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
Web site: 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 on 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**

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* = 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
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
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;
- work-force 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 cyber security 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

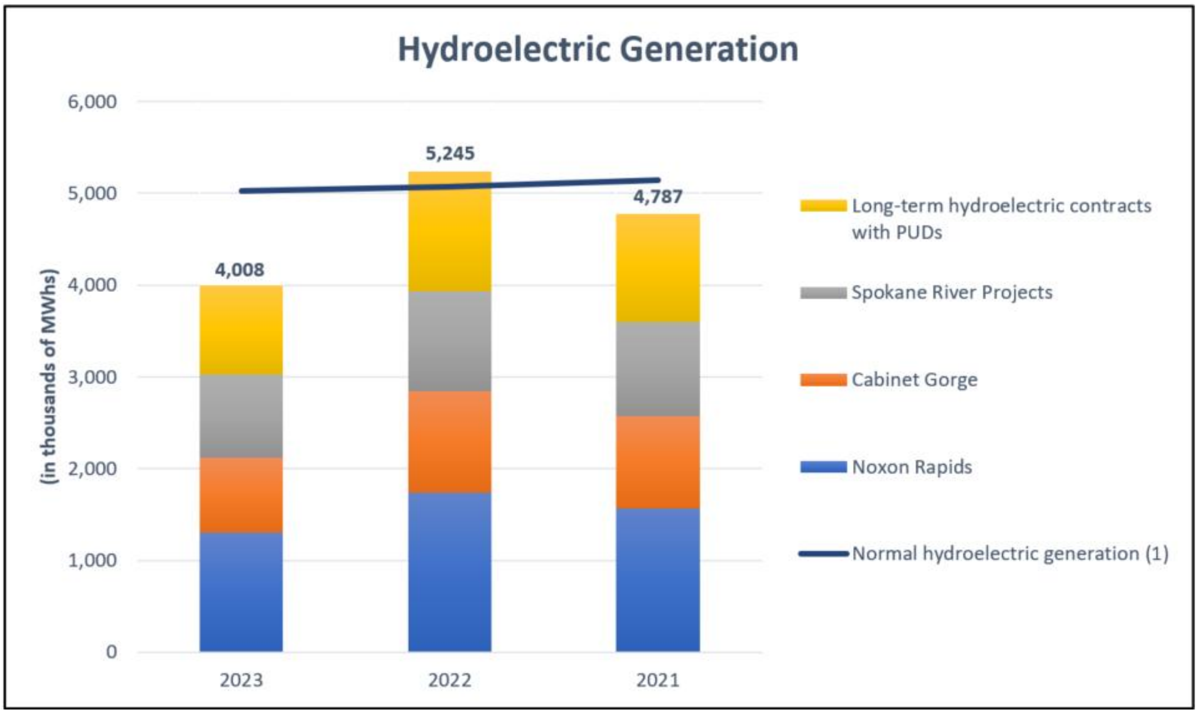
Avista Utilities has a diverse electric resource mix of Company-owned and contracted hydroelectric, thermal, wind and solar generation facilities, and other contracts for power purchases and exchanges. As of December 31, 2023, Avista Utilities' electric generation resource mix (including contracts for 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:



(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 and 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.

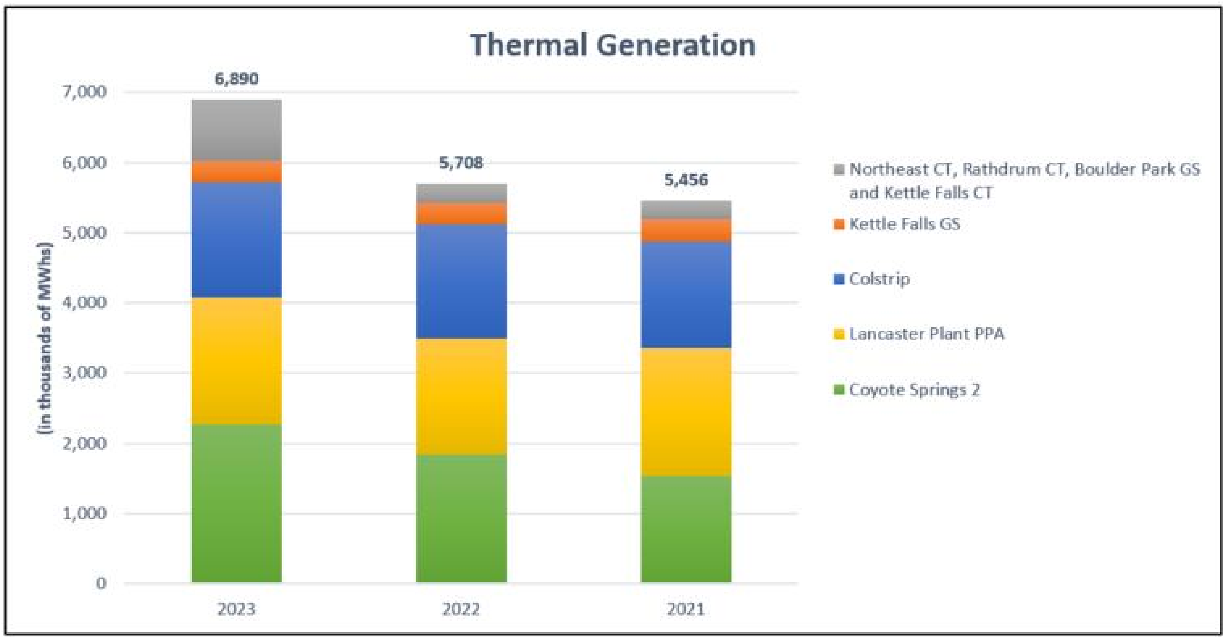
The Northeast CT, Rathdrum CT, Boulder Park GS and Kettle Falls CT generating units are primarily used to meet peaking electric requirements. We also operate these facilities when marginal costs are below prevailing wholesale electric prices. These generating facilities have access to natural gas supplies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



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).

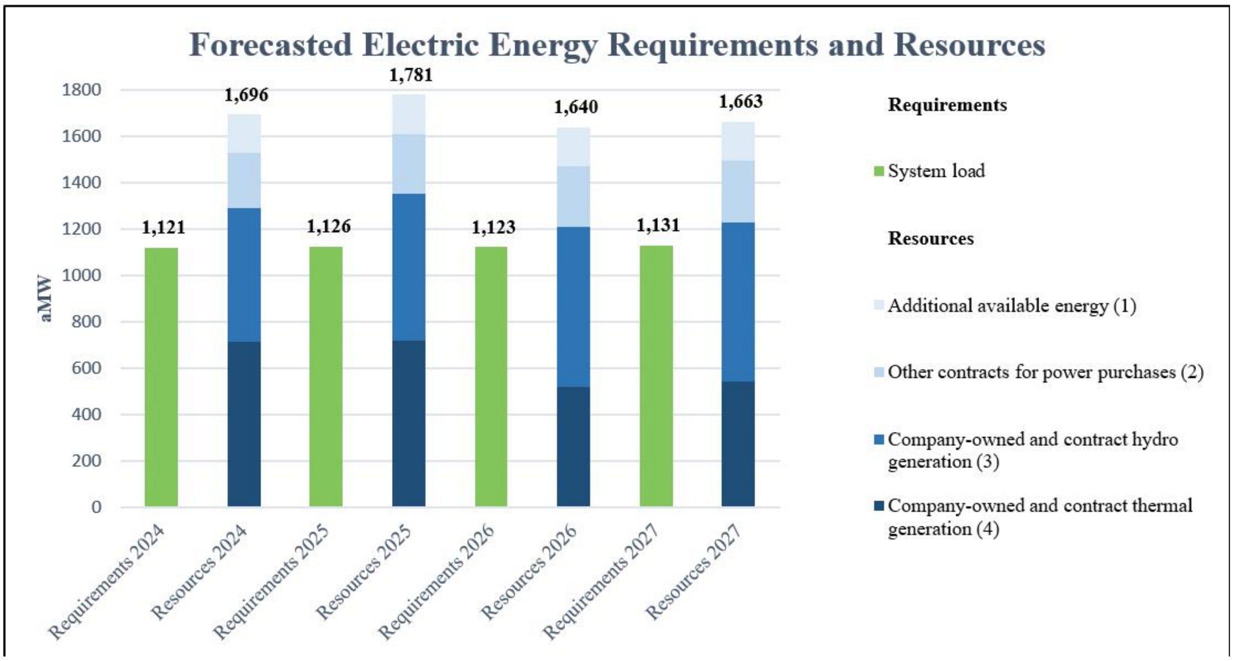
Cabinet Gorge and Noxon Rapids are under one 45-year FERC license expiring in 2046. This license embodies a settlement agreement relating to project operations and resource protection and mitigation efforts over the license term.

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:



(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
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

	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.

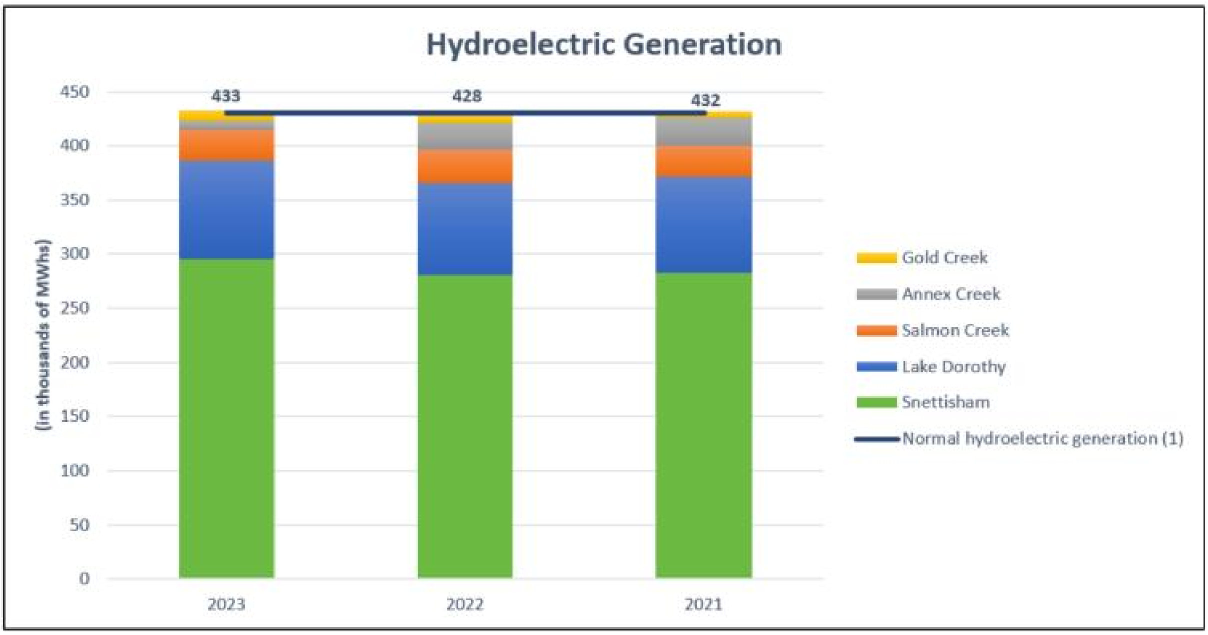
AEL&P owns and operates electric generation, transmission and distribution facilities located in Juneau. AEL&P operates five hydroelectric generation facilities with 102.7 MW of hydroelectric generation capacity. AEL&P owns four of these generation facilities (totaling 24.5 MW of capacity) and has a 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:



(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 and 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 and 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 1 – 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 a 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

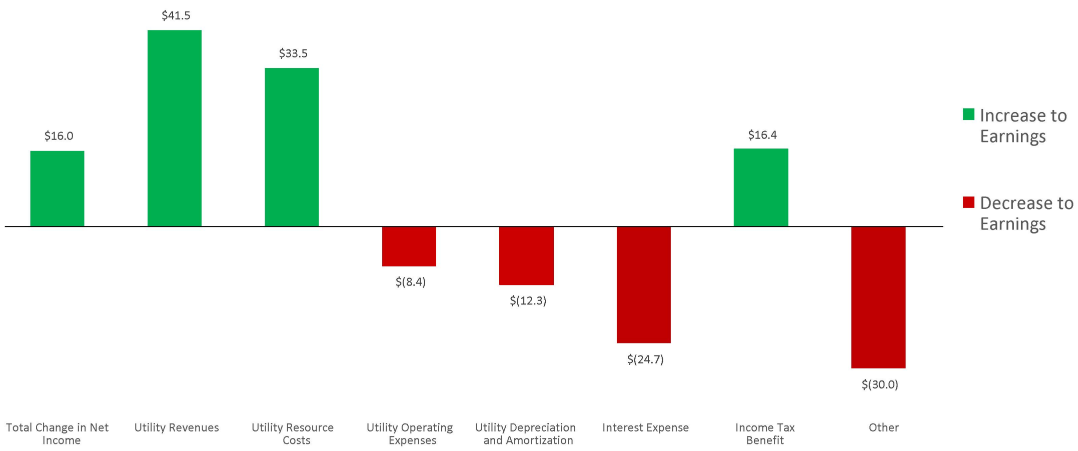
See "Note 23 of the Notes to Consolidated Financial Statements" for discussion of these regulatory mechanisms.

