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, 2021 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. ☒

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 $2,972,676,681 based on the last reported sale price thereof on the consolidated tape on June 30, 2021.

As of January 31, 2022, 71,572,570 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 12, 2022. Prior to such filing, the Proxy Statement was filed in connection with the annual meeting of shareholders held on May 11, 2021.	**Part III, Items 10, 11, 12, 13 and 14**

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* = not an applicable item in the 2021 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
AM&D	-	Advanced Manufacturing and Development, doing business as METALfx
ASC	-	Accounting Standards Codification
ASU	-	Accounting Standards Update
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
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
Ecology	-	The State of Washington’s Department of Ecology
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

FASB	-	Financial Accounting Standards Board
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)
Hydro One	-	Hydro One Limited, based in Toronto, Ontario, Canada.
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
Juneau	-	The City and Borough of Juneau, Alaska
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
LNG	-	Liquefied Natural Gas
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
PGE	-	Portland General Electric Company
PPA	-	Power Purchase Agreement
PSE	-	Puget Sound Energy, Inc.
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)
Watt	-	Unit of measurement of electric power or capability; a watt is equal to the rate of work represented by a current of one ampere under a pressure of one volt
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, interest rate swap derivatives, 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

- pandemics (including the current COVID-19 pandemic), 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;
- wildfires ignited, or allegedly ignited, by Avista Corp. equipment or facilities could cause significant loss of life and property or result in liability for resulting fire suppression costs, 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, and the potential increasing frequency and intensity of such events due to 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;
- explosions, fires, accidents, mechanical breakdowns or other incidents that could impair assets and may disrupt operations of any 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;

- 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 any effects of terrorism, cyberattacks, ransomware, or vandalism that damage or disrupt information technology systems;
- 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 any 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;
- change in the use, availability or abundancy of water resources and/or rights needed for operation of our hydroelectric facilities;

Cyber and Technology Risk

- cyberattacks on the operating systems that are 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 that are 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;
- 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;
- 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 that may be sold back to the utility, and alternative energy suppliers and delivery arrangements;
- entering into or growth of non-regulated activities may increase earnings volatility;
- 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 global climate changes;
- 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

- 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;
- our ability to obtain financing through the issuance of debt and/or equity securities, 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, our ability to effectively hedge interest rates for anticipated debt issuances, variable interest rate borrowing and the extent to which we recover interest costs through retail rates collected from customers;
- 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 energy demand related to customer energy efficiency, conservation measures and/or increased distributed generation;
- 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;
- 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;

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 to us from such transactions, and the market value of derivative assets and liabilities;
- default or nonperformance on the part of any 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 for us 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 that are 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, 2021, 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, most of whom are employees who operate Avista Utilities' Noxon Rapids generating facility. 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 $2.2 billion as of December 31, 2021, which includes a $117.5 million investment in Avista Capital and a $108.5 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:

- developing, retaining and attracting a diverse 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 Company 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 create a workplace culture that values trust and respect and helps guide our overall commitment to doing what is right and offering all employees the opportunity to enrich their lives and careers through challenging and meaningful work – all in an equal opportunity workplace that is surrounded by a supportive and inclusive environment. With a strong workplace culture as a foundation, we actively engage and listen to our employees, customers and communities in order to help measure and inform our equity, inclusion, diversity, and racial and social justice practices. Our equity, inclusion, and diversity initiatives are focused on employee recruitment, employee training and development, and employee engagement, including participation in employee resource groups. Employee resource groups are voluntary, employee led groups that foster a diverse and inclusive workplace aligned with our organizational mission, values and goals and business practices.

On December 31, 2021, Avista Utilities employed 1,809 with an employee profile of:

	Women	**Under Represented Groups (a)**
Bargaining Unit	3%	6%
Non-bargaining Unit	45%	9%
Executives (b)	17%	8%
Overall	29%	8%

(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 38 percent of Avista Utilities' employees.

People Development, Retention and Attraction

We strive to hire and retain talented people who are innovative and skilled so that we can continue to provide safe, reliable and affordable service to our customers and advance our Company at the same time.

Continuous learning plays a large part in fostering collaboration and innovation among our employees and is embedded 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 in order to meet the emerging challenges that lay ahead. We develop training that is relevant, necessary and in demand for our organization. Training may be delivered through instructor-led courses, self-service topics, computer-based learning modules, and field based, hands-on workshop models that cover the range of our operations. These programs encompass craft apprenticeship programs, engineering development programs, leadership development, communication skills, cross-functional learning and equity, inclusion and diversity topics. In addition to our internally led courses, 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 to our local colleges and universities.

Workplace Safety

Safety is an essential part of our mission. We have a variety of programs and initiatives in place that are intended to help employees complete their work safely through heightened vigilance, hazard recognition, defensive strategies, lessons learned, human and organizational performance improvement 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.

During the COVID-19 Pandemic, we have transitioned through various stages of response designed to protect the health and safety of our employees and meet compliance obligations, while continuing to provide essential services to our customers. We have focused on care and concern for our employees, customers and other key stakeholders, proactively communicating about the risks and relying on facts and credible information from our regional, state and federal health and safety organizations. This focus included providing options to employees and customers to best protect themselves from COVID-19 when engaging in our work.

Additional Information

Additional information highlighting the Company's commitments to corporate responsibility, including the Company’s commitments to our environment, our people, our customers and communities and ethical governance, is available on the Company’s website at www.avistacorp.com. Material on the Company’s website is not part of this report.

AVISTA UTILITIES

General

At the end of 2021, Avista Utilities supplied retail electric service to approximately 406,000 customers and retail natural gas service to approximately 372,000 customers across its service territory. Avista Utilities' service territory covers 30,000 square miles with a population of 1.7 million. See “Item 2. Properties” for further information on our utility assets. See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations – Economic Conditions and Utility Load Growth” for information on economic conditions in our service territory.

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, most of whom are employees who operate Avista Utilities' Noxon Rapids generating facility.

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. In order 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.

On the basis of 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 all of 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 2021 was 1,889 MW, which occurred on June 30, 2021. In 2020, our peak electric native load was 1,721 MW, which occurred during the summer, and in 2019, it was 1,656 MW, which occurred during the summer.

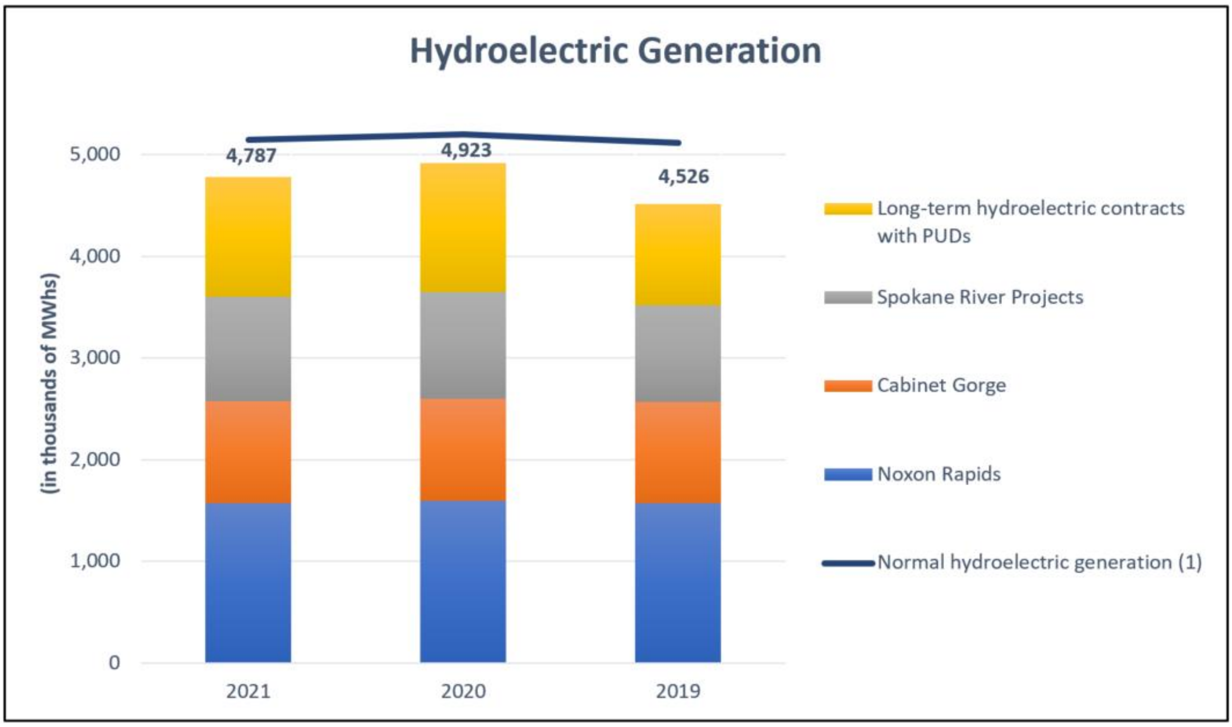
Electric Resources

Avista Utilities has a diverse electric resource mix of Company-owned and contracted hydroelectric, thermal and wind generation facilities, and other contracts for power purchases and exchanges. As of December 31, 2021, Avista Utilities' electric generation resource mix (including contracts for power purchases) was approximately 49 percent hydroelectric, 42 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 with certain PUDs in the state of Washington. Our estimate of normal annual hydroelectric generation for 2022 (including resources purchased under long-term hydroelectric contracts with certain PUDs) is 579 aMW (or 5.1 million MWhs).

See "Item 2. Properties - Avista Utilities - Generation Properties" for the nameplate rating and 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 takes into account any water flow changes from upstream dams due to releasing or holding back water. The calculation of "normal" varies annually due to the timing of upstream dam regulation throughout the year, as well as changes in PUD contracts.

Thermal Resources Avista Utilities owns the following thermal generating resources:

- the combined cycle natural gas-fired CT, known as Coyote Springs 2, located near Boardman, Oregon,
- a 15 percent interest in Units 3 & 4 of Colstrip, a coal-fired boiler generating facility located in southeastern Montana; see “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations – Colstrip” for discussion on Colstrip,
- 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 Montana, 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.

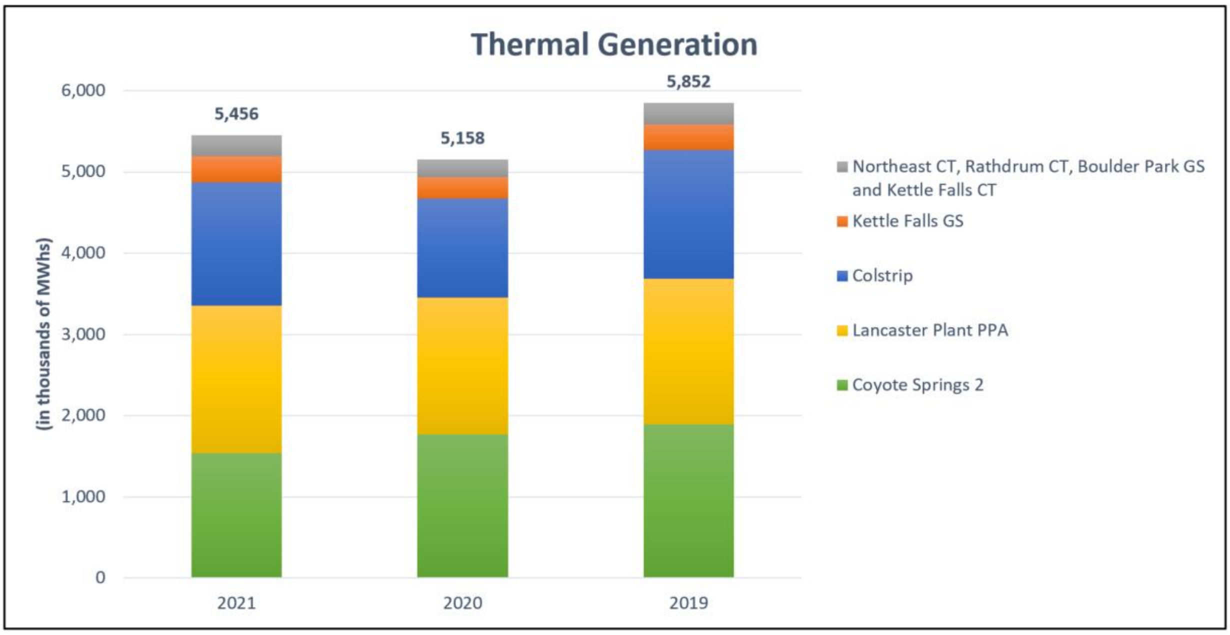
The primary fuel for the Kettle Falls GS is wood waste generated as a by-product and delivered by trucks from forest industry operations within 100 miles of the plant. A combination of long-term contracts and spot purchases has provided, and is expected to meet, fuel requirements for the Kettle Falls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

We have the exclusive rights to all the capacity of the Lancaster Plant, a 270 MW natural gas-fired combined cycle combustion turbine plant located in northern Idaho, owned by an unrelated third-party. All of the output from the Lancaster Plant is contracted to us through 2026 under a PPA. Under the terms of the PPA, we make the dispatch decisions, provide all natural gas fuel and receive all of the electric energy output from the Lancaster Plant; therefore, we consider this plant in our baseload resources. See "Note 6 of the Notes to Consolidated Financial Statements" for further discussion of this PPA.

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



<u>Wind Resources</u> We have exclusive rights to all the capacity of Palouse Wind, a wind generation project developed, owned and managed by an unrelated third-party and located in Whitman County, Washington. The PPA expires in 2042 and requires us to acquire all of 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. Generation from Palouse Wind was 360,783 MWhs in 2021, 370,142 MWhs in 2020 and 302,136 MWhs in 2019. We have an annual option to purchase the wind project beginning in December 2022. 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. Under the terms of the PPA, we do not have any input into the day-to-day operation of the project, including maintenance decisions. All such rights are held by the owner.

We have exclusive rights to all of 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 PPA is a 20-year agreement that began in December 2020 and requires us to acquire all of 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. Generation from Rattlesnake Flat Wind was 423,510 MWhs in 2021. Under the terms of the PPA, we do not have any input into the day-to-day operation of the project, including maintenance decisions. All such rights are held by the owner.

Solar Resources We have exclusive rights to all 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. The PPA expires in 2038 and requires us to acquire all the power and renewable attributes produced by the project at a fixed price per MWh. The project has a nameplate capacity of 28 MW. The facility generated 43,328 MWhs in 2021, 45,281 MWhs in 2020, and 42,346 MWhs in 2019. Under the terms of the PPA, we do not have any input into the day-to-day operation of the project, including maintenance decisions. All such rights are held by the owner.

Other Purchases, Exchanges and Sales In addition to the resources described above, we purchase and sell power under various long-term contracts, and we also 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 2021, 2020 and 2019. See “Electric Operations” above for additional information with respect to the use of wholesale purchases and sales as part of our resource optimization process and also see "Future Resource Needs" below for the magnitude of these power purchase and sales contracts in future periods.

Avista Corp. understands that there are many coal-fired electric generating stations throughout the western United States that 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. At the same time, the retirement of Colstrip Units 3 & 4, if it were effected, could increase the volume of energy that we are required to purchase in this marketplace. However, after December 31, 2025, we will be effectively prohibited by Clean Energy Transformation Act (CETA) from using energy produced by coal-fired plants to serve our retail customers in Washington, and, to the extent necessary for that purpose, we will have to 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."

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).

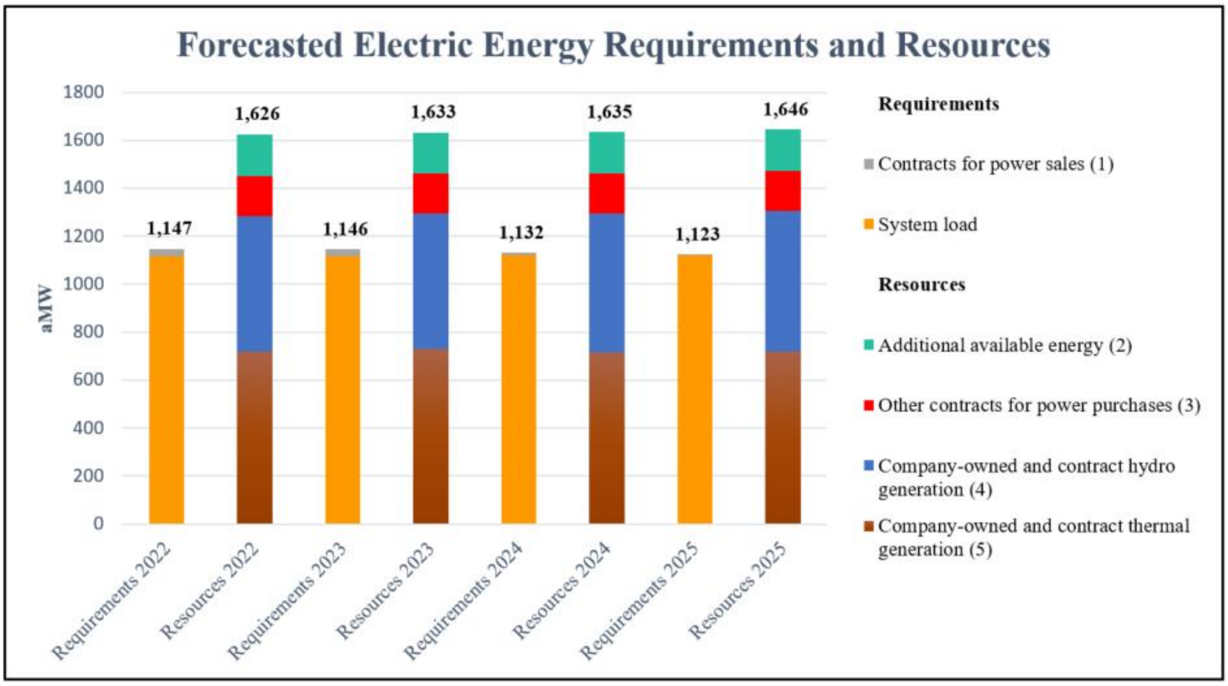
Cabinet Gorge and Noxon Rapids are under one 45-year FERC license issued in 2001. This license embodies a settlement agreement relating to project operations and resource protection and mitigation efforts over the license term. See “Item 7. Management's Discussion and Analysis – Environmental Issues and Contingencies" for discussion of dissolved atmospheric gas levels that exceed the state of Idaho and federal numeric water quality standards downstream of Cabinet Gorge during periods when we must divert excess river flows over the spillway, as well as efforts related to bull trout, a threatened species under the Endangered Species Act.

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 issued in 2009 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, signed in 1994.

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 widely because of the factors that influence demand over intra-hour, hourly, daily, monthly and annual durations. Our average hourly load was 1,113 aMW in 2021, 1,064 aMW in 2020 and 1,081 aMW in 2019.

The following graph shows our forecast of our average annual energy requirements and our available resources for 2022 through 2025:



(1) The contracts for power sales decrease due to certain contracts expiring in each of these years. We are evaluating the future plan for the additional resources made available due to the expiration of these contracts.

(2) 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.

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

(4) The forecast assumes near normal hydroelectric generation.

(5) 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) 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 April 2021, we filed our 2021 Electric IRP with the WUTC and the IPUC. Later that same month, we filed an amended IRP to include the results of the 2020 Renewable Request for Proposal (RFP).

Highlights of the 2021 IRP include the following expectations and/or assumptions:

- We have adequate resources between owned and contractually controlled generation, when combined with conservation and market purchases, to meet customer demand through October 2026. Our first long-term capacity deficit, net of energy efficiency, begins in October 2026 and is 247 MW by January 2027.
- The resource strategy reduces greenhouse gas emissions between 80-90 percent from present levels.
- We anticipate customer load growth of 0.3 percent per year.
- Assumes Colstrip will exit the portfolio by 2025 (see “Item 7. Management’s Discussion and Analysis of Financial Condition – Environmental Issues and Contingencies” for further discussion of Colstrip in relation to the Washington Clean Energy Transformation Act).
- New natural gas-fired peaking units are the most economic means to meet the capacity shortfall in 2027 since long-term energy storage is not yet available at a cost effective price.
- Demand response programs begin in 2025 and grow to 72 MW by 2045.
- Our first new renewable resource identified in the IRP is in 2025, as a wind project located in Montana. Actual resource selection will be determined by a future RFP.

The resource strategy embodied in the IRP is intended to move us closer to achieving our corporate clean electricity goal to provide customers with 100 percent net clean electricity by 2027. Net clean energy is defined as either 100 percent non-carbon emitting resources or investing in or acquiring carbon offsets to net-out emissions created from carbon emitting resources. The addition of natural gas peaking units in 2027 would require us to purchase carbon offsets.

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 that we will require will either be owned by us or be owned by other parties who will sell the capacity and energy to us 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.

Request for Proposals for Renewable Energy

We sought proposals from renewable energy project developers who are capable of constructing, owning and operating up to 120 aMWs whether through one or multiple proposals with a minimum net annual output of 20 aMW. We did not consider a self-build option for this facility or facilities.

Our intent was to secure the output from renewable generation resources, including electricity, capacity and associated environmental attributes. Our interest in acquiring renewable energy resources was to offset market purchases and fossil-fuel thermal generation. Final bidders were selected for review in October 2020 and the Company successfully negotiated a fixed cost contract for a 5 percent share of output (88 MW / 51 aMW) of Chelan PUD’s Chelan hydro system (Rocky Reach and Rock Island hydro projects) signed in March 2021 and an additional contract for a 10 percent share (177 MW) in December 2021. The December 2021 contract starts with a 5 percent share from 2026 to 2030, and increases to a 10 percent share from 2031 to 2045.

Clean Energy Goals

In April 2019, we announced a goal to serve our customers with 100 percent clean electricity by 2045 and to have a carbon-neutral supply of electricity by the end of 2027. To help achieve our goals and add to our clean electricity portfolio, in the last three years, we have implemented renewable energy projects on behalf of our customers including entering into PPAs for the Solar Select project (28 MW) in Lind, Washington and the Rattlesnake Flat Wind project (144 MW) in Adams County, Washington. We also entered into two power purchase contracts with Chelan County Public Utility District for a percentage share of the output of their Rocky Reach and Rock Island hydro projects for 22 years starting in 2024 (88-264 MW). 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 that 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 such that it will allow us to meet our goals while also 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 insofar as we may need to acquire emission offsets to meet our goals. See the discussion in Item 1 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 that have been in place for many years, we created a new comprehensive 10-year Wildfire Resiliency Plan that includes improved defense strategies and operating practices for a more resilient system. This plan will be periodically updated and informed by observed experience as well as changes in observed landscape and climatic conditions.

We have 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 approximately $330 million implementing the plan components over the life of the 10-year plan. The IPUC and WUTC have approved deferral of certain costs of the wildfire resiliency plan and seek recovery 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 to procure 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. On the basis of 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 approval is received, the plan is implemented and monitored by our gas supply and risk management groups.

The plan's progress is also 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. Any 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 any 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.

Clean Energy Goals

In April 2021, we announced an aspirational goal to reduce carbon emissions for natural gas 30 percent by 2030 and 100 percent 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.

Achieving the carbon emission reductions for the natural gas system will involve various pathways. The initial primary pathways include renewable natural gas (RNG), energy efficiency, customer voluntary RNG and carbon offset programs. See

“Item 7. Management’s Discussion and Analysis of Financial Condition – Environmental Issues and Contingencies” for further discussion on clean energy, including applicable regulations.

Natural Gas Supply Avista Utilities purchases all of its natural gas in wholesale markets. We 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 us to make 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 sourced supply. 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. As an owner, 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 at a later time. 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 April 2021, we filed our 2021 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. The IPUC and OPUC have formally acknowledged our IRP; the WUTC is still processing the IRP.

