,345

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 hired prior to January 1, 2014. The Company accrues the estimated cost of postretirement benefit obligations during the years 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 benefit payments under other postretirement benefit plans will total (dollars in thousands):

	2024	2025	2026	2027	2028	Total 2029–2033
Expected benefit payments	$ 7,084	$ 7,266	$ 7,436	$ 7,608	$ 7,822	$ 40,805

The Company expects to contribute $7.1 million to other postretirement benefit plans in 2024. 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, 2023 and 2022 and the components of net periodic benefit costs for the years ended December 31, 2023, 2022 and 2021 (dollars in thousands):

	Pension Benefits		Other Postretirement Benefits	
	2023	2022	2023	2022
Change in benefit obligation:				
Benefit obligation as of beginning of year	$ 557,709	$ 799,042	$ 115,635	$ 167,598
Service cost	14,350	23,877	2,394	4,369
Interest cost	33,245	26,536	6,766	5,503
Actuarial (gain)/loss	21,373	(204,775)	4,799	(54,120)
Plan change	—	3,302	—	—
Settlement	—	(60,206)	—	—
Benefits paid	(41,432)	(30,067)	(7,210)	(7,715)
Benefit obligation as of end of year	$ 585,245	$ 557,709	$ 122,384	$ 115,635
Change in plan assets:				
Fair value of plan assets as of beginning of year	$ 540,703	$ 750,963	$ 49,472	$ 59,544
Actual return on plan assets	78,838	(163,866)	8,654	(10,072)
Employer contributions	10,000	42,000	—	—
Settlement	—	(60,206)	—	—
Benefits paid	(39,558)	(28,188)	—	—
Fair value of plan assets as of end of year	$ 589,983	$ 540,703	$ 58,126	$ 49,472
Funded status	$ 4,738	$ (17,006)	$ (64,258)	$ (66,163)
Amounts recognized in the Consolidated Balance Sheets:				
Other non-current assets	$ 32,997	$ 13,382	$ —	$ —
Other current liabilities	(2,212)	(1,934)	(652)	(706)
Non-current liabilities	(26,047)	(28,454)	(63,606)	(65,457)
Net amount recognized	$ 4,738	$ (17,006)	$ (64,258)	$ (66,163)
Accumulated pension benefit obligation	$ 514,295	$ 495,654		
Accumulated postretirement benefit obligation:				
For retirees			$ 68,087	$ 61,984
For fully eligible employees			$ 16,054	$ 19,731
For other participants			$ 38,243	$ 33,920
Included in accumulated other comprehensive loss (income) (net of tax):				
Unrecognized prior service cost (credit)	$ 3,717	$ 4,105	$ (1,081)	$ (1,911)
Unrecognized net actuarial loss	69,002	83,794	13,103	13,643
Total	72,719	87,899	12,022	11,732
Less regulatory asset	(71,983)	(85,198)	(12,401)	(12,375)
Accumulated other comprehensive loss for unfunded benefit obligation for pensions and other postretirement benefit plans	$ 736	$ 2,701	$ (379)	$ (643)

	Pension Benefits		Other Postretirement Benefits	
	2023	2022	2023	2022
Weighted-average assumptions as of December 31:				
Discount rate for benefit obligation	5.86%	6.10%	5.83%	6.10%
Discount rate for annual expense	6.10%	3.39%	6.10%	3.40%
Expected long-term return on plan assets	8.30%	5.80%	7.20%	4.70%
Rate of compensation increase	4.87%	4.69%		
Medical cost trend pre-age 65—initial			6.50%	6.25%
Medical cost trend pre-age 65—ultimate			5.00%	5.00%
Ultimate medical cost trend year pre-age 65			2030	2028
Medical cost trend post-age 65—initial			6.50%	6.25%
Medical cost trend post-age 65—ultimate			5.00%	5.00%
Ultimate medical cost trend year post-age 65			2030	2028

	Pension Benefits			Other Postretirement Benefits		
	2023	2022	2021	2023	2022	2021
Components of net periodic benefit cost:						
Service cost [1]	$ 14,350	$ 23,877	$ 25,306	$ 2,394	$ 4,369	$ 4,114
Interest cost	33,245	26,536	26,160	6,766	5,503	5,139
Expected return on plan assets	(43,656)	(43,872)	(39,088)	(3,562)	(2,799)	(2,400)
Amortization of prior service cost (credit)	491	257	257	(1,050)	(1,050)	(921)
Net loss recognition	4,915	4,180	6,645	319	3,344	3,865
Settlement loss [2]	—	11,828	—	—	—	—
Net periodic benefit cost	$ 9,345	$ 22,806	$ 19,280	$ 4,867	$ 9,367	$ 9,797

(1) 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.

(2) The settlement loss was deferred as a regulatory asset and is being amortized over 12 years in accordance with regulatory accounting orders.

Plan Assets

The Finance Committee of the 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, and trusts and partnerships that hold marketable debt and equity securities and real estate. 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 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:

	2023	2022
Equity securities	55%	55%
Debt securities	40%	40%
Real estate	5%	5%

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 comparable in coupon, rating, maturity and industry).

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

The plan's investments in common/collective trusts have redemption limitations that permit quarterly redemptions following notice requirements of 45 to 60 days. Most of the plan's investments in closely held investments and partnership interests have redemption limitations ranging from bi-monthly to semi-annually following redemption notice requirements of 60 to 90 days.

The following table discloses by level within the fair value hierarchy (see Note 18 for a description of the fair value hierarchy) of the pension plan's assets measured and reported as of December 31, 2023 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ —	$ 6,984	$ —	$ 6,984
Fixed income securities:				
U.S. government issues	—	19,293	—	19,293
Corporate issues	—	175,460	—	175,460
International issues	—	27,052	—	27,052
Municipal issues	—	13,772	—	13,772
Mutual funds:				
U.S. equity securities	169,993	—	—	169,993
International equity securities	74,749	—	—	74,749
Plan assets measured at NAV (not subject to hierarchy disclosure)				
Common/collective trusts:				
Real estate	—	—	—	25,284
Partnership/closely held investments:				
International equity securities	—	—	—	70,652
Real estate	—	—	—	6,744
Total	$ 244,742	$ 242,561	$ —	$ 589,983

The following table discloses by level within the fair value hierarchy (see Note 18 for a description of the fair value hierarchy) of the pension plan's assets measured and reported as of December 31, 2022 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ —	$ 5,110	$ —	$ 5,110
Fixed income securities:				
U.S. government issues	—	16,732	—	16,732
Corporate issues	—	161,180	—	161,180
International issues	—	23,108	—	23,108
Municipal issues	—	13,427	—	13,427
Mutual funds:				
U.S. equity securities	154,442	—	—	154,442
International equity securities	58,933	—	—	58,933
Plan assets measured at NAV (not subject to hierarchy disclosure)				
Common/collective trusts:				
Real estate	—	—	—	30,406
Partnership/closely held investments:				
International equity securities	—	—	—	69,792
Real estate	—	—	—	7,573
Total	$ 213,375	$ 219,557	$ —	$ 540,703

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 determines fair value based upon other inputs (including valuations of securities comparable in coupon, rating, maturity and industry). The target asset allocation was 60 percent equity securities and 40 percent debt securities in both 2023 and 2022.

The fair value of other postretirement plan assets was determined to be $58.1 million and $49.5 million as of December 31, 2023 and 2022, respectively. The assets consist of a balanced index mutual fund, which is a single mutual fund that includes a percentage of U.S. equity and fixed income securities and International equity and fixed income securities. This mutual fund is classified as Level 1 in the fair value hierarchy (see Note 18 for a description of the fair value hierarchy).

401(k) Plans and Executive Deferral Plan

Avista Utilities 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):

	2023	2022	2021
Employer 401(k) matching contributions	$ 15,022	$ 13,258	$ 11,671

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 included in other property and investments—net and corresponding deferred compensation liabilities included in other non-current liabilities and deferred credits on the Consolidated Balance Sheets of the following amounts as of December 31 (dollars in thousands):

	2023	2022
Deferred compensation assets and liabilities	$ 7,794	$ 7,541

NOTE 13. ACCOUNTING FOR INCOME TAXES

Income Tax Expense

Income tax expense consisted of the following for the years ended December 31 (dollars in thousands):

	2023	2022	2021
Current income tax expense	$ 3,207	$ 1,040	$ 807
Deferred income tax expense (benefit)	(36,837)	(18,231)	11,224
Total income tax expense (benefit)	$ (33,630)	$ (17,191)	$ 12,031

A reconciliation of federal income taxes derived from the statutory federal tax rate of 21 percent applied to income before income taxes is as follows for the years ended December 31 (dollars in thousands):

	2023		2022		2021	
Federal income taxes at statutory rates	$ 28,886	21.0%	$ 28,977	21.0%	$ 33,467	21.0%
Increase (decrease) in tax resulting from:						
Tax effect of regulatory treatment of utility plant differences [1]	(12,270)	(8.9)	(12,366)	(9.0)	(13,820)	(8.7)
State income tax expense	2,077	1.5	1,676	1.2	1,385	0.8
Flow through related to deduction of meters and mixed service costs [2]	(47,983)	(34.9)	(34,454)	(25.0)	(8,678)	(5.4)
Tax credits	(2,334)	(1.7)	(258)	(0.2)	(75)	—
Other	(2,006)	(1.4)	(766)	(0.5)	(248)	(0.2)
Total income tax expense (benefit)	$ (33,630)	(24.4)%	$ (17,191)	(12.5)%	$ 12,031	7.5%

(1) Prior to 2022, for the depreciation-related temporary differences under the normalization tax accounting method, the Company utilized the average rate assumption method to compute the amounts returned to customers. Beginning in 2022, the Company changed to the alternative method, to comply with the revenue procedure and private letter rulings.

(2) The Company's general rate cases included approval of base rate increases, offset by tax customer credits. As the tax customer credits are returned to customers, this results in a decrease to income tax expense due to flowing through the benefits related to meters and mixed service costs.

Deferred Income Taxes

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes and tax credit carryforwards.

The total net deferred income tax liability consisted of the following as of December 31 (dollars in thousands):

	2023	2022
Deferred income tax assets:		
Regulatory liabilities	$ 192,099	$ 197,998
Tax credits and net operating loss carryforwards	76,969	74,782
Provisions for pensions	19,100	20,132
Other	47,839	54,903
Total gross deferred income tax assets	336,007	347,815
Valuation allowances for deferred tax assets	(10,461)	(3,874)
Total deferred income tax assets after valuation allowances	325,546	343,941
Deferred income tax liabilities:		
Utility property, plant, and equipment	746,876	712,470
Regulatory assets	268,833	281,483
Other	28,155	24,983
Total deferred income tax liabilities	1,043,864	1,018,936
Net long-term deferred income tax liability	$ 718,318	$ 674,995

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, 2023, the Company had $17.3 million of state tax credit carryforwards. Of the total amount, the Company believes that it is more likely than not that it will only be able to utilize $6.8 million of the state tax credits. As such, the Company has recorded a valuation allowance of $10.5 million against the state tax credit carryforwards and reflected the net amount of $6.8 million as an asset as of December 31, 2023. State tax credits expire from 2024 to 2037.

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 2018 are open for an IRS tax examination. The IRS is reviewing tax year 2019.

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

All tax years after 2019 are open for examination in Idaho, Oregon, Montana and Alaska.

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

NOTE 14. ENERGY PURCHASE CONTRACTS

The below discussion only relates to Avista Utilities. The sole energy purchase contract at AEL&P is a PPA for the Snettisham hydroelectric project and it is accounted for as a lease. AEL&P does not have any other significant operating agreements or contractual obligations. See Note 5 for further discussion of the Snettisham PPA.

Avista Utilities 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 Consolidated Statements of Income, were as follows for the years ended December 31 (dollars in thousands):

	2023	2022	2021
Utility power resources	$ 607,155	$ 660,967	$ 431,199

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

	2024	2025	2026	2027	2028	Thereafter	Total
Power resources	$ 336,766	$ 293,389	$ 266,251	$ 235,751	$ 234,756	$ 2,245,762	$ 3,612,675
Natural gas resources	122,241	81,141	46,033	41,708	41,168	280,562	612,853
Total	$ 459,007	$ 374,530	$ 312,284	$ 277,459	$ 275,924	$ 2,526,324	$ 4,225,528

These energy purchase contracts were entered into as part of Avista Utilities' obligation to serve its retail electric and natural gas customers' energy requirements, including contracts entered into for resource optimization. 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 future contractual commitments for power resources include fixed contractual amounts related to the Company's contracts with PUDs to purchase portions of the output of certain generating facilities. Although Avista Utilities has no investment in the PUD generating facilities, the contracts obligate Avista Utilities 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 Consolidated Statements of Income. The contractual amounts included above consist of Avista Utilities' 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, 2023 (principal and interest) was $275.1 million.

In addition, Avista Utilities 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 Consolidated Statements of Income.

The following table details future contractual commitments under these agreements (dollars in thousands):

	2024	2025	2026	2027	2028	Thereafter	Total
Contractual obligations	$ 39,156	$ 40,226	$ 18,630	$ 19,085	$ 9,390	$ 177,553	$ 304,040

NOTE 15. SHORT-TERM BORROWINGS

Avista Corp.