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

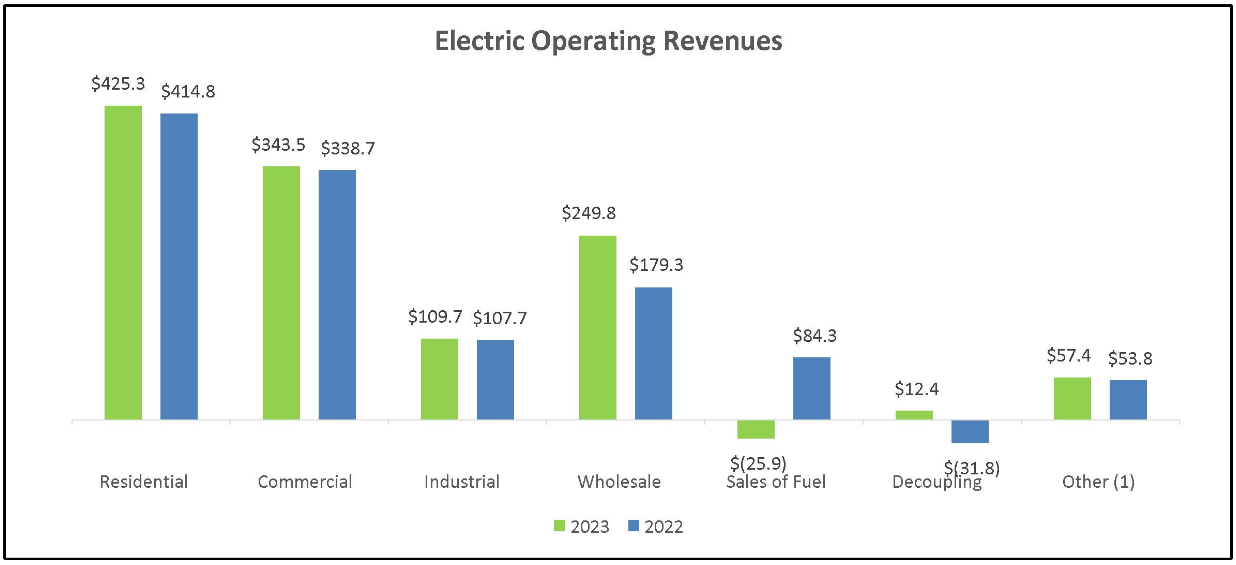
We engage in resource optimization, which involves the selection from available energy resources to serve our load obligations and the use of these resources to capture economic value through wholesale market transactions, which is ultimately intended to lower net power and natural gas supply costs. 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

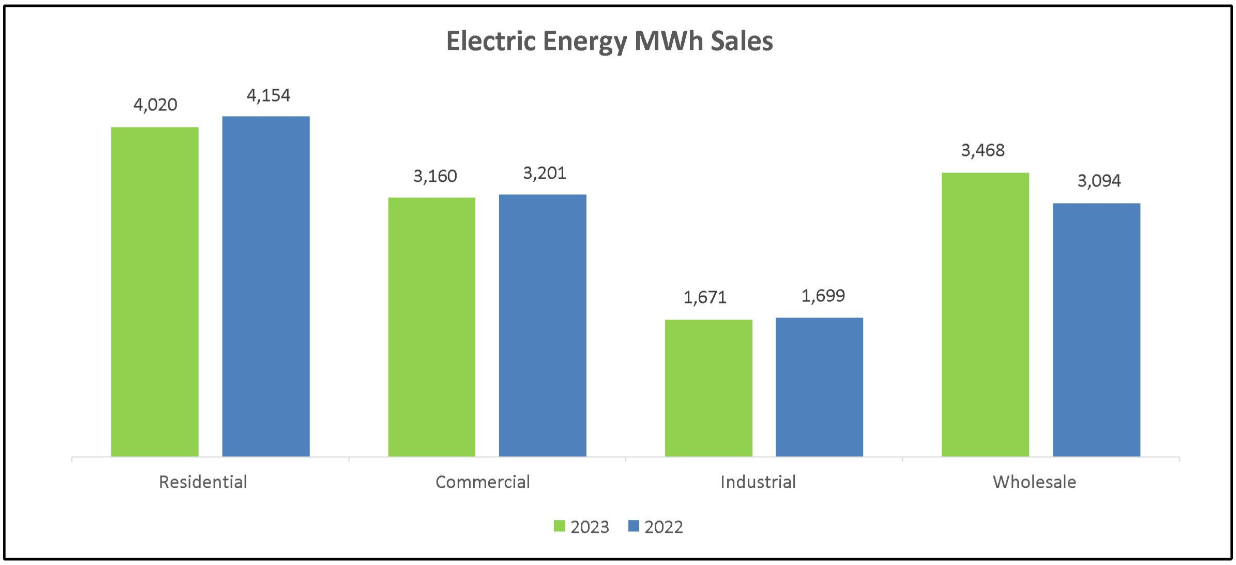
Utility Operating Revenues

The following graphs present Avista Utilities' electric operating revenues and MWh sales for 2023 and 2022, respectively (dollars in millions and MWhs in thousands):



(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.



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)

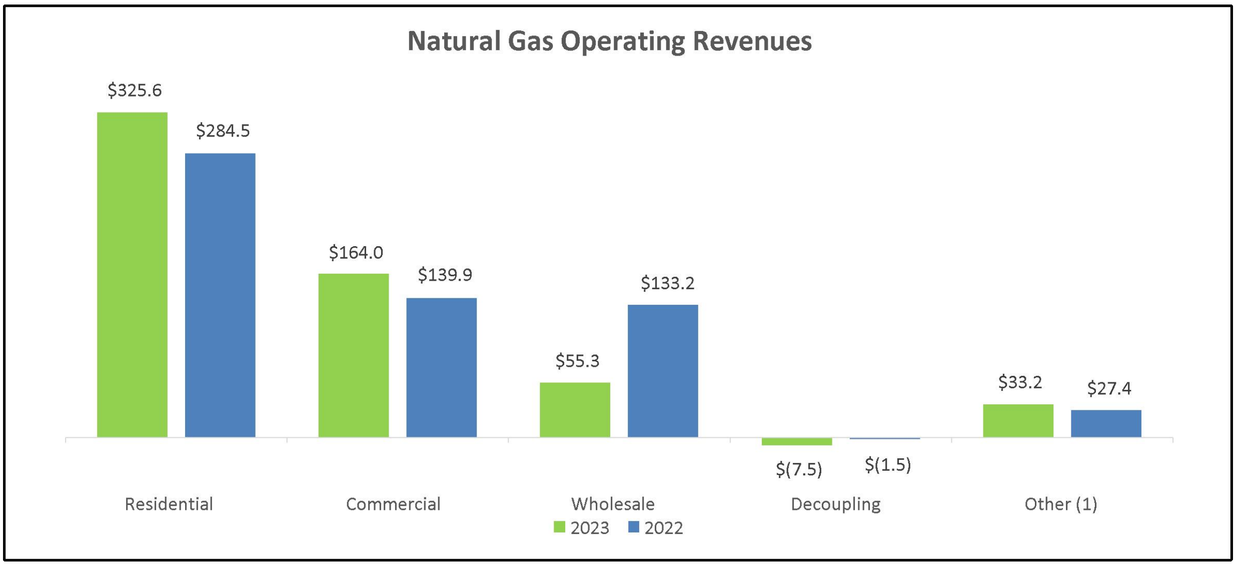
(a) Positive amounts are increases in decoupling revenue in the current year and will be surcharged to customers in future years. Negative amounts are decreases in decoupling revenue in the current year and will be rebated to customers in future years.

(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:

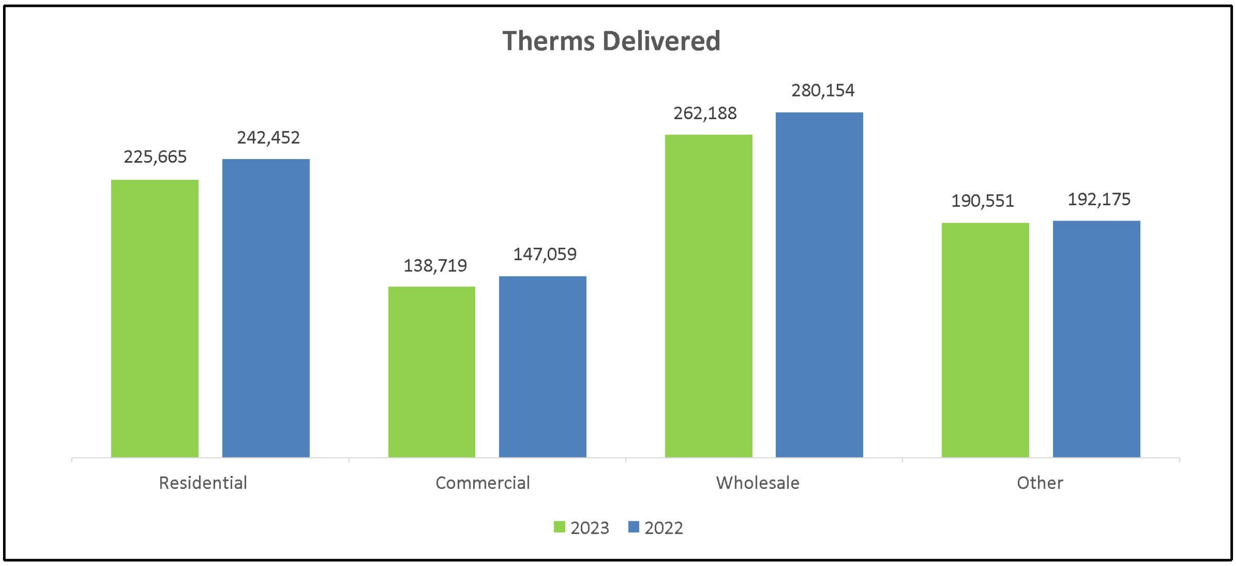
- a $17.7 million increase in retail electric revenues due to an increase in revenue per MWh (increased revenues $38.0 million), partially offset by a decrease in total MWhs sold (decreased revenues $20.3 million).
  - The decrease in total retail MWhs sold was primarily the result of decreased customer 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):



(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.



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.

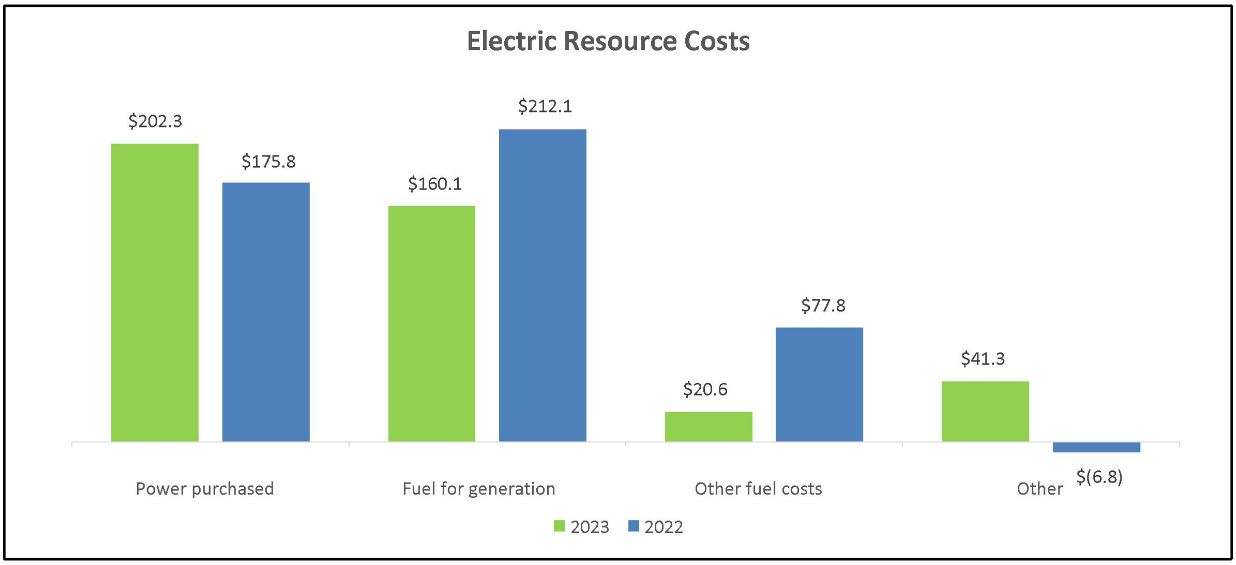
(b) Positive amounts are increases in decoupling revenue in the current year and are related to the amortization of rebate balances that resulted in prior years and are being refunded to customers (causing a corresponding decrease in retail revenue from customers) in the current year. Negative amounts 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):