Highlights of the 2021 natural gas IRP include the following expectations and/or assumptions:

- We anticipate having sufficient natural gas resources during the 20-year planning horizon.
- Due to expected carbon legislation at the state levels through a cap and reduce mechanism (Oregon) or a social cost of carbon tax mechanism (Washington), we expect our retail natural gas rates to include a carbon price adder in Oregon and Washington, but not in Idaho.
- Regional supply constraints are beginning to increase in their likelihood causing prices to act in a more volatile fashion. This volatility in pricing paired with supply side resource availability has made our procurement plan an increasingly important piece to manage customer rates, diversity of supply and peak day demand.
- LNG exports, power generation and exports to Mexico will continue to add demand for natural gas.
- We expect lower use per customer and an increased amount of demand side management (DSM). The combination of low-priced natural gas in addition to carbon fees or other programs has led to a higher potential for DSM measures.
- We view renewable natural gas and low carbon fuels as an important component of our corporate environment strategy and decarbonization goals.

We will monitor these assumptions on an on-going basis and adjust our resource requirements accordingly.

We are required to file a natural gas IRP every two years and we anticipate our next IRP to be filed in 2023.

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 also 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 also 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 any 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 for us 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 on the basis of 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. 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, 12 and 23 of the Notes to Consolidated Financial Statements" for additional information about regulation, depreciation and deferred income taxes.

General Rate Cases Avista Utilities regularly reviews the need for electric and natural gas rate changes in each state in which we provide service. See "Item 7. Management's Discussion and Analysis – Regulatory Matters – General Rate Cases" for information on general rate case activity.

Power Cost Deferrals Avista Utilities defers the recognition in the income statement of certain power supply costs that vary from the level currently recovered from our retail customers as authorized by the WUTC and the IPUC. See "Item 7. Management's Discussion and Analysis – Regulatory Matters – Power Cost Deferrals and Recovery Mechanisms" and "Note 23 of the Notes to Consolidated Financial Statements" for information on power cost deferrals and recovery mechanisms in Washington and Idaho.

Purchased Gas Adjustments (PGA) Under established regulatory practices in each state, Avista Utilities defers the recognition in the income statement of the natural gas costs that vary from the level currently recovered from our retail customers as authorized by each of our jurisdictions. See “Item 7. Management’s Discussion and Analysis – Regulatory Matters – Purchased Gas Adjustments” and “Note 23 of the Notes to Consolidated Financial Statements” for information on natural gas cost deferrals and recovery mechanisms in Washington, Idaho and Oregon.

Decoupling Mechanisms Decoupling (also known as FCA in Idaho) is a mechanism designed to sever the link between a utility's revenues and consumers' energy usage. In each of its 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" usage, rather than being based on actual usage. 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. See “Item 7. Management’s Discussion and Analysis – Regulatory Matters – Decoupling and Earnings Sharing Mechanisms” for further discussion of these mechanisms.

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 any 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 (ISO).

The Company currently meets its 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 its participation in NorthernGrid, the Company is able to meet the regional transmission planning requirements of FERC Order Nos. 890 and 1000, and their 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 the Company’s operations or financial performance.

Regional Energy Markets

The CAISO operates the Western Energy Imbalance Market (EIM) in the western United States. Most investor-owned utilities in the Pacific Northwest are either participants in the Western EIM or plan to integrate into the market in the near future. The Company has announced its decision to participate in the Western EIM and is slated to commence EIM operations by March

2022. The decision to join the Western EIM was based on a number of factors, including the amount of expected variable generating resources the Company will need to integrate within its balancing authority area in the foreseeable future, and the expected costs and benefits associated with joining the Western EIM. The 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 has 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, the Company 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, particularly electric and natural gas utility companies in the United States and abroad, have become the subject of cyberattacks and ransomware attacks with increased frequency. The Company’s administrative and operating networks are targeted by hackers on a regular basis.

A successful attack on the Company’s administrative networks could compromise the security and privacy of data, including operating, financial and personal information. A successful attack on the Company’s operating networks could impair the operation of the Company’s 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.

The Company continually reinforces and updates its defensive systems and is in compliance with NERC’s reliability standards. See “Reliability Standards," "Item 1A. Risk Factors – Cyber and Technology Risk Factors” and “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations – Enterprise Risk Management – Cyber and Technology Risks” for further information.

AVISTA UTILITIES ELECTRIC OPERATING STATISTICS

	Years Ended December 31,		
	2021	2020	2019
ELECTRIC OPERATIONS			
OPERATING REVENUES (Dollars in Thousands):			
Residential	$ 394,717	$ 377,785	$ 369,102
Commercial	326,173	303,972	317,589
Industrial	106,756	103,103	105,802
Public street and highway lighting	7,472	7,303	7,448
Total retail	835,118	792,163	799,941
Wholesale	89,768	77,277	73,232
Sales of fuel	63,673	28,773	48,040
Other	36,288	30,149	28,995
Alternative revenue programs	(19,525)	(4,361)	8,699
Deferrals and amortizations for rate refunds to customers	1,730	3,539	3,141
Total electric operating revenues	$ 1,007,052	$ 927,540	$ 962,048
ENERGY SALES (Thousands of MWhs):			
Residential	3,955	3,807	3,766
Commercial	3,158	2,995	3,170
Industrial	1,666	1,615	1,691
Public street and highway lighting	17	18	18
Total retail	8,796	8,435	8,645
Wholesale	2,461	2,680	2,787
Total electric energy sales	11,257	11,115	11,432
ENERGY RESOURCES (Thousands of MWhs):			
Hydro generation (from Company facilities)	3,598	3,651	3,520
Thermal generation (from Company facilities)	3,635	3,474	4,054
Purchased power	4,954	4,922	4,833
Power exchanges	(398)	(446)	(504)
Total power resources	11,789	11,601	11,903
Energy losses and Company use	(532)	(486)	(471)
Total energy resources (net of losses)	11,257	11,115	11,432
NUMBER OF RETAIL CUSTOMERS (Average for Period):			
Residential	356,387	350,669	345,064
Commercial	44,110	43,497	42,930
Industrial	1,205	1,277	1,305
Public street and highway lighting	666	639	612
Total electric retail customers	402,368	396,082	389,911
RESIDENTIAL SERVICE AVERAGES:			
Annual use per customer (KWh)	11,098	10,857	10,914
Revenue per KWh (in cents)	9.98	9.92	9.80
Annual revenue per customer	$ 1,107.55	$ 1,077.33	$ 1,069.66
AVERAGE HOURLY LOAD (aMW)	1,113	1,064	1,081

AVISTA UTILITIES ELECTRIC OPERATING STATISTICS

	Years Ended December 31,		
	2021	2020	2019
RETAIL NATIVE LOAD at time of system peak (MW):			
Winter	1,696	1,613	1,577
Summer	1,889	1,721	1,656
COOLING DEGREE DAYS: (1)			
Spokane, WA			
Actual	946	546	488
Historical average	546	537	531
% of average	173 %	102 %	92 %
HEATING DEGREE DAYS: (2)			
Spokane, WA			
Actual	6,124	6,187	6,817
Historical average	6,596	6,651	6,613
% of average	93 %	93 %	103 %

(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,		
	2021	2020	2019
NATURAL GAS OPERATIONS			
OPERATING REVENUES (Dollars in Thousands):			
Residential	$ 221,405	$ 213,612	$ 196,430
Commercial	100,819	94,937	92,168
Interruptible	4,781	4,285	2,257
Industrial	3,015	2,843	3,006
Total retail	330,020	315,677	293,861
Wholesale	113,277	104,910	135,039
Transportation	8,547	7,917	8,674
Other	7,325	5,034	7,375
Alternative revenue programs	12,890	547	915
Deferrals and amortizations for rate refunds to customers	1,254	1,797	1,368
Total natural gas operating revenues	$ 473,313	$ 435,882	$ 447,232
THERMS DELIVERED (Thousands of Therms):			
Residential	219,835	219,988	231,238
Commercial	130,399	127,659	140,578
Interruptible	16,013	14,854	9,138
Industrial	5,402	5,424	6,212
Total retail	371,649	367,925	387,166
Wholesale	356,891	542,372	590,802
Transportation	172,260	180,361	187,514
Interdepartmental and Company use	479	369	421
Total therms delivered	901,279	1,091,027	1,165,903
NUMBER OF RETAIL CUSTOMERS (Average for Period):			
Residential	332,187	327,125	321,343
Commercial	36,448	36,164	35,804
Interruptible	42	40	45
Industrial	190	225	241
Total natural gas retail customers	368,867	363,554	357,433
RESIDENTIAL SERVICE AVERAGES:			
Annual use per customer (therms)	662	672	720
Revenue per therm (in dollars)	$ 1.01	$ 0.97	$ 0.85
Annual revenue per customer	$ 666.51	$ 653.00	$ 611.28
HEATING DEGREE DAYS: (1)			
Spokane, WA			
Actual	6,124	6,187	6,817
Historical average	6,596	6,651	6,613
% of average	93 %	93 %	103 %
Medford, OR			
Actual	4,107	4,181	4,439
Historical average	4,254	4,281	4,291
% of average	97 %	98 %	103 %

(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. AEL&P is 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.

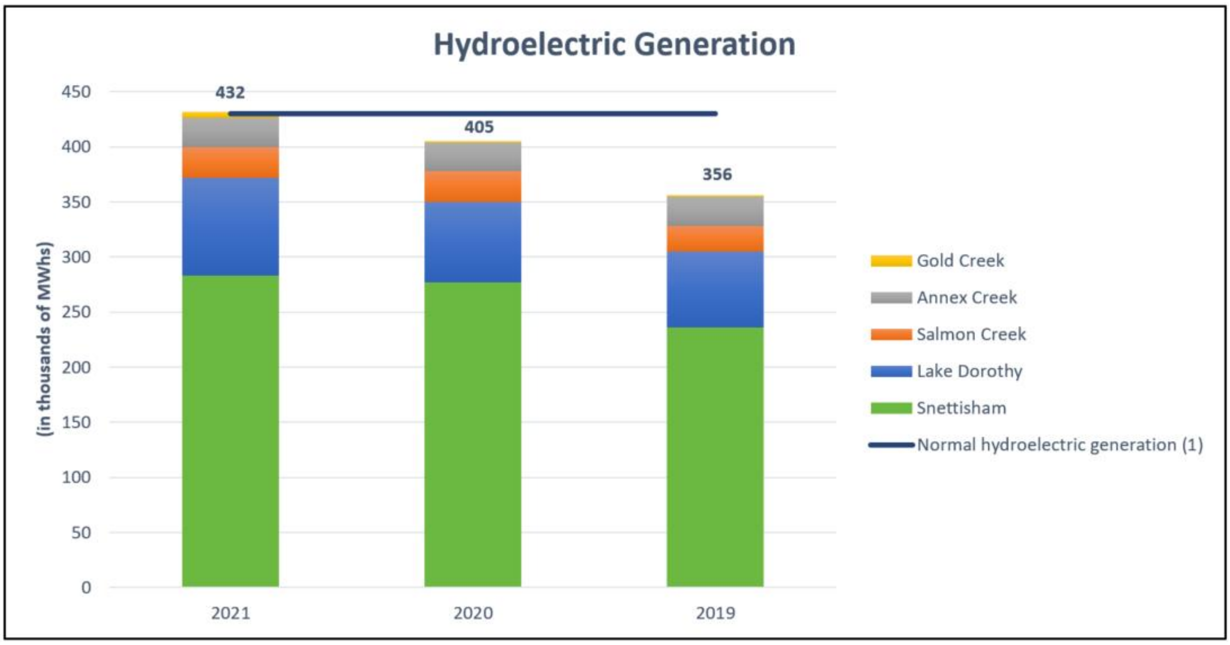
AEL&P owns and operates electric generation, transmission and distribution facilities located in Juneau. AEL&P operates five hydroelectric generation facilities with 102.7 MW of hydroelectric generation capacity. AEL&P owns four of these generation facilities (totaling 24.5 MW of capacity) and has a PPA for the entire 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 $48.8 million at December 31, 2021 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, to purchase all of the output of the project. 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, 2021, the finance lease obligation was $48.8 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 also 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, 2021, AEL&P served approximately 17,400 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 rates, standard of service, facilities, accounting and certain other matters, but not with respect to the issuance of securities. Rate adjustments for AEL&P's customers require approval by the RCA pursuant to RCA regulations.

AEL&P is also 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. 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. In addition, 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,		
	2021	2020	2019
ELECTRIC OPERATIONS			
OPERATING REVENUES (Dollars in Thousands):			
Residential	$ 18,940	$ 18,618	$ 17,134
Commercial and government	25,861	23,754	19,391
Public street and highway lighting	250	251	254
Total retail	45,051	42,623	36,779
Other	315	186	486
Total electric operating revenues	$ 45,366	$ 42,809	$ 37,265
ENERGY SALES (Thousands of MWhs):			
Residential	160	157	143
Commercial and government	243	227	193
Public street and highway lighting	1	1	1
Total electric energy sales	404	385	337
NUMBER OF RETAIL CUSTOMERS (Average for Period):			
Residential	14,919	14,840	14,755
Commercial and government	2,282	2,271	2,280
Public street and highway lighting	230	228	228
Total electric retail customers	17,431	17,339	17,263
RESIDENTIAL SERVICE AVERAGES:			
Annual use per customer (KWh)	10,773	10,581	9,692
Revenue per KWh (in cents)	11.84	11.86	11.98
Annual revenue per customer	$ 1,269.52	$ 1,254.58	$ 1,161.23
HEATING DEGREE DAYS: (1)			
Juneau, AK			
Actual	8,394	8,119	7,476
Historical average	8,335	8,351	8,041
% of average	101 %	97 %	93 %

(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, 2021 and 2020 (dollars in thousands):

Entity and Asset Type	2021	2020
Avista Capital		
Unconsolidated equity investments	$ 91,057	$ 59,318
Note receivable – parent	1,404	8,743
Real estate investments	7,895	11,252
Notes receivable – third parties	17,474	18,065
Other assets	4,294	2,477
Alaska companies (AERC and AJT Mining)	10,034	9,803
Total	$ 132,158	$ 109,658

Avista Capital

- Unconsolidated equity investments are primarily in emerging technology venture capital funds and companies, including an investment in a joint venture focused on local real estate development and economic growth.
- Avista Edge is a wholly owned, unregulated, non-utility subsidiary of Avista Capital whose services initially support public electric utilities with advanced broadband networks and patented technology located at the electric meter, allowing their customers access to high-speed internet services.
- Real estate consists of mixed use commercial, retail office space and land.
- Other assets that consist of income tax receivables, machinery and equipment, cash and other deferred charges.

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. Please also 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 inflationary pressures. 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 are expected 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

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 any repair to such facilities could be significant. Any wildfires caused by our equipment could cause significant damage to our reputation, which could erode shareholder, customer and community satisfaction with our Company. In addition, wildfires caused by our equipment could lead to increased 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 experienced in the region.

The COVID 19 pandemic is disrupting our business and could have a negative effect on our results of operations, financial condition and cash flows.

The COVID-19 pandemic is currently impacting our business, as well as the global, national and local economy. We cannot predict the full extent to which COVID-19 will impact our operations, results of operations, cash flows, financial condition or capital resources. It is possible that the continued spread of COVID-19 and efforts to contain the virus may result in significant disruptions in various public, commercial or industrial activities, interruption to various supply chains upon which our operations depend, and cause employee absences which could interfere with operation and maintenance of the Company’s facilities. Any of these circumstances could adversely affect our operations, results of operations, financial condition and cash flows in many ways, including, but not limited to:

- an increase in operating expenses, including bad debt expense due to our customers’ inability to pay amounts due to us,
- an increase in operating expenses and potential workforce disruption or losses resulting from compliance with state or federal vaccine mandates,
- increased costs and/or reduced revenue associated with interruptions in operations due to federal and state vaccine mandates, including but not limited to employee strikes, protests, retirements or resignations, and additional costs associated with ensuring business continuity,
- a decrease in net operating cash inflows, which could negatively impact our liquidity and limit our ability to fund capital expenditures, dividends, and other contractual commitments,
- a negative impact on the ability of suppliers, vendors or contractors to perform, which could increase costs and delay capital projects,
- possible reluctance on the part of regulatory commissions to approve our requests to defer and recover increased expenses,
- delays in regulatory filings and the regulatory approval process, which could impact our ability to timely recover our operating expenses and costs associated with investments in utility assets,
- an increase in cyber and technology risks, including the impact on internal controls, due to a significant number of employees working remotely,
- disruption, weakness and volatility in the financial markets, which could increase our costs to fund capital requirements, and
- possible limited access to the capital markets, that could require us to seek alternative sources of funding for operations and for working capital, any of which could increase our cost of capital.

We cannot predict the duration and severity of the COVID-19 pandemic. The longer and more severe the business disruptions are, the greater the impact on our operations, results of operations, financial condition and cash flows will be.

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,
- 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
- 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 national 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 us against liability, extra expenses and operating disruptions from all of 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 to us. 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 any 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.

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 any 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. Any issues that negatively affect AEL&P's ability to generate or transmit power or any 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 Avista’s 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 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".

Cyber and Technology 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.

In the course of our operations, 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, particularly 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.

Terrorist attacks could also be directed at our physical electric and natural gas facilities, as well as technology systems or at an interconnected third party, which could result in disruption to our systems.

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.

Our technology may become obsolete 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 technology that is heavily relied upon by us 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. Technology failures 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 any or all of 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 any of 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 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,
- 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 a number of 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. Such legislation could restrict the operation and raise the costs of our power generation resources as well as the distribution of natural gas to our customers.

We expect continuing 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 and other issues which may affect our operations, including legislation that was recently passed in Washington State.

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 particular issue, including the extent, if any, of insurance coverage or that amounts payable by us may be recoverable 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

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.

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 winter and summer 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 also 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.

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 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 any of 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. Any defaults could also induce vendors and other counterparties to demand collateral. In the event of any such default, it would be difficult for us 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 hedge a portion of our interest rate risk with financial derivative instruments. 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.

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.

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 us to recover 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 any 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. See “Item 7. Management's Discussion and Analysis – Environmental Issues and Contingencies" for discussion regarding environmental and other issues surrounding Colstrip, including the requirement that we cannot serve Washington electricity customers after 2025 with 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 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

	No. of Units	Nameplate Rating (MW) (1)	Present Capability (MW) (2)
Hydroelectric Generating Stations (River)			
Washington:			
Long Lake (Spokane)	4	71.1	88.0
Little Falls (Spokane)	4	43.2	48.0
Nine Mile (Spokane)	4	37.6	40.6
Upper Falls (Spokane)	1	10.0	10.2
Monroe Street (Spokane)	1	14.8	15.0
Idaho:			
Cabinet Gorge (Clark Fork) (3)	4	265.0	273.0
Post Falls (Spokane)	6	14.8	11.9
Montana:			
Noxon Rapids (Clark Fork)	5	487.8	562.4
Total Hydroelectric		944.3	1,049.1
Thermal Generating Stations (cycle, fuel source)			
Washington:			
Kettle Falls GS (combined-cycle, wood waste) (4)	1	50.7	53.5
Kettle Falls CT (combined-cycle, natural gas) (4)	1	7.2	6.9
Northeast CT (simple-cycle, natural gas)	2	61.8	64.8
Boulder Park GS (simple-cycle, natural gas)	6	24.6	24.6
Idaho:			
Rathdrum CT (simple-cycle, natural gas)	2	166.5	166.5
Montana:			
Colstrip Units 3 & 4 (simple-cycle, coal) (5)	2	233.4	222.0
Oregon:			
Coyote Springs 2 (combined-cycle, natural gas)	1	295.0	295.0
Total Thermal		839.2	833.3
Total Generation Properties		1,783.5	1,882.4

(1) Nameplate rating, also referred to as “installed capacity,” is the manufacturer’s assigned power capability under specified conditions.

(2) Present capability is the maximum capacity of the plant under standard test conditions without exceeding specified limits of temperature, stress and environmental conditions. Information is provided as of December 31, 2021.

(3) 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.

(4) 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.

(5) Jointly owned; data refers to our 15 percent interest. See “Item 7. Management’s Discussion and Analysis of Financial Condition – Colstrip” for information related to Colstrip Units 3 & 4.

Electric Distribution and Transmission Plant

Avista Utilities owns and operates approximately 19,300 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 Energy 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 for us to optimize resources by entering into 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 Energy, 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 3,500 miles in Washington, 2,100 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

	No. of Units	Nameplate Rating (MW) (1)	Present Capability (MW) (2)
Hydroelectric Generating Stations			
Snettisham (3)	3	78.2	78.2
Lake Dorothy	1	14.3	14.3
Salmon Creek	1	8.4	5.0
Annex Creek	2	4.1	3.6
Gold Creek	3	1.6	1.6
Total Hydroelectric		106.6	102.7
Diesel Generating Stations			
Lemon Creek	11	61.4	51.8
Auke Bay	3	28.4	25.2
Gold Creek	5	8.2	7.0
Industrial Blvd. Plant	1	23.5	23.5
Total Diesel		121.5	107.5
Total Generation Properties		228.1	210.2

(1) Nameplate rating, also referred to as “installed capacity,” is the manufacturer’s assigned power capability under specified conditions.

(2) Present capability is the maximum capacity of the plant under standard test conditions without exceeding specified limits of temperature, stress and environmental conditions. Information is provided as of December 31, 2021.

(3) 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 (whether or not energy is received), all of 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, 2022, there were 6,574 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 2021 and 2020 financial statement items and year-to-year comparisons between 2021 and 2020. Discussion of 2019 financial statement items and year-to-year comparisons between 2020 and 2019 that are 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, 2020.

Business Segments

As of December 31, 2021, 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) attributable to Avista Corp. shareholders for each of our business segments (and the other businesses) for the year ended December 31 (dollars in thousands):

	2021	2020	2019
Avista Utilities	$ 125,558	$ 124,810	$ 183,977
AEL&P	7,224	8,095	7,458
Other	14,552	(3,417)	5,544
Net income attributable to Avista Corporation shareholders	$ 147,334	$ 129,488	$ 196,979

Executive Level Summary

Overall Results

Net income attributable to Avista Corp. shareholders was $147.3 million for 2021, an increase from $129.5 million for 2020.

Avista Utilities' net income increased primarily due to general rate cases, including the impact of the timing of recognition of income taxes, and non-decoupled revenue growth and customer growth. These increases were partially offset by higher power supply costs, increased other operating expenses, and increased depreciation due to plant additions during the year. In addition, 2020 included an accrual for customer refunds related to the outcome of our 2015 Washington General rate case, an accrual for disallowed replacement power during an unplanned outage at Colstrip and a contribution to the Colstrip community fund, all of which decreased net income in 2020.

AEL&P net income decreased slightly, primarily due to higher other operating costs compared to 2020.

The increase in net income at our other businesses was primarily due to increased net investment gains in 2021.

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).

Summer Weather Conditions

The Pacific Northwest experienced hot and dry weather conditions throughout the second and third quarters of 2021 compared to normal weather conditions for these times of year. These weather conditions resulted in higher than usual customer loads, as well as lower than usual hydroelectric generation. In these periods, we often have excess generation to sell into the wholesale markets, which benefits our net power supply costs. This did not occur at expected levels in 2021 primarily due to the hot and dry weather conditions throughout the Pacific Northwest.

As a result of our lower than normal hydroelectric generation capability and in order to serve higher than usual loads, we were required to rely more heavily than usual on purchased power and our thermal generation, which in turn resulted in higher than authorized resource costs due to higher volumes of energy and fuel purchased and higher market prices of each. In 2021, we recognized a pre-tax expense of $7.7 million under the ERM, compared to $6.2 million of pre-tax benefit recognized in 2020.

These hot conditions had minimal impact on reported revenues, as the majority of the increase in revenues associated with the increased usage was offset with adjustments under the decoupling mechanisms that cover a majority of our customers.