Lines of Credit

Avista Corp. has a committed line of credit in the total amount of $500.0 million, with expiration date of June 2028. The Company has the option to extend for two additional one year periods (subject to customary conditions). In June 2023, the then-existing agreement was amended to increase the capacity of the committed line of credit from $400.0 million to $500.0 million, extend the expiration date, and replace the London Interbank Offered Rate (LIBOR) provisions with Secured Overnight Financing Rate (SOFR) provisions. 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.

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

	2023	2022
Balance outstanding at end of period	$ 349,000	$ 313,000
Letters of credit outstanding at end of period	4,700	35,563
Average interest rate at end of period	6.46%	5.31%

In December 2022, Avista Corp. entered into an additional revolving agreement in the amount of $100.0 million. As of December 31, 2022, the Company did not have any outstanding borrowings under this agreement. The agreement was terminated in June 2023.

As of December 31, 2023 and 2022, the borrowings outstanding under Avista Corp.'s committed lines of credit were classified as short-term borrowings on the Consolidated Balance Sheets.

2022 Term Loan

In December 2022, the Company entered into a term loan agreement in the amount of $150.0 million with a maturity date of March 30, 2023. The Company borrowed the entire $150.0 million available under the agreement in 2022 and repaid the entire outstanding balance in March 2023. The borrowings outstanding under this agreement were classified as short-term borrowings on the Consolidated Balance Sheets.

2022 Letter of Credit Facility

In December 2022, the Company entered into a continuing letter of credit agreement in the aggregate amount of $50.0 million. Either party may terminate the agreement at any time.

The Company had $20.0 million and $18.5 million in letters of credit outstanding under this agreement as of December 31, 2023 and December 31, 2022, respectively. Letters of credit are not reflected on the Consolidated Balance Sheets. If a letter of credit were drawn upon by the holder, we would have an immediate obligation to reimburse the bank that issued that letter.

Covenants and Default Provisions

The short-term borrowing agreements contain customary covenants and default provisions, including a change in control (as defined in the agreements). The events of default under each of the credit facilities also include a cross default from other indebtedness (as defined) and in some cases other obligations. Most of the short-term borrowing agreement also include a covenant which does not permit the ratio of "consolidated total debt" to "consolidated total capitalization" of Avista Corp. to be greater than 65 percent at any time. As of December 31, 2023, the Company complied with this covenant.

AEL&P

AEL&P has a committed line of credit in the amount of $25.0 million that expires in June 2028. The committed line of credit is secured by non-transferable first mortgage bonds of AEL&P issued to the agent bank that would only become due and payable in the event, and then only to the extent, that AEL&P defaults on its obligations under the committed line of credit.

The committed line of credit agreement contains customary covenants and default provisions. The credit agreement has a covenant which does not permit the ratio of "consolidated total debt at AEL&P" to "consolidated total capitalization at AEL&P," including the impact of the Snettisham bonds to be greater than 67.5 percent at any time. As of December 31, 2023, AEL&P complied with this covenant.

As of December 31, 2023, and 2022 there were no borrowings under the AEL&P committed line of credit.

NOTE 16. LONG-TERM DEBT

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

Maturity Year	Description	Interest Rate	2023	2022
Avista Corp. Secured Long-Term Debt				
2023	Secured Medium-Term Notes	7.18%–7.54%	$ —	$ 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	2.90%	140,000	140,000
2052	First Mortgage Bonds	4.00%	400,000	400,000
2053	First Mortgage Bonds (2)	5.66%	250,000	—
	Total Avista Corp. secured long-term debt		2,543,700	2,307,200
Alaska Electric Light and Power Company Secured Long-Term Debt				
2044	First Mortgage Bonds	4.54%	75,000	75,000
	Total secured long-term debt		2,618,700	2,382,200
Alaska Energy and Resources Company Unsecured Long-Term Debt				
2024	Unsecured Term Loan	3.44%	15,000	15,000
	Total secured and unsecured long-term debt		2,633,700	2,397,200
Other Long-Term Debt Components				
	Unamortized debt discount		(689)	(726)
	Unamortized long-term debt issuance costs		(18,953)	(18,261)
	Total		2,614,058	2,378,213
	Secured Pollution Control Bonds held by Avista Corporation (1)		(83,700)	(83,700)
	Current portion of long-term debt		(15,000)	(13,500)
	Total long-term debt		$ 2,515,358	$ 2,281,013

(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. The new bonds were not offered to the public and were purchased by Avista Corp. due to market conditions. The Company can remarket these bonds to unaffiliated investors at a later date, subject to market conditions. So long as Avista Corp. is the holder of these bonds, the bonds are not reflected as an asset or a liability on the Consolidated Balance Sheets.

(2) In March 2023, the Company issued and sold $250.0 million of 5.66 percent first mortgage bonds due in 2053 with institutional investors in the private placement market. A portion of the net proceeds from the sale of these bonds was used for the construction or improvement of utility facilities, and a portion was used to refinance existing indebtedness, including the repayment of Avista Corp.'s $150.0 million term loan. In connection with the pricing of the first mortgage bonds in March 2023, the Company cash settled four interest rate swap derivatives (notional aggregate amount of $40.0 million) and received a net amount of $7.5 million. See Note 8 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 17) (dollars in thousands):

	2024	2025	2026	2027	2028	Thereafter	Total
Debt maturities	$ 15,000	$ —	$ —	$ —	$ 25,000	$ 2,561,547	$ 2,601,547

Substantially all of Avista Utilities' and AEL&P's owned properties are subject to the lien of their respective mortgage indentures. Under the Mortgages and Deeds of Trust (Mortgages) securing their first mortgage bonds (including secured medium-term notes), Avista Utilities and AEL&P may each issue additional first mortgage bonds under their specific mortgage in an aggregate principal amount equal to the sum of:

- $66\frac{2}{3}$ percent of the cost or fair value to the Company (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 Utilities and AEL&P may not individually 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 that entity's 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, 2023, property additions and retired bonds would have allowed, and the net earnings test would not have prohibited, the issuance of $1.2 billion in an aggregate principal amount of additional first mortgage bonds at Avista Utilities and $51.4 million by AEL&P, at an assumed interest rate of 8 percent in each case.

NOTE 17. LONG-TERM DEBT TO AFFILIATED TRUSTS

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. Effective on July 3, 2023, the reference to LIBOR in the formulation for the distribution rate on these securities was replaced, by operation of law, with three-month CME Term SOFR, as calculated and published by CME Group Benchmark Administration, Ltd. (a successor administrator), plus a tenor spread adjustment of 0.26 percent. Accordingly, the distribution rate on the Preferred Trust Securities is now three-month CME Term SOFR plus 1.137 percent.

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

	2023	2022	2021
Low distribution rate	5.64%	1.05%	0.99%
High distribution rate	6.55%	5.64%	1.10%
Distribution rate at the end of the year	6.51%	5.64%	1.05%

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 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. The Company does not include these capital trusts in its consolidated financial statements as Avista Corp. is not the primary beneficiary. As such, the sole assets of the capital trusts are $51.5 million of junior subordinated deferrable interest debentures of Avista Corp., which are reflected on the Consolidated Balance Sheets. Interest expense to affiliated trusts in the Consolidated Statements of Income represents interest expense on these debentures.

NOTE 18. FAIR VALUE

The carrying values of cash and cash equivalents, accounts and notes receivable, accounts payable and short-term borrowings are reasonable estimates of their fair values. Long-term debt (including current portion), finance leases, and long-term debt to affiliated trusts are reported at carrying value on the Consolidated 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 financial instruments 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 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 Consolidated Balance Sheets as of December 31 (dollars in thousands):

	2023		2022	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Long-term debt (Level 2)	$ 1,100,000	$ 968,893	$ 1,113,500	$ 966,881
Long-term debt (Level 3)	1,450,000	1,166,512	1,200,000	881,480
Snettisham finance lease obligation (Level 3)	42,495	39,600	45,730	41,700
Long-term debt to affiliated trusts (Level 3)	51,547	46,098	51,547	42,836

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 62.73 to 107.245, where a par value of 100.00 represents the carrying value recorded on the Consolidated 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. Due to the unique nature of the Snettisham finance lease obligation, the estimated fair value of these items was determined based on a discounted cash flow model using available market information. The Snettisham finance lease obligation was discounted to present value using the Morgan Markets A Ex-Fin discount rate as published on December 31, 2023.

The following table discloses by level within the fair value hierarchy the Company's assets and liabilities measured and reported on the Consolidated Balance Sheets as of December 31, 2023 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, 2023					
Assets:					
Energy commodity derivatives [(2)]	$ —	$ 30,954	$ —	$ (22,802)	$ 8,152
Foreign currency exchange derivatives	—	2	—	—	2
Interest rate swap derivatives	—	3,667	—	—	3,667
Equity investments [(3)]	—	—	50,254	—	50,254
Deferred compensation assets:					
Mutual Funds:					
Fixed income securities [(3)]	1,117	—	—	—	1,117
Equity securities [(3)]	6,524	—	—	—	6,524
Total	$ 7,641	$ 34,623	$ 50,254	$ (22,802)	$ 69,716
Liabilities:					
Energy commodity derivatives [(2)]	$ —	$ 91,844	$ 8,250	$ (65,157)	$ 34,937
Interest rate swap derivatives	—	182	—	—	182
Total	$ —	$ 92,026	$ 8,250	$ (65,157)	$ 35,119

The following table discloses by level within the fair value hierarchy the Company's assets and liabilities measured and reported on the Consolidated Balance Sheets as of December 31, 2022 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, 2022					
Assets:					
Energy commodity derivatives [(2)]	$ —	$ 146,232	$ 288	$ (136,605)	$ 9,915
Foreign currency exchange derivatives	—	43	—	—	43
Interest rate swap derivatives	—	11,184	—	—	11,184
Equity investments [(3)]	—	—	54,284	—	54,284
Deferred compensation assets:					
Mutual Funds:					
Fixed income securities [(3)]	1,267	—	—	—	1,267
Equity securities [(3)]	6,132	—	—	—	6,132
Total	$ 7,399	$ 157,459	$ 54,572	$ (136,605)	$ 82,825
Liabilities:					
Energy commodity derivatives [(2)]	$ —	$ 258,769	$ 18,022	$ (242,044)	$ 34,747
Foreign currency exchange derivatives	—	3	—	—	3
Interest rate swap derivatives	—	52	—	—	52
Total	$ —	$ 258,824	$ 18,022	$ (242,044)	$ 34,802

(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 payables and receivables for cash collateral held or placed with these same counterparties.

(2) The Level 3 energy commodity derivative balances are associated with natural gas exchange agreements.

(3) These assets are included in other property and investments-net and other non-current assets on the Consolidated Balance Sheets.

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 Consolidated Balance Sheets is due to netting arrangements with certain counterparties. See Note 8 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 U.S. 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.

Level 3 Fair Value

Natural Gas Exchange Agreement

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 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, 2023 (dollars in thousands):

	Fair Value (Net) at December 31, 2023	Valuation Technique	Unobservable Input	Range
Natural gas exchange	$ (8,250)	Internally derived	Forward purchase prices	$1.64–$3.07/mmBTU
		weighted-average		$2.40 Weighted-average
		cost of gas	Forward sales prices	$2.13–$8.99/mmBTU
				$5.45 Weighted-average
			Purchase volumes	300,000–310,000 mmBTUs
			Sales volumes	75,000–310,000 mmBTUs

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

Equity Investments

The Company has two equity investments measured at fair value on a recurring basis. For one investment, fair value is determined using a market approach, starting with enterprise values from recent market transaction data for comparable companies with similar equity instruments. The market transaction data was used to estimate an enterprise value of the underlying investment and that value was allocated to the various classes of equity via an option pricing model and a waterfall approach. The selection of appropriate comparable companies and the expected time to a liquidation event requires management judgment. The significant assumptions in the analysis include the comparable market transactions and related enterprise values, time to liquidity event and the market discount for lack of liquidity.

For the second investment, the fair value is determined using an income approach utilizing a discounted cash flow model. The model is based on income statement forecasts from the underlying company to determine cash flows for the period of ownership. The model then utilizes market multiples from publicly traded comparable companies in similar industries and projects to estimate the terminal fair value. The market multiples are reduced to reflect the difference in the life cycle between the publicly traded comparable companies and the start-up nature of the investment company. The selection of appropriate comparable companies, market multiples and the reduction to those market multiples requires management judgment. The significant assumptions in the model include the discount rate representing the risk associated with the investment, market multiples and the related reduction to those multiples, revenue forecasts, and the estimated terminal date for the investment.