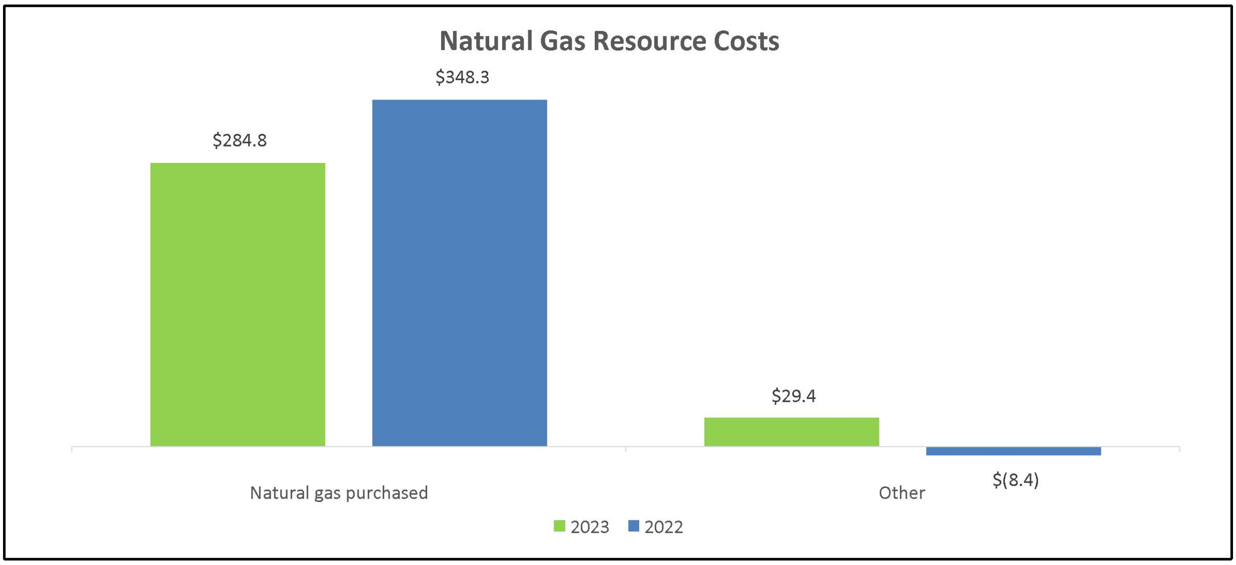


Total electric resource costs in the graph above include intracompany resource costs of $33.4 million and $54.8 million for 2023 and 2022, respectively.

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 above 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):

	December 31, 2023		December 31, 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:

- 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.

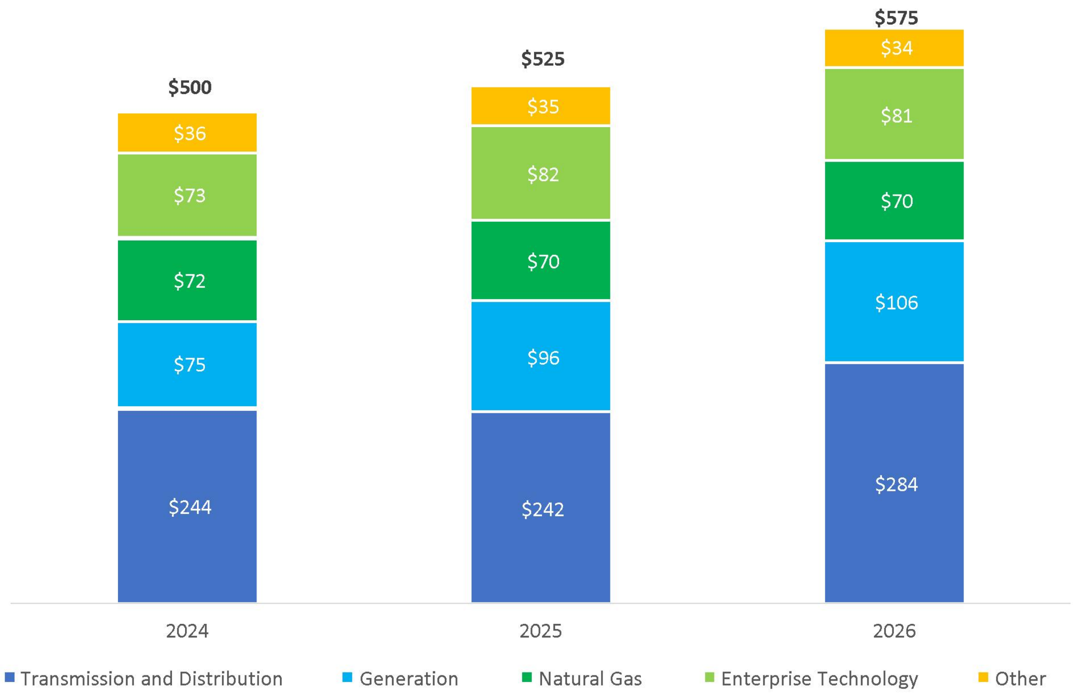
However, Avista Corp. and AEL&P may not individually issue any additional first mortgage bonds (with certain exceptions in the case of bonds issued on the basis of retired bonds) unless the particular entity issuing the bonds has “net earnings” (as defined in the respective Mortgages) for any period 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):



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 expenditures	$ 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 and 4. The owners of Units 3 and 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 post-retirement 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):

	December 31, 2023	December 31, 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 post-retirement 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 post-retirement 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):

	December 31, 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):

	December 31, 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 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			2022			2021		
	Avista Utilities	AEL&P	Total Utility	Avista Utilities	AEL&P	Total Utility	Avista Utilities	AEL&P	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	2022	2021
	Avista Utilities	Avista Utilities	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 investments-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	
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 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 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 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 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 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 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 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 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 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	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 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 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:

- 66-2/3 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 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.

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 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.

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 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	(1) Earning A Return	Not Earning A Return	(2) Expected Recovery or Refund	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 us 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 INDEX

	Previously Filed (1)		
Exhibit	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.*
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.
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.
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).
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).
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.
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)	10.1	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

Exhibit 10.24

AVISTA CORPORATION

PERFORMANCE AWARD AGREEMENT

This Performance Award Agreement (the "Agreement") is made by and between Avista Corporation, a Washington Corporation (the "Company") and the individual named in section 1 (the "Participant") as designated by the Avista Corporation Compensation and Organization Committee (the "Plan Administrator").

WHEREAS, Performance Awards are granted under the January 19, 2016 amended and restated Avista Corporation Long-Term Incentive Plan (the "Plan"). The terms and conditions of the Performance Awards are set forth below and in the Plan, which is incorporated into this Agreement by reference.

NOW, THEREFORE, in consideration of the premises contained herein and in the Plan, it is agreed as follows:

1. **Terms of Performance Awards**. The terms of the Performance Awards are set forth as follows:

(a) The "Participant" is **«First_Name» «Last_Name».**

(b) The "Grant Date" is **February 2, 2023**.

(c) The total target number of eligible "Performance Awards" shall be **«Total_Performance_Shares»** units. "Performance Awards" granted under this Agreement are units that will be reflected in a book account maintained by the Company or a third party administrator during the Performance Cycle, and that will be settled in cash or shares of Avista Corporation Common Stock ("Common Stock") to the extent provided in this Agreement and the Plan.

(d) The "Performance Cycle" is the period beginning on January 1, 2023 and ending on December 31, 2025.

2. **Conditions to Award**. Pursuant to this Award, the number of Performance Awards earned will depend upon the Company's performance against specific performance metrics. The performance metrics are (i) Relative Total Shareholder Return, which accounts for **(#_of)** units of the total target award as set forth in section 1(c), and (ii) Cumulative Earnings Per Share ("CEPS") which accounts for **(#_of)** units of the total target award set forth in section 1(c). The total number of shares of Stock that will be issued in the settlement of this Award, based upon the Company's satisfaction of the metrics, will be determined by multiplying the Target Number of units allocated for each metric set forth in this section 2 by the applicable Payout Factor in accordance with the provisions of Exhibit 1 and Exhibit 2, which is attached to and forms a part of this Agreement.

3. **Settlement of Performance Awards**. The Company shall deliver to the Participant one share of Common Stock (or cash equal to the Fair Market Value of one share of Common Stock) for each Performance Award earned by the Participant, as determined in accordance with the provisions of Exhibit 1 and Exhibit 2, which is attached to and forms a part of this Agreement. The earned Performance Award payable to the Participant shall be paid in shares of Common Stock or in cash (based on the Fair Market Value of the Common Stock as of the date the Plan Administrator certifies the attainment of the performance goals), or in a combination of the two, as determined by the Plan Administrator in its sole discretion, except that cash may be distributed in lieu of any fractional share

of Common Stock.

All Performance Awards and any Dividend Equivalents (as described in Section 5 below) earned by a Participant under this Agreement are subject to the Recoupment Policy adopted by the Company's Board of Directors as amended from time to time ("Recoupment Policy"). If a Participant becomes subject to the Recoupment Policy any Performance Award and associated Dividend Equivalent may be forfeited in whole or in part and all or part of any distribution payable to a Participant or his or her beneficiary under this Agreement may be recovered by the Company pursuant to the Recoupment Policy.

4. **Time of Payment**. Except as otherwise provided in this Agreement, payment of Performance Awards earned will be delivered as soon as feasible after the end of the Performance Cycle and after the Plan Administrator certifies the attainment of the performance goals.

5. **Dividend Equivalent Rights**. Any Performance Awards may, in the Plan Administrator's discretion, earn Dividend Equivalent Rights. In respect of any Performance Award that is outstanding on the dividend record date for Common Stock, the Participant may be credited with an amount equal to the cash distributions that would have been paid on the shares of Common Stock covered by such Award had such covered shares been issued and outstanding on such dividend record date. Dividend Equivalent Rights are to be paid in cash based on the total number of Performance Awards earned at the end of the Performance Cycle and delivered as soon as feasible after the Performance Cycle and after the Plan Administrator certifies the attainment of the performance goals. Dividend Equivalent Rights are subject to all applicable taxes, which are the responsibility of the Participant. The Dividend Equivalent Rights in respect of any Performance Awards that are not earned as of the end of a Performance Cycle, shall be forfeited as of the end of the Performance Cycle.

6. **Termination of Employment during Performance Cycle**. Except as otherwise provided in section 7, this section 6 shall apply if the Participant's employment terminates during a Performance Cycle. If the Participant's employment with the Company and/or Subsidiaries terminates during the Performance Cycle because of Retirement, Disability, or Death, the Participant shall be entitled to a prorated value of the Performance Award earned in accordance with Exhibit 1 and Exhibit 2, determined at the end of the Performance Cycle, and based on the ratio of the number of whole months the Participant was employed during the Performance Cycle to the total number of months in the Performance Cycle (36). If a Participant's employment or services with the Company and/or Subsidiaries terminate on or as of the last day of a Performance Cycle, such Participant will be deemed to have terminated after the end of such Performance Cycle. If the Participant's employment with the Company and/or Subsidiaries terminates during the Performance Cycle for any reason other than Retirement, Disability, or Death, the Performance Award granted under this Agreement will be forfeited on the Date of Termination (as defined in section 9(b)); provided, however, that in such circumstances, the Plan Administrator, in its sole discretion, may determine that the Participant will be entitled to receive a prorated or other portion of the Performance Award. In case of termination for Cause, the Performance Award granted shall automatically terminate upon first notification to the Participant of such termination, unless the Plan Administrator determines otherwise. If a Participant's employment with the Company is suspended pending an investigation of whether the Participant shall be terminated for Cause, all the Participant's rights under any Award likewise shall be suspended during the period of investigation. The effect of a Company-approved leave of absence on the terms and conditions of an Award shall be determined by the Plan Administrator, in its sole discretion.

7. **Change in Control**. If a Change in Control occurs during the Performance Cycle, and the Participant's Date of Termination (as defined in section 9(b)) does not occur before the Change in Control date, the Participant shall be entitled to a prorated value of the Performance Award that would have been earned by the Participant in accordance with Exhibit 1 and Exhibit 2, determined as of the date of the Change in Control, prorated based on the ratio of the number of whole months the Participant is employed during the Performance Cycle through the date of the Change in Control, to the total number of months in the Performance Cycle; provided, however, that a Payout Factor of at least 100% as set forth in Exhibit 1 and Exhibit 2 for the Performance Cycle shall be deemed to have been achieved as of the date of the Change in Control. Notwithstanding the provisions of sections 3 (with the exception of the application of the Recoupment Policy), 4, and 5, the value of the Performance Award, and any Dividend Equivalent Right, earned in accordance with the foregoing provisions of this section shall be delivered to the Participant in a lump sum cash payment as soon as feasible after the occurrence of a Change

in Control, with the value of a Performance Award equal to the Fair Market Value of a share of Common Stock determined under the provision of section 3 as of the date of the Change in Control. Distributions to the Participant under sections 3 and 5 shall not be affected by payments under this section, except that the number of Performance Awards and Dividend Equivalent Rights earned by and payable to the Participant shall be reduced by the number of Performance Awards and Dividend Equivalent Rights with respect to which payment was made to the Participant under this section.

8. **Taxes**. The Participant is liable for any and all taxes, including withholding taxes, arising out of the grant, vesting, payment or settlement of any Performance Awards and Dividend Equivalent Rights. The Company shall have the right to require the Participant to remit to the Company, or to withhold awarded shares of Common Stock, or from any Dividend Equivalent Rights or other amounts due to the Participant, as compensation or otherwise, an amount sufficient to satisfy all federal, state and local withholding tax requirements.