COVID-19 Pandemic

The COVID-19 pandemic is impacting our business, as well as the global, national and local economies. However, through 2021 the economies in our service territory have opened, and the impacts of the pandemic have been less severe than 2020. The pandemic has affected and may continue to affect our operations, results of operations, financial condition, liquidity and cash flows in the following ways:

Operations

We continue to experience supply chain delays due to the effects of the COVID-19 pandemic that have impacted the delivery times of some of our materials and equipment. The delays are being managed with minimal impact. The issues that could potentially result from future delays are being proactively mitigated through several planning and review activities, but could have an impact on our planned projects going forward.

It is possible that COVID-19 could have a negative impact on the ability of suppliers or contractors to perform, which could increase operating costs and delay and/or increase the costs of capital projects.

Results of Operations

We observed economic recovery and improvement in employment during 2021. We received accounting orders in each of our jurisdictions to defer the recognition of COVID-19 expenses as well as identified cost savings of other COVID-19 related benefits. COVID-19 deferred regulatory assets and liabilities as of December 31, 2021 and December 31, 2020 were as follows:

	December 31, 2021	December 31, 2020
Regulatory asset	$ 13,591	$ 8,166
Regulatory liability	(12,500)	(10,949)
Total	$ 1,091	$ (2,783)

Financial Condition, Liquidity and Cash Flows

After considering the impacts of COVID-19, and the planned issuances of long-term debt and equity during 2022, we expect net cash flows from operations, together with cash available under our committed lines of credit, to provide adequate resources to fund capital expenditures, dividends and other contractual commitments.

We cannot predict the duration and severity of the COVID-19 pandemic or if emerging variants will result in the reimplementation of economic restrictions. The longer and more severe the economic restrictions and business disruption, the greater the impact on our operations, results of operations, financial condition and cash flows.

General Rate Cases and Regulatory Lag

We experienced regulatory lag during 2021 and we expect this to continue through the end of 2022 due to our continued investment in utility infrastructure. In 2021, we concluded general rates cases in each of our jurisdictions. The settlement of these cases provided rate relief in 2021. Going forward, we will continue to strive to reduce the regulatory timing lag and more closely align our earned returns with those authorized by 2023. This will require adequate and timely rate relief in all our jurisdictions. We have filed multi-year electric and natural gas general rate cases in Washington in January 2022. See "Regulatory Matters" for additional discussion of the general rate cases.

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.

With regards to the timing and plans for future filings, 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 and Other Proceedings

2019 General Rate Cases

In March 2020, we received an order from the WUTC that approved a partial multi-party settlement. The approved rates were designed to increase annual base electric revenues by $28.5 million, or 5.7 percent, and annual natural gas base revenues by $8.0 million, or 8.5 percent, effective April 1, 2020. The revenue increases incorporate a 9.4 percent return on equity (ROE) with a common equity ratio of 48.5 percent and a rate of return (ROR) on rate base of 7.21 percent.

As part of the WUTC order, we are returning approximately $40 million from the ERM rebate to customers over a two-year period.

Included in the WUTC order is the acceleration of depreciation of Colstrip Units 3 & 4 to reflect a remaining useful life through December 31, 2025. The order utilized certain electric tax benefits associated with the 2018 tax reform to partially offset these increased costs. The order also set aside $3 million for community transition efforts to mitigate the impacts of the eventual closure of Colstrip, half funded by customers and half funded by our shareholders. See “Colstrip” section for further information on on-going issues and disputes regarding the eventual closure of Colstrip.

Lastly, the order included the extension of electric and natural gas decoupling mechanisms through March 31, 2025, with one modification in that new customers added after any test period will not be decoupled until included in a future test period.

2020 General Rate Cases

In September 2021, we received an order from the WUTC that approved a partial multi-party settlement and resolved all remaining issues for the electric and natural gas general rate cases with the WUTC. The approved rates are designed to increase annual base electric revenues by $13.6 million, or 2.6 percent, and annual natural gas base revenues by $8.1 million, or 7.7 percent, effective October 1, 2021. The revenue increases incorporate a 9.4 percent ROE with a common equity ratio of 48.5 percent and a ROR of 7.12 percent.

While base rates increased, there was no increase in billed rates at this time because of the use of offsetting tax benefits.

The WUTC's order approved recovery of capital additions including investments in advanced metering infrastructure, wildfire resiliency, joining the Western Energy Imbalance Market, and other projects. The WUTC disallowed $2.5 million of costs associated with Colstrip SmartBurn technology.

The WUTC order also approves the Company's request to defer incremental wildfire expenses incurred during 2021, as well as the Company's use of a wildfire balancing account to track the level of expense associated with wildfire resiliency going forward.

2022 General Rate Cases

In January 2022, we filed multi-year electric and natural gas general rate cases with the WUTC. The proposed rates are designed to increase annual base electric revenues by $52.9 million (or 9.6 percent of base revenues), effective in December 2022, and $17.1 million (or 2.8 percent of base revenues), effective in December 2023. For natural gas, the proposed rates are designed to increase annual base natural gas revenues by $10.9 million (or 9.5 percent of base revenues), effective in December 2022, and $2.2 million (or 1.7 percent of base revenues), effective in December 2023.

We are proposing to offset part of the base rate request with a Residual Tax Customer Credit that arose out of the Company's Washington electric and natural gas general rate cases that went into effect on October 1, 2021. The order for those general rate cases stipulated that the residual tax customer credit was to be flowed through to customers over a 10-year period beginning in 2023; however, we are now proposing that this credit be incrementally flowed through to customers over a two-year period. The estimated benefits to customers of this credit would be $25.5 million for electric customers and $12.5 million for natural gas customers over a two-year period from December 2022 to December 2024.

The proposed electric and natural gas revenue increase requests are based on a 10.25 percent ROE with a common equity ratio of 48.5 percent and a rate of ROR base of 7.3 percent. Increasing fixed expenses and ongoing capital investments (including replacement of wood poles and natural gas distribution pipe, continued investment in the wildfire resiliency plan, and technology) were the main drivers of proposed increases. As a part of the multi-year rate plan, if approved, we would not file a new general rate case for a new rate plan to be effective prior to December 2024. The WUTC has up to eleven months to review the general rate case filings and issue a decision.

Washington Engrossed Substitute Senate Bill 5295

This bill, which was signed into law and is effective as of July 25, 2021, is designed to promote multi-year rate plans and performance-based rate making for electric and natural gas utilities. The bill includes a number of provisions such as required multi-year rate plans from 2-4 years in length, methodologies the WUTC may use to minimize regulatory lag and/or adjust for under earning and starts an investigation into Performance Based Ratemaking Metrics, an initial move that may help to modify the historical test-year ratemaking construct. On October 20, 2021, the WUTC issued a notice of opportunity to comment on a proposed work plan to be conducted in various phases between 2021 and 2025, initially focusing on Performance Based Ratemaking and identifying performance metrics. Thereafter, the WUTC will address revenue adjustment mechanisms and performance incentives in the context of multi-year rate plans. The new law leaves much to the discretion of the WUTC, and we cannot predict the extent to which the WUTC will embrace the options now permitted.

Idaho General Rate Cases and Other Proceedings

2021 General Rate Cases

In January 2021, we filed electric and natural gas general rate cases with the IPUC.

In September 2021, the IPUC approved the all party settlement agreement. The approved rates under the settlement agreement are 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 proposed rates under the settlement agreement are 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 have 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 electric and natural gas rates over the two-year plan.

The settlement incorporates 9.4 percent ROE with a common equity ratio of 50 percent and a ROR of 7.05 percent.

2023 General Rate Cases

We expect to file electric and natural gas general rate cases with IPUC in the first half of 2023.

Oregon General Rate Cases and Other Proceedings

2020 General Rate Case

In March 2020, we filed a natural gas general rate case with the OPUC. Through several settlement stipulations the parties resolved all issues and, in December 2020, the OPUC approved all stipulations.

The new rates were designed to increase annual base revenue by $3.9 million, or 5.7 percent effective January 16, 2021, reflecting an ROE of 9.4 percent, with a common equity ratio of 50 percent and a ROR of 7.24 percent.

2021 General Rate Case

In October 2021, we filed a natural gas general rate case with the OPUC. The proposal is designed to increase overall natural gas base revenue by $3.8 million and is based on a proposed ROR of 7.35 percent with a common equity ratio of 50 percent and a 9.9 percent ROE. We have proposed that the increase be fully offset for a two-year period with tax customer credits (related to the flow through of certain tax items) of the same amount.

In January 2022, a partial settlement stipulation was filed with the OPUC that addressed cost of capital issues. The parties agreed to an overall ROR of 7.05 percent based on a 50 percent common equity ratio and ROE of 9.4 percent.

Alaska Electric Light and Power Company

AEL&P is required to file its next general rate case by August 30, 2022.

Avista Utilities

Purchased Gas Adjustments

PGAs are designed to pass through changes in natural gas costs to Avista Utilities' customers with no change in utility margin (operating revenues less resource costs) or net income. In Oregon, we absorb (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 among all jurisdictions were a net asset of $21.0 million as of December 31, 2021 and $1.4 million as of December 31, 2020. These deferred natural gas cost balances represent amounts due from customers.

The following PGAs went into effect in our various jurisdictions during 2019 through 2022:

Jurisdiction	PGA Effective Date	Percentage Increase / (Decrease) in Billed Rates
Washington	November 1, 2019	10.4%
	November 1, 2020	(0.1)%
	November 1, 2021	10.6%
Idaho	November 1, 2019	5.6%
	November 1, 2020	0.7%
	September 1, 2021	13.5%
	February 1, 2022	7.6%
Oregon	November 1, 2019	4.7%
	November 1, 2020	2.8%
	November 1, 2021	9.6%

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. These differences primarily result from changes in:

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

For our Washington customers, the ERM is an accounting method used to track certain differences between Avista Utilities' actual power supply costs, net of wholesale sales and sales of fuel, and the amount included in base retail rates. Total net deferred power costs under the ERM were liabilities of $11.9 million as of December 31, 2021 and $37.9 million as of December 31, 2020. These deferred power cost balances represent amounts due to customers.

Under the ERM, Avista Utilities absorbs the cost or receives the benefit from the initial amount of power supply costs in excess of or below the level in retail rates, which is referred to as the deadband. The annual (calendar year) deadband amount is $4.0 million.

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%

Under the ERM, 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.

Pursuant to WUTC requirements, should the cumulative deferral balance exceed $30 million (in either direction), we must make a filing with the WUTC to adjust customer rates to either return the balance to customers or recover the balance from customers. The cumulative rebate balance as of December 31, 2019 exceeded $30 million and as a result, our 2019 filing contained a proposed rate refund. The ERM proceeding was considered with our 2019 general rate case proceeding and a refund was approved and is being returned to customers over a two-year period that began on April 1, 2020. See further discussion in the section "Washington General Rate Cases" above.

Avista Utilities has a PCA mechanism in Idaho that allows us to modify electric rates on October 1 of each year with IPUC approval. Under the PCA mechanism, we defer 90 percent of the difference between certain actual net power supply expenses and the amount included in base retail rates for our Idaho customers. The October 1 rate adjustments recover or rebate power supply costs deferred during the preceding July-June twelve-month period. Total net power supply costs deferred under the PCA mechanism were an asset of $10.8 million as of December 31, 2021 and $2.5 million as of December 31, 2020. These deferred power cost balances represent amounts due from customers.

Decoupling and Earnings Sharing Mechanisms

Decoupling (also known as a FCA in Idaho) is a mechanism designed to sever the link between a utility's revenues and consumers' energy usage. In each of our 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 our decoupling mechanisms.

Washington Decoupling and Earnings Sharing

In our 2019 Washington general rate cases, the WUTC approved an extension of the mechanisms for an additional five-year term through March 31, 2025, with one modification in that new customers added after any test period would not be decoupled until included in a future test period.

The decoupling mechanisms each include an after-the-fact earnings test. At the end of each calendar year, separate electric and natural gas earnings calculations are made for the calendar year just ended. These earnings tests reflect actual decoupled revenues, normalized power supply costs and other normalizing adjustments. If we earn more than our authorized ROR in Washington, 50 percent of excess earnings are rebated to customers through adjustments to existing decoupling surcharge or rebate balances. We have proposed to modify this earnings test in our 2022 general rate case, so that if the Company earns more than 0.5 percent higher than the ROR authorized by the WUTC in the multi-year rate plan, the Company would defer these excess revenues and later return them to customers.

Idaho FCA Mechanism

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

Oregon Decoupling Mechanism

In Oregon, we have a decoupling mechanism for natural gas. An earnings review is conducted on an annual basis. In the annual earnings review, if we earn more than 100 basis points above our allowed return on equity, one-third of the earnings above the 100 basis points would be deferred and later rebated to customers.

Cumulative Decoupling and Earnings Sharing Balances

Total net cumulative decoupling deferrals among all jurisdictions were regulatory assets of $15.2 million as of December 31, 2021 and $21.3 million as of December 31, 2020. These decoupling assets represent amounts due from customers. Total net earnings sharing balances among all jurisdictions were regulatory liabilities of $0.7 million as of December 31, 2021 and December 31, 2020. These earnings sharing liabilities represent amounts due to customers.

See "Results of Operations - Avista Utilities" for further discussion of the amounts recorded to operating revenues in 2021 and 2020 related to the decoupling and earnings sharing mechanisms.

COVID-19 Deferrals

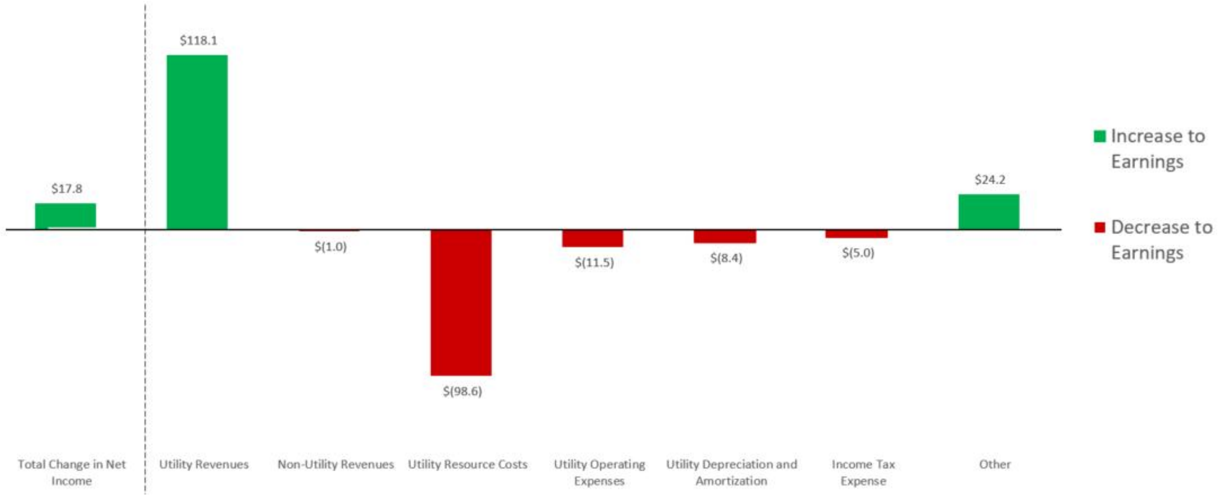
See “Note 1 of the Notes to Consolidated Financial Statements” for discussion on COVID-19 deferrals.

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.

2021 compared to 2020

The following graph shows the total change in net income attributable to Avista Corp. shareholders for 2021 to 2020, as well as the various factors that caused such change (dollars in millions):



Utility revenues increased at Avista Utilities primarily due to increased loads from non-decoupled customers as a result of reduced COVID-19 restrictions during 2021, as well as weather that was warmer than normal and warmer than the prior year. In addition, utility revenues increased due to general rate increases in Oregon (effective January 16, 2021) and Washington (effective April 1, 2020), as well as customer growth. In addition, in 2020 there was a $4.9 million decrease to revenue due to the outcome of the 2015 Washington general rate cases.

Utility resource costs increased at Avista Utilities due to increased purchased power, fuel for generation and other fuel costs, as well as higher natural gas purchases. See "Summer Weather Conditions" in the Executive Level Summary above for further discussion of increased net power supply costs.

The increase in utility operating expenses was primarily due to increases in insurance, information technology, and labor and benefits costs at Avista Utilities, as well as a $2.5 million write off of Colstrip SmartBurn technology assets disallowed under the Washington general rate case settled during 2021. The increases were partially offset by an accrual recorded in 2020 for disallowed replacement power during an unplanned outage at Colstrip.

Utility depreciation and amortization increased primarily due to additions to utility plant during the period. This was partially offset by a one-time increase to depreciation expense in 2020 as we were able to utilize $10.9 million ($8.4 million when tax-effected) of electric tax benefits to offset costs associated with accelerating the deprecation of Colstrip based on a settlement in Washington.

Income taxes increased primarily due to a decrease in tax expense during 2020 related to the offset of $8.4 million of deferred income taxes against accelerated depreciation for Colstrip based on a settlement in Washington and an increase in pre-tax earnings. This was offset by a change in tax methodology to the flow through method for certain items in 2021, as accepted by IPUC and WUTC through our general rate cases. Our effective tax rate was 7.5 percent in 2021 compared to 5.2 percent in 2020. See “Note 12 of the Notes to Condensed Consolidated Financial Statements” for further details and a reconciliation of our effective tax rate.

The increase in other was primarily related to net investment gains during 2021, compared to net investment losses experienced during 2020 (including impairment and write off of notes receivable). Additionally, other increased due to the gain on sale of certain subsidiary assets associated with the Spokane Steam Plant in 2021.

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."

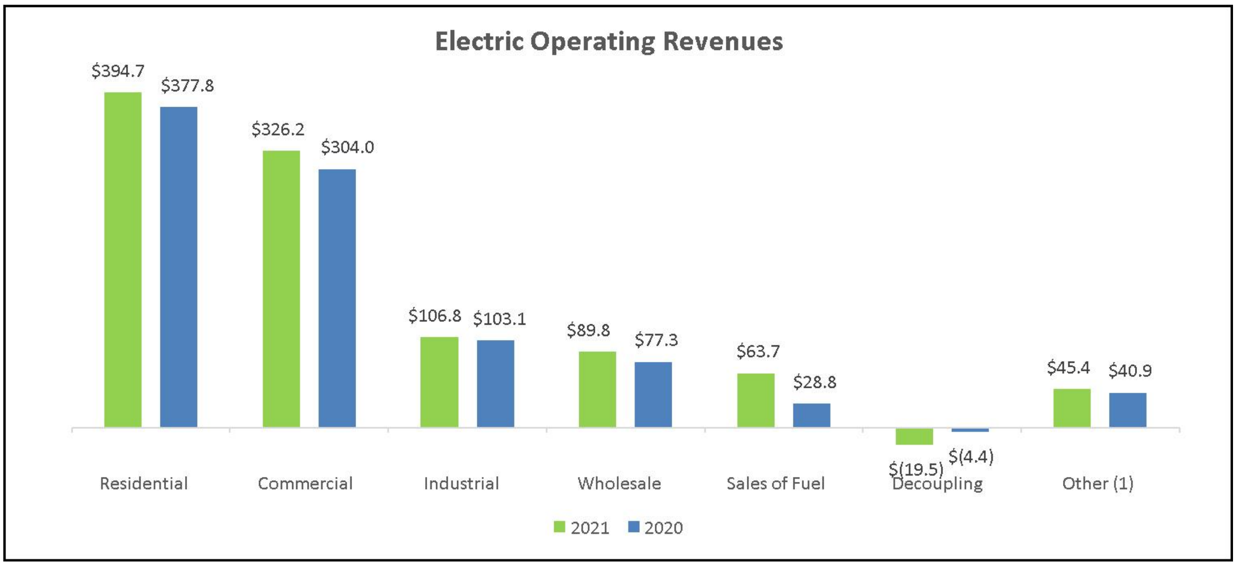
The presentation of electric utility margin and natural gas utility margin is intended to enhance understanding of our operating performance. We use these measures internally and believe they provide useful information to investors in their analysis of how changes in loads (due to weather, economic or 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 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

2021 compared to 2020

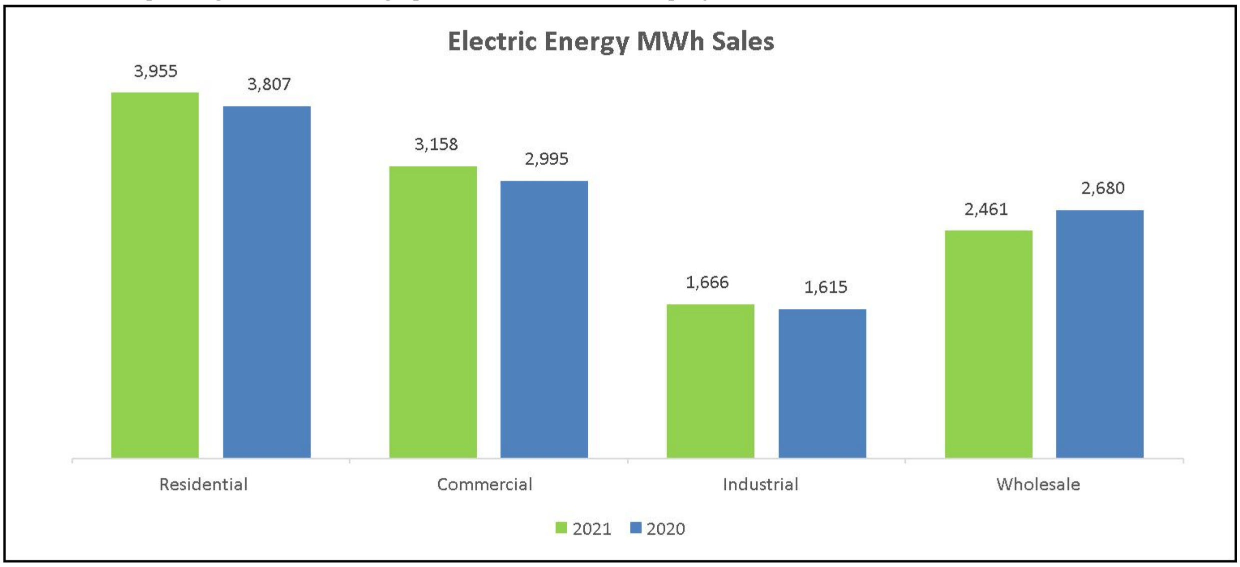
Utility Operating Revenues

The following graphs present Avista Utilities' electric operating revenues and megawatt-hour (MWh) sales for the years ended December 31 (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 $28.7 million and $36.4 million for 2021 and 2020, respectively.



The following table presents the current year deferrals and the amortization of prior year decoupling balances that are reflected in utility electric operating revenues for the years ended December 31 (dollars in thousands):

	Electric Operating Revenues	
	2021	2020
Current year decoupling deferrals (a)	$ (6,053)	$ 11,449
Amortization of prior year decoupling deferrals (b)	(13,472)	(15,810)
Total electric decoupling revenue	$ (19,525)	$ (4,361)

(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) 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. 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.