The following table presents the quantitative information which was used to estimate the fair values of the Level 3 equity investments as of December 31, 2023 (dollars in thousands):

	Fair Value at December 31, 2023	Valuation Technique	Unobservable Input	Range
Equity investments	$ 50,254	Market approach	Comparable enterprise values	$130,000–$388,600 $246,000 Average
			Time to liquidity event	1.5 years
		Discounted cash flows	Revenue market multiples	0.45x to 5.69x Revenue 1.89x Average
			Market exit reduction	50%
			Discount rate	25%
			Annual revenues	$15,000–$245,000
			Terminal date	2027

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

	Natural Gas Exchange Agreement [(1)]	Equity Investments	Total
Year ended December 31, 2023:			
Balance as of January 1, 2023	$ (17,734)	$ 54,284	$ 36,550
Total gains or (losses) (realized/unrealized):			
Included in regulatory assets	9,238	—	9,238
Recognized in net income	—	(4,323)	(4,323)
Purchases and debt conversions	—	3,293	3,293
Settlements	246	—	246
Other	—	(3,000)	(3,000)
Ending balance as of December 31, 2023	$ (8,250)	$ 50,254	$ 42,004
Year ended December 31, 2022:			
Balance as of January 1, 2022	$ (7,771)	$ —	$ (7,771)
Transfers in [(2)]	—	20,902	20,902
Total gains or (losses) (realized/unrealized):			
Included in regulatory assets	(4,740)	—	(4,740)
Recognized in net income	—	33,382	33,382
Settlements	(5,223)	—	(5,223)
Ending balance as of December 31, 2022	$ (17,734)	$ 54,284	$ 36,550
Year ended December 31, 2021:			
Balance as of January 1, 2021	$ (8,410)	$ —	$ (8,410)
Total gains (realized/unrealized):			
Included in regulatory assets	4,292	—	4,292
Settlements	(3,653)	—	(3,653)
Ending balance as of December 31, 2021	$ (7,771)	$ —	$ (7,771)

(1) There were no purchases, issuances or transfers from other categories of derivatives instruments during the periods presented in the table above.

(2) The Company elected to account for certain equity investments at recurring fair value in 2022, as such the transfer in represents the value as of the election. See further discussion within Note 7.

NOTE 19. 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 Utilities 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, 2023 was $295.6 million.

See the Consolidated Statements of Equity for dividends declared in the years 2021 through 2023.

The Company has 10 million authorized shares of preferred stock. The Company did not have preferred stock outstanding as of December 31, 2023 and 2022.

Common Stock Issuances

The Company issued common stock for total net proceeds of $112.3 million in 2023. 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. In 2023, 3.0 million shares were issued under these agreements resulting in total net proceeds of $111.8 million.

NOTE 20. ACCUMULATED OTHER COMPREHENSIVE LOSS

Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss—net of tax, consisted of the following as of December 31 (dollars in thousands):

	2023	2022
Unfunded benefit obligation for pensions and other postretirement benefit plans—net of taxes of $95 and $547, respectively	$ 357	$ 2,058

The following table details the reclassifications out of accumulated other comprehensive loss by component for the years ended December 31 (dollars in thousands):

Details about Accumulated Other Comprehensive Loss Components (Affected Line Item in Statements of Income)	Amounts Reclassified from Accumulated Other Comprehensive Loss		
	2023	2022	2021
Amortization of defined benefit pension and postretirement benefit items			
Amortization of net prior service cost (a)	$ (558)	$ (4,095)	$ (793)
Amortization of net loss (a)	18,872	57,650	38,070
Adjustment due to effects of regulation (a)	(16,161)	(42,187)	(33,050)
Total before tax (b)	2,153	11,368	4,227
Tax expense (b)	(452)	(2,387)	(888)
Net of tax (b)	$ 1,701	$ 8,981	$ 3,339

(a) These accumulated other comprehensive loss components are included in the computation of net periodic pension cost (see Note 12 for additional details).

(b) Description is also the affected line item on the Consolidated Statements of Income.

NOTE 21. EARNINGS PER COMMON SHARE

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

	2023	2022	2021
Numerator:			
Net income	$ 171,180	$ 155,176	$ 147,334
Denominator:			
Weighted-average number of common shares outstanding—basic	76,396	72,989	69,951
Effect of dilutive securities:			
Performance and restricted stock awards	100	104	134
Weighted-average number of common shares outstanding—diluted	76,495	73,093	70,085
Earnings per common share:			
Basic	$ 2.24	$ 2.13	$ 2.11
Diluted	$ 2.24	$ 2.12	$ 2.10

There were no shares excluded from the calculation because they were antidilutive.

NOTE 22. 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 will vigorously protect and defend its interests and pursue its rights. However, no assurance can be given as to the ultimate outcome of any matter because litigation and other contested proceedings are subject to numerous uncertainties. For matters affecting Avista Utilities' or AEL&P'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 36 percent of all Avista Utilities' employees. The Company's largest represented group, representing approximately 90 percent of Avista Utilities' bargaining unit employees in Washington and Idaho, are covered under a four year agreement which expires in March 2025.

The current agreement includes a clause to negotiate wages in effect for the last year of the agreement. The Company is in the process of negotiating these wages. There is a risk that if an agreement on wages is not reached, the employees subject to the agreement could strike. Given the number of employees that are covered by the collective bargaining agreement, a strike could result in disruptions to the Company's operations. However, the Company believes the possibility of this occurring is remote.

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 of 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 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., along with its independent vegetation management contractors Asplundh Tree Company and CN Utility Consulting, were negligent in failing to identify and remove the tree before it came into contact with the line. Avista Corp. disputes that it was negligent in failing to identify and remove the tree in question. Additional lawsuits were subsequently 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, at this time the Company is unable to predict the likelihood of an adverse outcome or estimate a range of potential loss in the event of such an outcome.

Road 11 Fire

In April 2022, Avista Corp. received a notice of claim from property owners seeking damages of $5 million in connection with a fire that occurred in Douglas County, Washington, in July 2020. In June 2022, those claimants filed suit in the Superior Court of Douglas County, Washington, seeking unspecified damages. The fire, which was designated as the "Road 11 Fire," occurred in the vicinity of an Avista Corp. 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 Company disputes that it is liable for the fire and will vigorously defend itself in the pending legal proceeding; however, at this time the Company is unable to predict the likelihood of an adverse outcome or estimate a range of potential loss in the event of such an outcome.

Labor Day 2020 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 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. However, the Company's investigations found no evidence of negligence with respect to any of those fires. Consistent with that conclusion, the statute of limitations with respect to the claims arising out of the Labor Day 2020 Windstorm has now passed and, except with respect to the Babb Road Fire discussed below, no legal action has been commenced.

Babb Road Fire

In May 2021 the Company learned 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.

Eleven lawsuits have been filed in connection with the Babb Road fire. Asplundh Tree Company and CNUC Utility Consulting, which both perform vegetation management services as independent contractors to the Company, are also named as defendants in each of the lawsuits. The lawsuits include six subrogation actions filed by insurance companies seeking to recover approximately $23 million purportedly paid to insureds to date; four actions on behalf of individual plaintiffs seeking unspecified damages; and a class action lawsuit seeking unspecified damages. All proceedings, except for one action filed on September 1, 2023 on behalf of three individual plaintiffs, have been consolidated in the Superior Court of Spokane County Washington under the lead action *Blakeley v. Avista Corporation et al.*, and variously assert causes of action for negligence, private nuisance, and trespass (the Blakeley Proceeding).

In November 2023, all parties to the Blakeley Proceeding agreed to a stipulated order, which was presented to and entered by the Superior Court of Spokane County, Washington. The order consolidates the Blakeley Proceeding for trial (in addition to discovery and pre-trial proceedings) and bifurcates the trial into liability and damages phases, such that the initial trial in the case will focus solely on whether the defendants are legally responsible for the Babb Road Fire. A trial date on the liability phase has been set for May 5, 2025.

In addition, the order memorializes the plaintiffs' agreement to voluntarily dismiss all claims asserting inverse condemnation as a theory of liability without prejudice to their ability to seek permission from the Court to refile those claims at a later date if there is good cause to do so. The individual action that was not consolidated into the Blakeley Proceeding does not include claims for inverse condemnation. The parties to the Blakeley Proceeding agreed to a preliminary mediation no later than 60 days prior to the liability trial, and, if there is a trial following that mediation and if the jury returns a verdict in the plaintiffs' favor in the liability trial, a second mediation within 90 days following the verdict focusing on damages. Finally, the plaintiffs agreed to complete a damages questionnaire identifying all claimed damages being sought in connection with the litigation.

The Company will vigorously defend itself in the legal proceedings; however, at this time the Company is unable to predict the likelihood of an adverse outcome or estimate a range of potential loss in the event of such an outcome.

Orofino Fire

In August 2023, a fire subsequently referred to as the "Hospital Fire," started in windy conditions near Orofino, Idaho, burning 3 acres and seven primary residences, as well as several outbuildings. The Idaho Department of Lands investigated and has issued a report in which it concluded the fire was caused by an electrical fault igniting three separate spots which then spread uphill. The Company has a distribution line in the area near the ignition point. While the Company has not yet completed its own investigation, the Company has to date found no evidence suggesting negligence on its part. Except for one claim for damage to personal property, the Company has not, at this time, received any claims in connection with the fire. The Company will vigorously defend itself in the event any such claims are asserted; however, at this time, it is unable to estimate the likelihood of an adverse outcome nor the amount or range of a potential loss in the event of an adverse outcome.

Colstrip

Colstrip Owners Arbitration and Litigation

Colstrip Units 3 & 4 are owned by the Company, PacifiCorp, Portland General Electric (PGE), and Puget Sound Energy (PSE) (collectively, the "Western Co-Owners"), as well as NorthWestern and Talen Montana, LLC (Talen), as tenants in common under an Ownership and Operating Agreement, dated May 6, 1981, as amended (O&O Agreement), in the percentages set forth below:

Co-Owner	Unit 3	Unit 4
Avista	15%	15%
PacifiCorp	10%	10%
PGE	20%	20%
PSE	25%	25%
NorthWestern	—	30%
Talen	30%	—

Colstrip Units 1 & 2, owned by PSE and Talen, were shut down in 2020 and are in the process of being decommissioned. The co-owners of Units 3 & 4 also own undivided interests in facilities common to both Units 3 & 4, as well as in certain facilities common to all four Colstrip units.

The Washington Clean Energy Transformation Act (CETA), among other things, imposes deadlines by which each electric utility must eliminate from its electricity rates in Washington the costs and benefits associated with coal-fired resources, such as Colstrip. The practical impact of CETA is electricity from such resources, including Colstrip, may no longer be delivered to Washington retail customers after 2025.

The co-owners of Colstrip Units 3 & 4 have differing needs for the generating capacity of these units. Accordingly, certain business disagreements have arisen among the co-owners, including, disagreements as to the requirements for shutting down these units. NorthWestern has initiated arbitration pursuant to the O&O Agreement to resolve these business disagreements, and two actions have been initiated to compel arbitration of those disputes: one by Talen in the Montana Thirteenth Judicial District Court for Yellowstone County, and one by the Western Co-Owners, which is pending in Montana Federal District Court. In light of the ownership transfer agreements discussed below, the Colstrip owners agreed to stay both the litigation and the arbitration through March 2024.

Agreement Between Talen and Puget Sound Energy

In September 2022, PSE and Talen entered into an agreement through which PSE has agreed to transfer its 25 percent ownership in Colstrip Units 3 & 4 to Talen at the end of 2025. The terms and conditions of the agreement are similar in most respects to the NorthWestern transaction discussed below.

Agreement Between Avista and NorthWestern

In January 2023, the Company entered into an agreement with NorthWestern under which, subject to the terms and conditions specified in the agreement, the Company will transfer its 15 percent ownership in Colstrip Units 3 & 4 to NorthWestern. There is no monetary exchange included in the transaction. The transaction is scheduled to close on December 31, 2025 or such other date as the parties mutually agree upon.

Under the agreement, the Company will remain obligated through the close of the transaction to pay its share of (i) operating expenses, (ii) capital expenditures, but not in excess of the portion allocable pro rata to the portion of useful life (through 2030) expired through the close of the transaction, and (iii) except for certain costs relating to post-closing activities, site remediation expenses. In addition, the Company would enter into an agreement under which it would retain its voting rights with respect to decisions relating to remediation.

The Company will retain its Colstrip transmission system assets, which are excluded from the transaction.

Under the Colstrip O&O Agreement, each of the other owners of Colstrip has a 90-day period in which to evaluate the transaction and determine whether to exercise their respective rights of first refusal as to a portion of the generation being turned over to NorthWestern. That period has now expired, and no owners have exercised a right to first refusal.

The transaction is subject to the satisfaction of customary closing conditions including the receipt of any required regulatory approvals, as well as NorthWestern's ability to enter into a new coal supply agreement by December 31, 2024.

The Company does not expect this transaction to have a direct material impact on its financial results.

Burnett et al. v. Talen et al.

Multiple property owners 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 adverse to the Company's interests.