9. **Definitions**. For purposes of this Agreement, the terms used in this Agreement shall be subject to the following:

(a) Change in Control. The term "Change in Control" is defined in section 2.4 of the amended and restated Avista Corp. Long Term Incentive Plan.

(b) Date of Termination. The Participant’s "Date of Termination" shall be the first day occurring on or after the Grant Date on which the Participant is not employed by the Company or any Subsidiary, regardless of the reason for the termination of employment; provided that a termination of employment shall not be deemed to occur by reason of a transfer of the Participant between the Company and a Subsidiary or between two Subsidiaries; and further provided that the Participant’s employment shall not be considered terminated while the Participant is on a leave of absence from the Company or a Subsidiary approved by the Participant’s employer. If, as a result of a sale or other transaction, the Participant’s employer ceases to be a Subsidiary (and the Participant’s employer is or becomes an entity that is separate from the Company), and the Participant is not, at the end of the 30-day period following the transaction, employed by the Company or an entity that is then a Subsidiary, then the occurrence of such transaction shall be treated as the Participant’s Date of Termination caused by the Participant being discharged by the employer.

(c) Disability. ‘‘Disability’’ means ‘‘disability’’ as that term is defined for purposes of the Company’s Long Term Disability Plan or other similar successor plan applicable to employees.

(d) Retirement. "Retirement" of the Participant shall mean retirement as of the individual’s retirement date under the Retirement Plan for Employees of Avista Corporation or other similar successor plan applicable to employees.

10. **Assignability**. No Performance Award or Dividend Equivalent Right granted or awarded under the Plan may be assigned or transferred by the Participant other than by will or by the applicable laws of descent and distribution, and, during the Participant’s lifetime, settlements of such Awards may be payable only to the Participant or a permitted assignee or transferee of the Participant (as provided below). Notwithstanding the foregoing, the Plan Administrator, in its sole discretion, may permit such assignment or transfer and may permit a Participant of such Performance Awards or Dividend Equivalent Rights to designate a beneficiary who may receive compensation settlement under the Performance Award after the Participant’s death; provided, however, that any amount so assigned or transferred shall be subject to all the same terms and conditions contained in this Agreement.

11. **General**.

11.1 Award Agreements. Performance Awards granted under the Plan shall be evidenced by a written agreement that shall contain such terms, conditions, limitations and restrictions as the Plan Administrator shall deem advisable and that are not inconsistent with the Plan.

11.2 Continued Employment or Services; Rights in Awards. Nothing contained in this Agreement, the Plan, or any action of the Plan Administrator taken under the Plan or this Agreement shall be construed as giving any Participant or employee of the Company any right to be retained in the employ of the Company or any Subsidiary or to limit the Company's or any Subsidiary's right to terminate the employment or services of the Participant.

11.3 Registration. At the present time, the Company has an effective registration statement with respect to the shares. The Company intends to maintain this registration but has no obligation to do so. In the event that such registration ceases to be effective, the Participant will not receive a Performance Award settlement or payment unless exemptions from registration under federal and state securities laws are available; such exemptions from registration are very limited and might be unavailable. **By accepting the Agreement, the Participant hereby acknowledges that he/she has read the section of the Plan and this Agreement entitled Registration.**

11.4 No Rights as a Shareholder. No Award under this Agreement shall entitle the Participant to any dividends (except to the extent provided in an award of Dividend Equivalent Rights), voting or any other right of a shareholder unless and until the date of issuance under the Plan of the shares that are the subject of such Performance Award, are free of all applicable restrictions.

11.5 Compliance with Laws and Regulations. Notwithstanding anything in the Plan to the contrary, the Board of Directors, in its sole discretion, may bifurcate the Plan so as to restrict, limit or condition the use of any provision of the Plan to Participants who are officers or directors subject to Section 16 of the Exchange Act without so restricting, limiting or conditioning the Plan with respect to other Participants.

11.6 Severability. The invalidity or unenforceability of any provision of this Agreement shall not affect the validity and enforceability of any other provision of this Agreement. If any provision of the Agreement is determined to be invalid, illegal or unenforceable in any jurisdiction, or as to any person, or would disqualify any Performance Award under any law deemed applicable by the Plan Administrator, such provision shall be construed or deemed amended by the Plan Administrator to conform to applicable laws, or, if the Plan Administrator determines that the provision cannot be so construed or deemed amended without materially altering the intent of the Plan or the Performance Award, such provision shall be stricken as to such jurisdiction, person or Performance Award, and the remainder of the Agreement and any such Performance Award shall remain in full force and effect.

12. **Administration**. The authority to manage and control the operation and administration of this Agreement shall be vested in the Plan Administrator, and the Plan Administrator shall have all powers with respect to this Agreement as it has with respect to the Plan. Any interpretation of the Agreement by the Plan Administrator and any decision made by it with respect to the Agreement are final and binding.

13. **Construction**. This Agreement is subject to and shall be construed in accordance with the Plan, the terms of which are explicitly made applicable hereto. Unless otherwise defined herein, capitalized terms in this Agreement shall have the same definitions as set forth in the Plan. In the event of any conflict between the provisions hereof and those of the Plan, the provisions of the Plan shall govern.

14. **Amendment**. This Agreement may be amended by written agreement of the Participant and the Company, without the consent of any other person.

15. **Governing Law**. The validity, construction, interpretation and enforceability of this Agreement shall be determined and governed by the laws of the State of Washington without giving effect to the principles of conflicts of laws. For the purpose of litigating any dispute that arises under this Agreement, the parties hereby consent to exclusive jurisdiction in Washington State and agree that such litigation shall be conducted in the courts of Spokane County, Washington or the federal courts of the United States for the eastern district of Washington.

16. **Successors**. The Company shall require any successor (whether direct or indirect, by purchase, merger, consolidation or otherwise to all or substantially all of the business and/or assets of the Company) to agree in writing to assume the Company's obligations under this Agreement and to perform such obligations in the same manner and to the same extent that the Company is required to perform them. As used in this Agreement, "Company" shall mean the Company and any successor to its business and/or assets that assumes and agrees to perform the Company's obligations under the

Agreement by operation of law or otherwise.

IN WITNESS WHEREOF, the Participant has executed this Agreement, and the Company has caused these presents to be executed in its name and on its behalf, all effective as of the Grant Date.

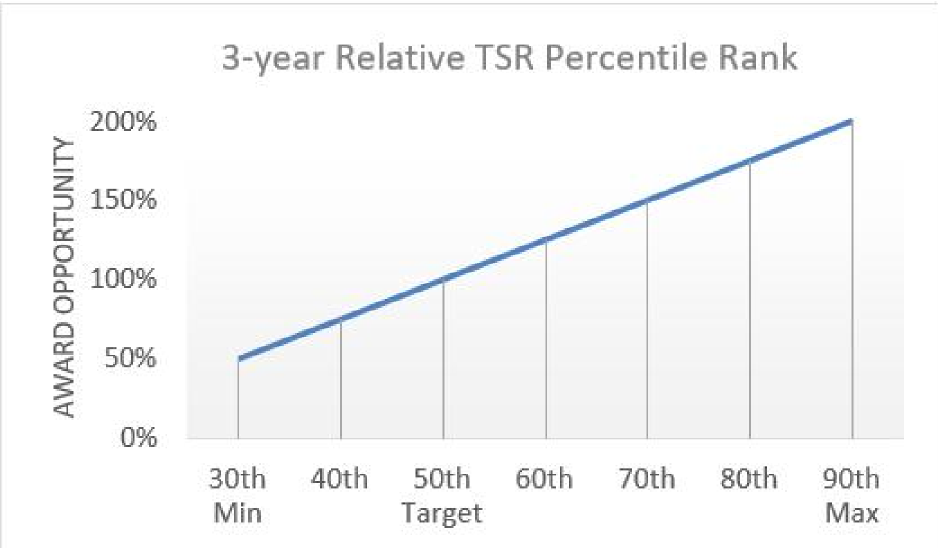
AVISTA CORPORATION

By: Dennis Vermillion
President and Chief Executive Officer

EXHIBIT 1

Performance Award Plan
Relative Total Shareholder Return Metric and Goals
2023 - 2025 Performance Cycle

The following graph and table represent the relationship between the Company's relative three-year Total Shareholder Return ("TSR") commencing January 1, 2023 and ending December 31, 2025 and the target award opportunity. The number of shares delivered at the end of the three-year Performance Cycle can range from zero to 200% of the target number of units allocated under this metric. The actual issuance of shares depends on Avista's three-year TSR performance compared to the returns of the peer companies reported in the S&P 400 Utilities Index and how we rank among them. To receive 100% of the Award allocated under this metric, Avista must perform at the 50th percentile among the companies in the S&P 400 Utilities Index. To receive 200% of the Award, Avista must rank at the 90th percentile. If Avista ranks below the 30th percentile, no stock awards or cash Dividend Equivalent Rights will be earned. Dividend Equivalent Rights are calculated and paid out in cash when and to the extent the Performance Awards are issued. The following graph demonstrates the relationship between TSR ranking and various payout factors. Performance Awards are interpolated on a straight line for performance results between the figures shown.



	TSR Percentile Ranking	Payout (% of Target)
Maximum	90th	200%
Target	50th	100%
Threshold	30th	50%
	<30th	0%

TSR is calculated using S&P's Research Insight software and reflects share price appreciation plus the impact of dividend distributions and the reinvestment of such dividends. TSR is calculated daily based on stock price changes and dividend payments, and then accumulated over the measurement period. Dividends are calculated using ex-date dividends per share. Beginning and ending share prices for the performance period reflect the average of closing share prices on the last 20 trading days ending on December 31st for both Avista and the peers.

From one year to the next, if S&P drops a company out of the index and adds another, the new company will be included in the ranking and the dropped company will be excluded. When a new company is added to the index, they will be added to the ranking as if they had been in the ranking from the beginning – provided that there is pricing and dividend data at the beginning of the cycle. When a company is dropped everything related to that company will be excluded from the ranking as if the company was never part of the ranking.

Settlement Formula Example:
Assuming that 1,000 Performance Award units were allocated under this metric at the beginning of the three-year Performance Cycle and Avista's TSR ranked at the 45th percentile after the three-year Performance Cycle, the Participant would receive 87.5% of 1,000 or 875 shares of Avista common stock plus cash dividend equivalents.

Payout Factor (% of Target)		Target Number of Performance Awards Granted		Final Number of Common Stocks Issued
87.5%	X	1,000	=	875 shares plus cash dividends

Percentile Ranking Methodology:
The percentile rank is calculated using the PERCENTRANK function in MS Excel, initially excluding Avista from the list. The results are rounded to the nearest whole percentile after Avista has been ranked.

The calculation can be replicated by arranging the TSR data from highest to lowest for all peers except Avista. A percentile ranking is calculated for each data point assuming 100.0th percentile for the highest data point, 0.0 percentile for the lowest data point, and the corresponding percentile for every other data point with an equal difference in percentile ranking for each data point. The TSR for Avista is calculated by determining Avista's rank in the list and interpolating between the percentile rankings for the companies immediately above and below based on the differences in TSR. An example, based on sample data is as follows:

Company Ranking	TSR	Percentile Rank
1	63.6%	100.0%
2	62.8%	92.8%
11 (ABC Corp)	32.0%	28.5%
12(XYZ Corp)	10.0%	21.4%
14	4.4%	7.1%
15	-11.6%	0.0%

If a company's TSR is 29.1%, the resulting percentile ranking would be 27.6%, calculated as follows: 27.6% = 21.4% + [(29.1% - 10.0%) / (32.0% - 10.0%) * (28.5% - 21.4%)]

Total Shareholder Return (TSR) Methodology:
For purposes of this Agreement, a methodology for calculating a total return to shareholder with dividend reinvestment was established. Returns are calculated daily based on stock price changes and dividend payments and then accumulated over the Performance Cycle. Below are additional assumptions used in Avista's calculation for TSR.

General Assumptions:
The starting share price for the Performance Cycle is determined by averaging the closing stock price on the last 20 trading days ending on December 31st prior to the first day of Performance Cycle. The ending share price is determined by averaging the closing stock price on the last 20 trading days ending on December 31st at the end of the Performance Cycle. For demonstration purposes, the example below uses January 1, 2020 – December 31, 2022 as the Performance Cycle.

Date	**Closing Price**	Date	Closing Price
12/31/2019	48.09	12/30/2022	44.34
12/30/2019	47.90	12/29/2022	44.71
12/27/2019	47.77	12/28/2022	43.94
12/26/2019	47.71	12/27/2022	44.50
12/24/2019	47.73	12/23/2022	43.84
12/23/2019	47.73	12/22/2022	42.83
12/20/2019	48.40	12/21/2022	42.59
12/19/2019	49.07	12/20/2022	42.06
12/18/2019	49.21	12/19/2022	42.32
12/17/2019	49.00	12/16/2022	42.20
12/16/2019	48.60	12/15/2022	42.45
12/13/2019	47.69	12/14/2022	43.07
12/12/2019	47.55	12/13/2022	43.55
12/11/2019	47.71	12/12/2022	73.14
12/10/2019	47.21	12/9/2022	42.52
12/9/2019	47.03	12/8/2022	42.79
12/6/2019	47.34	12/7/2022	41.69
12/5/2019	47.24	12/6/2022	41.79
12/4/2019	47.23	12/5/2022	42.31
12/3/2019	46.83	12/2/2022	41.95
Average	47.8520	Average	42.9295

The example below reflects share price appreciation plus the impact of dividend distributions and the reinvestment of such dividends. Dividends are reinvested on a daily basis. For this example, a fictional ex- date for dividends per share is used. Daily returns are calculated over the performance cycle and added together resulting in the Cumulative TSR for the performance cycle.