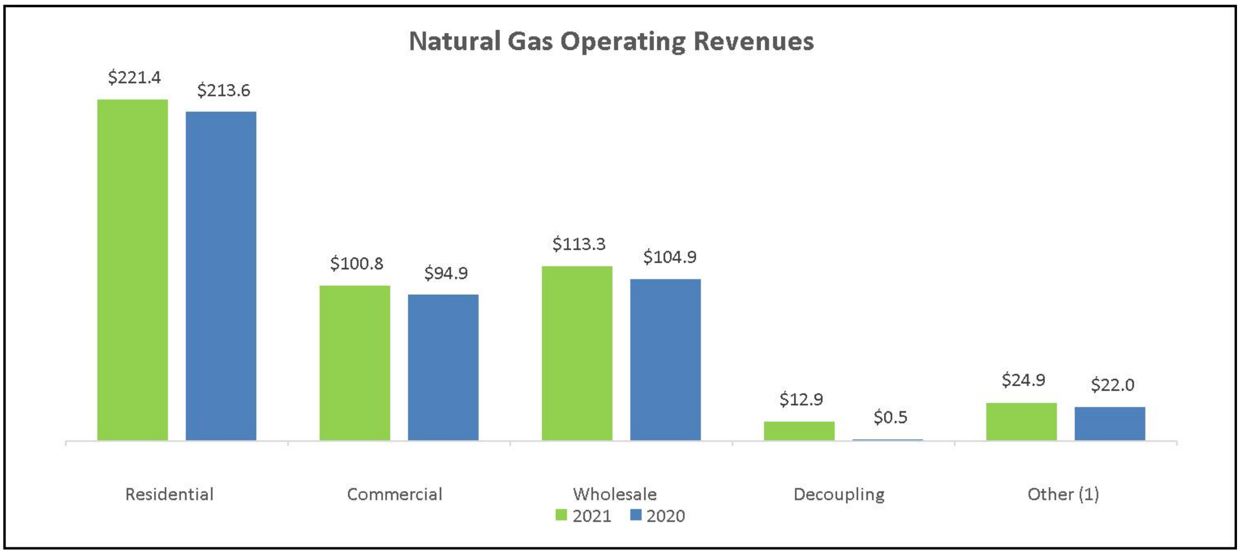
Total electric revenues increased $79.6 million for 2021 as compared to 2020. The primary fluctuations that occurred during the period were as follows:

- a $43.0 million increase in retail electric revenues due to an increase in total MWhs sold (increased revenues $34.3 million), as well as an increase in revenue per MWh (increased revenues $8.7 million).

- The increase in total retail MWhs sold was primarily the result of weather that was warmer than normal throughout the summer months, which increased cooling loads. Cooling degree days in Spokane during 2021 were 73 percent above historical norms, compared to 2 percent above historical norms in 2020. Also, there was a lifting of COVID-19 restrictions throughout 2021, which contributed to the increased loads and customer growth. Compared to 2020, use per residential customer increased 2.2 percent, and use per commercial customer increased 4.0 percent.
- The increase in revenue per MWh was primarily due to base rate increases in Washington, effective April 1, 2020, as well as passthrough rate changes, which do not have an impact on utility margin, such as the residential exchange program, low income rate assistance program, the ERM and PCA amortization rates and decoupling.

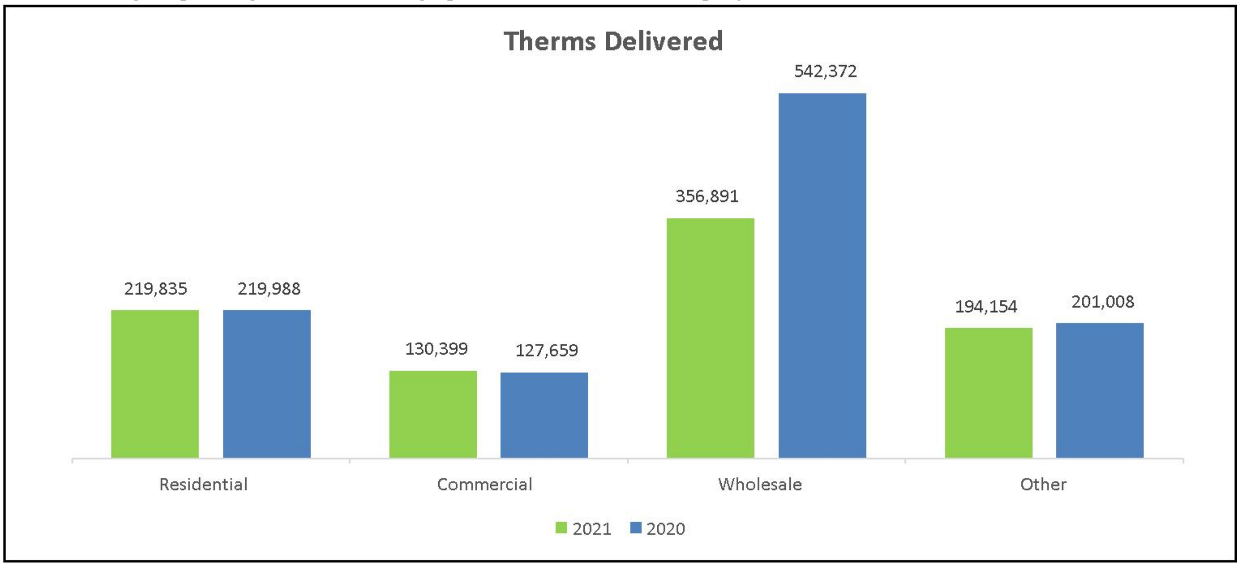
- a $12.5 million increase in wholesale electric revenues due to an increase in sales prices (increased revenues $20.5 million), partially offset by a decrease in sales volumes (decreased revenues $8.0 million). The fluctuation of volumes was due to our need to utilize our thermal generation assets more than normal due to lower than normal hydroelectric generation and increased customer loads, which limited our opportunities to sell generation in the wholesale power markets compared to 2020.
- a $34.9 million increase in sales of fuel due to thermal generation resource optimization activities.
- a $15.1 million decrease in electric decoupling revenue. This is primarily due to 2020 resulting in surcharges to non-residential customers, which had lower usage due to COVID-19 restrictions. In 2021, we experienced a rebate position due to higher than normal usage from warmer than normal weather in the cooling season, as well as lifting COVID-19 restrictions.
- a $4.5 million increase in other revenues primarily due to an increase in transmission revenues of $2.8 million as well as an accrual for customer refunds recorded in 2020 for $1.4 million related to our 2015 Washington general rate case.

The following graphs present Avista Utilities' natural gas operating revenues and therms delivered for the years ended December 31 (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 $58.6 million and $49.6 million for 2021 and 2020, respectively.



The following table presents the current year deferrals and the amortization of prior year decoupling balances that are reflected in natural gas operating revenues for the years ended December 31 (dollars in thousands):

	Natural Gas Operating Revenues	
	2021	2020
Current year decoupling deferrals (a)	$ 11,129	$ 1,797
Amortization of prior year decoupling deferrals (b)	1,761	(1,250)
Total natural gas decoupling revenue	$ 12,890	$ 547

(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.

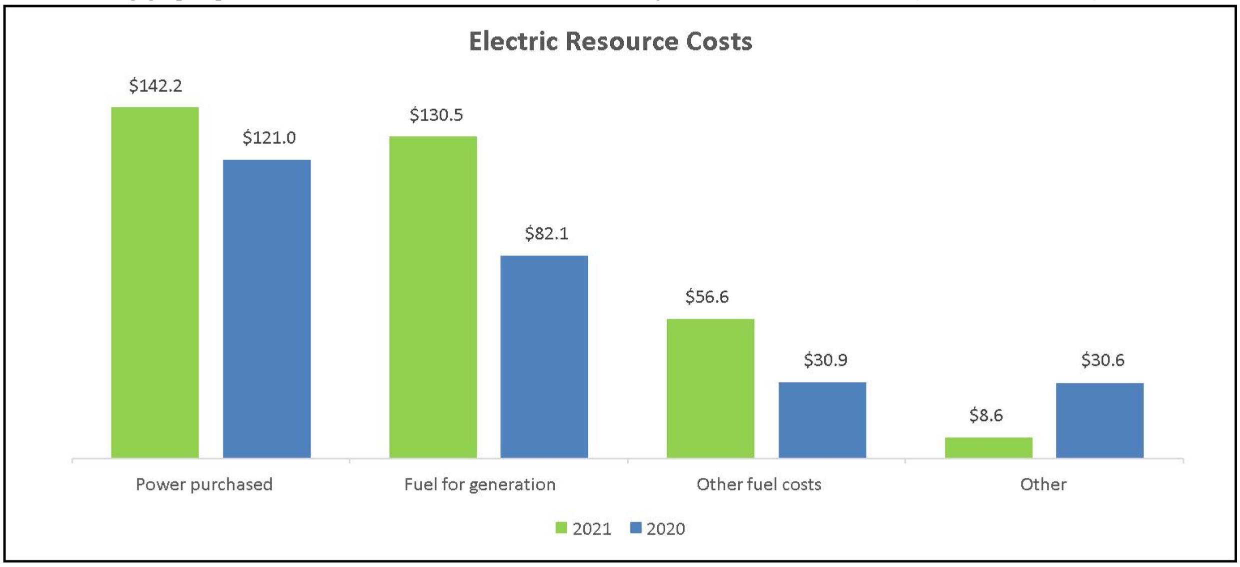
Total natural gas revenues increased $37.4 million for 2021 as compared to 2020. The primary fluctuations that occurred during the period were as follows:

- a $14.3 million increase in retail natural gas revenues (including industrial, which is included in other) due to higher retail rates (increased revenues $11.0 million), and higher sales volumes (increased revenues $3.3 million).
  - Retail rates increased due to general rate increases in Oregon (effective January 16, 2021), and Washington (effective April 1, 2020). Increases were also due to PGA rate increases, which do not impact utility margin.
  - Retail natural gas sales increased primarily due to higher commercial and industrial usage, as well as slight residential customer growth.
- an $8.4 million increase in wholesale natural gas revenues due to an increase in prices (increased revenues $67.2 million) offset by a decrease in volumes (decreased revenues $58.8 million) due to fewer resource optimization opportunities. 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 $12.4 million increase in decoupling revenues primarily increased in decoupling revenues related to warmer weather in 2021 compared to 2020. In addition, during 2020 we were amortizing decoupling surcharges, whereas in 2021 we are amortizing decoupling rebates.
- a $2.9 million increase in other revenues primarily related to an accrual in 2020 of $3.6 million for customer refunds related to our 2015 Washington general rate case.

Utility Resource Costs

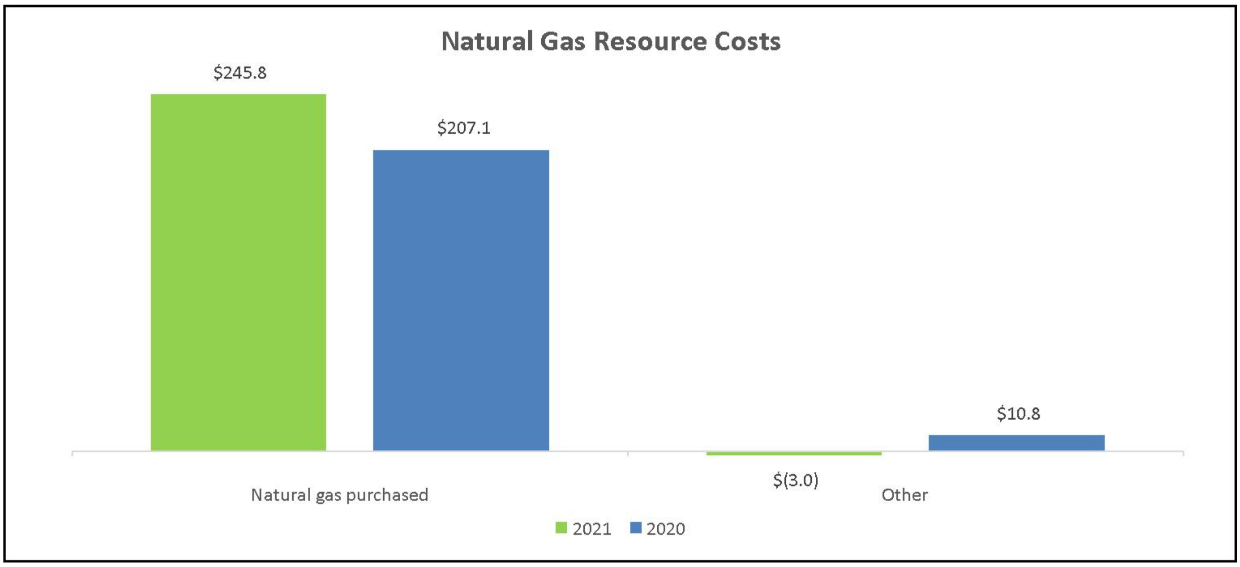
The following graphs present Avista Utilities' resource costs for the years ended December 31 (dollars in millions):



Total electric resource costs in the graph above include intracompany resource costs of $58.6 million and $49.6 million for 2021 and 2020, respectively.

Total electric resource costs increased $73.3 million for 2021 as compared to 2020. The primary fluctuations that occurred during the period were as follows:

- a $21.2 million increase in power purchased due to an increase in wholesale prices (increased costs by $18.6 million), and an increase in the volume of power purchases (increased costs by $2.6 million). The fluctuation in volumes was primarily the result of changes in how we were able to optimize our generation assets as compared to the prior year. Additionally, over the summer months of 2021, we had increased customer loads and lower than normal hydroelectric generation as a result of excessive heat in the Pacific Northwest, which contributed to our need to purchase power at increased prices. See "Summer Weather Conditions" in the Executive Level Summary above.
- a $48.4 million increase in fuel for generation primarily due to a decrease in hydroelectric generation requiring additional thermal generation. There was also an increase in natural gas prices in 2021 compared to 2020.
- a $25.7 million increase in other fuel costs. 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 $22.0 million decrease in other electric resource costs, primarily related to the deferral of increased power supply costs above authorized. There was also increased amortizations associated with the Washington ERM.



Total natural gas resource costs in the graph above include intracompany resource costs of $28.7 million and $36.4 million for 2021 and 2020, respectively.

Total natural gas resource costs increased $24.9 million for 2021 as compared to 2020. The primary fluctuations that occurred during the period were as follows:

- a $38.7 million increase in natural gas purchased due to increases in the price of natural gas (increased costs by $100.0 million) which was partially offset by a decrease in total therms purchased (decreased costs $61.3 million).
- a $13.8 million decrease from net amortizations and deferrals of natural gas 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	
	2021	2020	2021	2020	2021	2020	2021	2020
Operating revenues	$ 1,007,052	$ 927,540	$ 473,313	$ 435,882	$ (87,366)	$ (85,954)	$ 1,392,999	$ 1,277,468
Resource costs	337,866	264,595	242,789	217,902	(87,366)	(85,954)	493,289	396,543
Utility margin	$ 669,186	$ 662,945	$ 230,524	$ 217,980	$ —	$ —	$ 899,710	$ 880,925

Electric utility margin increased $6.2 million and natural gas utility margin increased $12.5 million.

Electric utility margin increased primarily due to customer growth and a general rate increase in Washington, effective April 1, 2020. In addition, 2020 included an accrual for customer refunds of $1.4 million related to our 2015 Washington general rate case. This was partially offset by an increase in net power supply costs as compared to the prior year due, in part, to the hot, dry weather conditions experienced in 2021 (see "Summer Weather Conditions" in the Executive Level Summary above). For 2021, we had a $7.7 million pre-tax expense under the ERM in Washington, compared to a $6.2 million pre-tax benefit in 2020.

Natural gas utility margin increased primarily due to general rate increases in Oregon (effective January 16, 2021) and Washington (effective April 1, 2020) as well as customer growth. The 2020 accrual for customer refunds of $3.5 million related to our 2015 Washington general rate case also contributed to the increase year over year.

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

2021 compared to 2020

Net income for AEL&P was $7.2 million for the year ended December 31, 2021, compared to $8.1 million for 2020. This decrease was primarily due a $1.0 million increase in other operating expenses.

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	
	2021	2020
Operating revenues	$ 45,366	$ 42,809
Resource costs	3,834	1,966
Utility margin	$ 41,532	$ 40,843

Utility margin increased slightly for 2021 primarily due to higher sales volumes to residential and commercial customers for 2021 as compared to 2020.

Results of Operations - Other Businesses

2021 compared to 2020

Our other businesses had net income of $14.6 million for 2021 compared to net loss of $3.4 million for 2020. The increase in net income primarily relates to net investment gains during 2021.

Accounting Standards to be Adopted in 2022

At this time, 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 2022. For information on accounting standards adopted in 2021 and accounting standards expected to be adopted in future periods, see “Note 2 of the Notes to Consolidated Financial Statements.”

Critical Accounting Policies and Estimates

The preparation of our consolidated financial statements in conformity with GAAP requires us to make 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 Financial Accounting Standards Board Accounting Standards Codification 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 our 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 were no longer allowed to apply regulatory accounting or no longer allowed recovery of these costs, we could 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.

- ***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. 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 particular 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 that were hired prior to January 1, 2014. For substantially all regular non-union full-time employees at Avista Utilities who were hired on or after January 1, 2014, a defined contribution 401(k) plan replaced the defined benefit pension plan. Union employees hired on or after January 1, 2014 are still covered under the defined benefit pension plan. See “Note 11 of the Notes to Consolidated Financial Statements” for further discussion of these individual plans.

Pension costs (including the SERP) were $19.3 million for 2021, $22.3 million for 2020 and $26.9 million for 2019. 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 we make 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 have to 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 any 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 that of 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):

	2021	2020	2019
Discount rate (exclusive of SERP)			
Pension discount rate	3.39 %	3.25 %	3.85 %
Increase/(decrease) to projected benefit obligation	$ (15.6)	$ 62.6	$ 41.7
Return on plan assets (a)			
Expected long-term return on plan assets	5.40 %	5.50 %	5.90 %
Increase/(decrease) to pension costs	$ 0.7	$ 2.5	$ (2.2)
Actual return on plan assets, net of fees	7.10 %	15.20 %	20.40 %
Actual gain on plan assets	$ 50.4	$ 96.6	$ 109.9

(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)%	$ — *	$ 3.6
Expected long-term return on plan assets	0.5 %	— *	(3.6)
Discount rate	(0.5)%	58.2	5.3
Discount rate	0.5 %	(51.7)	(4.7)

* 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 in order to fund these needs as well as fund maturing debt. See further discussion at “Capital Resources.”

We periodically file for rate adjustments for recovery of operating costs and capital investments and to seek the opportunity to earn reasonable returns as allowed by regulators.

Avista Utilities has 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 retail customers, net cash flows are negatively affected. Factors that could cause purchased power and natural gas costs to exceed the levels currently recovered from our customers include, but are not limited to, higher prices in wholesale markets when we buy energy or an increased need to purchase power in the wholesale markets, and a lack of regulatory approval for higher authorized net power supply costs through general rate case decisions. 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 climate change/weather or customer growth),
- reduced snowpack or lower streamflows (due to climate change/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, Avista Utilities enters into derivative instruments to hedge our exposure to certain risks, including fluctuations in commodity market prices, foreign exchange rates and interest rates (for purposes of issuing long-term debt in the future). These derivative instruments often require collateral (in the form of cash or letters of credit) or other credit enhancements, or reductions or terminations of a portion of the contract through cash settlement, in the event of a downgrade in the Company's 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 the Company's credit facilities and cash. See “Enterprise Risk Management – Credit Risk Liquidity Considerations” below.

We monitor the potential liquidity impacts of changes to energy commodity prices and other increased operating costs for our utility operations. We believe that we have adequate liquidity to meet such potential needs through our committed lines of credit.

Material contractual obligations arising in the normal course of business include energy purchase contracts, and contractual obligations related to generation facilities and transmission and distributions services. See "Note 13 of the Notes to Consolidated Financial Statements" for additional information related to these contractual obligations.

Additional capital resource requirements include borrowings and interest payment obligations (see "Notes 14-17 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 11 of the Notes to Consolidated Financial Statements") and investment fund commitments (see "Note 6 of the Notes to Consolidated Financial Statements").

As of December 31, 2021, we had $82.0 million of available liquidity under the Avista Corp. committed line of credit and $25.0 million under the AEL&P committed line of credit. With our $400.0 million credit facility that expires in June 2026 and AEL&P's $25.0 million credit facility that expires in November 2024, we believe that we have adequate liquidity to meet our needs for the next 12 months.

Review of Consolidated Cash Flow Statement

2021 compared to 2020

Consolidated Operating Activities

Net cash provided by operating activities was $267.3 million for 2021 compared to $331.0 million for 2020. The decrease in net cash provided by operating activities primarily relates to an increase in power and natural gas cost deferrals (reflecting higher power and natural gas supply costs), which decreased cash flows by $51.8 million in 2021 compared to decreasing cash flows by $9.9 million in 2020. In addition, the provision for deferred taxes increased in 2021 less than it did during 2021, decreasing operating cash flows by $33.7 million compared to 2020. Finally, there was also an increase in pension contributions made during the year, from $22.0 million in 2020 to $42.0 million in 2021.

These decreases were partially offset by changes in certain current assets and liabilities, which increased cash flows by $26.3 million.

Consolidated Investing Activities

Net cash used in investing activities was $444.9 million for 2021, an increase compared to $410.7 million for 2020. During 2021, we paid $439.9 million for utility capital expenditures, compared to $404.3 million for 2020.

Consolidated Financing Activities

Net cash provided by financing activities was $185.5 million for 2021 compared to $84.0 million for 2020. The increase in financing cash flows was primarily the result of changes in short-term borrowings of $63.8 million compared to 2020. In addition, there was an increase in proceeds from issuance of common stock of $17.8 million compared to 2020.

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, 2021 and 2020 (dollars in thousands):

	December 31, 2021		December 31, 2020	
	Amount	Percent of total	Amount	Percent of total
Current portion of long-term debt and leases	$ 257,386	5.4 %	$ 7,184	0.2 %
Short-term borrowings	284,000	6.0 %	203,000	4.6 %
Long-term debt to affiliated trusts	51,547	1.1 %	51,547	1.2 %
Long-term debt and leases	2,010,168	42.2 %	2,125,065	48.0 %
Total debt	2,603,101	54.7 %	2,386,796	54.0 %
Total Avista Corporation shareholders' equity	2,154,744	45.3 %	2,029,726	46.0 %
Total	$ 4,757,845	100.0 %	$ 4,416,522	100.0 %

Our shareholders' equity increased $125.0 million during 2021 primarily due to net income and the issuance of common stock, partially offset by dividends.

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.

Committed Lines of Credit

Avista Corp. has a committed line of credit with various financial institutions in the total amount of $400.0 million. In June 2021, we entered into an amendment that extends the expiration date to June 2026, with the option to extend for an additional one year period (subject to customary conditions). As of December 31, 2021, there was $82.0 million of available liquidity under this line of credit.

The Avista Corp. credit facility contains customary covenants and default provisions, including 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, 2021, we were in compliance with this covenant with a ratio of 54.7 percent.

Balances outstanding and interest rates on borrowings (excluding letters of credit) under Avista Corp.'s committed line of credit were as follows as of and for the year ended December 31 (dollars in thousands):

	2021	2020
Balance outstanding at end of year	$ 284,000	$ 102,000
Letters of credit outstanding at end of year (1)	$ 34,000	$ 27,618
Maximum balance outstanding during the year	$ 338,000	$ 310,000
Average balance outstanding during the year	$ 208,629	$ 138,890
Average interest rate during the year	1.14 %	1.59 %
Average interest rate at end of year	1.11 %	1.22 %

(1) Letters of credit represent off-balance sheet obligations.

AEL&P has a $25.0 million committed line of credit with an expiration date in November 2024. As of December 31, 2021, 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, 2021, AEL&P was in compliance with this covenant with a ratio of 51.9 percent.

As of December 31, 2021, Avista Corp. and its subsidiaries were in compliance with all of 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.

In April 2020, we entered into a $100.0 million credit agreement with an expiration date of April 2021. We borrowed the entire $100.0 million available under this agreement in April 2020 and repaid the outstanding balance in April 2021. See "Note 15 of the Notes to Consolidated Financial Statements."

Long-Term Debt

In September 2021, we issued and sold $70.0 million of 2.90 percent first mortgage bonds due in 2051 pursuant to a bond purchase agreement with institutional investors in the private placement market. We issued and sold the remaining $70.0 million under this same bond agreement in December 2021. The total net proceeds from the sale of the bonds were used to repay a portion of the outstanding balance under our $400.0 million committed line of credit. In connection with the pricing of the first mortgage bonds in September 2021, we cash-settled four interest rate swap derivatives (notional aggregate amount of $45.0 million) and paid a net amount of $17.2 million, which will be amortized as a component of interest expense over the life of the debt. The effective interest rate of the first mortgage bonds is 3.63 percent, including the effects of the settled interest rate swap derivatives and issuance costs.