Westmoreland Mine Permits

Two lawsuits have been commenced by the Montana Environmental Information Center and others, challenging certain permits relating to the operation of the Westmoreland Rosebud Mine, which provides coal to Colstrip. In the first, the Montana District Court for Rosebud County issued an order vacating a permit for one area of the mine, which decision was subsequently upheld by the Montana Supreme Court. In the second, the Montana Federal District Court vacated a decision by the federal Office of Surface Mining Reclamation and Enforcement, a branch of the United States Department of Interior, approving expansion of the mine into a new area, pending further analysis of potential environmental impact. An initial appeal of that decision to the Ninth Circuit was dismissed for lack of jurisdiction, pending further proceedings before the Department of the Interior. Avista Corp. is not a party to either of these proceedings, but continues to monitor the progress of both issues 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 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 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 engaged 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 excavation work. The incident resulted in a fire which destroyed one residence and resulted in minor injuries to the occupants. In January 2023, the Company was served with a lawsuit filed in the District Court of Kootenai County, Idaho by one property owner, seeking unspecified damages. In February 2024, the Company became aware of a second lawsuit filed by the owners of the adjacent property, seeking damages for personal injury and emotional distress from having witnessed the incident. The Company intends to vigorously defend itself in both actions.

Other Contingencies

In the normal course of business, the Company has various other legal claims and contingent matters outstanding. The Company believes 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 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 States of Montana and Idaho are each conducting general adjudications of water rights in areas that include the Company's facilities in these states. Claims within the Clark Fork River basin and the Spokane River basin could adversely affect the energy production of the Company's hydroelectric facilities. The Company is and will continue to be a participant in the 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 23. REGULATORY MATTERS

Regulatory Assets and Liabilities

The following table presents the Company's regulatory assets and liabilities as of December 31, 2023 (dollars in thousands):

		Receiving Regulatory Treatment			2023		2022	
	Remaining Amortization Period	Earning A Return (1)	Not Earning A Return	Expected Recovery or Refund (2)	Current	Non-current	Current	Non-current
Regulatory Assets:								
Deferred income tax	(3) (16)	$ —	$ 244,303	$ —	$ —	$ 244,303	$ —	$ 240,325
Pensions and other postretirement benefit plans	(4)	—	117,658	—	—	117,658	—	135,337
Climate Commitment Act	(14)	46,022	—	—	—	46,022	—	—
Energy commodity derivatives	(5)	—	69,139	—	51,419	17,720	112,090	18,185
Unamortized debt repurchase costs	(6)	5,701	—	—	—	5,701	—	6,177
Settlement with Coeur d'Alene Tribe	2059	36,692	—	—	—	36,692	—	37,809
Demand side management programs	(3)	—	10,033	—	—	10,033	—	3,683
Decoupling surcharge	2025	10,107	—	—	4,638	5,469	6,250	5,449
Utility plant abandoned	(7)	34,852	3,422	—	—	38,274	—	24,389
Interest rate swaps	(8)	178,898	—	591	—	179,489	—	185,919
Deferred power costs	(3)	49,844	—	—	29,190	20,654	23,356	24,043
Deferred natural gas costs	(3)	60,667	—	—	60,667	—	52,091	—
AFUDC above FERC allowed rate	(11)	49,985	—	—	—	49,985	—	51,649
COVID-19 deferrals	(12)	—	—	12,142	—	12,142	—	9,793
Advanced meter infrastructure	(13)	29,345	—	—	—	29,345	—	32,381
Other regulatory assets	(3)	41,072	35,793	4,229	413	80,681	—	58,189
Total regulatory assets		$ 543,185	$ 480,348	$ 16,962	$ 146,327	$ 894,168	$ 193,787	$ 833,328
Regulatory Liabilities:								
Deferred natural gas costs	(3)	$ 9,296	$ —	$ —	$ 9,296	$ —	$ —	$ —
Deferred power costs	(3)	4,000	—	—	—	4,000	—	—
Utility plant retirement costs	(9)	417,027	—	—	—	417,027	—	376,817
Excess deferred income taxes	(10)	307,539	—	—	14,510	293,029	15,310	314,096
Other income tax related liabilities	(3) (15)	—	81,711	—	25,129	56,582	57,957	76,638
Climate Commitment Act	(14)	37,231	—	—	—	37,231	—	—
Interest rate swaps	(8)	12,216	—	11,536	—	23,752	—	24,204
Decoupling rebate	2025	25,024	—	—	18,680	6,344	9,469	20,476
COVID-19 deferrals	(12)	—	8	10,164	—	10,172	—	11,874
Other regulatory liabilities	(3)	4,298	12,623	—	8,392	8,529	12,929	16,732
Total regulatory liabilities		$ 816,631	$ 94,342	$ 21,700	$ 76,007	$ 856,666	$ 95,665	$ 840,837

(1) Earning a return includes either interest on the regulatory asset/liability or a return on the investment as a component of rate base at the allowed rate of return.

(2) Expected recovery is pending regulatory treatment including regulatory assets and liabilities with prior regulatory precedence.

(3) Remaining amortization period varies depending on timing of underlying transactions.

(4) As the Company has historically recovered and currently recovers its pension and other postretirement benefit costs related to its regulated operations in retail rates, the Company records a regulatory asset for that portion of its pension and other postretirement benefit funding deficiency.

(5) The WUTC and the 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 losses result in adjustments to retail rates through PGAs, the ERM in Washington, the 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.

(6) Premiums paid or discounts received to repurchase debt are amortized over the remaining life of the original debt repurchased or, if new debt is issued in connection with the repurchase, these costs are amortized over the life of the new debt. These costs are recovered through retail rates as a component of interest expense.

(7) The WUTC approved recovery of AMI project costs through the 2020 general rate case settlements, including amortization of retired meters replaced through the project through 2033. The IPUC approved deferral accounting treatment for the Idaho AMI project, which will be included in a future rate case. In addition, the IPUC approved

the depreciation of Colstrip through 2027, and as such the remaining depreciation after our exit of Colstrip in 2025 is included in this balance. There are additional smaller projects included in the balance the Company expects to fully recover, which have not yet been through the regulatory process.

(8) 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. Settled interest rate swap derivatives which have been through a general rate case proceeding are classified as earning a return in the table above, whereas all unsettled interest rate swap derivatives and settled interest rate swap derivatives which have not been included in a general rate case are classified as expected recovery.

(9) This amount is dependent upon the cost of removal of underlying utility plant assets and the life of utility plant.

(10) This balance represents amounts due back to customers and resulted from the Tax Cuts and Jobs Act signed into law in December 2017, which changed the federal income tax rate from 35 percent to 21 percent. The Company revalued all deferred income taxes as of December 31, 2017. The Company expects the amounts for utility plant items for Avista Utilities to be returned to customers over a period of approximately 33 years. The Company expects the AEL&P amounts to be returned to customers over a period of approximately 22 years. Prior to 2022, for depreciation-related temporary differences under the normalized tax accounting method, the Company utilized the average rate assumption method to compute the amounts returned to customers. Beginning in 2022, the Company changed to the alternative method, to comply with revenue procedures and private letter rulings.

(11) This amount is being amortized based on the underlying utility plant assets and the life of utility plant.

(12) The WUTC, IPUC and OPUC issued accounting orders allowing the Company to defer certain costs, net of benefits, related to the COVID-19 pandemic. The Company has recorded all benefits on a gross basis as a regulatory liability to customers and all additional allowed costs are a regulatory asset. The ratemaking treatment will be determined in future general rate cases in each jurisdiction.

(13) This amount represents the deferral of the depreciation expense of the Company's AMI project in Washington state. Recovery of these amounts was approved by WUTC in the 2021 general rate case order, and the asset will be amortized through 2033.

(14) Regulatory assets related to the Climate Commitment Act represent costs incurred to comply with the program. Regulatory liabilities related to the Climate Commitment Act represent proceeds from the required sale of allowances, which will be returned to customers. The Company will submit filings periodically to receive approval to include these items in customer rates.

(15) The majority of this amount represents the remaining tax customer credits being returned to customers and the tax gross-up on tax customer credits and investment tax credits, which have a corresponding deferred tax asset within Note 13.

(16) The majority of this balance represents flow-through income tax accounting differences and the related tax gross-up which have a corresponding deferred tax liability within Note 13.

Power Cost Deferrals and Recovery Mechanisms

Deferred power supply costs are recorded as a deferred charge or liability on the Consolidated 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 Utilities 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 Utilities 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. Under the ERM, the Company defers these differences (over the $4.0 million deadband and sharing bands) for future surcharge or rebate to customers.

The following is a summary of the ERM:

Annual Power Supply Cost Variability	Deferred for Future Surcharge or Rebate to Customers	Expense or Benefit to the Company
Within +/- $0 to $4 million (deadband)	0%	100%
Higher by $4 million to $10 million	50%	50%
Lower by $4 million to $10 million	75%	25%
Higher or lower by over $10 million	90%	10%

Total net deferred power costs under the ERM were assets of $37.6 million as of December 31, 2023 and $30.5 million as of December 31, 2022. The deferred power cost assets represent amounts due from customers, and deferred power cost liabilities represent amounts due to customers.

Pursuant to WUTC requirements, should the cumulative deferral balance exceed $30 million in the rebate or surcharge direction, the Company must make a filing with the WUTC to adjust customer rates to either return the balance to customers or recover the balance from customers. Avista Utilities 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. In June 2023, the Company received approval from the WUTC for a rate surcharge to customers over a two-year period, effective July 1, 2023.

In the 2024 Washington general rate case, the Company proposed changing the ERM so the entire mechanism would result in a 95 percent customer, 5 percent company sharing basis. This request is pending WUTC approval.

Avista Utilities has a PCA mechanism in Idaho allowing for the modification of electric rates on October 1 of each year with IPUC approval. Under the PCA mechanism, Avista Utilities 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 assets of $7.6 million as of December 31, 2023 and $16.3 million as of December 31, 2022. Deferred power cost assets represent amounts due from customers and liabilities represent amounts due to customers.

Natural Gas Cost Deferrals and Recovery Mechanisms

Avista Utilities 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. In Oregon, the Company absorbs (cost or benefit) 10 percent of the difference between actual and projected natural gas costs included in base retail rates for supply that is not hedged. Total net deferred natural gas costs were an asset of $51.4 million as of December 31, 2023 and $52.1 million as of December 31, 2022. 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 Utilities' jurisdictions, Avista Utilities' 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 through March 31, 2025. In the Company's 2024 Washington general rate cases, it requested the mechanisms be extended through December 2026. That request is pending before the WUTC.

Electric and natural gas decoupling surcharge rate adjustments to customers are limited to a 3 percent increase on an annual basis, with remaining surcharge balance carried forward for recovery in a future period. There is no limit on the level of rebate rate adjustments. New customers added after a test period are not decoupled until included in a future test period.

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. Through the 2022 general rate cases, the Company modified its earnings test 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 ROE, one-third of the earnings above the 100 basis points would be deferred and later returned to customers. The earnings review is separate from the decoupling mechanism and was in place prior to decoupling.

Cumulative Decoupling and Earnings Sharing Mechanism Balances

As of December 31, 2023 and December 31, 2022, the Company had the following cumulative balances outstanding related to decoupling and earnings sharing mechanisms in its various jurisdictions (dollars in thousands):

	December 31, 2023	December 31, 2022
Washington		
Decoupling rebate	$ (3,232)	$ (13,210)
Idaho		
Decoupling rebate	$ (7,961)	$ (7,889)
Provision for earnings sharing rebate	(572)	(686)
Oregon		
Decoupling (rebate) surcharge	$ (3,724)	$ 2,853

NOTE 24. INFORMATION BY BUSINESS SEGMENTS

The business segment presentation reflects the basis used by the Company's management to analyze performance and determine the allocation of resources. The Company's management evaluates performance based on income (loss) from operations before income taxes as well as net income (loss). The accounting policies of the segments are the same as those described in the summary of significant accounting policies. Avista Utilities' business is managed based on the total regulated utility operation; therefore, it is considered one segment. AEL&P is a separate reportable business segment as it has separate financial reports reviewed in detail by the Chief Operating Decision Maker and its operations and risks are sufficiently different from Avista Utilities and the other businesses at AERC that it cannot be aggregated with other operating segments. The Other category, which is not a reportable segment, includes other investments and operations of various subsidiaries, as well as certain other operations of Avista Capital.