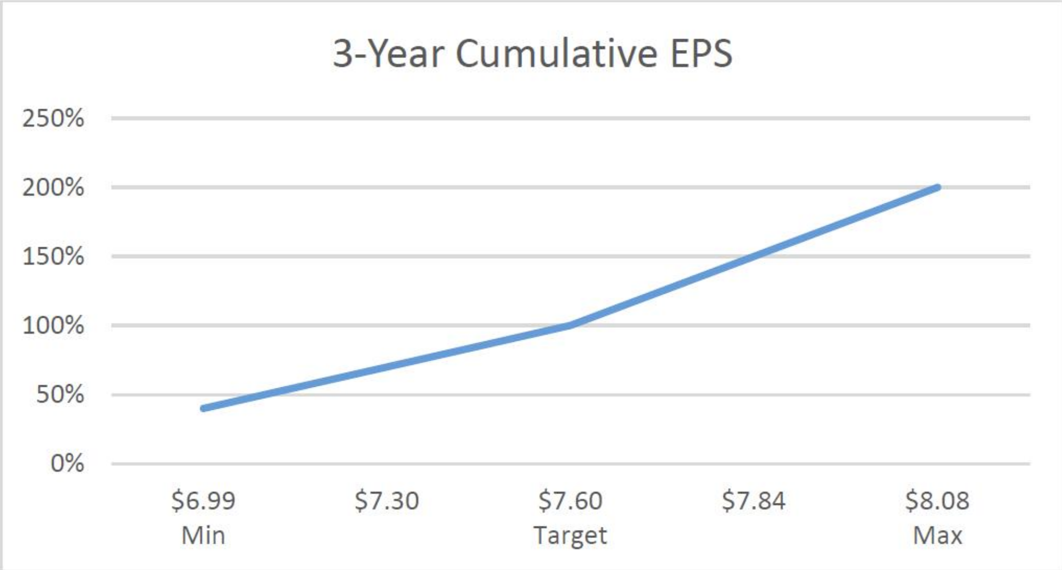
Date	Closing Price	Dividend	Daily TSR
11/19/2019	47.03	0	NA
11/20/2019	46.92	0.388	0.5911%*
11/21/2019	46.65	0	(0.5609%)
11/22/2019	46.41	0	(0.5190%)
11/25/2019	46.80	0	0.8392%
11/26/2019	46.91	0	0.2427%
Cumulative TSR 11/19/2019 to 11/26/2019			0.5978%

* [(46.92 + 0.388) / 47.03] -1

EXHIBIT 2

Performance Award Plan
Cumulative Earnings Per Share Metric and Goals
2023-2025 Performance Period

The following graph and table represent the relationship between the Company's Cumulative Earnings Per Share ("CEPS") commencing January 1, 2023 and ending December 31, 2025 and the target award opportunity. The number of shares delivered at the end of the three-year Performance Cycle can range from zero to 200% of the target number of units allocated under this metric. The actual issuance of shares depends on Avista's CEPS over the three-year Performance Cycle. To receive 100% of the Performance Award allocated under this metric, Avista must achieve CEPS $7.60 over the three-year cycle. To receive 200% of the Award, Avista must achieve CEPS of $8.08. If Avista's CEPS is less than $6.99, no stock awards or cash Dividend Equivalent Rights will be earned. Dividend Equivalent Rights are calculated and paid out in cash when and to the extent the Performance Awards are issued. The following graph demonstrates the relationship between CEPS and various payout factors. Performance Awards are interpolated on a straight line for performance results between the figures shown.



	3-Year CEPS	Payout Factor
Maximum	$8.08	200%
Target	$7.60	100%
Threshold	$6.99	40%
	<$6.99	0%

Performance is tracked over a three-year Performance Cycle thereby focusing on sustainability.

Cumulative EPS is fully diluted earnings per share determined in accordance with generally accepted accounting principles, and may be adjusted to remove the effects of such items as regulatory charges, income tax legislative changes and/or items of a non-routine or items of an extraordinary nature as determined by the Plan Administrator.

Settlement Formula Example:
Assuming that 1,000 Performance Award units were allocated under this metric at the beginning of the Performance Cycle and Avista's cumulative EPS was $7.72 over three years, the Participant would receive 125% of 1,000 or 1,250 shares of Avista common stock plus dividend equivalents in cash.

Payout Factor (% of Target)		Target Number of Performance Awards Granted		Number of Common Stocks Issued
125%	X	1,000	=	1,250 shares plus cash dividends

Using the example formulas in Exhibit 1 and Exhibit 2, the Participant would receive in total 106.3% of 2,000 (total target # of Performance Awards granted) or 2,125 Shares of Common Stock plus cash dividend equivalents.

	Payout Factor (% of Target)		Target Number of Performance Awards Granted		Number of Common Stocks Issued
TSR	87.5%	X	1,000	=	875
CEPS	125%	X	1,000	=	1,250
Total	**106.3%**	**X**	**2,000**	**=**	**2,125**

ACCEPTANCE AND ACKNOWLEDGMENT

I, a resident of the state of_________, accept the Performance Award described in this Agreement and in the Plan, and acknowledge that I have received a copy of this Agreement and the Plan. I have read and understand the Plan, and I hereby make the representations, warranties and acknowledgments, and undertake the indemnity and other obligations, therein specified.

Dated: __________________

____
Signature of Employee

____
Printed Name

Exhibit 10.25

2023 EXECUTIVE OFFICER ANNUAL CASH INCENTIVE PLAN

PLAN PROVISIONS
Approved by Board

Purpose: The Executive Officer Annual Cash Incentive Plan (Plan) is designed to align the interests of our NEOs and senior management with both shareholder and customer interests to achieve overall positive financial and operational performance for the Company. The Plan is an important element of the overall compensation of our executives which provides a compensation structure that is competitive with compensation paid to comparable executives of companies within the energy/utility industry and ensures the Company can attract and retain quality employees in key positions to lead the Company.

Plan Year: January 1, 2023 – December 31, 2023

Eligibility:

- All executive officers hired prior to October 1st and actively employed on December 31st of the plan year, are eligible to participate
- Subsidiary officers are not eligible to participate
- Other details available in section *Exceptions to Eligibility and Circumstances for Proration*

Performance Measurements: The Plan focuses on shareholders and customers by creating value through sound financial performance and controlling costs through driving efficiencies while paying close attention to our customers' voices regarding the products and services we provide. The Plan incorporates Consolidated Earnings Per Share (EPS), Operating & Maintenance Cost per Customer (O&M CPC), and measurement of our Non-Regulated activity as financial performance measurements. There are also three non-financial measurements: Customer Satisfaction Rating (Customer Satisfaction), Reliability Index (Reliability), and Dispatched Gas Emergency Response Time (Response Time). These performance goals help increase shareholder value, gain financial strength and maintain safe and reliable cost-effective service levels essential for our customers and for the long-term success of the Company, and, with the exception of the earnings per share and non-regulated activity goal, are identical to performance metrics used in the Company's annual cash incentive plan for non-officer employees. The Compensation Committee believes that having similar metrics for both the officer plan and the non-officer plan encourages employees at all levels of the organization to focus on common objectives.

Consolidated Diluted EPS - This metric reflects the financial strength and alignment of interests between officers and shareholders. Consolidated EPS includes Alaska Electric Light & Power (AEL&P) and other non-utility businesses within the corporation.

O&M CPC - The O&M CPC is a measure that focuses on controlling costs and driving efficiencies in order to keep our costs reasonable for our customers. The metric is based on targeted O&M expense and number of customers. These components are combined to create the O&M CPC metric.

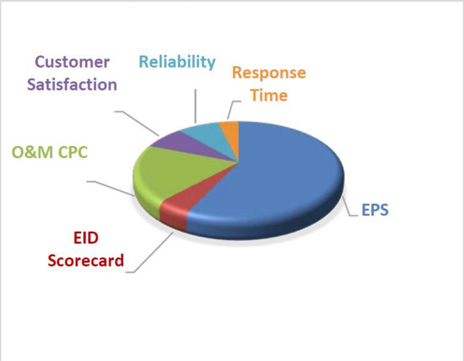
EID Scorecard – This is a measure that supports the Equity, Inclusion, and Diversity Strategic Plan and includes focus areas of Our People, Our Community & Customers, and Our Business Partners. The metric is based on achieving a set of five activity-based milestones.

Customer Satisfaction - This measure is derived from a Voice of the Customer survey, which is conducted each quarter by an independent agency. The rating measures the customer's overall satisfaction with the service they received during a recent contact with the Company's contact center and/or service center.

Reliability - This measure tracks how quickly the Company restores outages, how frequently customers are affected by outages and what percent of customers experience more than three sustained outages per year. The Company combined three common industry indices in order to balance our focus.

Response Time - This measure tracks how quickly the Company responds to dispatched natural gas emergency calls. The primary objective is customer and public safety while consistently treating customers the same throughout our service territory.

Award Opportunity: The Plan has six independent metrics, each having their own goal to achieve. The Plan is sliced into pieces – like a pie. Each piece or component makes up a portion of the employee's total incentive award opportunity as represented in the graph.
Consolidated EPS makes up 55 percent of the total incentive award opportunity while O&M CPC is 20 percent, customer satisfaction and reliability each 8 percent, EID Scorecard is 5 percent, and response time 4 percent.



Non-financial metrics: The non-financial pieces of the award (customer satisfaction, reliability, EID scorecard, response time) are all-or-nothing goals. If the Company meets or exceeds the target goal for any one of the metrics, employees receive 100% of the incentive award percentage related to the metric such as 4% for response time. If the Company fails to meet the target, employees would receive no award related to the metric. For example, if the Company achieves Customer Satisfaction with a 90% or better rating, employees would receive 8% of their total incentive award opportunity. If the Company achieves 88% which is below the target, employees would receive no award related to the metric. This works the same for each non- financial measurement. The maximum amount an employee could receive related to the non-financial metrics is 8% for customer satisfaction, 8% reliability, 5% for EID Scorecard, and 4% response time.

Financial metrics: The Consolidated EPS and O&M CPC metrics work a little differently due to the various performance levels that can be met. Depending on the Company's level of performance under each metric, employees may earn more or less than 100% of the award percentage related to each financial metric. Increasing levels of performance are established between threshold and maximum by using a sliding scale. The following graphs represent the relationship between the Company's performance targets and the award opportunity. *Performance levels were rounded up for graphing purposes only.*

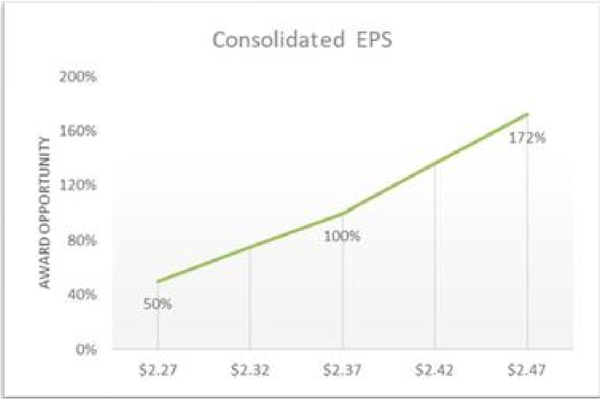


Figure 1

For employees to receive at least 50% of their award percentage related to the metric the Company must achieve or surpass the minimum or threshold level of performance. The better the Company performs, the more employees may earn as seen in the graphs to the right. For employees to receive 100% of their award percentage related to a financial metric, the Company must achieve the level of performance selected for target. If the Company performs above target level, employees may earn up to a maximum of 172% (rounded up) for Consolidated EPS and 150% (rounded up) for O&M CPC. Performance below threshold results in no award payment for the related metric.

For ease of communication and display purposes performance levels may be rounded using the accounting rules such as to the nearest whole number or up to two decimals. To calculate actual payments and to ensure no overpayments occur the performance levels within the
sliding scale actually extend out six (6) decimal places (ex. 166.666666%) for Consolidated EPS and four (4) decimals (ex. 149.9430%) for Cost per Customer. See **Calculation of Awards** section for more details on how payments are calculated.