Common Stock

We issued common stock in 2021 for total net proceeds of $90.0 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. We have board and regulatory authority to issue a maximum of 4.3 million shares, of which 2.1 million remain unissued as of December 31, 2021. In 2021, 2.2 million shares were issued under these agreements resulting in total net proceeds of $88.5 million.

2022 and 2023 Liquidity Expectations

During 2022, we expect to issue $400.0 million of long-term debt and $120.0 million of common stock in order to refinance $250 million of first mortgage bonds maturing on April 2, 2022 and to fund capital expenditures.

During 2023, we expect to issue $110 million of long-term debt and $110 million of common stock to fund planned capital expenditures.

After considering the expected issuances of long-term debt and common stock during 2022 and 2023, we expect net cash flows from operating activities, together with cash available under our committed line of credit agreements, 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, 2021, we could issue $1.5 billion of preferred stock at an assumed dividend rate of 4.6 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 (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.

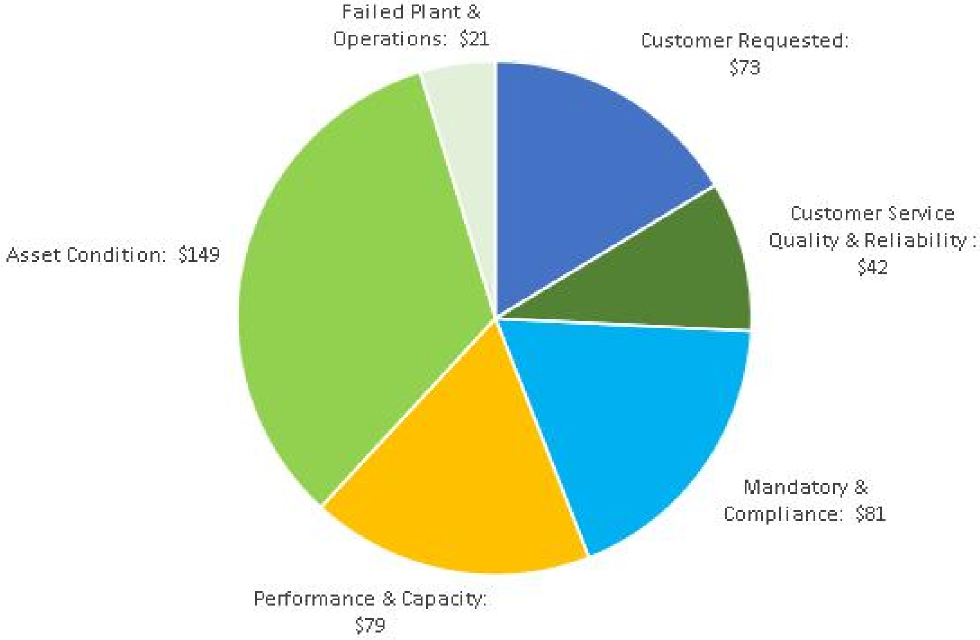
However, Avista Corp. and AEL&P may not individually issue any additional first mortgage bonds (with certain exceptions in the case of bonds issued on the basis of retired bonds) unless the particular entity issuing the bonds has “net earnings” (as defined in the respective Mortgages) for any period 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, 2021, property additions and retired bonds would have allowed, and the net earnings test would not have prohibited, the issuance of $1.8 billion in aggregate principal amount of additional first mortgage bonds at Avista Corp. and $38.2 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 are making 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, 2021 (in thousands):

	Avista Utilities	AEL&P
2021 Actual capital expenditures		
Capital expenditures (per the Consolidated Statement of Cash Flows)	$ 435,887	$ 4,052
Expected total annual capital expenditures (by year)		
2022	$ 445,000	$ 14,000
2023	445,000	13,000
2024	445,000	12,000

The following graph shows Avista Utilities' expected capital expenditures for 2022 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 are making 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 are making investments in emerging technology companies and venture capital funds. 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, 2021 (in thousands):

	Other
2021 Actual investments and capital expenditures	
Investments and capital expenditures (per the Consolidated Statement of Cash Flows)	$ 17,221
Expected total annual investments and capital expenditures (by year)	
2022	$ 15,000
2023	14,000
2024	10,000

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 2022 and thereafter.

Pension Plan

We contributed $42.0 million to the pension plan in 2021. We expect to contribute a total of $82.0 million to the pension plan in the period 2022 through 2026, with an annual contribution of $42.0 million for 2022 and $10.0 million from 2023 to 2026.

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 11 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 7 of the Notes to Consolidated Financial Statements.”

The following table summarizes our credit ratings as of February 22, 2022:

	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. Rates are designed to provide, after recovery of allowable operating expenses and capital investments, an opportunity for us 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 entered into a number of 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, or energy storage may also compete with us 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 state 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. In order 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 with us by tailoring our internal company initiatives to focus on choices for our 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.

Economic Conditions and Utility Load Growth

The general economic data, on both national and local levels, contained in this section is based, in part, on independent government and industry publications, reports by market research firms or other independent sources. While we believe that these publications and other sources are reliable, we have not independently verified such data and can make no representation as to its accuracy.

Avista Utilities

We track multiple economic indicators affecting the three largest metropolitan statistical areas in our Avista Utilities service area: Spokane, Washington, Coeur d'Alene, Idaho, and Medford, Oregon. The key indicators are employment change and unemployment rates. On an annual basis, 2021 showed positive job growth with lower unemployment rates in all three metropolitan areas. This reflects the on-going recovery from the 2020 COVID-19 induced recession. The unemployment rates in Spokane and Medford are near the national average, while Coeur d’Alene is lower. Other leading indicators, such as initial unemployment claims and residential building permits, signal continued growth over the next 12 months. Considering all relevant indicators, we expect economic growth in our service area in 2022 to be in-line with the U.S. as a whole.

Reflecting the on-going recovery from the COVID-19 recession, nonfarm employment (seasonally adjusted) in our eastern Washington, northern Idaho and southwestern Oregon metropolitan service areas increased in 2021. In Spokane, Washington employment increased 3.8 percent with gains in all major sectors except manufacturing; information; financial activities; and government. Employment increased 5.3 percent in Coeur d'Alene, Idaho, reflecting gains in all major sectors except mining and logging; manufacturing; and government. In Medford, Oregon, employment increased 2.7 percent, with gains in all major sectors except information and government. U.S. nonfarm sector employment increased 2.7 percent over the same period.

Changes in the unemployment rate in 2021 reflect a gradual recovery from the COVID-19 recession. In Spokane the unemployment rate was 8.8 percent in 2020 and fell to 4.9 percent in 2021; in Coeur d'Alene the rate fell from 6.9 percent in 2020 to 3.6 percent in 2021; and in Medford the rate fell from 7.8 percent in 2020 to 5.3 percent in 2021. The U.S. unemployment rate fell from 8.1 percent in 2020 percent to 5.3 percent in 2021.

Alaska Electric Light and Power Company

Our AEL&P service area is centered in Juneau. Although Juneau is Alaska’s state capital, it is not a metropolitan statistical area. This means breadth and frequency of economic data is more limited. Therefore, the dates of Juneau's economic data may significantly lag the period of this filing.

The Quarterly Census of Employment and Wages for Juneau shows employment increased 1.4 percent between the first half of 2020 and first half of 2021. There were employment gains in all major sectors, except trade, transportation, and utilities; information; financial activities; professional and business services; and other services. Government employment increased 2.3 percent during this period; this sector accounted for 41 percent of total employment in 2020. Between 2020 and 2021, the unemployment rate fell from 6.6 percent to 4.5 percent.

Forecasted Customer and Load Growth

Based on our forecast for 2022 through 2026 for Avista Utilities' service area, we expect annual electric customer growth to average 1.2 percent, within a forecast range of 0.8 percent to 1.6 percent. We expect annual natural gas customer growth to average 1.4 percent, within a forecast range of 0.8 percent to 2.0 percent. We anticipate retail electric load growth to average 0.6 percent, within a forecast range of 0.2 percent and 1.0 percent. We expect natural gas load growth to average 0.9 percent, within a forecast range of 0.4 percent and 1.4 percent. The forecast ranges reflect (1) the inherent uncertainty associated with the economic assumptions on which forecasts are based and (2) the historic variability of natural gas customer and load growth. These natural gas forecast ranges do not reflect the uncertainty regarding new natural gas laws or regulations that could be effective in future periods. See further discussion regarding these natural gas regulations as included in "Environmental Issues and Contingencies" below.

In AEL&P's service area, we expect no growth in residential, commercial and government customers for the period 2021 through 2024. We anticipate average annual total load growth will be in a narrow range around 0.5 percent, with residential load growth averaging 1.0 percent and no growth in commercial and government load. Residential load growth reflects (1) existing customers switching from diesel generated heat to electric heat pumps, and (2) an increase in the residential use of electric vehicles.

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. 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 our existing generating plants,
- requiring existing generating plant operations to be curtailed or shut down,
- reducing the amount of energy available from our 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 any such costs through the ratemaking process.

Washington Clean Energy Transformation Act (CETA)

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 would effectively prohibit sales of energy produced by coal-fired generation to Washington retail customers after December 31, 2025. In addition, CETA establishes the policy of Washington State that all 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 CETA on Colstrip and our continued participation in Colstrip. Our hydroelectric and biomass generation facilities can be used to comply with the CETA's clean energy standards. We intend to seek recovery of any costs associated with the clean energy legislation and regulations through the regulatory process.

As required under CETA, in October 2021, we filed our first Clean Energy Implementation Plan (CEIP) with the WUTC. This filing triggered comments from interested parties in January 2022, with WUTC action to follow thereafter in 2022. We must file a CEIP with the WUTC every four years.

Our CEIP is a road map of specific actions we propose to take over the next 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, which was passed by the Washington legislature and enacted into law in 2019. CETA requires electric supply to be greenhouse gas neutral by 2030 and 100 percent renewable or generated from zero-carbon resources by 2045.

Some highlights of our CEIP include:

- Beginning in 2022, we plan to serve 80 percent of our Washington customer demand with owned and purchased renewable energy, then increase this target by 5 percent every two years.
- To minimize rate impacts as we transition to cleaner energy, we are proposing to sell some of our renewable energy credits (RECs) on the open market through 2029. In 2030, we will utilize 100 percent of RECs on behalf of our customers, rather than selling RECs on the open market.
- The plan sets energy efficiency targets to reduce customer load by approximately 2 percent over the next four years by 204,305 megawatt hours through incentives and programs to lower energy use without impacting the customer.
- Our demand response target is to lower peak demand by 30 megawatts in periods of extreme heat or cold as an effort to eliminate the need for future resources.
- We have proposed a variety of initiatives to promote the equitable distribution of the benefits and burdens of renewable energy and are still working to find the best way to achieve these goals.

While the CEIP represents our current objectives, it is subject to change from time to time in the future as circumstances warrant including direct input from the WUTC.

Policies Related to Climate Change

Legal and policy changes responding to concerns about long-term global climate changes, and the potential impacts of such changes, could have a significant effect on our business. Our operations could be affected by changes in laws and regulations intended to mitigate the risk of, or alter, global climate changes, including restrictions on the operation of our power generation resources and obligations or limitations imposed on the sale of natural gas. Changing temperatures and precipitation, including snowpack conditions, affect the availability and timing of streamflows, which impact hydroelectric generation. Extreme weather events could increase fire risks, service interruptions, outages and maintenance costs. Changing temperatures could also change the magnitude and timing of customer demand.

Federal Regulatory Actions

In June 2019, the EPA released the final version of the Affordable Clean Energy (ACE) rule, the replacement for the Clean Power Plan (Federal CPP). The final ACE rule finalized the repeal of the Federal CPP and comprised the EPA's determination of the Best System of Emissions Reduction (BSER) for existing coal-fired power plants as heat rate efficiency improvements based on a range of "candidate technologies".

In January 2021, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) vacated the ACE Rule and remanded the record back to the EPA for further consideration consistent with its opinion, finding that the EPA misinterpreted the Clean Air Act when it determined that the language of Section 111 barred consideration of emissions reduction options that were not applied at the source. The Court also vacated the repeal of the Federal CPP. In February 2021, the EPA moved for a partial stay of the Court's mandate, noting that no Section 111(d) rule should go into effect until the EPA conducted new rulemaking in response to the January 2021 decision. The Court subsequently issued an order withholding issuance of the mandate with respect to the repeal of the Federal CPP and directing issuance of the mandate "in the normal course" for the vacatur of the replacement portion of the rule. In April 2021, numerous parties requested the Supreme Court's review of the

D.C. Circuit’s January 2021 decision, and in October 2021, the Supreme Court granted such review. Oral arguments are scheduled for February 2022 in this case.

Given the status of the EPA’s rulemaking, we cannot reasonably predict the timing, outcome or applicability of these issues with respect to any of the Company's generation resources.

Washington Legislation and Regulatory Actions

Clean Air Rule

In September 2016, the Washington State Department of Ecology adopted the Clean Air Rule (CAR) to cap and reduce greenhouse gas (GHG) emissions across the State of Washington in pursuit of the State’s GHG goals, which were enacted in 2008 by the Washington State Legislature. In response, the Company, Cascade Natural Gas Corporation, NW Natural and Puget Sound Energy jointly filed actions in both the Eastern District of Washington and in Thurston County Superior Court, challenging the CAR.

In January 2020, the Washington State Supreme Court issued a decision holding that the CAR was invalid as to non-emitters, such as natural gas distributors, but could be enforced against direct emitters, such as natural gas generation plants. The Court has remanded the matter to Thurston County Superior Court, where it has been stayed by the Court. At this time, we are continuing to evaluate the potential impact of the surviving portion of the rule, if any, to our generation facilities, should their emissions exceed the rule’s compliance threshold. The rule is not intended to apply to the Kettle Falls Generating Station. We plan to seek recovery of any costs related to compliance with the surviving portion of the CAR through the ratemaking process.

Emissions Performance Standard

Washington also applies a GHG emissions performance standard to electric generation facilities used to serve retail loads in their jurisdictions, whether the facilities are located within its state 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, in any case, have emission levels higher than 1,100 pounds of GHG per MWh. The Washington State Department of Commerce reviews the standard every five years. In September 2018, it adopted a new standard of 925 pounds of GHG per MWh. We intend to seek recovery of costs related to ongoing and new requirements through the ratemaking process.

Washington Climate Commitment Act

In 2021, the legislature passed the Climate Commitment Act, which establishes a cap and invest program to help achieve Washington’s greenhouse gas limits by 2050. The Washington Department of Ecology is responsible for the implementation and the start of this program by January 1, 2023, including the adoption of annual allowance budgets for the first compliance period of the program by October 1, 2022. There are various rule making proceedings regarding the details of the program pending before the Department of Ecology. We will actively monitor and participate in these rulemakings as they proceed but cannot reasonably predict how these programs may impact our facilities at this time.

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 greenhouse gas-related matters, with the aim of reducing Oregon’s overall GHG emissions to 80 percent below 1990 levels by 2050. Oregon agencies, including the Oregon Department of Environmental Quality (ODEQ) and the OPUC, issued reports discussing general intent to carry out the Executive Order.

The ODEQ subsequently developed cap and reduce rules known as the Climate Protection Program (Oregon CPP). Final rules were adopted by the Environmental Quality Commission (EQC) in December 2021 and become effective in 2022. The Oregon CPP originally proposed emission reduction targets of at least 45 percent below 1990 levels by 2035 and at least 80 percent below 1990 levels by 2050, in accordance with Executive Order 20-04. However, during the December 2021 ODEQ presentation to the EQC, substantial changes were made to the final version of the Oregon CPP, as compared to the version of the Oregon CPP that was open for public comment. One of the most significant items revises the emissions cap and mandates emissions reductions of at least 50 percent by 2035 and 90 percent by 2050. We are evaluating the potential impacts of these regulations. Compliance efforts to meet the Oregon CPP emissions reduction goals could materially impact our Oregon natural gas business.

The OPUC has opened a Natural Gas Fact-Finding effort to analyze the potential natural gas utility bill impacts that may result from limiting GHG emissions of regulated natural gas utilities under the ODEQ's Oregon CPP and to identify appropriate regulatory tools to mitigate potential customer impacts. According to the OPUC Staff, the ultimate goal of the Fact-Finding Docket will be to inform future policy decisions and other key analyses to be considered in 2022. We expect the OPUC Staff will present a final report on the Fact-Finding effort to the OPUC in late spring of 2022 with recommendations for further OPUC engagement later in 2022.

Emissions Performance Standard

Like Washington, Oregon applies a GHG emissions performance standard to electric generation facilities, requiring that any new baseload natural gas plant, non-base load natural gas plant, and non-generating facility reduce its net carbon dioxide emissions 17% below 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 in other states. The standard can be met by any 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 ongoing and new requirements through the ratemaking process.

Clean Electricity and Coal Transition Act

In Oregon, legislation was enacted in 2016 which requires Portland General Electric and PacifiCorp to remove coal-fired generation from their Oregon rate base by 2030. This legislation does not directly relate to Avista Corp. because Avista Corp. is not an electric utility in Oregon. However, because these two utilities, along with Avista Corp., hold minority interests in Colstrip, the legislation could indirectly impact Avista Corp., though specific impacts cannot be reasonably predicted at this time. While the legislation requires Portland General Electric and PacifiCorp to eliminate Colstrip from their rates, they would be permitted to sell the output of their shares of Colstrip into the wholesale market or, as is the case with PacifiCorp, reallocate generation from Colstrip to other states. We cannot predict the eventual outcome of actions arising from this legislation at this time or estimate the effect thereof on Avista Corp.; however, we intend to continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to our generation assets.

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 a number of 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.

Threatened and Endangered Species and Wildlife

A number of species of fish in the Northwest are listed as threatened or endangered under the Federal Endangered Species Act. We are implementing fish protection measures at our hydroelectric project on the Clark Fork River under a 45-year FERC operating license for Cabinet Gorge and Noxon Rapids (issued in 2001) that incorporates a comprehensive settlement agreement. The restoration of native salmonid fish, including bull trout, a threatened species, is a key part of the agreement. The result is a collaborative native salmonid restoration program with the U.S. Fish and Wildlife Service, Native American tribes and the states of Idaho and Montana on the lower Clark Fork River, consistent with requirements of the FERC license. Recent efforts in this program include the development of a permanent fish passage facility at Cabinet Gorge dam, as well as fish capture facilities on tributaries to the Clark Fork River. The U.S. Fish & Wildlife Service issued an updated Critical Habitat Designation for bull trout in 2010 that includes the lower Clark Fork River, as well as portions of the Coeur d'Alene basin within our Spokane River Project area, and issued a final Bull Trout Recovery Plan under the ESA. Regional efforts are underway evaluating the potential of re-establishing anadromous fish above previously blocked areas, including the Spokane River, which is upstream from Grand Coulee dam.

Various statutory authorities, including the Migratory Bird Treaty Act, have established penalties for the unauthorized take of migratory birds. Because we operate facilities that can pose risks to a variety of such birds, we have developed and follow an avian protection plan.

We are also aware of other threatened and endangered species and issues related to them that could be impacted by our operations and we make every effort to comply with all laws and regulations relating to these threatened and endangered species. We expect costs associated with these compliance efforts to be recovered through the ratemaking process.

Cabinet Gorge Total Dissolved Gas Abatement Plan

Dissolved atmospheric gas levels (referred to as "Total Dissolved Gas" or "TDG") in the Clark Fork River exceed state of Idaho and federal water quality numeric standards downstream of Cabinet Gorge particularly during periods when excess river flows must be diverted over the spillway. Under the terms of the Clark Fork Settlement Agreement as incorporated in the FERC license for the Clark Fork Project, we work in consultation with agencies, tribes and other stakeholders to address this issue through structural modifications to the spillgates, monitoring and analysis. After extensive testing, Clark Fork Settlement Agreement stakeholders have agreed that no further spillway modifications are justified. For the remainder of the FERC License term, we will continue to mitigate remaining impacts of TDG while periodically considering the potential for new approaches to further reduce TDG. We continue to work with stakeholders to determine the degree to which TDG abatement impacts future mitigation obligations. We have sought, and intends to continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to this issue.

Other

For other environmental issues and other contingencies see “Note 22 of the Notes to Consolidated Financial Statements.”

<u>Colstrip</u>

Colstrip is a coal-fired generating plant in southeastern Montana that includes four units and which is owned by six separate entities. We have a 15 percent ownership interest in Units 3 & 4. The other owners are Puget Sound Energy, Inc., Portland General Electric Company, NorthWestern Corporation, Pacificorp and Talen Montana, LLC (which is also the operator of the plant). In January 2020, the owners of Units 1 & 2, in which the Company has no ownership, closed those two units. The owners of Units 3 & 4 currently share operating and capital costs pursuant to the terms of an operating agreement among them (the Ownership and Operation Agreement).

Depreciation of Colstrip Assets

We received orders from the IPUC and WUTC allowing us to accelerate the depreciation of our 15 percent ownership interest in Colstrip to 2027 for Idaho and 2025 for Washington.

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, 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. We recently adjusted our share of the posted surety bonds to $17.3 million. This amount will be 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 continue to assess the best options for Colstrip in conjunction with our co-owners. We intend to seek recovery of any 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 our organization. Our Board of Directors and its Committees take an active role in the oversight of risk affecting the Company. Our risk management department facilitates the collection of risk information across the Company, providing senior management with a consolidated view of 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
- Cyber and 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 our Board of Directors. See “Regulatory Matters” for further discussion of regulatory matters affecting our 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 our 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 our Board of Directors and from senior management with input from each operating department.

Climate Change Risk

Multiple departments at the Company 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 the Company’s operations, and in more specific efforts, such as the Wildfire Resiliency Plan. Power Supply staff, as a regular course of business, 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 in order to engage these efforts constructively and prepare for compliance matters.

The Company has created four councils that are centered around its primary focus areas: our customers, our people, performance and invention. The Perform Council is an interdisciplinary team of management and other employees of the Company which regularly meets to discuss, assess and manage current issues associated with the Company’s performance. A key area of focus for the Perform Council is potential risks and opportunities associated with long-term global 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 for the Company,
- develops recommendations on climate related policy positions and action plans, and
- provides direction and oversight with respect to the Company's clean energy goals.

In addition, issues concerning climate-related risk and the Company’s 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 any critical or emerging risks and/or related policies. Likewise, the Audit Committee provides oversight of the Company's climate-related disclosures.

Cyber and Technology Risk

We mitigate cyber and technology risk through trainings and exercises at all levels of the Company. The Environmental, Technology and Operations Committee of our Board of Directors along with senior management are regularly briefed on security policy, programs and incidents. 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.

Technology governance is led by senior management, which includes new technology strategy, risk planning and major project planning and approval. The technology project management office and enterprise capital planning group provide project cost, timeline and schedule oversight. In addition, there are independent third party audits of our critical infrastructure security program and our business risk security controls.

We have a Technology department dedicated to securing, maintaining, evaluating and developing our information technology systems. There are regular training sessions for the technology and security team. This group also evaluates the Company's technology for obsolescence and makes recommendations for upgrading or replacing systems as necessary. Additionally, this group monitors for intrusion and security events that may include a data breach or attack on our operations.

Strategic Risk

Oversight of our strategic risk is performed by the Board of Directors and senior management. We have a Chief Strategy Officer who leads strategic initiatives, to search for and evaluate opportunities for the Company and makes recommendations to senior management. 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 our reputational risk primarily through a focus on adherence to our core policies, including our Code of Conduct, maintaining an appropriate Company culture and tone at the top, and through communication and engagement with our external stakeholders.