The following table presents information for each of the Company's business segments (dollars in thousands):

	Avista Utilities	Alaska Electric Light and Power Company	Total Utility	Other	Intersegment Eliminations [1]	Total
For the year ended December 31, 2023:						
Operating revenues	$ 1,702,857	$ 48,139	$ 1,750,996	$ 558	$ —	$ 1,751,554
Resource costs	698,546	3,826	702,372	—	—	702,372
Other operating expenses	398,523	15,085	413,608	2,760	—	416,368
Depreciation and amortization	254,401	10,928	265,329	80	—	265,409
Income (loss) from operations	242,678	17,294	259,972	(2,282)	—	257,690
Interest expense [2]	136,924	5,852	142,776	1,881	(1,358)	143,299
Income tax expense (benefit)	(35,353)	3,315	(32,038)	(1,592)	—	(33,630)
Net income (loss)	167,016	8,937	175,953	(4,773)	—	171,180
Capital expenditures [3]	484,716	13,921	498,637	—	—	498,637
For the year ended December 31, 2022:						
Operating revenues	$ 1,663,815	$ 45,704	$ 1,709,519	$ 688	$ —	$ 1,710,207
Resource costs	732,298	3,564	735,862	—	—	735,862
Other operating expenses	390,597	14,568	405,165	11,603	—	416,768
Depreciation and amortization	242,198	10,819	253,017	125	—	253,142
Income (loss) from operations	185,582	15,700	201,282	(11,040)	—	190,242
Interest expense [2]	112,213	5,960	118,173	791	(272)	118,692
Income tax expense (benefit)	(27,368)	2,337	(25,031)	7,840	—	(17,191)
Net income	117,901	7,545	125,446	29,730	—	155,176
Capital expenditures [3]	443,373	8,622	451,995	834	—	452,829
For the year ended December 31, 2021:						
Operating revenues	$ 1,392,999	$ 45,366	$ 1,438,365	$ 571	$ —	$ 1,438,936
Resource costs	493,289	3,834	497,123	—	—	497,123
Other operating expenses	352,241	13,884	366,125	5,927	—	372,052
Depreciation and amortization	221,552	10,363	231,915	261	—	232,176
Income (loss) from operations	217,663	16,186	233,849	(5,617)	—	228,232
Interest expense [2]	99,629	6,096	105,725	522	(95)	106,152
Income tax expense	6,029	2,763	8,792	3,239	—	12,031
Net income	125,558	7,224	132,782	14,552	—	147,334
Capital expenditures [3]	435,887	4,052	439,939	1,270	—	441,209
Total Assets:						
As of December 31, 2023	$ 7,262,704	$ 269,683	$ 7,532,387	$ 191,665	$ (21,575)	$ 7,702,477
As of December 31, 2022	6,976,164	264,322	7,240,486	187,027	(10,163)	7,417,350
As of December 31, 2021	6,458,244	265,422	6,723,666	132,158	(2,241)	6,853,583

(1) Intersegment eliminations reported as interest expense represent intercompany interest. Intersegment eliminations reported as assets represent intersegment accounts receivable.

(2) Including interest expense to affiliated trusts.

(3) The capital expenditures for the other businesses are included in other investing activities on the Consolidated Statements of Cash Flows.

ITEM 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

Not applicable.

ITEM 9A. Controls and Procedures

CONCLUSION REGARDING THE EFFECTIVENESS OF DISCLOSURE CONTROLS AND PROCEDURES

The Company has disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (Act) that are designed to ensure that information required to be disclosed in the reports it files or submits under the Act is recorded, processed, summarized and reported on a timely basis. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Company in the reports that it files or submits under the Act is accumulated and communicated to the Company's management, including its principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. With the participation of the Company's principal executive officer and principal financial officer, the Company's management evaluated its disclosure controls and procedures as of the end of the period covered by this report. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives. Based upon this evaluation, the Company's principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures are effective at a reasonable assurance level as of December 31, 2023.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The Company's management, together with its consolidated subsidiaries, is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934). The Company's internal control over financial reporting is a process designed under the supervision of the Company's principal executive officer and principal financial officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external reporting purposes in accordance with accounting principles generally accepted in the United States of America.

The Company's internal control over financial reporting includes policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets; provide reasonable assurances that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures are being made only in accordance with authorizations of management and the directors of the Company; and provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the Company's financial statements.

Under the supervision and with the participation of the Company's management, including the Company's principal executive officer and principal financial officer, the Company conducted an assessment of the effectiveness of the Company's internal control over financial reporting based on the framework established in Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management determined that the Company's internal control over financial reporting as of December 31, 2023 is effective at a reasonable assurance level.

The Company's independent registered public accounting firm, Deloitte & Touche LLP, has issued an attestation report on the Company's internal control over financial reporting as of December 31, 2023.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There have been no changes in the Company's internal control over financial reporting that occurred during the Company's last fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of Avista Corporation

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Avista Corporation and subsidiaries (the "Company") as of December 31, 2023, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2023, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2023, of the Company and our report dated February 20, 2024, expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 20, 2024

ITEM 9B. Other Information

During the fiscal quarter ended December 31, 2023, none of our directors or officers informed U.S. of the adoption or termination of a "Rule 10b5-1 trading arrangement" or "non-Rule 10b5-1 trading arrangement," as those terms are defined in Regulation S-K, Item 408.

ITEM 9C. Disclosure Regarding Foreign Jurisdictions That Prevent Inspections

Not applicable.

Part III

ITEM 10. Directors, Executive Officers and Corporate Governance

The information required by this Item (other than the information regarding executive officers and the Company's Code of Business Conduct and Ethics set forth below) is omitted pursuant to General Instruction G to Form 10-K. Such information is incorporated herein by reference as follows:

- on and after the date of filing with the SEC the Registrant's definitive Proxy Statement relating to its Annual Meeting of Shareholders scheduled to be held on May 1, 2024, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 31, 2023, relating to its Annual Meeting of Shareholders held on May 11, 2023.

Information about our Executive Officers

Name	Age	Business Experience
Dennis P. Vermillion	**62**	Chief Executive Officer since October 2019; Director since January 2018; President of Avista Corp. from January 2018 to October 2023; Senior Vice President from January 2010 to January 2018; Vice President July 2007–December 2009; President—Avista Utilities since January 2009; Vice President of Energy Resources and Optimization—Avista Utilities July 2007–December 2008; President and Chief Operating Officer of Avista Energy February 2001–July 2007; various other management and staff positions with the Company since 1985.
Heather L. Rosentrater	**46**	President and Chief Operating Officer since October 2023; Senior Vice President and Chief Operating Officer from September 2022 to October 2023; Senior Vice President, Energy Delivery and Shared Services from January 2020 to September 2022; Senior Vice President, Energy Delivery from October 2019 to December 2019; Vice President of Energy Delivery from December 2015 to October 2019; various other management and staff positions with the Company since 1996.
Kevin J. Christie	**56**	Senior Vice President, Chief Financial Officer, Treasurer and Regulatory Affairs Officer since May 2023; Senior Vice President, External Affairs and Chief Customer Officer from October 2019 to May 2023; Vice President, External Affairs and Chief Customer Officer January 2018 to October 2019; Vice President of Customer Solutions from February 2015 to January 2018; various other management and staff positions with the Company since 2005.
Bryan A. Cox	**54**	Senior Vice President, Safety and Chief People Officer since October 2023; Vice President, Safety and Chief People Officer from September 2022 to October 2023; Vice President, Safety and Human Resources from January 2020 to September 2022; Vice President, Safety and HR Shared Services from January 2018 to January 2020; various other management and staff positions with the Company since 1997.
Gregory C. Hesler	**46**	Senior Vice President, General Counsel, Corporate Secretary and Chief Ethics/Compliance Officer since September 2022; Vice President, General Counsel, Corporate Secretary and Chief Ethics/Compliance Officer from May 2020 to September 2022; Vice President, General Counsel and Chief Compliance Officer from January 2020 to May 2020; various other management and staff positions with the Company since 2015.

Jason R. Thackston	**54**	Senior Vice President, Chief Strategy and Clean Energy Officer since September 2022; Senior Vice President of Energy Resources and Environmental Compliance Officer from May 2018 to September 2022; Senior Vice President of Energy Resources from January 2014 to May 2018; Vice President of Energy Resources from December 2012 to January 2014; Vice President of Customer Solutions—Avista Utilities from June 2012 to December 2012; Vice President of Energy Delivery from April 2011 to December 2012; Vice President of Finance from June 2009 to April 2011; various other management and staff positions with the Company since 1996.
Joshua D. DiLuciano	**43**	Vice President of Energy Delivery since September 2022; various other management and staff positions with the Company since 2006.
Latisha D. Hill	**45**	Vice President of Community and Economic Vitality since January 2020; various other management and staff positions with the Company since 2005.
Scott J. Kinney	**55**	Vice President of Energy Resources since September 2022; various other management and staff positions with the Company since 1999.
Ryan L. Krasselt	**54**	Vice President, Controller and Principal Accounting Officer since October 2015; various other management and staff positions with the Company since 2001.
Wayne O. Manuel	**51**	Vice President, Chief Information Officer and Chief Security Officer since June 2023; prior to employment with the Company, Senior Vice President, Chief Strategy Officer and Chief Information Officer of Valley Medical Center from 2014 to May 2023.
David J. Meyer	**70**	Vice President and Chief Counsel for Regulatory and Governmental Affairs since February 2004; Senior Vice President and General Counsel from September 1998 to February 2004.

All of the Company's executive officers, with the exception of Joshua D. DiLuciano, Scott J. Kinney, David J. Meyer and Wayne O. Manuel were officers or directors of one or more of the Company's subsidiaries in 2023. The Company's executive officers are appointed annually by the Board of Directors.

The Company has adopted a Code of Conduct for directors, officers (including the principal executive officer, principal financial officer and principal accounting officer), and employees. The Code of Conduct is available on the Company's website at www.avistacorp.com and will be provided to any shareholder without charge upon written request to:

Avista Corp.
General Counsel
P.O. Box 3727 MSC-10
Spokane, Washington 99220-3727

Any changes to or waivers for executive officers and directors of the Company's Code of Conduct will be posted on the Company's website.

ITEM 11. Executive Compensation

The information required by this Item is omitted pursuant to General Instruction G to Form 10-K. Such information is incorporated herein by reference as follows:

- on and after the date of filing with the SEC the Registrant's definitive Proxy Statement relating to its Annual Meeting of Shareholders scheduled to be held on May 1, 2024, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 31, 2023, relating to its Annual Meeting of Shareholders held on May 11, 2023.

ITEM 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

(a) Security ownership of certain beneficial owners (owning 5 percent or more of Registrant's voting securities):

Information regarding security ownership of certain beneficial owners (owning 5 percent or more of Registrant's voting securities) has been omitted pursuant to General Instruction G to Form 10-K. Such information is incorporated herein by reference as follows:

- on and after the date of filing with the SEC the Registrant's definitive Proxy Statement relating to its Annual Meeting of Shareholders scheduled to be held on May 1, 2024, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 31, 2023, relating to its Annual Meeting of Shareholders held on May 11, 2023; reference also being made to Schedules 13G, as amended, on file with the SEC with respect to the Registrant's voting securities (the information contained in such schedules 13G, as amended, not being incorporated herein by reference).

(b) Security ownership of management:

The information required by this Item regarding the security ownership of management is omitted pursuant to General Instruction G to Form 10-K. Such information is incorporated herein by reference as follows:

- on and after the date of filing with the SEC the Registrant's definitive Proxy Statement relating to its Annual Meeting of Shareholders scheduled to be held on May 1, 2024, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 31, 2023, relating to its Annual Meeting of Shareholders held on May 11, 2023.

(c) Changes in control:

None.

(d) Securities authorized for issuance under equity compensation plans as of December 31, 2023:

Plan category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights [(1)]	(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders [(2)]	—	$ —	665,198

(1) Excludes unvested restricted shares and performance share awards granted under Avista Corp.'s Long-Term Incentive Plan. At December 31, 2023, 152,140 Restricted Share awards were outstanding. Performance and market-based share awards may be paid out at zero shares at a minimum achievement level; 258,150 shares at target level; or 516,300 shares at a maximum level. Because there is no exercise price associated with restricted shares or performance and market-based share awards, such shares are not included in the weighted-average price calculation.

(2) Includes the Long-Term Incentive Plan approved by shareholders in 1998 (amended in 2016) and the Non-Employee Director Stock Plan approved by shareholders in 1996. In February 2005, the Board of Directors elected to terminate the Non-Employee Director Stock Plan.

ITEM 13. Certain Relationships and Related Transactions, and Director Independence

The information required by this Item is omitted pursuant to General Instruction G to Form 10-K. Such information is incorporated herein by reference as follows:

- on and after the date of filing with the SEC the Registrant's definitive Proxy Statement relating to its Annual Meeting of Shareholders scheduled to be held on May 1, 2024, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 31, 2023, relating to its Annual Meeting of Shareholders held on May 11, 2023.

ITEM 14. Principal Accounting Fees and Services

The information required by this Item is omitted pursuant to General Instruction G to Form 10-K. Such information is incorporated herein by reference as follows:

- on and after the date of filing with the SEC the Registrant's definitive Proxy Statement relating to its Annual Meeting of Shareholders scheduled to be held on May 1, 2024, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 31, 2023, relating to its Annual Meeting of Shareholders held on May 11, 2023.

Part IV

ITEM 15. Exhibits, Financial Statement Schedules

(a) 1. Financial Statements (Included in Part II of this report):

Report of Independent Registered Public Accounting Firm

Consolidated Statements of Income for the Years Ended December 31, 2023, 2022 and 2021

Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2023, 2022 and 2021

Consolidated Balance Sheets as of December 31, 2023, and 2022

Consolidated Statements of Cash Flows for the Years Ended December 31, 2023, 2022 and 2021

Consolidated Statements of Equity for the Years Ended December 31, 2023, 2022 and 2021

Notes to Consolidated Financial Statements

(a) 2. Financial Statement Schedules:

None

(a) 3. Exhibits:

Reference is made to the Exhibit Index commencing on the following page. The Exhibits include the management contracts and compensatory plans or arrangements required to be filed as exhibits to this Form 10-K pursuant to Item 15(b).