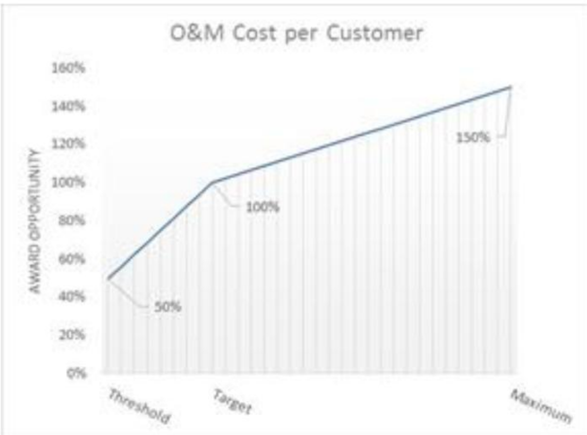


Figure 2

Establish Targets: The Compensation and Organization Committee of the Board (Committee) in conjunction with management reviews and reestablishes the targets for each measurement on an annual basis. The computations for this Plan are described below:

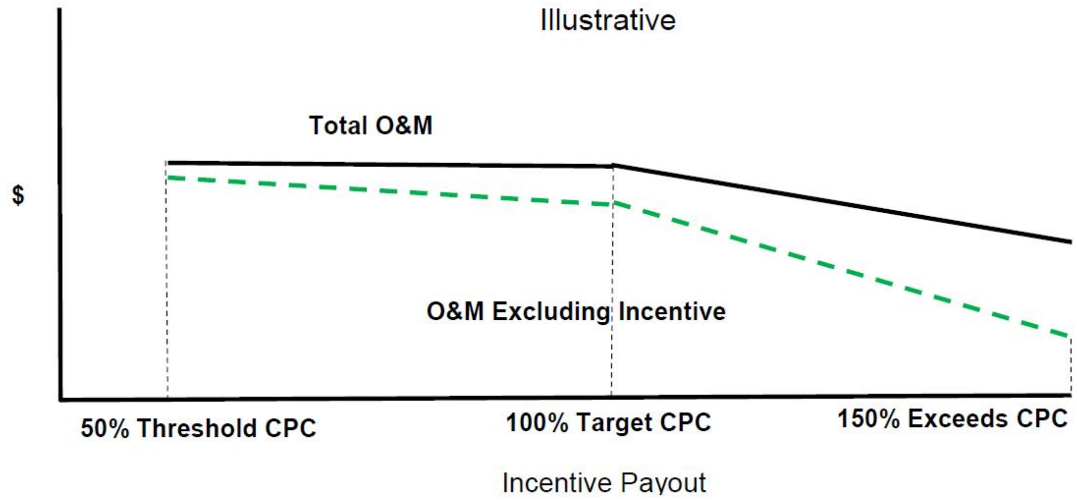
Consolidated Earnings per Share: To determine the Consolidated EPS goal for the Plan, the Committee, in conjunction with the Finance Committee of the Board and management, considered and incorporated the EPS target range contained in the Company's original publicly disclosed earnings guidance and reviewed this in light of the budgeted EPS numbers. The earnings guidance for the Consolidated EPS **excludes** the earnings impact associated with changes in the Energy Recovery Mechanism (ERM). The target in the Plan is Diluted Earnings per Share and includes executive incentive payout/accrual-pro-forma and net of taxes. The actual Consolidated EPS results will be affected by positive or negative changes in the ERM when computing the Plan payout. Occasionally, adjustments to actual results may be deemed necessary. An example of such an adjustment was in 2017 when the Tax Cuts and Job Act became effective.

The Company's original 2022 guidance for EPS is $2.27 to $2.47.

Since the portion of the incentive related to EPS indirectly benefits the customer it is charged below the line to account 417.

O&M CPC: For this measurement the Company uses the total budget for O&M expense (numerator) plus customer growth (denominator).

Numerator: The numerator of the formula is derived from the Company's total budget for O&M expense. Certain items are excluded from the total O&M budget such as, Pacesetters and certain accounting adjustments. For each performance level, the Company estimates the potential payout for the incentive which includes payroll taxes and subtracts the result from the total O&M budget. The estimation is based on budgeted labor costs, employee job levels and the corresponding individual target award opportunities.



To establish the performance levels between threshold and target, the Company assumes a 1:1 ratio between O&M spend (solid line) and threshold and target (dash line). Cost sharing occurs once we exceed target at 100%. Performance levels between target and maximum assumes a 2:1 ratio between O&M spend and target and maximum (disregarding the impact of customer growth).

Denominator: The target uses a net customer growth of 10,854. Variability in the final customer count will impact the amount of O&M savings necessary to achieve an incentive payment.

Equity, Inclusion, and Diversity (EID) Scorecard: The purpose of this metric is to align the Officers with our Equity, Inclusion, and Diversity strategy. The three EID strategic plan sections are Our People, Our Community and Customers, and Our Business Partners. Specifically, for Our People, there is one goal for each of the subcategories of Equity, Inclusion, and Diversity. For Our Community/Customers and Our Business Partners, there is one goal for each, for a total of five specific goals. In this plan, the target is set at achieving four out of the five specific goals, or 80% achievement, to meet this metric. The measurable action is listed in the yearly plan document.

Customer Satisfaction: For this measure, the Company uses the ratings from question three of the Voice of the Customer survey which measures the customer's *Overall Satisfaction* with the service they received in a recent contact through the Avista contact center and/or service center. The *Overall Satisfaction* question from surveys such as this is widely used in the industry for external reporting purposes. Rather than using the standard "satisfied" rating, which is typically used in the industry, the Company uses the average of the combined "*satisfied"* and "*very satisfied"* ratings. By combining these two ratings the target is more difficult to achieve and more emphasis is placed on serving the customer. In this Plan, the target is set at 90% very satisfied/satisfied for the customer's Overall Satisfaction rating.

Reliability: This index combines *Customer Average Interruption Duration Index (CAIDI), System Average Interruption Frequency Index (SAIFI) and Customer Experiencing Multiple Interruptions ($CEMI_3$)*. $CEMI_3$ measures the percentage of customers that experience more than three sustained outages in the year. The Company chose this level of outages over others because industry data received from JD Power's customer service surveys indicate that customers are more apt to be dissatisfied after three outages. Providing safe and reliable energy to our customers is the backbone of our business, therefore, it makes good sense to focus on service levels for our customers. By focusing on these measurements it enables the Company to direct our resources appropriately and efficiently in order to contain costs and plan for future infrastructure upgrades that will benefit the customer.

To determine the target for the Reliability portion of the Plan, the Company sets a separate target for each metric, weighs them equally and combines them into one metric (see the formula below). In this Plan the target is set at 1.00.

$$Index = \frac{CAIDI\ Target\ /\ CAIDI\ Actual}{3} + \frac{SAIFI\ Target\ /\ SAIFI\ Actual}{3} + \frac{CEMI^3\ Target\ /\ CEMI^3\ Actual}{3}$$

The formula used to set the target for each metric is described below:

- Customer Average Interruption Duration Index (CAIDI): *outage duration multiplied by the number of customers affected for all sustained outages (> 5 minutes), divided by the number of customers which had sustained outages*. Per industry practice Major Event Days (MEDs) are excluded from this metric. In this Plan the Company uses a 5 year average with a standard deviation of 0.72 (76% probability) to set the target which is 2 hours and 33 minutes restoration time.
- System Average Interruption Frequency Index (SAIFI): *the number of customers which had sustained outages (> 5 minutes), divided by the number of customers served.* Per industry

practice MEDs are excluded from this metric. In this Plan the Company uses a 5 year average and a standard deviation of 0.72 (76% probability) to set the target which is 1.15 outages per customer.

- Customers Experiencing Multiple Sustained Interruptions more than 3 ($CEMI_3$): *the total number of customers that experience more than 3 sustained outages per year, divided by total number of customers served.* To be consistent with the other two indices, MEDs are excluded from this metric. In this Plan the Company uses a 5 year average with a standard deviation of 0.72 (76% probability) to set the target at 6.74% of our customers.

Response Time: This metric measures how quickly the Company responds to natural gas system emergency calls. The Company tracks the average response time between the receipt of the emergency call to the time our crew or serviceman arrives on-site, assesses the situation and *reports back* to dispatch. The Company wants crews and/or serviceman to respond within the targeted response time goal. To be consistent with other service metrics, response times in excess of 24 hours are excluded from the metric. A "natural gas system emergency" is defined as an event when there is a natural gas explosion or fire, fire in the vicinity of natural gas facilities, police or fire are standing by, leads identified in the field as "Grade 1", high or low gas pressure problems identified by alarms or customer calls, natural gas system emergency alarms, carbon monoxide calls, natural gas odor calls, runaway furnace calls, or delayed ignition calls. In this Plan the Company aligns the response time with the Service Reliability Target negotiated with the Washington Utility Commission and set the target goal to respond within an average of, and not to exceed, 55 minutes.

Incentive Targets for 2023:

	Earnings Per Share	O&M Cost per Customer	Customer Satisfaction Rating	Reliability Index	Average Response Time Minutes	Equity, Inclusion, & Diversity Scorecard
% of Total Opportunity	55%	20%	8%	8%	4%	5%
Threshold 50%	$2.27	$447.54				
Target 100%	**$2.37**	**$444.60**	**90%**	**1.00**	**<55 Min**	**4/5 milestones achieved**
Maximum 172%	$2.47					
Maximum 150%		$433.62				

*rounded for display or communication purposes only

Individual Target Award Opportunities: During the February Board meeting, the Committee and the Chief Executive Officer (CEO) jointly review and approve the individual target award opportunities for the participants of the Plan. Each eligible employee has an incentive target award opportunity expressed as a percentage of their base salary. Target opportunities range from 40% to 100% of base salary and are assigned based on position. Actual award payments are calculated based on the employee's target award opportunity in effect as of December 31st and year-end regular earnings unless otherwise noted in the Plan document (see provisions under *Exceptions to Eligibility and Circumstances for Proration* section).

Individual Target Award Opportunity % of Base Pay by Position Type				
CEO	EVP	Senior VP	VP	Past Officer PT Advisor*
100%	65%	60%	40%	40%

*Past officer part-time advisor will remain in plan at prior opportunity % level

Distribution of Awards: If earned, incentive award payments will be distributed as soon as feasible usually in February after the Compensation Committee of the Board certifies and approves the achievement of the performance goals.

Calculation of Awards: In most instances actual amounts will be calculated using the participant's regular year-end earnings (as defined in the provisions section of the Plan), individual target award opportunity and employment status in effect as of December 31st of the Plan year. See the section *Exceptions to Eligibility and Circumstances for Proration* for definitions and exceptions.

For purposes of calculating the actual payments and ensure no overpayments or underpayments occur, the final performance results will be extended out six decimal places (ex. 166.666666%) for Consolidated EPS and four decimals (ex. 149.9323%) for Cost per Customer and rounded based on accounting rules. The following table shows how an overpayment can occur if the final performance level is rounded to two decimals and used to calculate the final payment.

	Metric	Target Opportunity	Metric Allocation	Maximum Results	Maximum % Allowed	Maximum Dollar Value
Maximum	Net Income	$ 152,248.39	60%	166.666666%	100.000000%	$ 152,248.39
Over Payment	Net Income	$ 152,248.39	60%	166.670000%	**100.002000%**	**$ 152,251.43**

Figure 4

Since the non-financial metrics have only two performance levels, 0% or 100%, rounding the final results is not an issue.

Once the total incentive amount is calculated, all cash payments will be rounded to the nearest penny based on accounting rules.

Example Award Calculation: Below is an example of the methodology the Company will use to calculate final payments.

The Company achieved the targets indicated below:

(1) Consolidated EPS = 166.666666% on the sliding scale

(2) Cost per Customer = 148.6468% on the sliding scale

(3) Customer Satisfaction = 100% = met/pass

(4) Reliability = 100% = met/pass

(5) Response Time = 100% = met/pass

(6) EID Scorecard = 100% = 4/5 milestones met

Non-CEO Average Earnings = $395,538					Average Target Opportunity = 53% or $209,635.38		
Goal	**Opportunity**		**Weighting**		**% Results**		**Amount**
Consolidated EPS	$ 209,635.38	x	55%	x	166.666666%	=	$ 192,165.77
Cost per Customer	$ 209,635.38	x	20%	x	148.6468%	=	$ 62,323.26
Customer Satisfaction	$ 209,635.38	x	8%	x	100%	=	$ 16,770.83
Reliability	$ 209,635.38	x	8%	x	100%	=	$ 16,770.83
Response Time	$ 209,635.38	x	4%	x	100%	=	$ 8,385.42
EID Scorecard	$ 209,635.38	x	5%	x	100%	=	$ 10,481.77
Total Payout = $306,898 or 146.4% of Target							

Figure 4

Communication: When communicating the results of the financial metrics and the payout, the Company will round results to the nearest 100th percent based on accounting rules. For example, if the O&M CPC result is 148.6468%, the Company will communicate the results using 148.65%.

When communicating the results of the non-financial metrics, the Company will round results to the nearest whole number or, in the case of reliability, out two decimal points based on accounting rules. For example, customer satisfaction would be rounded to 93% from 92.8% and reliability would be 1.23 from 1.232.

Recoupment Policy: All incentive awards earned by a participant under this Plan are subject to the Recoupment Policy adopted by the Company's Board of Directors as amended from time to time ("Recoupment Policy"). If a participant becomes subject to the Recoupment Policy any award may be forfeited in whole or in part and all or part of any distribution payable to a participant or his or her beneficiary under this Plan may be recovered by the Company pursuant to the Recoupment Policy.