External Mandates Risk

Oversight of our external mandate risk mitigation strategies is performed by the Environmental, Technology and Operations Committee of our Board of Directors and senior management. We have a Perform Council which meets internally to assess the potential impacts of climate policy to our business and to identify strategies to plan for change. Our ESG 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:

- communication and involvement 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 our internal company initiatives to focus on choices for our 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

Our financial risk is impacted by many factors. Several of these risks include regulation and rates, weather, 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 and/or hedging strategies. Oversight of our financial risk mitigation strategies is performed by senior management and the Finance Committee of our Board of Directors.

Regulation and Rates

Our Regulatory 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 for the Company. 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 "Regulatory Matters" 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 our 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 our existing debt, our future borrowing requirements, and our pension and other post-retirement benefit obligations. We manage debt interest rate exposure by limiting our variable rate debt to a percentage of total capitalization of the Company. We hedge a portion of our interest rate risk on forecasted debt issuances with financial derivative instruments. The Finance Committee of our 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 our interest rate risk management plan. Additionally, interest rate risk is managed by 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.

Our interest rate swap derivatives are considered economic hedges against the future forecasted interest rate payments of our 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.

Even though we work to manage our exposure to interest rate risk by locking in certain long-term interest rates through interest rate swap derivatives, 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. However, through our regulatory accounting practices similar to our energy commodity derivatives, any interim mark-to-market gains or losses are offset by regulatory assets and liabilities. Upon settlement of interest rate swap derivatives, the cash payments made or received are recorded as a regulatory asset or liability and are subsequently amortized as a component of interest expense over the life of the associated debt. The settled interest rate swap derivatives are also included as a part of Avista Corp.'s cost of debt calculation for ratemaking purposes.

The following table summarizes our interest rate swap derivatives outstanding as of December 31, 2021 and December 31, 2020 (dollars in thousands):

	December 31, 2021	December 31, 2020
Number of agreements	16	16
Notional amount	$ 170,000	$ 175,000
Mandatory cash settlement dates	2022 to 2024	2021 to 2023
Long-term derivative assets (1)	$ 1,149	$ —
Short-term derivative liability (1) (2)	(24,026)	(11,525)
Long-term derivative liability (1) (2)	(78)	(31,238)

(1) There are offsetting regulatory assets and liabilities for these items on the Consolidated Balance Sheets in accordance with regulatory accounting practices.

(2) The balance as of December 31, 2020 reflects the offsetting of $8.1 million, of cash collateral against the net derivative positions where a legal right of offset exists. There is no offsetting cash collateral in the 2021 balances.

We estimate that a 10 basis point increase in forward LIBOR interest rates as of December 31, 2021 would increase the interest rate swap derivative net liability by $5.3 million, while a 10 basis point decrease would decrease the interest rate swap derivative net liability by $5.4 million.

We estimated that a 10 basis point increase in forward LIBOR interest rates as of December 31, 2020 would have increased the interest rate swap derivative net liability by $5.9 million, while a 10 basis point decrease would decrease the interest rate swap derivative net liability by $6.1 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 our long-term debt (including current portion) and related weighted-average interest rates, by expected maturity dates as of December 31, 2021 (dollars in thousands):

	2022	2023	2024	2025	2026	Thereafter	Total	Fair Value
Fixed rate long-term debt (1)	$ 250,000	$ 13,500	$ 15,000	$ —	$ —	$ 1,885,000	$ 2,163,500	$ 2,524,270
Weighted-average interest rate	5.13 %	7.35 %	3.44 %	—	—	4.25 %	4.37 %	
Variable rate long-term debt to affiliated trusts	—	—	—	—	—	$ 51,547	$ 51,547	$ 43,299
Weighted-average interest rate	—	—	—	—	—	1.05 %	1.05 %	

(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 our 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 our 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 11 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

Counterparty non-performance risk relates to potential losses that we would incur as a result of 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 enter into bilateral transactions with various counterparties. We also trade energy and related derivative instruments through clearinghouse exchanges.

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 current credit exposures,
- asserting our 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 our capital requirements.

Counterparties' credit exposure to us is dynamic in normal markets and may change significantly in more volatile markets. The amount of potential default risk to us 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 credit risk and demands 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 allow us 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 any unsecured credit threshold. Counterparties may seek assurances of performance from us 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, 2021, we had cash deposited as collateral of $30.6 million and letters of credit of $34.0 million outstanding related to our energy contracts. Price movements and/or a downgrade in our credit ratings 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 our positions outstanding at December 31, 2021 (including contracts that are considered derivatives and those that are considered non-derivatives), we would potentially be required to post the following additional collateral (in thousands):

		December 31, 2021
Additional collateral taking into account contractual thresholds	$	7,983
Additional collateral without contractual thresholds		9,194

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, 2021, we had interest rate swap agreements outstanding with a notional amount totaling $170.0 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 our interest rate swap derivatives outstanding at December 31, 2021, we would potentially be required to post the following additional collateral (in thousands):

		December 31, 2021
Additional collateral taking into account contractual thresholds (1)	$	11,730
Additional collateral without contractual thresholds		25,273

(1) This amount is different from the amount disclosed in “Note 7 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 7, this analysis also takes into account contractual threshold limits that are not considered in Note 7.

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 our 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 7 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 our 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 our 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 that costs are essentially fixed by virtue of known fuel supply costs or projected hydroelectric conditions. To the extent that 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 are able to 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 our 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.

Our 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 seek to 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 our 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, 2021 that are expected to settle in each respective year (dollars in thousands). There are 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)
2022	(269)	—	(260)	6,198	650	1,572	(3,479)	(16,859)
2023	—	—	(54)	1,964	—	—	(1,612)	(757)
2024	—	—	(34)	296	—	—	(1,603)	5
2025	—	—	—	—	—	—	(1,146)	—

The following table presents energy commodity derivative fair values as a net asset or (liability) as of December 31, 2020 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)
2021	$ 2	$ (414)	$ (87)	$ 10,549	$ (15)	$ 716	$ (2,152)	$ (10,672)
2022	—	—	247	1,920	—	—	(1,697)	(1,536)
2023	—	—	—	(122)	—	—	(1,599)	(42)
2024	—	—	—	—	—	—	(1,673)	—
2025	—	—	—	—	—	—	(1,219)	—

(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 to our Company 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 our compliance risk strategy is performed by senior management, including our Chief Compliance Officer, and the Environmental, Technology and Operations Committee and the Audit Committee of our 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, 2021 and 2020, the related consolidated statements of income, comprehensive income, equity, and cash flows, for each of the three years in the period ended December 31, 2021, 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, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021, 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, 2021, 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 22, 2022, 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 Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates 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 matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

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 multiple financial statement line items and disclosures, such as property, plant, and equipment, regulatory assets and liabilities, operating revenues, operation and maintenance expense, and depreciation expense.

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 as property, plant, and equipment 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 22, 2022

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

	2021	2020	2019
Operating Revenues:			
Utility revenues:			
Utility revenues, exclusive of alternative revenue programs	$ 1,445,000	$ 1,324,091	$ 1,323,524
Alternative revenue programs	(6,635)	(3,814)	9,614
Total utility revenues	1,438,365	1,320,277	1,333,138
Non-utility revenues	571	1,614	12,484
Total operating revenues	1,438,936	1,321,891	1,345,622
Operating Expenses:			
Utility operating expenses:			
Resource costs	497,123	398,509	439,817
Other operating expenses	366,125	354,614	345,212
Merger transaction costs	—	—	19,675
Depreciation and amortization	231,915	223,507	205,365
Taxes other than income taxes	109,353	106,501	105,652
Non-utility operating expenses:			
Other operating expenses	5,927	5,344	18,883
Depreciation and amortization	261	716	629
Total operating expenses	1,210,704	1,089,191	1,135,233
Income from operations	228,232	232,700	210,389
Interest expense	105,731	104,348	103,012
Interest expense to affiliated trusts	421	713	1,342
Capitalized interest	(3,987)	(4,083)	(4,174)
Merger termination fee	—	—	(103,000)
Other income-net	(33,298)	(4,817)	(14,928)
Income before income taxes	159,365	136,539	228,137
Income tax expense	12,031	7,051	31,374
Net income	147,334	129,488	196,763
Net loss attributable to noncontrolling interests	—	—	216
Net income attributable to Avista Corp. shareholders	$ 147,334	$ 129,488	$ 196,979
Weighted-average common shares outstanding (thousands), basic	69,951	67,962	66,205
Weighted-average common shares outstanding (thousands), diluted	70,085	68,102	66,329
Earnings per common share attributable to Avista Corp. shareholders:			
Basic	$ 2.11	$ 1.91	$ 2.98
Diluted	$ 2.10	$ 1.90	$ 2.97

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

	2021	2020	2019
Net income	$ 147,334	$ 129,488	$ 196,763
Other Comprehensive Income (Loss):			
Change in unfunded benefit obligation for pension and other postretirement benefit plans - net of taxes of $888, $(1,095) and $(636), respectively	3,339	(4,119)	(2,393)
Total other comprehensive income (loss)	3,339	(4,119)	(2,393)
Comprehensive income	150,673	125,369	194,370
Comprehensive loss attributable to noncontrolling interests	-	-	216
Comprehensive income attributable to Avista Corporation shareholders	$ 150,673	$ 125,369	$ 194,586

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED BALANCE SHEETS

Avista Corporation

As of December 31

Dollars in thousands

	2021	2020
Assets:		
Current Assets:		
Cash and cash equivalents	$ 22,168	$ 14,196
Accounts and notes receivable, net	203,035	163,772
Materials and supplies, fuel stock and stored natural gas	84,733	67,451
Regulatory assets	43,783	13,673
Other current assets	80,754	84,885
Total current assets	434,473	343,977
Net utility property	5,225,515	4,991,612
Goodwill	52,426	52,426
Non-current regulatory assets	860,626	750,443
Other property and investments-net and other non-current assets	280,543	263,639
Total assets	$ 6,853,583	$ 6,402,097
Liabilities and Equity:		
Current Liabilities:		
Accounts payable	$ 133,096	$ 106,613
Current portion of long-term debt	250,000	—
Short-term borrowings	284,000	203,000
Regulatory liabilities	77,149	46,435
Other current liabilities	168,861	149,831
Total current liabilities	913,106	505,879
Long-term debt	1,898,370	2,008,534
Long-term debt to affiliated trusts	51,547	51,547
Pensions and other postretirement benefits	153,467	211,880
Deferred income taxes	642,709	594,712
Non-current regulatory liabilities	861,515	784,820
Other non-current liabilities and deferred credits	178,125	214,999
Total liabilities	4,698,839	4,372,371
Commitments and Contingencies (See Notes to Consolidated Financial Statements)		
Equity:		
Avista Corporation Shareholders’ Equity:		
Common stock, no par value; 200,000,000 shares authorized; 71,497,523 and 69,238,901 shares issued and outstanding, respectively	1,380,152	1,286,068
Accumulated other comprehensive loss	(11,039)	(14,378)
Retained earnings	785,631	758,036
Total equity	2,154,744	2,029,726
Total liabilities and equity	$ 6,853,583	$ 6,402,097

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

	2021	2020	2019
Operating Activities:			
Net income	$ 147,334	$ 129,488	$ 196,763
Non-cash items included in net income:			
Depreciation and amortization	232,176	224,223	205,994
Provision for deferred income taxes	11,224	44,964	15,098
Power and natural gas cost amortizations (deferrals), net	(51,847)	(9,923)	(45,917)
Amortization of debt expense	2,606	3,237	2,680
Amortization of investment in exchange power	—	—	1,633
Stock-based compensation expense	4,713	5,846	11,353
Equity-related AFUDC	(7,004)	(6,970)	(6,585)
Pension and other postretirement benefit expense	29,077	33,812	36,417
Other regulatory assets and liabilities and deferred debits and credits	676	10,287	65
Change in decoupling regulatory deferral	6,056	2,971	(10,327)
Realized and unrealized gain on assets and investments	(23,187)	(5,170)	(13,077)
Other	(2,859)	2,373	(7,899)
Contributions to defined benefit pension plan	(42,000)	(22,000)	(22,000)
Cash paid on settlement of interest rate swap agreements	(17,568)	(33,499)	(13,325)
Cash received on settlement of interest rate swap agreements	324	—	—
Changes in certain current assets and liabilities:			
Accounts and notes receivable	(46,107)	(10,960)	(4,366)
Materials and supplies, fuel stock and stored natural gas	(17,282)	(868)	(6,148)
Collateral posted for derivative instruments	(17,564)	1,579	63,974
Income taxes receivable	20,199	(41,363)	(8,736)
Other current assets	930	(2,401)	(3,657)
Accounts payable	33,369	(10,152)	7,471
Other current liabilities	4,074	15,530	(1,199)
Net cash provided by operating activities	267,340	331,004	398,212
Investing Activities:			
Utility property capital expenditures (excluding equity-related AFUDC)	(439,939)	(404,306)	(442,510)
Issuance of notes receivable	(1,841)	(4,393)	(7,303)
Equity and property investments	(16,001)	(5,925)	(13,508)
Proceeds from sale of investments	8,306	6,786	16,407
Other	4,559	(2,905)	1,403
Net cash used in investing activities	$ (444,916)	$ (410,743)	$ (445,511)

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

	2021	2020	2019
Financing Activities:			
Net increase (decrease) in short-term borrowings	$ 81,000	$ 17,200	$ (4,200)
Proceeds from issuance of long-term debt	140,000	165,000	180,000
Maturity of long-term debt and finance leases	(2,935)	(54,800)	(92,660)
Issuance of common stock, net of issuance costs	89,998	72,200	64,573
Cash dividends paid	(118,211)	(110,254)	(102,772)
Other	(4,304)	(5,307)	(2,402)
Net cash provided by financing activities	185,548	84,039	42,539
Net increase (decrease) in cash and cash equivalents	7,972	4,300	(4,760)
Cash and cash equivalents at beginning of year	14,196	9,896	14,656
Cash and cash equivalents at end of year	$ 22,168	$ 14,196	$ 9,896
Supplemental Cash Flow Information:			
Cash paid (received) during the year:			
Interest	$ 98,592	$ 97,717	$ 99,060
Income taxes paid	3,652	1,901	26,764
Income tax refunds	(22,330)	(918)	(979)
Non-cash financing and investing activities:			
Accounts payable for capital expenditures	23,938	32,039	25,644

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

	2021	2020	2019
Common Stock, Shares:			
Shares outstanding at beginning of year	69,238,901	67,176,996	65,688,356
Shares issued through equity compensation plans	93,806	139,726	75,399
Shares issued through Employee Investment Plan	14,480	17,179	3,653
Shares issued through sales agency agreements	2,150,336	1,905,000	1,409,588
Shares outstanding at end of year	71,497,523	69,238,901	67,176,996
Common Stock, Amount:			
Balance at beginning of year	$ 1,286,068	$ 1,210,741	$ 1,136,491
Equity compensation expense	5,079	5,535	10,568
Issuance of common stock through equity compensation plans	931	965	827
Issuance of common stock through Employee Investment Plan	610	674	175
Issuance of common stock through sales agency agreements, net of issuance costs	88,457	70,561	63,571
Payment of minimum tax withholdings for share-based payment awards	(993)	(2,408)	(891)
Balance at end of year	1,380,152	1,286,068	1,210,741
Accumulated Other Comprehensive Loss:			
Balance at beginning of year	(14,378)	(10,259)	(7,866)
Other comprehensive income (loss)	3,339	(4,119)	(2,393)
Balance at end of year	(11,039)	(14,378)	(10,259)
Retained Earnings:			
Balance at beginning of year	758,036	738,802	644,595
Net income attributable to Avista Corporation shareholders	147,334	129,488	196,979
Dividends on common stock	(119,739)	(110,254)	(102,772)
Balance at end of year	785,631	758,036	738,802
Total Avista Corporation shareholders’ equity	$ 2,154,744	$ 2,029,726	$ 1,939,284
Noncontrolling Interests:			
Balance at beginning of year	$ —	$ —	$ 825
Net loss attributable to noncontrolling interests	—	—	(216)
Deconsolidation of noncontrolling interests related to sale of METALfx	—	—	(609)
Balance at end of year	—	—	—
Total equity	$ 2,154,744	$ 2,029,726	$ 1,939,284
Dividends declared per common share	$ 1.69	$ 1.62	$ 1.55

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, most of whom are employees who operate the Company's Noxon Rapids generating facility.

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 all of the subsidiary companies in the non-utility businesses, with the exception of AJT Mining Properties, Inc., which is a subsidiary of AERC. See Note 24 for business segment information. See Note 26 for discussion of the sale of METALfx, which was an unregulated subsidiary of the Company.

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 resulting from its interests in jointly owned plants (see Note 8).

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,
- 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 also subject to federal regulation primarily by the FERC, as well as various other federal agencies with regulatory oversight of particular aspects of its operations.

Depreciation

For utility operations, depreciation expense is estimated by a method of depreciation accounting utilizing composite rates for utility plant. Such rates are designed to provide for retirements of properties at the expiration of their service lives. For utility operations, the ratio of depreciation provisions to average depreciable property was as follows for the years ended December 31:

	2021	2020	2019
Avista Utilities			
Ratio of depreciation to average depreciable property	3.54 %	3.43 %	3.28 %
Alaska Electric Light and Power Company			
Ratio of depreciation to average depreciable property	2.77 %	2.77 %	2.48 %

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	42
Hydroelectric production	81	42
Electric transmission	50	43
Electric distribution	39	40
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:

	2021	2020	2019
Avista Utilities	7.19 %	7.25 %	7.39 %
Alaska Electric Light and Power Company	8.90 %	8.04 %	8.96 %

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's largest deferred income tax item is the difference between the book and tax basis of utility plant. This item results from the temporary difference on depreciation expense. In early tax years, this item is recorded as a deferred income tax liability that will eventually reverse and become subject to income tax in later tax years.

The Company did not incur any penalties on income tax positions in 2021, 2020 or 2019. The Company would recognize interest accrued related to income tax positions as interest expense and any penalties incurred as other operating expense.

Stock-Based Compensation

The Company currently issues three types of stock-based compensation awards - restricted shares, market-based awards and performance-based awards. Historically, these stock compensation awards have not been material to the Company's overall financial results. Compensation cost relating to share-based payment transactions is recognized in the Company’s financial statements based on the fair value of the equity 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):

	2021	2020	2019
Stock-based compensation expense	$ 4,713	$ 5,846	$ 11,353
Income tax benefits	990	1,228	2,384
Excess tax expenses on settled share-based employee payments	(909)	(165)	(612)

Restricted share awards vest in equal thirds each year over 3 years and are payable in Avista Corp. common stock at the end of each year if the service condition is met. Restricted stock is valued at the close of market of the Company’s common stock on the grant date.

Total Shareholder Return (TSR) awards are market-based awards and Cumulative Earnings Per Share (CEPS) awards are performance awards. Both types of awards vest after a period of 3 years and are payable in cash or Avista Corp. common stock at the end of the three-year period. The method of settlement is at the discretion of the Company and historically the Company has settled these awards through issuance of Avista Corp. common stock and intends to continue this practice. Both types of awards entitle the recipients to dividend equivalent rights, are subject to forfeiture under certain circumstances, and are subject to meeting specific market or performance conditions. Based on the level of attainment of the market or performance conditions, the amount of cash paid or common stock issued will range from 0 to 200 percent of the initial awards granted. Dividend equivalent rights are accumulated and paid out only on shares that eventually vest and have met the market and performance conditions.

The Company accounts for both the TSR awards and CEPS awards as equity awards and compensation cost for these awards is recognized over the requisite service period, provided that the requisite service period is rendered. For TSR awards, if the market condition is not met at the end of the three-year service period, there will be no change in the cumulative amount of compensation cost recognized, since the awards are still considered vested even though the market metric was not met. For CEPS awards, at the end of the three-year service period, if the internal performance metric of cumulative earnings per share is not met, all compensation cost for these awards is reversed as these awards are not considered vested.

The fair value of each TSR award is estimated on the date of grant using a statistical model that incorporates the probability of meeting the market targets based on historical returns relative to a peer group. The estimated fair value of the CEPS awards was estimated on the date of grant as the share price of Avista Corp. common stock on the date of grant.

The following table summarizes the number of grants, vested and unvested shares, earned shares (based on market metrics), and other pertinent information related to the Company's stock compensation awards for the years ended December 31:

	2021	2020	2019
Restricted Shares			
Shares granted during the year	62,594	45,540	50,061
Shares vested during the year	34,854	56,203	48,228
Unvested shares at end of year	96,127	71,706	93,351
Unrecognized compensation expense at end of year (in thousands)	$ 2,215	$ 2,003	$ 2,054
TSR Awards			
TSR shares granted during the year	64,910	47,848	99,214
TSR shares vested during the year	77,174	71,299	106,858
TSR shares earned based on market metrics	58,652	—	—
Unvested TSR shares at end of year	107,854	122,133	178,035
Unrecognized compensation expense at end of year (in thousands)	$ 2,653	$ 2,296	$ 3,377
CEPS Awards			
CEPS shares granted during the year	64,910	47,848	49,609
CEPS shares vested during the year	38,590	35,622	53,454
CEPS shares earned based on market metrics	26,627	63,763	106,908
Unvested CEPS shares at end of year	107,854	83,464	88,990
Unrecognized compensation expense at end of year (in thousands)	$ 1,223	$ 1,090	$ 2,401

Outstanding restricted, TSR and CEPS share awards include a dividend component that is paid in cash. A liability for the dividends payable related to these awards is accrued as dividends are announced throughout the life of the award. As of December 31, 2021 and 2020, the Company had recognized a liability of $1.5 million and $0.8 million, respectively, related to the dividend equivalents payable on the outstanding and unvested share grants.

Other Income - Net

Other income - net consisted of the following items for the years ended December 31 (dollars in thousands):

	2021	2020	2019
Interest income	$ (1,943)	$ (1,952)	$ (2,587)
Interest on regulatory deferrals	(1,206)	(1,222)	(1,460)
Equity-related AFUDC	(7,004)	(6,970)	(6,585)
Non-service portion of pension and other postretirement benefit expenses	1,386	6,433	8,899
Earnings on investments	(21,402)	(905)	(14,299)
Other expense (income)	(3,129)	(201)	1,104
Total	$ (33,298)	$ (4,817)	$ (14,928)

Earnings per Common Share Attributable to Avista Corporation Shareholders

Basic earnings per common share attributable to Avista Corp. shareholders is computed by dividing net income attributable to Avista Corp. shareholders by the weighted-average number of common shares outstanding for the period. Diluted earnings per common share attributable to Avista Corp. shareholders is calculated by dividing net income attributable to Avista Corp. shareholders 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):

	2021	2020	2019
Allowance as of the beginning of the year	$ 11,387	$ 2,419	$ 5,233
Additions expensed during the year (1)	9,279	11,280	460
Net deductions (2)	(10,201)	(2,312)	(3,274)
Allowance as of the end of the year	$ 10,465	$ 11,387	$ 2,419

(1) Increases in 2021 and 2020 related to COVID-19 bad debt expense in excess of the amount recovered through rates.

(2) Increase in 2021 relates to COVID forgiveness program.

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 10 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 has recorded the amount of estimated retirement costs collected from customers (that do not represent legal or contractual obligations) and included them as a non-current regulatory liability on the Consolidated Balance Sheets in the following amounts as of December 31 (dollars in thousands):

	2021	2020
Regulatory liability for utility plant retirement costs	$ 350,190	$ 325,832

Goodwill

Goodwill arising from acquisitions represents the future economic benefit arising from other assets acquired in a business combination that are not individually identified and separately recognized. The Company evaluates goodwill for impairment using a fair value to carrying amount comparison (Step 1). The Company completed its annual evaluation of goodwill for potential impairment as of November 30, 2021 and determined that goodwill was not impaired at that time (carrying value was less than the determined fair value). There were no events or circumstances that changed between November 30, 2021 and December 31, 2021 that would more likely than not reduce the fair values of the reporting units below their carrying amounts.