Exhibit	Previously Filed [1] With Registration Number	As Exhibit	
2.1	(with Form 8-K filed as of January 17, 2023)	2.1	Colstrip Units 3 & 4 Interests Abandonment and Acquisition agreement, dated as of January 16, 2023, among Avista Corporation and NorthWestern Corporation.
3.1	(with June 30, 2012 Form 10-Q)	3.1	Restated Articles of Incorporation of Avista Corporation, as amended and restated June 6, 2012.
3.2	(with Form 8-K filed as of August 17, 2016)	3.2	Bylaws of Avista Corporation, as amended August 17, 2016.
4.1	2-4077	B-3	Mortgage and Deed of Trust, dated as of June 1, 1939.*
4.2	2-9812	4(c)	First Supplemental Indenture, dated as of October 1, 1952.*
4.3	2-60728	2(b)-2	Second Supplemental Indenture, dated as of May 1, 1953.*
4.4	2-13421	4(b)-3	Third Supplemental Indenture, dated as of December 1, 1955.*
4.5	2-13421	4(b)-4	Fourth Supplemental Indenture, dated as of March 15, 1967.*
4.6	2-60728	2(b)-5	Fifth Supplemental Indenture, dated as of July 1, 1957.*
4.7	2-60728	2(b)-6	Sixth Supplemental Indenture, dated as of January 1, 1958.*
4.8	2-60728	2(b)-7	Seventh Supplemental Indenture, dated as of August 1, 1958.*
4.9	2-60728	2(b)-8	Eighth Supplemental Indenture, dated as of January 1, 1959.*
4.10	2-60728	2(b)-9	Ninth Supplemental Indenture, dated as of January 1, 1960.*
4.11	2-60728	2(b)-10	Tenth Supplemental Indenture, dated as of April 1, 1964.*
4.12	2-60728	2(b)-11	Eleventh Supplemental Indenture, dated as of March 1, 1965.*
4.13	2-60728	2(b)-12	Twelfth Supplemental Indenture, dated as of May 1, 1966.*
4.14	2-60728	2(b)-13	Thirteenth Supplemental Indenture, dated as of August 1, 1966.*
4.15	2-60728	2(b)-14	Fourteenth Supplemental Indenture, dated as of April 1, 1970.*
4.16	2-60728	2(b)-15	Fifteenth Supplemental Indenture, dated as of May 1, 1973.*
4.17	2-60728	2(b)-16	Sixteenth Supplemental Indenture, dated as of February 1, 1975.*
4.18	2-60728	2(b)-17	Seventeenth Supplemental Indenture, dated as of November 1, 1976.*
4.19	2-69080	2(b)-18	Eighteenth Supplemental Indenture, dated as of June 1, 1980.*
4.20	(with 1980 Form 10-K)	4(a)-20	Nineteenth Supplemental Indenture, dated as of January 1, 1981.*
4.21	2-79571	4(a)-21	Twentieth Supplemental Indenture, dated as of August 1, 1982.*

Exhibit	Previously Filed[1] With Registration Number	As Exhibit	
4.22	(with Form 8-K dated September 20, 1983)	4(a)-22	Twenty-First Supplemental Indenture, dated as of September 1, 1983.*
4.23	2-94816	4(a)-23	Twenty-Second Supplemental Indenture, dated as of March 1, 1984.*
4.24	(with 1986 Form 10-K)	4(a)-24	Twenty-Third Supplemental Indenture, dated as of December 1, 1986.*
4.25	(with 1987 Form 10-K)	4(a)-25	Twenty-Fourth Supplemental Indenture, dated as of January 1, 1988.*
4.26	(with 1989 Form 10-K)	4(a)-26	Twenty-Fifth Supplemental Indenture, dated as of October 1, 1989.*
4.27	33-51669	4(a)-27	Twenty-Sixth Supplemental Indenture, dated as of April 1, 1993.*
4.28	(with 1993 Form 10-K)	4(a)-28	Twenty-Seventh Supplemental Indenture, dated as of January 1, 1994.
4.29	(with 2001 Form 10-K)	4(a)-29	Twenty-Eighth Supplemental Indenture, dated as of September 1, 2001.
4.30	333-82502	4(b)	Twenty-Ninth Supplemental Indenture, dated as of December 1, 2001.
4.31	(with June 30, 2002 Form 10-Q)	4(f)	Thirtieth Supplemental Indenture, dated as of May 1, 2002.
4.32	333-39551	4(b)	Thirty-First Supplemental Indenture, dated as of May 1, 2003.
4.33	(with September 30, 2003 Form 10-Q)	4(f)	Thirty-Second Supplemental Indenture, dated as of September 1, 2003.
4.34	333-64652	4(a)33	Thirty-Third Supplemental Indenture, dated as of May 1, 2004.
4.35	(with Form 8-K dated as of December 15, 2004)	4.1	Thirty-Fourth Supplemental Indenture, dated as of November 1, 2004.
4.36	(with Form 8-K dated as of December 15, 2004)	4.2	Thirty-Fifth Supplemental Indenture, dated as of December 1, 2004.
4.37	(with Form 8-K dated as of December 15, 2004)	4.3	Thirty-Sixth Supplemental Indenture, dated as of December 1, 2004.
4.38	(with Form 8-K dated as of December 15, 2004)	4.4	Thirty-Seventh Supplemental Indenture, dated as of December 1, 2004.
4.39	(with Form 8-K dated as of May 12, 2005)	4.1	Thirty-Eighth Supplemental Indenture, dated as of May 1, 2005.
4.40	(with Form 8-K dated as of November 17, 2005)	4.1	Thirty-Ninth Supplemental Indenture, dated as of November 1, 2005.
4.41	(with Form 8-K dated as of April 6, 2006)	4.1	Fortieth Supplemental Indenture, dated as of April 1, 2006.
4.42	(with Form 8-K dated as of December 15, 2006)	4.1	Forty-First Supplemental Indenture, dated as of December 1, 2006.
4.43	(with Form 8-K dated as of April 3, 2008)	4.1	Forty-Second Supplemental Indenture, dated as of April 1, 2008.

Exhibit	Previously Filed [1] With Registration Number	As Exhibit	
4.44	(with Form 8-K dated as of November 26, 2008)	4.1	Forty-Third Supplemental Indenture, dated as of November 1, 2008.
4.45	(with Form 8-K dated as of December 16, 2008)	4.1	Forty-Fourth Supplemental Indenture, dated as of December 1, 2008.
4.46	(with Form 8-K dated as of December 30, 2008)	4.3	Forty-Fifth Supplemental Indenture, dated as of December 1, 2008.
4.47	(with Form 8-K dated as of September 15, 2009)	4.1	Forty-Sixth Supplemental Indenture, dated as of September 1, 2009.
4.48	(with Form 8-K dated as of November 25, 2009)	4.1	Forty-Seventh Supplemental Indenture, dated as of November 1, 2009.
4.49	(with Form 8-K dated as of December 15, 2010)	4.5	Forty-Eighth Supplemental Indenture, dated as of December 1, 2010.
4.50	(with Form 8-K dated as of December 20, 2010)	4.1	Forty-Ninth Supplemental Indenture, dated as of December 1, 2010.
4.51	(with Form 8-K dated as of December 30, 2010)	4.1	Fiftieth Supplemental Indenture, dated as of December 1, 2010.
4.52	(with Form 8-K dated as of February 11, 2011)	4.1	Fifty-First Supplemental Indenture, dated as of February 1, 2011.
4.53	(with Form 8-K dated as of August 16, 2011)	4.1	Fifty-Second Supplemental Indenture, dated as of August 1, 2011.
4.54	(with Form 8-K dated as of December 14, 2011)	4.1	Fifty-Third Supplemental Indenture, dated as of December 1, 2011.
4.55	(with Form 8-K dated as of November 30, 2012)	4.1	Fifty-Fourth Supplemental Indenture, dated as of November 1, 2012.
4.56	(with Form 8-K dated as of August 14, 2013)	4.1	Fifty-Fifth Supplemental Indenture, dated as of August 1, 2013.
4.57	(with Form 8-K dated as of April 18, 2014)	4.1	Fifty-Sixth Supplemental Indenture, dated as of April 1, 2014.
4.58	(with Form 8-K dated as of December 18, 2014)	4.1	Fifty-Seventh Supplemental Indenture, dated as of December 1, 2014.
4.59	(with Form 8-K dated as of December 16, 2015)	4.1	Fifty-Eighth Supplemental Indenture, dated as of December 1, 2015.
4.60	(with Form 8-K dated as of December 16, 2016)	4.1	Fifty-Ninth Supplemental Indenture, dated as of December 1, 2016.
4.61	(with Form 8-K dated as of December 14, 2017)	4.1	Sixtieth Supplemental Indenture, dated as of December 1, 2017.

Exhibit	Previously Filed [1] With Registration Number	As Exhibit	
4.62	(with Form 8-K dated as of May 15, 2018)	4(a)(62)	Sixty-First Supplemental Indenture, dated as of May 1, 2018.
4.63	(with Form 8-K dated as of November 26, 2019)	4.1	Sixty-Second Supplemental Indenture, dated as of November 1, 2019.
4.64	(with Form 8-K dated as of June 4, 2020)	4.1	Sixty-Third Supplemental Indenture, dated as of June 1, 2020.
4.65	(with Form 8-K dated as of September 30, 2020)	4.1	Sixty-Fourth Supplemental Indenture, dated as of September 1, 2020.
4.66	(with Form 8-K dated as of September 30, 2021)	4.1	Sixty-Fifth Supplemental Indenture, dated as of September 1, 2021.
4.67	(with Form 8-K dated as of March 8, 2022)	4.1	Sixty-Sixth Supplemental Indenture, dated as of March 1, 2022.
4.68	(with Form 8-K dated as of March 29, 2023)	4.1	Sixty-Seventh Supplemental Indenture, dated as of March 1, 2023.
4.69	(with Form 8-K dated as of June 8, 2023)	4.1	Sixty-Eighth Supplemental Indenture, dated as of June 1, 2023.
4.70	333-82165	4(a)	Indenture dated as of April 1, 1998 between Avista Corporation and The Bank of New York, as Successor Trustee.
4.71	(with Form 8-K dated as of December 15, 2004)	4.5	Supplemental Indenture No. 1, dated as of December 1, 2004 to the Indenture dated as of April 1, 1998 between Avista Corporation and JPMorgan Chase Bank, N.A.
4.72	(with Form 8-K dated as of December 15, 2010)	4.1	Loan Agreement between City of Forsyth, Montana and Avista Corporation $66,700,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 2010A dated as of December 1, 2010.
4.73	(with Form 8-K dated as of December 15, 2010)	4.3	Trust Indenture between City of Forsyth, and the Bank of New York Mellon Trust Company, N.A., as Trustee, $66,700,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 2010A, dated as of December 1, 2010.
4.74	(with Form 8-K dated as of December 15, 2010)	4.2	Loan Agreement between City of Forsyth, Montana and Avista Corporation $17,000,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 2010B dated as of December 1, 2010.
4.75	(with Form 8-K dated as of December 15, 2010)	4.4	Trust Indenture between City of Forsyth, and the Bank of New York Mellon Trust Company, N.A., as Trustee, $17,000,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 2010B, dated as of December 1, 2010.
4.76	(with June 30, 2012 Form 10-Q)	3.1	Restated Articles of Incorporation of Avista Corporation, as amended and restated June 6, 2012 (see Exhibit 3.1 herein).