Administration of Plan: The Committee is responsible for administering the Plan and may delegate specific administrative tasks to corporate staff, as appropriate. The Committee has the authority to:

- Terminate, amend or modify this Plan in whole or in part for any reason at any time without prior notice to participants
- Modify or adjust financial targets due to extraordinary occurrences and/or significant reorganizations
- Grant discretionary awards up to 15% of the individual target award opportunity
- May pay incentive amounts in excess of 100% (up to 150%) of an individual's target opportunity in the form of non-cash equivalents

Participation in this Plan should in no way be construed as a contract or promise of employment and/or compensation.

Exceptions to Eligibility and Circumstances for Proration:

Pay Periods: There are 26 pay periods and pay dates during the Plan year. A pay period (pp) is made up of two pay weeks. Each pay week typically starts 12:00am Monday and ends 11:59pm Sunday.

Employees are paid on the pay date on the following Friday, after the end of the pay period. The first pay period of the year consists of the date range 12/19/2022 – 1/1/2023 which is paid on pay date 1/6/2023. Changes effective during this pay period will count towards the 2023 plan since the earnings and pay date are part of 2023. Changes effective during the dates 12/18/2023 – 12/31/2023 are *not included* in the 2023 Plan because the earnings and pay date are part of 2024.

Pay Period Schedule for 2023:

Pay Period	Date Range	Pay Date	Pay Period	Date Range	Pay Date
1	12/19/22 – 01/01/2023	1/6	14	6/19 – 7/02	7/7
2	1/02 – 1/15	1/20	15	7/03 – 7/16	7/21
3	1/16 – 1/29	2/3	16	7/17 – 7/30	8/4
4	1/30 – 2/12	2/17	17	7/31 – 8/13	8/18
5	2/13 – 2/26	3/3	18	8/14 – 8/27	9/1
6	2/27 – 3/12	3/17	19	8/28 – 9/10	9/15
7	3/13 – 3/26	3/31	20	9/11 – 9/24	9/29
8	3/27 – 4/9	4/14	21	9/25 – 10/08	10/13
9	4/10 – 4/23	4/28	22	10/9 – 10/22	10/27
10	4/24 – 5/07	5/12	23	10/23 – 11/05	11/10
11	5/08 – 5/21	5/26	24	11/06 – 11/19	11/24
12	5/22 – 6/04	6/9	25	11/20 – 12/03	12/08
13	6/05 – 6/18	6/23	26	12/04 – 12/17	12/22

Proration: Prorating an employee's award is based on the number of pay dates associated with a change. Each change of status (COS) has an effective date. The date determines which pay period and pay date is to be counted as part of the proration.

Use the **Pay Period Schedule** above to count the pay dates. Using the effective date from the COS, search through the date ranges to find the pay period and pay date associated with it. Count the pay dates to the end of the Plan year or to the next COS effective date whichever comes first. The employee receives 1 pay period credit for each pay date counted.

For example:

- Employee #1 is hired on 5/6 and remains employed through the end of the year. The date 5/6 falls in the date range associated with pay period 10 which is paid on pay date 5/12. Since employee #1 worked till the end of the year, count the number of pay dates till the end of the year. The employee receives 17 pay periods towards his award.
- Employee #2 is hired on 9/21 and remains employed through the end of the year. Her date falls in pay period 20 and is associated with pay date 9/29. She receives 7 pay periods towards her award.
- Employee #3 receives credit for his time working in a non-union position. He transfers temporarily from a union position to a non-union position on 5/19 and returns to his regular union position on 12/2. The transfer date of 5/19 falls within pay period 11 which is associated with pay date 5/26. The returning date of 12/2 falls within pay period 25 which is associated with pay date 12/08. Count the number of pay dates starting with 5/26 and end with 11/24 which is the pay date prior to the next COS date of 12/2. He receives 14 pay periods of credit towards the non-union portion of his incentive award. Remember, only count the pay periods

until the next COS date or until the end of the year whichever comes first. He also receives 12 pay periods credited (26-14=12) toward his union incentive award.

Pay Period	Date Range	Pay Date	EE #1	EE #2	EE #3
10	4/24 – 5/07	5/12	1		
11	5/08 – 5/21	5/26	1		1
12	5/22 – 6/04	6/9	1		1
13	6/05 – 6/18	6/23	1		1
14	6/19 – 7/2	7/7	1		1
15	7/3 – 7/16	7/21	1		1
16	7/17 – 7/30	8/4	1		1
17	7/31 – 8/13	8/18	1		1
18	8/14 – 8/27	9/1	1		1
19	8/28 – 9/10	9/15	1		1
20	9/11 – 9/24	9/29	1	1	1
21	9/25 – 10/08	10/13	1	1	1
22	10/9 – 10/22	10/27	1	1	1
23	10/23 – 11/05	11/10	1	1	1
24	11/6 – 11/19	11/24	1	1	1
25	11/20 – 12/03	12/8	1	1	
26	12/4 – 12/17	12/22	1	1	
	Total Pay Periods		17	7	14

Regular Earnings: Regular earnings will be used in calculating the final awards. The earnings to be used and their associated codes are as follows:

Earnings Type	Earnings Codes
Regular	01, 02, 32, 32B
1.5x Overtime	04, 21, 23, 71, 76, 78, 83
Light Duty	29
Swing Shift	31
Alternative/dual	20
Relief Pay	08
Retro Pay	70
One Leave/PTO	10, 14, 14B, 15, 16, 16PFM, 34B, 34C, 61, 73
Short-term Disability 100% & 60%	18, 80
Workers Compensation	19, 19A, 85, 85C, 86, 87, 88
Holiday	25, 25P, 26, 63E, 63F, 75
Jury Duty	35
Military Pay	36, 36C

New Hires: Employees hired on or after October 1st will not be eligible for an award under this Plan. Employees hired prior to October 1st will have their awards calculated based on the provisions detailed above.

Leave of Absence: Eligible employees on approved unpaid leave of absence must have at least 6 full pay periods of active service during the Plan year to receive an award. Awards will be calculated based on the provisions detailed above. *Short- term disability leave does not affect an eligible employee's award and is excluded from this provision.*

Resignation/Termination: Any eligible employee who resigns or is terminated for reasons other than retirement, disability or death prior to December 31st will not be eligible to receive an award under this Plan. Eligible employees who terminate after the Plan year may receive an award at the time of distribution unless reason for termination is due to poor performance or for cause, see section on Discipline or Poor Performance below.

Death, Long-term Disability & Retirement: In the case of death, total disability (as defined under the Company's Long-term Disability Plan) or retirement (as defined under the Retirement Plan for Employees), an eligible employee or estate must have at least 6 pay periods of active service within the Plan year to be eligible to receive an award. Awards will be calculated based on the provisions detailed above.

Discipline or Poor Performance: Employees who receive a **fails to meet** performance rating for the Plan year or a **Last Chance Agreement** under the Company's formal discipline program and effective as of December 31st are not eligible to receive an award under this Plan. Any employee who is terminated for poor performance or for cause by the Company **after** December 31st and up to the time of distribution, will not be eligible to receive an award under this Plan.

Transfers from Subsidiaries to Corp/Utilities: Eligible employees who transfer from a subsidiary will be treated as a new hire to the Company and all Plan criteria apply as is. Prorated awards are at the discretion of the Committee and CEO.

Other Company Short-term Incentive Plans: Employees can only participate under one formal incentive plan a year. If the employee becomes eligible for a different plan during the year, the Committee and CEO has full discretion to determine which plan the employee may receive an award under. Status and/or time in position may be factors in determining whether the employee receives a prorated award from both plans or from one plan based on the employee's position and/or status as of December 31st.

Exhibit 10.26

3/16/2023

Dear Wayne:

We are pleased to extend a conditional offer of employment to you as Vice President, Chief Information Officer & Chief Security Officer in our Executive Department. This offer is conditioned on your successful completion of a background check and drug test and on Avista board approval.

Key elements of our offer are as follows:

Your anticipated starting date will be June 1, 2023.

Regular Compensation

Your base salary will be $360,000 annually, payable in substantially equal installments on Avista's regular paydays. This position is classified as exempt under the Fair Labor Standards Act. Accordingly, your salary is compensation for all hours worked and you are not eligible for overtime pay.

Your 2023 target short-term incentive (STI) compensation opportunity is 40% of your 2023 base salary, which equals $144,000, payable in February 2024, subject to your continued employment with Avista and satisfaction of applicable performance metrics.[1]

Upon hire, the Avista Compensation & Organization Committee will make a regular long-term incentive grant with a grant date value at target of $210,000. That grant will be made up of 30% time-based restricted stock units (RSUs) and 70% performance share units (PSUs). The RSUs will vest 1/3 annually on January 1 of 2024, 2025 and 2026, subject to your continued employment with Avista. The PSU performance period is 3 years (1/1/2023-12/31/2025) and is subject to your continued employment with Avista. The RSUs and PSUs will be eligible for dividend equivalents. References in this letter to RSU and PSU grants do not constitute actual grants, but rather grants will be made pursuant to and subject to the terms of the applicable long-term incentive plan and the award agreement governing such grants.

You will be eligible to participate in the Avista 401(k) plan, which includes a 100% match on the first 6% of contributions plus a non-elective company contribution of 3/4/5% based on your age. You will also be eligible to participate in Avista's welfare benefit plans, including our group health plan, subject to the terms of such plans. Participation in these plans is subject to plan terms and applicable law and Avista reserves the right to modify, amend, suspend or terminate such plans.

You will be eligible to participate in the Executive Deferred Compensation Plan, which is a non-qualified deferred compensation plan that allows an executive to defer compensation (base or short-term incentive) and is also used to provide a matching contribution intended to make up for lost matching contributions to the 401(k) plan due to the application of compensation limits imposed on qualified retirement plans.

[1] Your STI compensation opportunity for the 2024 calendar year and beyond as an Avista VP will be 40% of your base salary regular earnings during each year.

Each February, as part of Avista's market-based compensation program, the Avista Compensation & Organization Committee, in its discretion, considers management's recommendations, deliberates and may approve new grants to the executive team.

Transition Compensation & Support

Upon starting, you will receive a signing bonus of $75,000.
Upon starting, you will receive a short-term incentive replacement of $140,000.
Upon starting, the Avista Compensation & Organization Committee will make a special long-term incentive grant of RSUs with a grant date value at target of $125,000. The RSUs will vest on January 1, 2024, subject to your continued employment with Avista. The RSUs will be eligible for dividend equivalents.
In February 2024, management will request that the Avista Compensation & Organization Committee make a second special long-term incentive grant of RSUs with a grant date value at target of $125,000. The RSUs will vest on January 1, 2025, subject to your continued employment with Avista. The RSUs will be eligible for dividend equivalents.
A relocation allowance of up to $100,000 to reimburse your moving expenses. This allowance is available for up to 18 months to support your move. Please work with your manager to submit expense reports as you incur the expenses. We are also evaluating how best to support you with relocation firms that specialize in this area. The following expenses are example of covered items: reasonable real estate agent fees, closing costs, inspections, surveys, house hunting trips, temporary housing, travel and living, shipment of household good etc.

Paid Time Off

You will receive 120 hours of One Leave in your paid time off bank on your starting date.
You will receive a frontloaded amount of One Leave in the first quarter of 2024 and the first quarter of each year thereafter to ensure that your annual One Leave totals at least 25 days (200 hours).
In addition to One Leave, you will receive the regular Avista holidays and 3 personal holidays.

Other

Your role as an Avista executive is subject to the Avista Officer Stock Ownership Policy, which includes a share ownership requirement of 1x base salary to strengthen alignment with shareholders, with an expectation for you to reach that level within 5 years. Prior to reaching that level you may sell up to 50% of vested shares. All shares held directly, or indirectly in the 401(k) plan and unvested RSU grants, are counted toward this requirement.
You will participate in Avista's executive change-in-control plan. Please see attached.
You will receive company-paid executive life insurance (income continuation) at 2x base salary.
You will be eligible for the full package of employee benefits as outlined in our "Employee Benefits Summary."
All full-time employees have a six-month probationary period.
All amounts payable to you will be subject to applicable tax withholding and other deductions.
This offer is intended to comply with or otherwise be exempt from Section 409A of the Internal Revenue Code and will be interpreted and administered in accordance with such intention. In the event you are a "specified employee" for purposes of Section 409A, any compensation that you receive as a result of your separation from service that is not otherwise exempt from Section 409A and that would otherwise be paid during the six months immediately following your separation will be delayed and paid in a single lump sum on the first regular payroll date following such six-month period. If you are entitled to be paid or reimbursed for any taxable expenses hereunder, and such payments or reimbursements are taxable to you, the amount of such expenses reimbursable in any one calendar year shall not affect the amount reimbursable in any other calendar year, the reimbursement of an eligible expense must be made no later than December 31 of the year after the year in which the expense was incurred, and no right to reimbursement of expenses shall be subject to liquidation or exchange for another benefit. For purposes of Section 409A, each payment in a series of installments shall be treated as a separate payment.
Executive positions at Avista are primarily in-person roles with support for occasional remote work. Your

primary work location is 1411 E. Mission, Spokane, WA 99220.
Avista is a non-smoking/vaping, drug free workplace.
This offer contains the entire understanding between you and Avista with respect to the subject matter in this offer and supersedes any other agreement, written or oral, between us relating to the subject matter of this offer, including but not limited to any prior discussions, understandings, or agreements between us, written or oral, at any time. By signing this offer, you confirm that you are not relying on any statement, promise or agreement that is not contained in this offer.