There were no changes in the carrying amount of goodwill during 2020 and 2021, and the balance was as follows (dollars in thousands):

	AEL&P	Accumulated Impairment Losses	Total
Balance as of December 31, 2020 and 2021	$ 52,426	$ -	$ 52,426

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 rates cases. The resulting regulatory assets associated with energy commodity derivative instruments have been concluded to be probable of recovery through future rates.

Substantially all forward contracts to purchase or sell power and natural gas are recorded as derivative assets or liabilities at estimated fair value with an offsetting regulatory asset or liability. Contracts that are not considered derivatives are accounted for on the accrual basis until they are settled or realized unless there is a decline in the fair value of the contract that is determined to be other-than-temporary.

For interest rate swap derivatives, Avista Corp. records all mark-to-market gains and losses in each accounting period as assets and liabilities, as well as offsetting regulatory assets and liabilities, such that there is no income statement impact. The interest rate swap derivatives are risk management tools similar to energy commodity derivatives. Upon settlement of interest rate swap derivatives, the regulatory asset or liability is amortized as a component of interest expense over the term of the associated debt. The Company records an offset of interest rate swap derivative assets and liabilities with regulatory assets and liabilities, based on the prior practice of the commissions to provide recovery through the ratemaking process.

The Company has multiple master netting agreements with a variety of entities that allow for cross-commodity netting of derivative agreements with the same counterparty (i.e. power derivatives can be netted with natural gas derivatives). In addition, some master netting agreements allow for the netting of commodity derivatives and interest rate swap derivatives for the same counterparty. The Company does not have any agreements which allow for cross-affiliate netting among multiple affiliated legal entities. The Company nets all derivative instruments when allowed by the agreement for presentation in the 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, as well as derivatives related to interest rate swap derivatives and foreign currency exchange derivatives, 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 that certain costs and/or obligations (such as incurred power and natural gas costs not currently reflected in rates, but expected to be recovered or refunded in the future), are reflected as deferred charges or credits on the 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 that it no longer meets the criteria for continued application of regulatory accounting practices for all or a portion of its regulated operations, the Company could be:

- required to write off its regulatory assets, and
- precluded from the future deferral of costs or decoupled revenues not recovered through rates at the time such amounts are incurred, even if the Company expected to recover these amounts from customers in the future.

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

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

	2021	2020
Appropriated retained earnings	$ 53,620	$ 47,473

Contingencies

The Company has unresolved regulatory, legal and tax issues which have inherently uncertain outcomes. The Company accrues a loss contingency if it is probable that a liability has been incurred and the amount of the loss or impairment can be reasonably estimated. The Company also discloses loss contingencies that do not meet these conditions for accrual, if there is a reasonable possibility that a material loss may be incurred. As of December 31, 2021, the Company has not recorded any significant amounts related to unresolved contingencies. See Note 22 for further discussion of the Company's commitments and contingencies.

COVID-19

In 2020, the WUTC, IPUC, and OPUC approved accounting orders that allow the Company to defer certain net COVID-19 related costs and benefits. As such, as of December 31, 2021, the Company has deferred net costs of $1.1 million for all jurisdictions.

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

NOTE 2. NEW ACCOUNTING STANDARDS

ASU 2018-13 "Fair Value Measurement (Topic 820)"

In August 2018, the FASB issued ASU No. 2018-13, which amends the fair value measurement disclosure requirements of ASC 820. The requirements of this ASU include additional disclosure regarding the range and weighted average used to develop significant unobservable inputs for Level 3 fair value estimates and the elimination of certain other previously required disclosures, such as the narrative description of the valuation process for Level 3 fair value measurements. This ASU became effective on January 1, 2020 and the requirements of this ASU did not have a material impact on the Company's fair value disclosures. See Note 18 for the Company's fair value disclosures.

ASU No. 2018-14 "Compensation - Retirement Benefits - Defined Benefit Plans - General (Subtopic 715-20)"

In August 2018, the FASB issued ASU No. 2018-14, which amends ASC 715 to add, remove and/or clarify certain disclosure requirements related to defined benefit pension and other postretirement plans. The additional disclosure requirements are primarily narrative discussion of significant changes in the benefit obligations and plan assets. The removed disclosures are primarily information about accumulated other comprehensive income expected to be recognized over the next year and the effects of changes associated with assumed health care costs. This ASU became effective for periods ending after December 15, 2020 and the requirements of this ASU did not have a material impact on the Company’s disclosures upon adoption.

NOTE 3. BALANCE SHEET COMPONENTS

Materials and Supplies, Fuel Stock and Stored Natural Gas

Inventories of materials and supplies, fuel stock and stored natural gas are recorded at average cost for regulated operations and the lower of cost or market for non-regulated operations and consisted of the following as of December 31 (dollars in thousands):

	2021	2020
Materials and supplies	$ 62,003	$ 53,258
Fuel stock	5,126	4,658
Stored natural gas	17,604	9,535
Total	$ 84,733	$ 67,451

Other Current Assets

Other current assets consisted of the following as of December 31 (dollars in thousands):

	2021	2020
Collateral posted for derivative instruments after netting with outstanding derivative liabilities	$ 21,477	$ 4,336
Prepayments	24,387	24,411
Income taxes receivable	29,615	49,814
Other	5,275	6,324
Total	$ 80,754	$ 84,885

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):

	2021	2020
Operating lease ROU assets	$ 70,133	$ 71,891
Finance lease ROU assets	43,697	47,338
Non-utility property	20,033	19,508
Equity investments	91,057	59,318
Investment in affiliated trust	11,547	11,547
Notes receivable	14,949	14,454
Deferred compensation assets	9,513	9,174
Assets held for sale (1)	—	3,462
Other	19,614	26,947
Total	$ 280,543	$ 263,639

(1) The Company sold certain subsidiary assets associated with Steam Plant Square and Brew Pub during 2021.

Other Current Liabilities

Other current liabilities consisted of the following as of December 31 (dollars in thousands):

	2021	2020
Accrued taxes other than income taxes	$ 41,706	$ 45,099
Derivative liabilities	28,801	14,008
Employee paid time off accruals	27,741	26,495
Accrued interest	17,538	17,083
Pensions and other postretirement benefits	13,582	11,987
Other	39,493	35,159
Total	$ 168,861	$ 149,831

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):

	2021	2020
Operating lease liabilities	$ 66,068	$ 67,716
Finance lease liabilities	45,730	48,815
Deferred investment tax credits	29,313	29,866
Asset retirement obligations	17,142	17,194
Derivative liabilities	4,525	37,427
Other	15,347	13,981
Total	$ 178,125	$ 214,999

NOTE 4. REVENUE

ASC 606 defines the core principle of the revenue recognition model is that an entity should identify the various performance obligations in a contract, allocate the transaction price among the performance obligations and recognize revenue when (or as) the entity satisfies each performance obligation.

Utility Revenues

Revenue from Contracts with Customers

General

The majority of Avista Corp.'s revenue is from rate-regulated sales of electricity and natural gas to retail customers, which has two performance obligations, (1) having service available for a specified period (typically a month at a time) and (2) the delivery of energy to customers. The total energy price generally has a fixed component (basic charge) related to having service available and a usage-based component, related to the delivery and consumption of energy. The commodity is sold and/or delivered to and consumed by the customer simultaneously, and the provisions of the relevant utility commission authorization determine the charges the Company may bill the customer. Given that all revenue recognition criteria are met upon the delivery of energy to customers, revenue is recognized immediately.

In addition, the sale of electricity and natural gas is governed by the various state utility commissions, which set rates, charges, terms and conditions of service, and prices. Collectively, these rates, charges, terms and conditions are included in a “tariff,” which governs all aspects of the provision of regulated services. Tariffs are only permitted to be changed through a rate-setting process involving an independent, third-party regulator empowered by statute to establish rates that bind customers. Thus, all regulated sales by the Company are conducted subject to the regulator-approved tariff.

Tariff sales involve the current provision of commodity service (electricity and/or natural gas) to customers for a price that generally has a basic charge and a usage-based component. Tariff rates also include certain pass-through costs to customers such as natural gas costs, retail revenue credits and other miscellaneous regulatory items that do not impact net income, but can cause total revenue to fluctuate significantly up or down compared to previous periods. The commodity is sold and/or delivered to and consumed by the customer simultaneously, and the provisions of the relevant tariff determine the charges the Company may bill the customer, payment due date, and other pertinent rights and obligations of both parties. Generally, tariff sales do not involve a written contract. Given that all revenue recognition criteria are met upon the delivery of energy to customers, revenue is recognized immediately at that time.

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,
- current rates,
- meter reading dates,
- actual native load for electricity,
- actual throughput for natural gas, and
- electric line losses and natural gas system losses.

Any difference between actual and estimated revenue is automatically corrected in the following month when the actual meter reading and customer billing occurs.

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

	2021	2020
Unbilled accounts receivable	$ 74,479	$ 71,258

Non-Derivative Wholesale Contracts

The Company has certain wholesale contracts which are not accounted for as derivatives and, accordingly, are within the scope of ASC 606 and considered revenue from contracts with customers. Revenue is recognized as energy is delivered to the customer or the service is available for specified period of time, consistent with the discussion of rate regulated sales above.

Alternative Revenue Programs (Decoupling)

ASC 606 retained existing GAAP associated with alternative revenue programs, which specified that alternative revenue programs are contracts between an entity and a regulator of utilities, not a contract between an entity and a customer. GAAP requires that an entity present revenue arising from alternative revenue programs separately from revenues arising from contracts with customers on the face of the 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 any alternative revenue program, like decoupling, the revenue must be expected to be collected from customers within 24 months of the deferral to qualify for recognition in the current period Consolidated Statements of Income. Any amounts included in the Company's decoupling program that are not expected to be collected from customers within 24 months are not recorded in the financial statements until the period in which revenue recognition criteria are met. The amounts expected to be collected from customers within 24 months represents an estimate which must be made by the Company on an ongoing basis due to it being based on the volumes of electric and natural gas sold to customers on a go-forward basis.

The Company records alternative program revenues under the gross method, which is to amortize the decoupling regulatory asset/liability to the alternative revenue program line item on the 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 specifically scoped out of ASC 606. As such, these revenues are disclosed separately from revenue from contracts with customers. Revenue is recognized for these items upon the settlement/expiration of the derivative contract. Derivative revenue includes those transactions that are entered into and settled within the same month.

Other Utility Revenue

Other utility revenue includes rent, sales of materials, late fees and other charges that do not represent contracts with customers. This revenue is scoped out of ASC 606, as this revenue does not represent items where a customer is a party that has contracted with the Company to obtain goods or services that are an output of the Company’s ordinary activities in exchange for consideration. As such, these revenues are presented separately from revenue from contracts with customers.

Other Considerations for Utility Revenues

Gross Versus Net Presentation

Revenues and resource costs from Avista Utilities’ settled energy contracts that are “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 taxes that are imposed on Avista Utilities as opposed to being imposed on its customers; therefore, Avista Utilities is the taxpayer and records these transactions on a gross basis in revenue from contracts with customers and operating expense (taxes other than income taxes). The utility-related taxes collected from customers at AEL&P are imposed on the customers rather than AEL&P; therefore, the customers are the taxpayers and AEL&P is acting as their agent. As such, these transactions at AEL&P are presented on a net basis within revenue from contracts with customers.

Utility-related taxes that were included in revenue from contracts with customers were as follows for the years ended December 31 (dollars in thousands):

	2021	2020	2019
Utility-related taxes	$ 62,736	$ 59,319	$ 59,528

Non-Utility Revenues

Revenue from Contracts with Customers

Non-utility revenue from contracts with customers is derived from contracts with one performance obligation. Prior to its sale in April 2019 (See Note 26 for further discussion on the sale of METALfx), METALfx had one performance obligation, the delivery of a product, and revenues were recognized when the risk of loss transferred to the customer, which occurred when products were shipped.

Other Revenue

Other non-utility revenue primarily relates to rent revenue, which is scoped out of ASC 606; therefore, this revenue is presented separately from revenue from contracts with customers.

Significant Judgments and Unsatisfied Performance Obligations

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

The Company has certain capacity arrangements, where the Company has a contractual obligation to provide either electric or natural gas capacity to its customers for a fixed fee. Most of these arrangements are paid for in arrears by the customers and do not result in deferred revenue and only result in receivables from the customers. The Company does have one capacity agreement where the customer makes payments throughout the year. As of December 31, 2021, the Company estimates it had unsatisfied capacity performance obligations of $17.4 million, which will be recognized as revenue in future periods as the capacity is provided to the customers. These performance obligations are not reflected in the financial statements, as the Company has not received payment for these services.

Disaggregation of Total Operating Revenue

The following table disaggregates total operating revenue by segment and source for the years ended December 31 (dollars in thousands):

	2021	2020	2019
Avista Utilities			
Revenue from contracts with customers	$ 1,233,904	$ 1,157,746	$ 1,152,125
Derivative revenues	152,590	110,313	118,741
Alternative revenue programs	(6,635)	(3,814)	9,614
Deferrals and amortizations for rate refunds to customers	2,984	5,335	4,509
Other utility revenues	10,156	7,888	10,884
Total Avista Utilities	1,392,999	1,277,468	1,295,873
AEL&P			
Revenue from contracts with customers	45,051	42,624	36,779
Deferrals and amortizations for rate refunds to customers	(190)	(190)	(190)
Other utility revenues	505	375	676
Total AEL&P	45,366	42,809	37,265
Other			
Revenue from contracts with customers	2	564	11,286
Other revenues	569	1,050	1,198
Total Other	571	1,614	12,484
Total operating revenues	$ 1,438,936	$ 1,321,891	$ 1,345,622

Utility Revenue from Contracts with Customers by Type and Service

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

	2021			2020			2019		
	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	$ 394,717	$ 18,940	$ 413,657	$ 377,785	$ 18,618	$ 396,403	$ 369,102	$ 17,134	$ 386,236
Commercial and governmental	326,173	25,861	352,034	303,972	23,754	327,726	317,589	19,391	336,980
Industrial	106,756	—	106,756	103,103	—	103,103	105,802	—	105,802
Public street and highway lighting	7,472	250	7,722	7,303	252	7,555	7,448	254	7,702
Total retail revenue	835,118	45,051	880,169	792,163	42,624	834,787	799,941	36,779	836,720
Transmission	21,005	—	21,005	18,236	—	18,236	18,180	—	18,180
Other revenue from contracts with customers	33,870	—	33,870	19,252	—	19,252	26,969	—	26,969
Total revenue from contracts with customers	$ 889,993	$ 45,051	$ 935,044	$ 829,651	$ 42,624	$ 872,275	$ 845,090	$ 36,779	$ 881,869

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

	2021	2020	2019
	Avista Utilities	Avista Utilities	Avista Utilities
NATURAL GAS OPERATIONS			
Revenue from contracts with customers			
Residential	$ 221,405	$ 213,612	$ 196,430
Commercial	100,819	94,937	92,168
Industrial and interruptible	7,796	7,128	5,263
Total retail revenue	330,020	315,677	293,861
Transportation	8,547	7,917	8,674
Other revenue from contracts with customers	5,344	4,501	4,500
Total revenue from contracts with customers	$ 343,911	$ 328,095	$ 307,035

NOTE 5. LEASES

ASC 842, outlines a model for entities to use in accounting for leases. The core principle of the model is that an entity should recognize the ROU assets and liabilities that arise from leases on the balance sheet and depreciate or amortize the asset and liability over the term of the lease, as well as provide disclosure to enable users of the consolidated financial statements to assess the amount, timing, and uncertainty of cash flows arising 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 arising from the lease. 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 include any lease payments made and exclude lease incentives, if any, that accrue to the benefit of the lessee.

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

Description of Leases

Operating Leases

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

In addition to the lease with the State of Montana, the Company also has other operating leases for land associated with its utility operations, as well as communication sites which support network and radio communications within its service territory. The Company's leases have remaining terms of 1 to 72 years. Most of the Company's leases include options to extend the lease term for periods of 5 to 50 years. Options are exercised at the Company's discretion.

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

Avista Corp. does not record leases with a term of 12 months or less in the Consolidated Balance Sheets. Total short-term lease costs for the year ended December 31, 2021 are immaterial.

Finance Lease

AEL&P has a PPA which is treated as a finance lease for accounting purposes related to the Snettisham hydroelectric project, which expires in 2034. For ratemaking purposes, this lease is treated as an operating lease with a constant level of annual rental expense (straight line rent expense). Because of this regulatory treatment, any difference between the operating lease expense for ratemaking purposes and the expenses recognized under GAAP (interest expense and amortization of the finance lease ROU asset) is 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):

	2021	2020
Operating lease cost:		
Fixed lease cost (Other operating expenses)	$ 4,970	$ 4,746
Variable lease cost (Other operating expenses)	1,180	1,099
Total operating lease cost	$ 6,150	$ 5,845
Finance lease cost:		
Amortization of ROU asset (Depreciation and amortization)	$ 3,641	$ 3,641
Interest on lease liabilities (Interest expense)	2,522	2,662
Total finance lease cost	$ 6,163	$ 6,303

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

	2021	2020
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash outflows:		
Operating lease payments	$ 4,805	$ 4,612
Interest on finance lease	2,522	2,662
Total operating cash outflows	$ 7,327	$ 7,274
Finance cash outflows:		
Principal payments on finance lease	$ 2,935	$ 2,800

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

	December 31, 2021	December 31, 2020
Operating Leases		
Operating lease ROU assets (Other property and investments-net and other non-current assets)	$ 70,133	$ 71,891
Other current liabilities	$ 4,301	$ 4,249
Other non-current liabilities and deferred credits	66,068	67,716
Total operating lease liabilities	$ 70,369	$ 71,965
Finance Leases		
Finance lease ROU assets (Other property and investments-net and other non-current assets)	$ 43,697	$ 47,338
Other current liabilities	$ 3,085	$ 2,935
Other non-current liabilities and deferred credits	45,730	48,815
Total finance lease liabilities	$ 48,815	$ 51,750
Weighted Average Remaining Lease Term		
Operating leases	24.22 years	25.20 years
Finance leases	6.32 years	7.22 years
Weighted Average Discount Rate		
Operating leases	4.28 %	4.28 %
Finance leases	4.35 %	4.62 %

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

	Operating Leases	Finance Leases
2022	$ 4,820	$ 5,460
2023	4,849	5,456
2024	4,875	5,459
2025	4,882	5,454
2026	4,867	5,456
Thereafter	91,845	38,204
Total lease payments	$ 116,138	$ 65,489
Less: imputed interest	(45,769)	(16,674)
Total	$ 70,369	$ 48,815

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

	Operating Leases	Finance Leases
2021	$ 4,779	$ 5,457
2022	4,799	5,460
2023	4,827	5,456
2024	4,852	5,459
2025	4,865	5,454
Thereafter	96,734	43,661
Total lease payments	$ 120,856	$ 70,947
Less: imputed interest	(48,891)	(19,197)
Total	$ 71,965	$ 51,750

NOTE 6. VARIABLE INTEREST ENTITIES

Lancaster Power Purchase Agreement

The Company has a PPA for the purchase of all the output of the Lancaster Plant, a 270 MW natural gas-fired combined cycle combustion turbine plant located in Kootenai County, Idaho, owned by an unrelated third-party (Rathdrum Power LLC), through 2026.

Avista Corp. has a variable interest in the PPA. Accordingly, Avista Corp. made an evaluation of which interest holders have the power to direct the activities that most significantly impact the economic performance of the entity and which interest holders have the obligation to absorb losses or receive benefits that could be significant to the entity. Avista Corp. pays a fixed capacity and operations and maintenance payment and certain monthly variable costs under the PPA. Under the terms of the PPA, Avista Corp. makes the dispatch decisions, provides all natural gas fuel and receives all of the electric energy output from the Lancaster Plant. However, Rathdrum Power LLC (the owner) controls the daily operation of the Lancaster Plant and makes operating and maintenance decisions. Rathdrum Power LLC controls all of the rights and obligations of the Lancaster Plant after the expiration of the PPA in 2026 and Avista Corp. does not have any further obligations after the expiration. It is estimated that the plant will have 15 to 25 years of useful life after that time. Rathdrum Power LLC bears the maintenance risk of the plant and will receive the residual value of the Lancaster Plant. Avista Corp. has no debt or equity investments in the Lancaster Plant and does not provide financial support through liquidity arrangements or other commitments (other than the PPA). Based on its analysis, Avista Corp. does not consider itself to be the primary beneficiary of the Lancaster Plant. Accordingly, neither the Lancaster Plant nor Rathdrum Power LLC is included in Avista Corp.'s consolidated financial statements. The Company has a future contractual obligation of $143.4 million under the PPA (representing the fixed capacity and operations and maintenance payments through 2026) and believes this would be its maximum exposure to loss. However, the Company believes that such costs will be recovered through retail rates.

Limited Partnerships and Similar Entities

Under current 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 any 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. As of December 31, 2021, Avista Corp. has invested $75.4 million in these investment funds, with an additional commitment of $27.0 million remaining to be invested. In addition, the Company is not allowed to withdraw any capital contributions from the investment funds until after the funds' expiration dates and all liabilities of the funds are settled. The expiration dates range from 2022 to 2040, with three investments having no termination date (as they are perpetual). One of the funds is closed and expired and the Company is awaiting final distribution as soon as the underlying investments are liquidated. As of December 31, 2021, the Company has a total carrying amount of $79.2 million in these investment funds.

NOTE 7. DERIVATIVES AND RISK MANAGEMENT

Energy Commodity Derivatives

Avista Corp. is exposed to market risks relating to changes in electricity and natural gas commodity prices and certain other fuel prices. Market risk is, in general, the risk of fluctuation in the market price of the commodity being traded and is influenced primarily by supply and demand. Market risk includes the fluctuation in the market price of associated derivative commodity instruments. Avista Corp. utilizes derivative instruments, such as forwards, futures, swap derivatives and options in order to manage the various risks relating to these commodity price exposures. Avista Corp. has an energy resources risk policy and control procedures to manage these risks.

As part of Avista Corp.'s resource procurement and management operations in the electric business, the Company engages in an ongoing process of resource optimization, which involves the economic selection from available energy resources to serve Avista Corp.'s load obligations and the use of these resources to capture available economic value through wholesale market transactions. These include sales and purchases of electric capacity and energy, fuel for electric generation, and derivative contracts related to capacity, energy and fuel. Such transactions are part of the process of matching resources with load obligations and hedging a portion of the related financial risks. These transactions range from terms of intra-hour up to multiple years.

As part of its resource procurement and management of its natural gas business, Avista Corp. makes continuing projections of its natural gas loads and assesses available natural gas resources including natural gas storage availability. Natural gas resource planning typically includes peak requirements, low and average monthly requirements and delivery constraints from natural gas supply locations to Avista Corp.'s distribution system. However, daily variations in natural gas demand can be significantly different than monthly demand projections. On the basis of these projections, Avista Corp. plans and executes a series of transactions to hedge a portion of its projected natural gas requirements through forward market transactions and derivative instruments. These transactions may extend as much as three natural gas operating years (November through October) into the future. Avista Corp. also leaves a significant portion of its natural gas supply requirements unhedged for purchase in short-term and spot markets.

Avista Corp. plans for sufficient natural gas delivery capacity to serve its retail customers for a theoretical peak day event. Avista Corp. generally has more pipeline and storage capacity than what is needed during periods other than a peak day. Avista Corp. optimizes its natural gas resources by using market opportunities to generate economic value that mitigates the fixed costs. Avista Corp. also optimizes its natural gas storage capacity by purchasing and storing natural gas when prices are traditionally lower, typically in the summer, and withdrawing during higher priced months, typically during the winter. However, if market conditions and prices indicate that Avista Corp. should buy or sell natural gas at other times during the year, Avista Corp. engages in optimization transactions to capture value in the marketplace. Natural gas optimization activities include, but are not limited to, wholesale market sales of surplus natural gas supplies, purchases and sales of natural gas to optimize use of pipeline and storage capacity, and participation in the transportation capacity release market.