Exhibit	Previously Filed[1] With Registration Number	As Exhibit	
4.77	(with Form 8-K filed as of August 17, 2016)	3.2	Bylaws of Avista Corporation, as amended August 17, 2016 (see Exhibit 3.2 herein).
4.78	(with 2022 Form 10-K)	4.76	Description of the Registrant's Securities registered under Section 12 of the Securities Exchange Act of 1934.
10.1	(with Form 8-K dated as of February 11, 2011)	10.1	Credit Agreement, dated as of February 11, 2011, among Avista Corporation, the Banks Party hereto, The Bank of New York Mellon, Keybank National Association, and U.S. Bank National Association, as Co-Documentation Agents, Wells Fargo Bank National Association as Syndication Agent and an Issuing Bank, and Union Bank N.A. as Administrative Agent and an Issuing Bank.
10.2	(with Form 8-K dated as of April 18, 2014)	10.1	Second Amendment to Credit Agreement, dated as of April 18, 2014, among Avista Corporation, Wells Fargo Bank, National Association, as an Issuing Bank, Union Bank, N.A. as Administrative Agent and an Issuing Bank, and the financial institutions identified hereof as Continuing Lenders and Exiting Lender.
10.3	(with Form 8-K dated as of June 8, 2023)	10.1	Fifth Amendment to Credit Agreement, dated as of June 8, 2023, among Avista Corporation, the lending financial institutions, U.S. Bank National Corporation and Wells Fargo Bank National Association as issuing banks, and MUFG Bank, LTD as Administrative Agent.
10.4	(with Form 8-K dated as of April 18, 2014)	10.2	Bond Delivery Agreement, dated as of April 18, 2014, between Avista Corporation and Union Bank, N.A.
10.5	(with Form 8-K dated as of June 8, 2023)	10.2	Bond Delivery Agreement, dated as of June 8, 2023, between Avista Corporation and Union Bank, N.A.
10.6	(with Form 8-K dated as of December 14, 2011)	10.1	First Amendment and Waiver Thereunder, dated as of December 14, 2011, to the Credit Agreement dated as of February 11, 2011, among Avista Corporation, the Banks Party hereto, Wells Fargo Bank National Association as an Issuing Bank, and Union Bank N.A. as Administrative Agent and an Issuing Bank.
10.7	(with 2002 Form 10-K)	10(b)-3	Priest Rapids Project Product Sales Contract executed by Public Utility District No. 2 of Grant County, Washington and Avista Corporation dated December 12, 2001 (effective November 1, 2005 for the Priest Rapids Development and November 1, 2009 for the Wanapum Development).
10.8	(with 2002 Form 10-K)	10(b)-4	Priest Rapids Project Reasonable Portion Power Sales Contract executed by Public Utility District No. 2 of Grant County, Washington and Avista Corporation dated December 12, 2001 (effective November 1, 2005 for the Priest Rapids Development and November 1, 2009 for the Wanapum Development).
10.9	(with 2002 Form 10-K)	10(b)-5	Additional Product Sales Agreement (Priest Rapids Project) executed by Public Utility District No. 2 of Grant County, Washington and Avista Corporation dated December 12, 2001 (effective November 1, 2005 for the Priest Rapids Development and November 1, 2009 for the Wanapum Development)

Exhibit	Previously Filed [1] With Registration Number	As Exhibit	
10.10	2-60728	5(g)	Power Sales Contract (Wells Project) with Public Utility District No. 1 of Douglas County, Washington, dated as of September 18, 1963.*
10.11	2-60728	5(g)-1	Amendment to Power Sales Contract (Wells Project) with Public Utility District No. 1 of Douglas County, Washington, dated as of February 9, 1965.*
10.12	2-60728	5(h)	Reserved Share Power Sales Contract (Wells Project) with Public Utility District No. 1 of Douglas County, Washington, dated as of September 18, 1963.*
10.13	2-60728	5(h)-1	Amendment to Reserved Share Power Sales Contract (Wells Project) with Public Utility District No. 1 of Douglas County, Washington, dated as of February 9, 1965.*
10.14	(with September 30, 1985 Form 10-Q)	1	Settlement Agreement and Covenant Not to Sue executed by the United States Department of Energy acting by and through the Bonneville Power Administration and the Company, dated as of September 17, 1985, describing the settlement of Project 3 litigation.*
10.15	(with 1981 Form 10-K)	10(s)-7	Ownership and Operation Agreement for Colstrip Units No. 3 & 4, dated as of May 6, 1981.*
10.16	(with 2019 Form 10-K)	10.14	Avista Corporation Executive Deferral Plan (2020 Component). [3][5]
10.17	(with 2019 Form 10-K)	10.15	Avista Corporation Supplemental Executive Retirement Plan (Post-2004 Component, Amended in 2018). [3][6]
10.18	(with 1992 Form 10-K)	10(t)-11	The Company's Unfunded Supplemental Executive Disability Plan. [3]*
10.19	(with 2007 Form 10-K)	10.34	Income Continuation Plan of the Company. [3]
10.20	(with 2018 Form 10-K)	10.21	Avista Corporation Long-Term Incentive Plan. [3]
10.21	(with 2010 Form 10-K)	10.23	Avista Corporation Performance Award Plan Summary.[3]
10.22	(with 2021 Form 10-K)	10.22	Avista Corporation Performance Award Agreement 2021. [3]
10.23	(with 2022 Form 10-K)	10.22	Avista Corporation Performance Award Agreement 2022. [3]
10.24	[2]		Avista Corporation Performance Award Agreement 2023. [3]
10.25	[2]		Avista Corporation Officer Incentive Plan.[3]
10.26	[2]		Employment Agreement between the Company and Wayne O. Manuel in the form of a Letter of Employment. [3]
10.27	(with Form 8-K dated August 13, 2008)	10.1	Employment Agreement between the Company and Mark T. Thies in the form of a Letter of Employment. [3]
10.28	(with September 30, 2019 Form 10-Q)	10.1	Form of Change of Control Plan between the Company and its Executive Officers. [3][5]
10.29	[2]		Avista Corporation Non-Employee Director Compensation.

Exhibit	Previously Filed[1] With Registration Number	As Exhibit	
10.30	(with Form 8-K dated November 30, 2022)	10.1	Credit Agreement dated as of November 29, 2022 among Avista Corporation and U.S. Bank, as Lender and Administrative Agent, and MUFG Bank Ltd. as Lender.
10.31	(with Form 8-K dated December 19, 2022)	0.1	Credit Agreement dated as of December 14, 2022 among Avista Corporation and Keybank National Association, as Lender and Administrative Agent.
10.32	(with Form 8-K dated December 19, 2022)	10.2	First Amendment, dated as of December 15, 2022, to the Credit Agreement dated as of November 29, 2022 among Avista Corporation and Keybank National Association, as Lender and Administrative Agent.
10.33	(with Form 8-K dated January 4, 2023)	10.1	Continuing Letter of Credit Agreement dated as of December 29, 2022, among Avista Corporation and MUFG Bank Ltd., as Issuer.
10.34	(with Form 8-K dated January 4, 2023)	10.2	Incremental Commitment and Joinder Agreement, dated as of December 30, 2022, among Avista Corporation and U.S. Bank National Association, as Administrative Agent, and CoBank as Incremental Lender.
21	[2]		Subsidiaries of Registrant.
23	[2]		Consent of Independent Registered Public Accounting Firm.
31.1	[2]		Certification of Chief Executive Officer (Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002).
31.2	[2]		Certification of Chief Financial Officer (Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002).
32	[4]		Certification of Corporate Officers (Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002).
97	[2]		Avista Corporation Dodd-Frank Recovery Policy.
101.INS	[2]		Inline XBRL Instance Document – the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.
101.SCH	[2]		Inline XBRL Taxonomy Extension Schema with embedded Linkbases Document.
104	[2]		Cover page formatted as Inline XBRL and contained in Exhibit 101.

** Exhibit originally filed with the U.S. Securities and Exchange Commission in paper format and as such, a hyperlink is not available.*

(1) *Incorporated herein by reference.*

(2) *Filed herewith.*

(3) *Management contracts or compensatory plans filed as exhibits to this Form 10-K pursuant to Item 15(b).*

(4) *Furnished herewith.*

(5) *Applies to Kevin J. Christie, Bryan A. Cox, Josh D. DiLuciano, Gregory C. Hesler, Latisha D. Hill, James M. Kensok, Scott J. Kinney, Ryan L. Krasselt, Wayne O. Manuel, David J. Meyer, Heather L. Rosentrater, Jason R. Thackston, and Dennis P. Vermillion.*

(6) *Applies to Kevin J. Christie, Bryan A. Cox, Josh D. DiLuciano, Latisha D. Hill, James M. Kensok, Scott J. Kinney, Ryan L. Krasselt, David J. Meyer, Heather L. Rosentrater, Jason R. Thackston, and Dennis P. Vermillion.*

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

AVISTA CORPORATION

February 20, 2024	By /s/ Dennis P. Vermillion
Date	Dennis P. Vermillion
	Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Dennis P. Vermillion Dennis P. Vermillion Chief Executive Officer	Principal Executive Officer and Director	February 20, 2024
/s/ Kevin J. Christie Kevin J. Christie Senior Vice President, Chief Financial Officer, Treasurer, and Regulatory Affairs Officer	Principal Financial Officer	February 20, 2024
/s/ Ryan L. Krasselt Ryan L. Krasselt Vice President, Controller and Principal Accounting Officer	Principal Accounting Officer	February 20, 2024
/s/ Scott L. Morris Scott L. Morris Chairman of the Board	Director	February 20, 2024
/s/ Julie A. Bentz Julie A. Bentz	Director	February 20, 2024
/s/ Donald C. Burke Donald C. Burke	Director	February 20, 2024
/s/ Kevin B. Jacobsen Kevin B. Jacobsen	Director	February 20, 2024
/s/ Rebecca A. Klein Rebecca A. Klein	Director	February 20, 2024
/s/ Sena M. Kwawu Sena M. Kwawu	Director	February 20, 2024
/s/ Scott H. Maw Scott H. Maw	Director	February 20, 2024
/s/ Jeffry L. Philipps Jeffry L. Philipps	Director	February 20, 2024
/s/ Heidi B. Stanley Heidi B. Stanley	Director	February 20, 2024
/s/ Janet D. Widmann Janet D. Widmann	Director	February 20, 2024

AVISTA CORPORATION

SUBSIDIARIES OF REGISTRANT

Subsidiary	**State or Country of Incorporation**
Avista Capital, Inc.	Washington
Avista Development, Inc.	Washington
Avista Edge, Inc.	Washington
Avista Northwest Resources, LLC	Washington
Pentzer Corporation	Washington
Pentzer Venture Holding II, Inc.	Washington
Avista Capital II	Delaware
Courtyard Office Center, LLC	Washington
Alaska Energy and Resources Company	Alaska
Alaska Electric Light and Power Company	Alaska
AJT Mining Properties, Inc.	Alaska
Snettisham Electric Company	Alaska
Salix, Inc.	Washington
University Development Company, LLC	Washington

EXHIBIT 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-33790, 333-179042 and 333-208986 on Form S-8 and in Registration Statement No. 333-264790 on Form S-3 of our reports dated February 20, 2024, relating to the financial statements of Avista Corporation, and the effectiveness of Avista Corporation's internal control over financial reporting, appearing in this Annual Report on Form 10-K of Avista Corporation for the year ended December 31, 2023.

/s/ DELOITTE & TOUCHE LLP

Portland, Oregon
February 20, 2024

CERTIFICATION

I, Dennis P. Vermillion, certify that:

1. I have reviewed this report on Form 10-K of Avista Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 20, 2024

/s/ Dennis P. Vermillion
Dennis P. Vermillion
Chief Executive Officer
(Principal Executive Officer)

EXHIBIT 31.2

CERTIFICATION

I, Kevin J. Christie, certify that:

1. I have reviewed this report on Form 10-K of Avista Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 20, 2024

/s/ Kevin J. Christie
Kevin J. Christie
Senior Vice President, Chief Financial Officer,
Treasurer and Regulatory Affairs Officer
(Principal Financial Officer)

CERTIFICATION OF CORPORATE OFFICERS

(Furnished Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002)

Each of the undersigned, Dennis P. Vermillion, Chief Executive Officer of Avista Corporation (the "Company"), and Kevin J. Christie, Senior Vice President and Chief Financial Officer of the Company, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Company's Annual Report on Form 10-K for the year ended December 31, 2023 fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934, as amended, and that the information contained therein fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 20, 2024

/s/ Dennis P. Vermillion
Dennis P. Vermillion
Chief Executive Officer

/s/ Kevin J. Christie
Kevin J. Christie
Senior Vice President, Chief Financial Officer,
Treasurer and Regulatory Affairs Officer

SELECTED FINANCIAL DATA

Avista Corporation

As of and for the years ended December 31,

Dollars in thousands, except per share data and ratios

	2023	2022	2021	2020	2019	2013
FINANCIAL RESULTS						
Operating revenues	$ 1,751,554	1,710,207	$ 1,438,936	$ 1,321,891	$ 1,345,622	$ 1,441,744
Operating expenses	1,493,864	1,519,965	1,210,704	1,089,191	1,135,233	1,210,655
Income from continuing operations	257,690	190,242	228,232	232,700	210,389	231,089
Interest expense	143,299	118,692	106,152	105,061	104,354	77,585
Income taxes	(33,630)	(17,191)	12,031	7,051	31,374	58,014
Net income from continuing operations	171,180	155,176	147,334	129,488	196,763	104,333
Net income (loss) from discontinued operations	—	—	—	—	—	7,961
Net income	171,180	155,176	147,334	129,488	196,763	112,294
Net income attributable to noncontrolling interests	—	—	—	—	216	(1,217)
Net income attributable to Avista Corp. shareholders:						
Net income from continuing operations attributable to Avista Corp. shareholders	$ 171,180	$ 155,176	$ 147,334	$ 129,488	$ 196,979	$ 104,273
Net income from discontinued operations attributable to Avista Corp. shareholders	—	—	—	—	—	6,804
Net income attributable to Avista Corp. shareholders	$ 171,180	$ 155,176	$ 147,334	$ 129,488	$ 196,979	$ 111,077
Earnings per common share attributable to Avista Corp. shareholders—diluted:						
Earnings from continuing operations	$ 2.24	$ 2.12	$ 2.10	$ 1.90	$ 2.97	$ 1.74
Earnings from discontinued operations	—	—	—	—	—	0.11
Total	$ 2.24	$ 2.12	$ 2.10	$ 1.90	$ 2.97	$ 1.85
Earnings per common share attributable to Avista Corp. shareholders—basic:	$ 2.24	$ 2.13	$ 2.11	$ 1.91	$ 2.98	$ 1.85
COMMON STOCK STATISTICS						
Dividends paid per common share	$ 1.84	$ 1.76	$ 1.69	$ 1.62	$ 1.55	$ 1.22
Book value per common share	31.83	31.15	30.14	29.31	28.87	21.61
Shares of common stock:						
Outstanding at year-end	78,075	74,946	71,498	69,239	67,177	60,077
Average—basic	76,396	72,989	69,951	67,962	66,205	59,960
Average—diluted	76,495	73,093	70,085	68,102	66,329	59,997
Return on average Avista Corp. stockholders' equity:						
Total company	7.1%	6.9%	7.1%	6.6%	10.5%	8.7%
Utility only	7.8%	5.9%	6.7%	7.1%	11.0%	9.3%
Non-utility only	1.6%	15.6%	10.0%	2.2%	6.6%	2.2%
Common stock price:						
High	$ 45.29	$ 46.90	$ 49.14	$ 53.00	$ 49.47	$ 29.26
Low	30.53	35.72	36.68	32.09	39.75	24.10
Year-end close	35.74	44.34	42.49	40.14	48.09	28.19