Attached you will find the "Employee Benefits Summary." If you have questions regarding benefits, please contact your HR Manager or Benefits at (509) 495-2340 and press 2.

We hope that you will join us at Avista, and we look forward to working with you. If you are agreeable to the terms and conditions set out in this offer, please sign the original and return it at your earliest convenience.

Sincerely,

/s/ Heather Rosentrater

Heather Rosentrater
Avista Senior Vice President, Chief Operating Officer

I understand the information outlined above and accept this offer of employment.

/s/ Wayne Manuel	3/16/2023
Wayne Manuel	Date

cc: Personnel file – Wayne Manuel

This offer is not a contract for continued or future employment with Avista Corporation or any of its subsidiaries. Employment at Avista is "at will" and may be terminated at any time in the future. Any benefits offered in the course of employment are administered in accordance with the plan documents and the policies of Avista Corporation and its subsidiaries.

Exhibit 10.29

Avista Corporation
Non-Employee Director Compensation - 2023

The Board of Directors (Board) of Avista Corporation (Avista Corp. or the Company) regularly reviews director compensation with the assistance of an outside advisor to determine whether it is appropriate and competitive in light of market circumstances and prevailing best practices for corporate governance for the energy/utility industry. Through this review process, the Board targets overall director compensation to the median of the same peer group used to review executive compensation. The elements of director compensation reflect the Board's view that compensation to the independent directors should consist of an appropriate mix of cash and stock. The cash portion of the retainer is paid quarterly, and the stock portion is paid annually (as soon as practicable following the Annual Meeting). Employee directors are not compensated for their Board service.

Elements of Director Compensation

Pay Element	2023 Compensation		
Annual Retainer (cash and stock)	Board Members: (Directors receive an annual retainer of $220,000, with $125,000 automatically paid in stock. Directors have the option of taking the remaining $95,000 in cash, stock or a combination of both cash and stock.)	**$**	**220,000**
Committee Chair Retainers (Cash)	Audit Committee:	**$**	**20,000**
	Compensation Committee:	**$**	**15,000**
	Environmental Committee:	**$**	**15,000**
	Finance Committee:	**$**	**15,000**
	Governance Committee:	**$**	**15,000**
	Vice Chair:	**$**	**30,000**
	Non-Executive Chairman:	**$**	**100,000**

Each director is entitled to reimbursement of reasonable out-of-pocket expenses incurred in connection with meetings of the Board or its committees and related activities, including third party director education courses and materials. These expenses include travel to and from the meetings, as well as any expenses they incur while attending the meetings.

Director Stock Ownership Policy

The Company has a minimum stock ownership expectation for all Board members. Outside directors are expected to achieve a minimum investment of five times the minimum stock portion of their retainer (currently, five times $125,000 = $625,000), and retain at least that level of investment while a Board member. Shares previously deferred under the former Non-Employee Director Stock Plan count for purposes of determining whether a director has achieved the ownership expectation.

The ownership expectation illustrates the Board's philosophy of the importance of stock ownership for directors to further strengthen the commonality of interest between the Board and shareholders. The Governance Committee annually reviews director holdings to determine whether they meet ownership expectations.

There were no annual stock option grants or non-stock incentive plan compensation payments to directors for services in 2023 and none are currently contemplated under the current compensation structure. The Company also does not provide a retirement plan or deferred compensation plan to its directors.

Exhibit 21

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

Exhibit 31.1

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)

Exhibit 32

AVISTA CORPORATION

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

Exhibit 97

AVISTA CORPORATION

Dodd-Frank Recovery Policy

As Adopted August 3, 2023

1. **Introduction**. On October 26, 2022, the Securities and Exchange Commission ("SEC") adopted a new rule and rule amendments to implement Section 954 of the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010 ("Dodd-Frank Act"), which added Section 10D to the Act. Section 10D of the Act, and Exchange Act Rule 10D-1 as adopted by the SEC, directs U.S. stock exchanges to adopt listing standards requiring all listed companies to adopt and comply with a written clawback policy concerning the recoupment of incentive-based compensation paid to current or former executives based on erroneously reported financial information.

   On February 22, 2023, the New York Stock Exchange ("NYSE") released a proposed rule designed to comply with Rule 10D-1. Through the proposed NYSE rule, which is codified in Section 303A.14 of the NYSE Listed Company Manual ("NYSE Manual"), companies listed on the NYSE are required to adopt a recovery policy compliant with the Section 303A.14 of the NYSE Manual, which itself conforms closely to the applicable language of Rule 10D-1. The NYSE rule became effective as of December 1, 2023 (the "Effective Date"). *See* NYSE Manual Section 303A.14(b)(i).

   As an NYSE-listed company, Avista Corporation (the "Company") is required to implement and comply with Rule 10D-1 and the NYSE Manual. Through the written policy described and adopted herein (the "Dodd-Frank Recovery Policy"), the Board of Directors (the "Board") of the Company believes the Company is in compliance with Rule 10D-1 and the NYSE Manual.

   Capitalized terms used in this Dodd-Frank Recovery Policy are defined as provided herein, or in Section 303A.14 of the NYSE Manual.

2. **Administration**. The Dodd-Frank Recovery Policy shall be administered by the Board, or, if so delegated by the Board, any committee or sub-committee of the Board. The Board has the sole discretion to interpret the terms of the Dodd-Frank Recovery Policy and make determinations under it. Any interpretations or determinations made by the Board shall be final and binding on all affected individuals.

3. **Covered Persons**. Any person who is or was an Executive Officer of the Company (as defined in Section 303A.14 of the NYSE Manual), who received incentive-based compensation after the Effective Date, is a "Covered Person" under the Dodd-Frank Recovery Policy. In accordance with the NYSE Manual, incentive-based compensation is deemed "received" in the Company's fiscal period during which the financial reporting measure specified in the incentive-based compensation award is attained, even if the payment or grant of the incentive-based compensation occurs after the end of that period.

4. **Incentive-Based Compensation.** "Incentive-based compensation" means any compensation received by a Covered Person (including compensation granted to, earned by, or vested to a Covered Person), that is based wholly or in part upon the attainment of a financial reporting measure.

   In accordance with the NYSE Manual, "financial reporting measures" are "measures that are determined and presented in accordance with the accounting principles used in preparing the Company's financial statements, and any measures that are derived wholly or in part from such measures," including stock price and total shareholder return. A financial reporting measure need not be presented within the Company's financial statements or included in a filing with the Commission to be applicable under the Dodd-Frank Recovery Policy.

5. **Mandatory Recovery of Incentive-Based Compensation Due to Financial Restatement.** In the event that the Company is required to prepare an accounting restatement due to the Company's material

noncompliance with any financial reporting requirement under the securities laws, including any required accounting restatement to correct an error in previously issued financial statements that is material to the previously issued financial statements, or that would result in a material misstatement if the error were corrected in the current period or left uncorrected in the current period, the Board shall reasonably promptly recover the amount of erroneously awarded incentive-based compensation.

The required recovery of compensation applies to all incentive-based compensation received by a Covered Person:

a. After beginning service as an Executive Officer;

b. Who served as an Executive Officer at any time during the performance period for that incentive-based compensation;

c. While the Company has a class of securities listed on a national securities exchange or a national securities association; and

d. During the three completed fiscal years immediately preceding the date that the Company is required to prepare an accounting restatement as described in paragraph (c)(1) of Section 303A.14 of the NYSE Manual. In addition to these last three completed fiscal years, the Board shall seek recovery of incentive-based compensation earned during any transition period (that results from a change in the Company's fiscal year) within or immediately following those three completed fiscal years. However, a transition period between the last day of the Company's previous fiscal year end and the first day of its new fiscal year that comprises a period of nine to 12 months is deemed to be a completed fiscal year.

6. **Determination of Relevant Recovery Period**. The Board shall seek recovery of erroneously awarded incentive-based compensation regardless of when or whether restated financial statements are filed with the SEC. For purposes of determining the period for which incentive-based compensation shall be recovered by the Board, the date that the Company is required to prepare an accounting restatement as described in paragraph (c)(1) of Section 303A.14 of the NYSE Manual is the earlier to occur of:

a. The date the Board, a committee of the Board, or the officer or officers of the Company authorized to take such action if Board action is not required, concludes, or reasonably should have concluded, that the Company is required to prepare an accounting restatement as described in paragraph (c)(1) of Section 303A.14 of the NYSE Manual; or

b. The date a court, regulator, or other legally authorized body directs the Company to prepare an accounting restatement as described in paragraph (c)(1) of Section 303A.14 of the NYSE Manual.

7. **Amount of Recovery**. The amount of incentive-based compensation that must be subject to this Dodd-Frank Recovery Policy is the amount of incentive-based compensation received that exceeds the amount of incentive-based compensation that otherwise would have been received had it been determined based on the restated amounts, and must be computed without regard to any taxes paid (the "Erroneously Awarded Compensation").

For incentive-based compensation based on stock price or total shareholder return, where the amount of Erroneously Awarded Compensation is not subject to mathematical recalculation directly from the information in an accounting restatement:

a. The amount must be based on a reasonable estimate of the effect of the accounting restatement on the stock price or total shareholder return upon which the incentive-based compensation was received; and

b. The Board shall ensure that the Company maintains documentation of the determination of that reasonable estimate and provide such documentation to the NYSE.

8. **Exceptions to Mandatory Recovery**. The Board shall recover Erroneously Awarded Compensation in

compliance with the Dodd-Frank Recovery Policy except to the extent that the conditions of paragraphs (c)(1)(iv)(A), (B), or (C) of Section 303A.14 of the NYSE Manual are met (those sections are recounted in parts 7(a), 7(b), and 7(c) immediately below), and the Board's committee of independent directors responsible for executive compensation decisions, or in the absence of such a committee, a majority of the independent directors serving on the board, has made a determination that recovery would be impracticable.

In accordance with the terms of this Section 7, the Board may forego recovery of Erroneously Awarded Compensation in the following circumstances:

a. The direct expense paid to a third party to assist in enforcing the Dodd-Frank Recovery Policy would exceed the amount to be recovered. Before concluding that it would be impracticable to recover any amount of Erroneously Awarded Compensation based on expense of enforcement, the Board must make a reasonable attempt to recover such Erroneously Awarded Compensation, document such reasonable attempt(s) to recover, and provide that documentation to the NYSE.

b. Recovery would likely cause an otherwise tax-qualified retirement plan, under which benefits are broadly available to employees of the Company, to fail to meet the requirements of 26 U.S.C. 401(a)(13) or 26 U.S.C. 411(a) and regulations thereunder.

9. **No Indemnification**. The Company is prohibited from indemnifying any Executive Officer or former Executive Officer against the loss of Erroneously Awarded Compensation.

10. **Effective Date.** The Amended Compensation Recoupment Policy shall be effective as of August 3, 2023 and shall apply to compensation that is awarded or granted to Covered Persons on or after that date.

11. **Required Disclosures**. In accordance with Rule 10D-1 and Section 303A.14(c)(2) of the NYSE Manual, the Company shall file a copy of this Dodd-Frank Recovery Policy as an exhibit to its annual report on form 10-K.

In the event that the Company is required to prepare an accounting restatement, the Company shall further make all required disclosures under the Federal securities laws, including those required under 17 CFR 229.402(w) ("Item 402(w)" of Regulation S-K). The required disclosures under Item 402(w) include the following:

a. For each restatement:

   i. The date on which the Company was required to prepare an accounting restatement;

   ii. The aggregate dollar amount of Erroneously Awarded Compensation attributable to such accounting restatement, including an analysis of how the amount was calculated;

   iii. If the financial reporting measure as defined in 17 CFR 240.10D–1(d) related to a stock price or total shareholder return metric, the estimates that were used in determining the Erroneously Awarded Compensation attributable to such accounting restatement and an explanation of the methodology used for such estimates;

   iv. The aggregate dollar amount of Erroneously Awarded Compensation that remains outstanding at the end of the last completed fiscal year; and

   v. If the aggregate dollar amount of Erroneously Awarded Compensation has not yet been determined, disclosure of this fact, an explanation the reason(s), and disclosure of the information required in paragraphs (w)(1)(i)(B) through (D) of Item 402(w) in the next filing that is required to include disclosure pursuant to Item 402 of Regulation S–K;

b. If recovery would be impracticable pursuant to 17 CFR 240.10D–1(b)(1)(iv), for each current and former named Executive Officer and for all other current and former Executive Officers as a group, disclosure of the amount of recovery forgone and a brief description of the reason the Company decided in each case not to pursue recovery; and

c. For each current and former named Executive Officer from whom, as of the end of the last completed fiscal year, Erroneously Awarded Compensation had been outstanding for 180 days or longer since the date the registrant determined the amount the individual owed, disclosure of the dollar amount of outstanding Erroneously Awarded Compensation due from each such individual.