SELECTED FINANCIAL DATA (continued)

Avista Corporation

As of and for the years ended December 31,

Dollars in thousands, except per share data and ratios

	2023	2022	2021	2020	2019	2013
DEBT AND PREFERRED STOCK STATISTICS						
Pretax interest coverage:						
Including AFUDC/AFUCE	1.99(x)	2.14(x)	2.54(x)	2.37(x)	3.30(x)	3.27(x)
Excluding AFUDC/AFUCE	1.92(x)	2.05(x)	2.43(x)	2.26(x)	3.19(x)	3.14(x)
Embedded cost of long-term debt	4.98%	4.87%	4.95%	5.06%	5.17%	5.53%
FINANCIAL CONDITION						
Total assets (1) (2)	$ 7,702,477	$ 7,417,350	$ 6,853,583	$ 6,402,097	$ 6,082,456	$ 4,011,533
Total net Avista Utilities property	5,541,683	5,294,804	5,078,326	4,842,995	4,649,884	3,202,425
Avista Utilities property capital expenditures						
(excluding equity-related AFUDC)	484,716	443,373	435,887	397,292	434,077	294,363
Long-term debt (including current portion) (2)	2,530,358	2,294,513	2,267,554	2,132,249	2,020,011	1,262,036
Nonrecourse long-term debt of Spokane						
Energy (including current portion)	—	—	—	—	—	17,838
Long-term debt to affiliated trusts	51,547	51,547	51,547	51,547	51,547	51,547
Avista Corporation stockholders' equity	$ 2,485,323	$ 2,334,668	$ 2,154,744	$ 2,029,726	$ 1,939,284	$ 1,298,266

(1) The total assets at year-end for 2013 exclude the total assets associated with Ecova of $339.6 million.

(2) The total assets and total long-term debt for 2013 were adjusted in accordance with a change in accounting standards.

Avista Corporation

As of and for the years ended December 31,

	2023	2022	2021	2020	2019	2013
AVISTA UTILITIES						
Electric Operations						
Electric operating revenues (millions of dollars):						
Residential	$ 425.3	$ 414.8	$ 394.7	$ 377.8	$ 369.1	$ 331.9
Commercial	343.5	338.7	326.2	304.0	317.6	289.6
Industrial	109.7	107.7	106.8	103.1	105.8	113.6
Public street and highway lighting	8.0	7.5	7.5	7.3	7.4	7.3
Total retail	886.4	868.7	835.1	792.2	799.9	742.4
Wholesale	249.8	179.3	89.8	77.3	73.2	127.5
Sales of fuel	(25.9)	84.3	63.7	28.8	48.0	126.7
Other	49.2	46.3	36.3	30.1	29.0	36.0
Decoupling	12.4	(31.8)	(19.5)	(4.4)	8.7	—
Provision for earning sharing	0.1	0.1	1.7	3.5	3.1	(2.0)
Total electric operating revenues	$ 1,172.2	$ 1,146.8	$ 1,007.1	$ 927.5	$ 962.0	$ 1,030.6
Electric energy sales (millions of kWhs):						
Residential	4,020	4,154	3,955	3,807	3,766	3,745
Commercial	3,160	3,201	3,158	2,995	3,170	3,147
Industrial	1,671	1,699	1,666	1,615	1,691	1,979
Public street and highway lighting	17	17	17	18	18	26
Total retail	8,868	9,071	8,796	8,435	8,645	8,897
Wholesale	3,468	3,094	2,461	2,680	2,787	3,874
Total electric energy sales	12,336	12,165	11,257	11,115	11,432	12,771
Retail electric customers (average per year):						
Residential	366,450	361,564	356,387	350,669	345,064	321,098
Commercial	45,341	44,550	44,110	43,497	42,930	40,202
Industrial	1,188	1,193	1,205	1,277	1,305	1,386
Public street and highway lighting	690	681	666	639	612	527
Total retail electric customers	413,669	407,988	402,368	396,082	389,911	363,213
Retail electric customers (at year-end):						
Residential	370,081	363,932	359,452	354,191	348,111	323,801
Commercial	44,452	44,806	44,303	43,968	42,790	40,492
Industrial	1,158	1,195	1,195	1,210	1,293	1,382
Public street and highway lighting	638	708	672	649	634	531
Total retail electric customers	416,329	410,641	405,622	400,018	392,828	366,206
Revenue per residential kWh (cents)	10.58	9.99	9.98	9.92	9.80	8.86
Use per residential customer (kWh)	10,971	11,487	11,098	10,857	10,914	11,664
Revenue per commercial kWh (cents)	10.87	10.58	10.33	10.15	10.02	9.20
Use per commercial customer (kWh)	69,687	71,805	71,589	68,847	73,842	78,276
Electric energy resources (millions of kWhs):						
Hydro generation (from Company facilities)	3,024	3,930	3,598	3,651	3,520	3,646
Thermal generation (from Company facilities)	5,084	4,055	3,635	3,474	4,054	3,383
Purchased power	5,121	5,065	4,954	4,922	4,833	6,375
Power exchanges	(421)	(385)	(398)	(446)	(504)	(20)
Total power resources	12,808	12,665	11,789	11,601	11,903	13,384
Energy losses and company use	(472)	(500)	(532)	(486)	(471)	(613)
Total electric energy resources	12,336	12,165	11,257	11,115	11,432	12,771

Avista Corporation

As of and for the years ended December 31,

	2023	2022	2021	2020	2019	2013
AVISTA UTILITIES						
Electric Operations (continued)						
Retail Native Load at time of system peak						
Winter	1,771	1,860	1,696	1,613	1,577	1,669
Summer	1,809	1,810	1,889	1,721	1,656	1,577
Natural Gas Operations						
Natural gas operating revenues (millions of dollars):						
Residential	$ 325.6	$ 284.5	$ 221.4	$ 213.6	$ 196.4	$ 206.3
Commercial	164.0	139.9	100.8	94.9	92.2	102.2
Industrial and interruptible	17.3	10.5	7.8	7.2	5.3	6.3
Total retail	507.0	434.8	330.0	315.7	293.9	314.8
Wholesale	55.3	133.2	113.3	104.9	135.0	194.7
Transportation	8.2	8.6	8.5	7.9	8.7	7.6
Other	6.8	8.2	7.3	5.0	7.4	8.6
Decoupling	(7.5)	(1.5)	12.9	0.6	0.9	—
Provision for earning sharing	0.9	0.1	1.3	1.8	1.4	(0.4)
Total natural gas operating revenues	$ 570.6	$ 583.5	$ 473.3	$ 435.9	$ 447.2	$ 525.3
Natural gas therms delivered (millions of therms):						
Residential	225.7	242.5	219.8	220.0	231.2	204.7
Commercial	138.7	147.1	130.4	127.7	140.6	122.2
Industrial and interruptible	25.1	19.8	21.4	20.3	15.4	10.9
Total retail	389.5	409.3	371.6	368.0	387.2	337.8
Wholesale	262.2	280.2	356.9	542.4	590.8	524.8
Transportation and other	165.5	172.4	172.7	180.6	187.9	160.4
Total natural gas therms delivered	817.1	861.8	901.3	1,091.0	1,165.9	1,023.0
Retail natural gas customers (average per year):						
Residential	340,655	337,073	332,187	327,125	321,343	288,708
Commercial	37,193	36,753	36,448	36,164	35,804	33,932
Industrial and interruptible	237	232	232	265	286	297
Total retail natural gas customers	378,085	374,058	368,867	363,554	357,433	322,937
Retail natural gas customers (at year-end):						
Residential	343,384	340,048	335,166	330,124	325,102	291,386
Commercial	37,383	37,136	36,622	36,483	36,101	34,084
Industrial and interruptible	235	236	237	229	292	287
Total retail natural gas customers	381,002	377,420	372,025	366,836	361,495	325,757
Revenue per residential therm (in dollars)	$ 1.44	$ 1.17	$ 1.01	$ 0.97	$ 0.85	$ 1.01
Use per residential customer (therms)	662	719	662	672	720	709
Revenue per commercial therm (in dollars)	$ 1.18	$ 0.95	$ 0.77	$ 0.74	$ 0.66	$ 0.84
Use per commercial customer (therms)	3,730	4,001	3,578	3,530	3,926	3,603
Heating degree days (at Spokane, Washington):						
Actual	6,012	6,811	6,124	6,187	6,817	6,683
30 year average	6,557	6,560	6,596	6,651	6,613	6,750
Actual as a percent of average	92%	104%	93%	93%	103%	99%

Avista Corporation

As of and for the years ended December 31,

	2023	2022	2021	2020	2019	2013
ALASKA ELECTRIC LIGHT AND POWER COMPANY						
Revenues (millions of dollars)	$ 48.1	$ 45.7	$ 45.4	$ 42.8	$ 37.3	$ —
Total assets (millions of dollars)	269.7	264.3	265.4	269.0	271.4	—
ECOVA						
Revenues (millions of dollars)	$ —	$ —	$ —	$ —	$ —	$ 176.8
Total assets (millions of dollars)	—	—	—	—	—	339.6
OTHER						
Revenues (millions of dollars)	$ 0.6	$ 0.7	$ 0.6	$ 1.6	$ 12.5	$ 39.5
Total assets (millions of dollars)	191.7	187.0	132.2	109.7	113.4	81.3

Corporate Information

Company Headquarters
Spokane, Washington

Avista on the Internet
Financial results, stock quotes, news releases, documents filed with the Securities and Exchange Commission (SEC), and information on the company's products and services are available on Avista's website at **investor.avistacorp.com**.

Direct Stock Purchase and Dividend Reinvestment Plan
Computershare sponsors and administers the Computershare Investment Plan (CIP) for Avista Corp. common stock. To invest, obtain forms, or for information about your holdings, please contact the transfer agent using the information below.

Transfer Agent
Computershare
P.O. Box 43006
Providence, RI 02940-3078
800.642.7365
computershare.com/investor

Investor Information
A copy of the company's financial reports, including the reports on Forms 10-K and 10-Q filed with the SEC, will be provided without charge upon request to:
Avista Corp.
Investor Relations
P.O. Box 3727 MSC-19
Spokane, WA 99220-3727
800.222.4931

Annual Meeting of Shareholders
The company's annual meeting will be held at 9:00 a.m. PDT on Wednesday, May 1, 2024.

This year's meeting will be held in a virtual format only.

Exchange Listing
Ticker Symbol: AVA
New York Stock Exchange

Certifications
On May 15, 2023, the Chief Executive Officer (CEO) of Avista Corp. filed a Section 303A.12(a) Annual CEO Certification with the New York Stock Exchange. The CEO Certification attests that the CEO is not aware of any violations by the company of NYSE's Corporate Governance Listing Standards.

Avista Corp. has included as exhibits to its annual report on Form 10-K for the year 2023, filed with the SEC, certifications of Avista's Chief Executive Officer and Chief Financial Officer regarding the quality of Avista's public disclosure in compliance with Section 302 of the Sarbanes-Oxley Act of 2002.

This annual report contains forward-looking statements regarding the company's current expectations. These statements are subject to a variety of risks and uncertainties that could cause actual results to differ materially from the expectations. These risks and uncertainties include, in addition to those discussed herein, all factors discussed in the company's annual report on Form 10-K for the year 2023. Our 2023 annual report is provided for shareholders. It is not intended for use in connection with any sale or purchase of or any solicitation of others to buy or sell securities.

The 2023 annual report is produced through a partnership of Avista employees and companies within Avista's service area. Design and Production: 116 & West; Photography: Dean Davis Photography; Printing: National Color Graphics

Help Us Help the Environment
Managing costs is a primary goal for Avista. You can help us meet this goal by agreeing to receive future annual reports and proxy statements electronically. This service saves on the costs of printing and mailing, provides timely delivery of information, and helps protect our environment by decreasing the need for paper, printing, and mailing materials.

For more information, please visit:
investor.avistacorp.com

In our commitment to green thinking, this year's annual report is printed on paper made from responsibly managed forests.

1411 East Mission Avenue, Spokane, Washington 99202 | 509.489.0500 | avistacorp.com