The following table presents the underlying energy commodity derivative volumes as of December 31, 2021 that are expected to be delivered in each respective year (in thousands of MWhs and mmBTUs):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical (1) MWh	Financial (1) MWh	Physical (1) mmBTUs	Financial (1) mmBTUs	Physical (1) MWh	Financial (1) MWh	Physical (1) mmBTUs	Financial (1) mmBTUs
2022	129	—	7,114	61,405	234	452	3,933	31,485
2023	—	—	378	23,218	—	—	1,360	9,323
2024	—	—	228	3,413	—	—	1,370	228
2025	—	—	—	—	—	—	1,115	—

As of December 31, 2021, there are no expected deliveries of energy commodity derivatives after 2025.

The following table presents the underlying energy commodity derivative volumes as of December 31, 2020 that were expected to be delivered in each respective year (in thousands of MWhs and mmBTUs):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical (1) MWh	Financial (1) MWh	Physical (1) mmBTUs	Financial (1) mmBTUs	Physical (1) MWh	Financial (1) MWh	Physical (1) mmBTUs	Financial (1) mmBTUs
2021	1	224	10,353	65,188	17	451	5,448	39,273
2022	—	—	450	25,525	—	—	1,360	12,030
2023	—	—	—	4,950	—	—	1,360	900
2024	—	—	—	—	—	—	1,370	—
2025	—	—	—	—	—	—	1,115	—

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

(1) Physical transactions represent commodity transactions in which Avista Corp. will take or make delivery of either electricity or natural gas; financial transactions represent derivative instruments with delivery of cash in the amount of the benefit or cost but with no physical delivery of the commodity, such as futures, swap derivatives, options, or forward contracts.

The electric and natural gas derivative contracts above will be included in either power supply costs or natural gas supply costs during the period they are scheduled to be delivered and will be included in the various deferral and recovery mechanisms (ERM, PCA, and PGAs), or in the general rate case process, and are expected to be collected through retail rates from customers.

Foreign Currency Exchange Derivatives

A significant portion of Avista Corp.'s natural gas supply (including fuel for power generation) is obtained from Canadian sources. Most of those transactions are executed in U.S. dollars, which avoids foreign currency risk. A portion of Avista Corp.’s short-term natural gas transactions and long-term Canadian transportation contracts are committed based on Canadian currency prices. The short term natural gas transactions are settled within 60 days with U.S. dollars. Avista Corp. hedges a portion of the foreign currency risk by purchasing Canadian currency exchange derivatives when such commodity transactions are initiated. The foreign currency exchange derivatives and the unhedged foreign currency risk have not had a material effect on Avista Corp.’s financial condition, results of operations or cash flows and these differences in cost related to currency fluctuations are included with natural gas supply costs for ratemaking.

The following table summarizes the foreign currency exchange derivatives that Avista Corp. has outstanding as of December 31 (dollars in thousands):

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

Interest Rate Swap Derivatives

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

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

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

See Note 16 for discussion of the bond purchase agreement and the related settlement of interest rate swaps in connection with the pricing of the bonds in September 2021.

The fair value of outstanding interest rate swap derivatives can vary significantly from period to period depending on the total notional amount of swap derivatives outstanding and fluctuations in market interest rates compared to the interest rates fixed by the swaps. Avista Corp. is required to make cash payments to settle the interest rate swap derivatives when the fixed rates are higher than prevailing market rates at the date of settlement. Conversely, Avista Corp. receives cash to settle its interest rate swap derivatives when prevailing market rates at the time of settlement exceed the fixed swap rates.

Summary of Outstanding Derivative Instruments

The amounts recorded on the Consolidated Balance Sheets as of December 31, 2021 and December 31, 2020 reflect the offsetting of derivative assets and liabilities where a legal right of offset exists.

The following table presents the fair values and locations of derivative instruments recorded on the Consolidated Balance Sheets as of December 31, 2021 (in thousands):

	Fair Value			
Derivative and Balance Sheet Location	Gross Asset	Gross Liability	Collateral Netting	Net Asset (Liability) on Balance Sheet
Foreign currency exchange derivatives				
Other current liabilities	$ —	$ (19)	$ —	$ (19)
Interest rate swap derivatives				
Other property and investments-net and other non-current assets	1,149	—	—	1,149
Other current liabilities	1,170	(25,196)	—	(24,026)
Other non-current liabilities and deferred credits	—	(78)	—	(78)
Energy commodity derivatives				
Other current assets	1,506	(107)	—	1,399
Other property and investments-net and other non-current assets	6,844	(5,335)	—	1,509
Other current liabilities	25,771	(39,616)	9,089	(4,756)
Other non-current liabilities and deferred credits	141	(4,589)	—	(4,448)
Total derivative instruments recorded on the balance sheet	$ 36,581	$ (74,940)	$ 9,089	$ (29,270)

The following table presents the fair values and locations of derivative instruments recorded on the Consolidated Balance Sheets as of December 31, 2020 (in thousands):

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

Exposure to Demands for Collateral

Avista Corp.'s derivative contracts often require collateral (in the form of cash or letters of credit) or other credit enhancements, or reductions or terminations of a portion of the contract through cash settlement. In the event of a downgrade in Avista Corp.'s credit ratings or changes in market prices, additional collateral may be required. In periods of price volatility, the level of exposure can change significantly. As a result, sudden and significant demands may be made against Avista Corp.'s credit facilities and cash. Avista Corp. actively monitors the exposure to possible collateral calls and takes steps to mitigate capital requirements.

The following table presents Avista Corp.'s collateral outstanding related to its derivative instruments as of December 31 (in thousands):

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

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

Certain of Avista Corp.'s derivative instruments contain provisions that require Avista Corp. to maintain an "investment grade" credit rating from the major credit rating agencies. If Avista Corp.'s credit ratings were to fall below "investment grade," it would be in violation of these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing collateralization on derivative instruments in net liability positions.

The following table presents the aggregate fair value of all derivative instruments with credit-risk-related contingent features that are in a liability position and the amount of additional collateral Avista Corp. could be required to post as of December 31 (in thousands):

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

NOTE 8. JOINTLY OWNED ELECTRIC FACILITIES

The Company has a 15 percent ownership interest in Units 3 & 4 of the Colstrip generating station, a coal-fired plant located in southeastern Montana, and provides financing for its ownership interest in the project. Pursuant to the ownership and operating agreements among the co-owners, the Company's share of related fuel costs as well as operating expenses for plant in service are included in the corresponding accounts in the 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):

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

See Note 10 for further discussion of AROs.

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

NOTE 9. PROPERTY, PLANT AND EQUIPMENT

Net Utility Property

Net utility property consisted of the following as of December 31 (dollars in thousands):

	2021	2020
Utility plant in service	$ 7,166,580	$ 6,809,797
Construction work in progress	205,405	175,767
Total	7,371,985	6,985,564
Less: Accumulated depreciation and amortization	2,146,470	1,993,952
Total net utility property	$ 5,225,515	$ 4,991,612

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):

	2021	2020
Avista Utilities:		
Electric production	$ 1,494,371	$ 1,457,497
Electric transmission	945,624	862,987
Electric distribution	2,093,937	1,978,868
Electric construction work-in-progress (CWIP) and other	424,733	384,372
Electric total	4,958,665	4,683,724
Natural gas underground storage	55,684	53,351
Natural gas distribution	1,356,477	1,282,563
Natural gas CWIP and other	87,852	83,644
Natural gas total	1,500,013	1,419,558
Common plant (including CWIP)	740,339	712,609
Total Avista Utilities	7,199,017	6,815,891
AEL&P:		
Electric production	106,094	105,076
Electric transmission	22,691	22,419
Electric distribution	27,138	25,814
Electric CWIP and other	7,319	6,677
Electric total	163,242	159,986
Common plant	9,726	9,687
Total AEL&P	172,968	169,673
Total gross utility property	7,371,985	6,985,564
Other (1)	17,818	16,394
Total	$ 7,389,803	$ 7,001,958

(1) Included in other property and investments-net and other non-current assets on the Consolidated Balance Sheets. Accumulated depreciation was $2.3 million as of December 31, 2021 and $2.2 million as of December 31, 2020 for the other businesses.

NOTE 10. ASSET RETIREMENT OBLIGATIONS

The Company has recorded liabilities for future AROs to:

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

Due to an inability to estimate a range of settlement dates, the Company cannot estimate a liability for the:

- removal and disposal of certain transmission and distribution assets, and

- abandonment and decommissioning of certain hydroelectric generation and natural gas storage facilities.

In 2015, the EPA issued a final rule regarding CCRs. Colstrip produces this byproduct. The CCR rule has been the subject of ongoing litigation. In August 2018, the D.C. Circuit struck down provisions of the rule. The rule includes technical requirements for CCR landfills and surface impoundments. The Colstrip owners developed a multi-year compliance plan to address the CCR requirements and existing state obligations.

The actual asset retirement costs related to the CCR rule requirements may vary substantially from the estimates used to record the ARO due to the uncertainty and evolving nature of the compliance strategies that will be used and the availability of data used to estimate costs, such as the quantity of coal ash present at certain sites and the volume of fill that will be needed to cap and cover certain impoundments. The Company updates its estimates as new information becomes available. The Company expects to seek recovery of any increased costs related to complying with the CCR rule through the ratemaking process.

In addition to the above, under a 2018 Administrative Order on Consent and ongoing negotiations with the Montana Department of Ecological Quality, the owners of Colstrip are required to provide financial assurance, primarily in the form of surety bonds, to secure each owner's pro-rata share of various anticipated closure and remediation of the ash ponds and coal holding areas. The amount of financial assurance required of each owner may, like the ARO, vary substantially due to the uncertainty and evolving nature of anticipated closure and remediation activities, and as those activities are completed over time.

The following table documents the changes in the Company's asset retirement obligation during the years ended December 31 (dollars in thousands):

	2021	2020	2019
Asset retirement obligation at beginning of year	$ 17,194	$ 20,338	$ 18,266
Liabilities incurred	825	(2,315)	2,699
Liabilities settled	(1,541)	(1,645)	(1,503)
Accretion expense	664	816	876
Asset retirement obligation at end of year	$ 17,142	$ 17,194	$ 20,338

NOTE 11. PENSION PLANS AND OTHER POSTRETIREMENT BENEFIT PLANS

The pension and other postretirement benefit plans described below only relate to Avista Utilities. AEL&P (not discussed below) participates in a defined contribution multiemployer plan for its union workers and a defined contribution money purchase pension plan for its nonunion workers. None of the subsidiary retirement plans, individually or in the aggregate, are significant to Avista Corp.

Avista Utilities

The Company has a defined benefit pension plan covering the majority of all regular full-time employees at Avista Utilities that were hired prior to January 1, 2014. Employees eligible for the plan continue to accrue benefits. Individual benefits under this plan are based upon the employee's years of service, date of hire and average compensation as specified in the plan. Non-union employees hired on or after January 1, 2014 participate in a defined contribution 401(k) plan in lieu of a defined benefit pension plan. Union employees hired on or after January 1, 2014 are still covered under the defined benefit pension plan. The Company's funding policy is to contribute at least the minimum amounts that are required to be funded under the Employee Retirement Income Security Act, but not more than the maximum amounts that are currently deductible for income tax purposes. The Company contributed $42.0 million in cash to the pension plan in 2021, and $22.0 million in 2020 and 2019. The Company expects to contribute $42.0 million in cash to the pension plan in 2022.

The Company also has a SERP that provides additional pension benefits to certain executive officers and certain key employees of the Company. The SERP is intended to provide benefits to individuals whose benefits under the defined benefit pension plan are reduced due to the application of Section 415 of the Internal Revenue Code of 1986 and the deferral of salary under deferred compensation plans. The liability and expense for this plan are included as pension benefits in the tables included in this Note.

The Company expects that benefit payments under the pension plan and the SERP will total (dollars in thousands):

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

The expected long-term rate of return on plan assets is based on past performance and economic forecasts for the types of investments held by the plan. In selecting a discount rate, the Company considers yield rates for highly rated corporate bond portfolios with maturities similar to that of the expected term of pension benefits.

The Company provides certain health care and life insurance benefits for eligible retired employees that were hired prior to January 1, 2014. The Company accrues the estimated cost of postretirement benefit obligations during the years that employees provide services. The liability and expense of this plan are included as other postretirement benefits. Non-union employees hired on or after January 1, 2014, will have access to the retiree medical plan upon retirement; however, Avista Corp. will no longer provide a contribution toward their medical premium.

The Company has a Health Reimbursement Arrangement (HRA) to provide employees with tax-advantaged funds to pay for allowable medical expenses upon retirement. The amount earned by the employee is fixed on the retirement date based on the employee's years of service and the ending salary. The liability and expense of the HRA are included as other postretirement benefits.

The Company provides death benefits to beneficiaries of executive officers who die during their term of office or after retirement. Under the plan, an executive officer's designated beneficiary will receive a payment equal to twice the executive officer's annual base salary at the time of death (or if death occurs after retirement, a payment equal to twice the executive officer's total annual pension benefit). The liability and expense for this plan are included as other postretirement benefits.

The Company expects that benefit payments under other postretirement benefit plans will total (dollars in thousands):

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

The Company expects to contribute $7.2 million to other postretirement benefit plans in 2022, representing expected benefit payments to be paid during the year excluding the Medicare Part D subsidy. The Company uses a December 31 measurement date for its pension and other postretirement benefit plans.

The following table sets forth the pension and other postretirement benefit plan disclosures as of December 31, 2021 and 2020 and the components of net periodic benefit costs for the years ended December 31, 2021, 2020 and 2019 (dollars in thousands):

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

	Pension Benefits		Other Post-retirement Benefits	
	2021	2020	2021	2020
Weighted-average assumptions as of December 31:				
Discount rate for benefit obligation	3.39 %	3.25 %	3.40 %	3.27 %
Discount rate for annual expense	3.25 %	3.85 %	3.27 %	3.89 %
Expected long-term return on plan assets	5.40 %	5.50 %	4.60 %	5.30 %
Rate of compensation increase	4.66 %	4.74 %		
Medical cost trend pre-age 65 – initial			6.00 %	6.25 %
Medical cost trend pre-age 65 – ultimate			5.00 %	5.00 %
Ultimate medical cost trend year pre-age 65			2026	2026
Medical cost trend post-age 65 – initial			6.00 %	6.25 %
Medical cost trend post-age 65 – ultimate			5.00 %	5.00 %
Ultimate medical cost trend year post-age 65			2026	2026

	Pension Benefits			Other Post-retirement Benefits		
	2021	2020	2019	2021	2020	2019
Components of net periodic benefit cost:						
Service cost (a)	$ 25,306	$ 22,392	$ 19,755	$ 4,114	$ 3,902	$ 3,006
Interest cost	26,160	27,853	28,417	5,139	6,042	5,598
Expected return on plan assets	(39,088)	(34,886)	(31,763)	(2,400)	(2,377)	(2,101)
Amortization of prior service cost (credit)	257	257	257	(921)	(958)	(981)
Net loss recognition	6,645	6,717	10,216	3,865	4,871	4,013
Net periodic benefit cost	$ 19,280	$ 22,333	$ 26,882	$ 9,797	$ 11,480	$ 9,535

(a) Total service costs in the table above are recorded to the same accounts as labor expense. Labor and benefits expense is recorded to various projects based on whether the work is a capital project or an operating expense. Approximately 40 percent of all labor and benefits is capitalized to utility property and 60 percent is expensed to utility other operating expenses.

Plan Assets

The Finance Committee of the Company's Board of Directors approves investment policies, objectives and strategies that seek an appropriate return for the pension plan and other postretirement benefit plans and reviews and approves changes to the investment and funding policies.

The Company has contracted with investment consultants who are responsible for monitoring the individual investment managers. The investment managers' performance and related individual fund performance is periodically reviewed by an internal benefits committee and by the Finance Committee to monitor compliance with investment policy objectives and strategies.

Pension plan assets are invested in mutual funds, trusts and partnerships that hold marketable debt and equity securities, real estate, and absolute return. In seeking to obtain a return that aligns with the funded status of the pension plan, the investment consultant recommends allocation percentages by asset classes. These recommendations are reviewed by the internal benefits committee, which then recommends their adoption by the Finance Committee. The Finance Committee has established target investment allocation percentages by asset classes and also investment ranges for each asset class. The target investment allocation percentages are typically the midpoint of the established range. The target investment allocation percentages by asset classes are indicated in the table below:

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

The target investment allocation percentages were revised in the first quarter of 2021 and the pension plan assets were reinvested to move toward the new target investment allocation percentages. The target asset allocation percentages were modified to better align the asset allocations with the funded status of the pension plan.

The fair value of pension plan assets invested in debt and equity securities was based primarily on fair value (market prices). The fair value of investment securities traded on a national securities exchange is determined based on the reported last sales price; securities traded in the over-the-counter market are valued at the last reported bid price. Investment securities for which market prices are not readily available or for which market prices do not represent the value at the time of pricing, the investment manager estimates fair value based upon other inputs (including valuations of securities that are comparable in coupon, rating, maturity and industry).

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

The Company's investments in common/collective trusts have redemption limitations that permit quarterly redemptions following notice requirements of 45 to 60 days. Most of the Company's investments in closely held investments and partnership interests have redemption limitations that range from bi-monthly to semi-annually following redemption notice requirements of 60 to 90 days. One investment in a partnership has a lock-up for redemption currently expiring in 2022 and is subject to extension.

The following table discloses by level within the fair value hierarchy (see Note 18 for a description of the fair value hierarchy) of the pension plan's assets measured and reported as of December 31, 2021 at fair value (dollars in thousands):

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

The following table discloses by level within the fair value hierarchy (see Note 18 for a description of the fair value hierarchy) of the pension plan's assets measured and reported as of December 31, 2020 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ —	$ 3,309	$ —	$ 3,309
Fixed income securities:				
U.S. government issues	—	10,990	—	10,990
Corporate issues	—	279,857	—	279,857
International issues	—	39,634	—	39,634
Municipal issues	—	22,431	—	22,431
Mutual funds:				
U.S. equity securities	146,375	—	—	146,375
International equity securities	96,311	—	—	96,311
Absolute return (1)	11,640	—	—	11,640
Plan assets measured at NAV (not subject to hierarchy disclosure)				
Common/collective trusts:				
Real estate	—	—	—	29,532
Partnership/closely held investments:				
Absolute return (1)	—	—	—	47,188
International equity securities	—	—	—	26,760
Real estate	—	—	—	7,997
Total	$ 254,326	$ 356,221	$ —	$ 722,024

(1) This category invests in multiple strategies to diversify risk and reduce volatility. The strategies include: (a) event driven, relative value, convertible, and fixed income arbitrage, (b) distressed investments, (c) long/short equity and fixed income and (d) market neutral strategies.

The fair value of other postretirement plan assets invested in debt and equity securities was based primarily on market prices. The fair value of investment securities traded on a national securities exchange is determined based on the last reported sales price; securities traded in the over-the-counter market are valued at the last reported bid price. For investment securities for which market prices are not readily available, the investment manager will determine fair value based upon other inputs (including valuations of securities that are comparable in coupon, rating, maturity and industry). The target asset allocation was 60 percent equity securities and 40 percent debt securities in both 2021 and 2020.

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

The following table discloses by level within the fair value hierarchy (see Note 18 for a description of the fair value hierarchy) of other postretirement plan assets measured and reported as of December 31, 2021 at fair value (dollars in thousands):

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

The following table discloses by level within the fair value hierarchy (see Note 18 for a description of the fair value hierarchy) of other postretirement plan assets measured and reported as of December 31, 2020 at fair value (dollars in thousands):

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

(1) The balanced index fund for 2021 and 2020 is a single mutual fund that includes a percentage of U.S. equity and fixed income securities and International equity and fixed income securities.

401(k) Plans and Executive Deferral Plan

Avista 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):

	2021	2020	2019
Employer 401(k) matching contributions	$ 11,671	$ 11,742	$ 10,412

The Company has an Executive Deferral Plan. This plan allows executive officers and other key employees the opportunity to defer until the earlier of their retirement, termination, disability or death, up to 75 percent of their base salary and/or up to 100 percent of their incentive payments. Deferred compensation funds are held by the Company in a Rabbi Trust.

There were deferred compensation assets 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):

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

NOTE 12. ACCOUNTING FOR INCOME TAXES

Income Tax Expense

Income tax expense consisted of the following for the years ended December 31 (dollars in thousands):

	2021	2020	2019
Current income tax expense (benefit)	$ 807	$ (37,913)	$ 16,276
Deferred income tax expense	11,224	44,964	15,098
Total income tax expense	$ 12,031	$ 7,051	$ 31,374

State income taxes do not represent a significant portion of total income tax expense on the Consolidated Statements of Income for any periods presented.

A reconciliation of federal income taxes derived from the statutory federal tax rate of 21 percent applied to income before income taxes as set forth in the accompanying Consolidated Statements of Income is as follows for the years ended December 31 (dollars in thousands):

	2021		2020		2019	
Federal income taxes at statutory rates	$ 33,467	21.0 %	$ 28,673	21.0 %	$ 47,909	21.0 %
Increase (decrease) in tax resulting from:						
Tax effect of regulatory treatment of utility plant differences	(13,820)	(8.7)	(12,893)	(9.4)	(9,967)	(4.3)
State income tax expense	1,385	0.8	814	0.6	1,465	0.6
Acquisition costs	—	—	—	—	(1,712)	(0.7)
Flow through related to deduction of meters and mixed service costs (1)	(8,678)	(5.4)	—	—	—	—
Non-plant excess deferred turnaround (2)	—	—	(8,476)	(6.2)	(5,690)	(2.5)
Tax loss on sale of METALfx	—	—	—	—	(1,272)	(0.6)
Customer refunds related to prior years at 35 percent	—	—	(1,189)	(0.9)	—	—
Other	(323)	(0.2)	122	0.1	641	0.3
Total income tax expense	$ 12,031	7.5 %	$ 7,051	5.2 %	$ 31,374	13.8 %

(1) With the approval of the Idaho and Washington general rate cases in 2021, a change in tax methodology resulted in recognizing a flow through benefit related to meters and mixed service costs.

(2) In March 2020, the WUTC approved an all-party settlement agreement related to electric tax benefits that were set aside for Colstrip in the 2020 general rate case order. In the approved settlement agreement, the parties agreed to utilize $10.9 million ($8.4 million when tax-effected) of the electric benefits to offset costs associated with accelerating the depreciation of Colstrip Units, to reflect a remaining useful life through December 31, 2025. In the second quarter of 2020, the Company recorded a one-time increase to depreciation expense with an offsetting decrease to income tax expense.

In March 2019, the IPUC approved an all-party settlement agreement related to electric tax benefits that were set aside for Colstrip in the 2020 general rate case order. In the approved settlement agreement, the parties agreed to utilize $6.4 million ($5.1 million when tax-effected) of the electric benefits to offset costs associated with accelerating the depreciation of Colstrip, to reflect a remaining useful life through December 31, 2027. In the second quarter of 2019, the Company recorded a one-time increase to depreciation expense with an offsetting decrease to income tax expense.

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):

	2021	2020
Deferred income tax assets:		
Regulatory liabilities	$ 200,513	$ 179,871
Tax credits and NOL carryforwards	64,994	57,516
Provisions for pensions	25,650	37,501
Other	38,181	42,641
Total gross deferred income tax assets	329,338	317,529
Valuation allowances for deferred tax assets	(9,626)	(10,021)
Total deferred income tax assets after valuation allowances	319,712	307,508
Deferred income tax liabilities:		
Utility property, plant, and equipment	688,856	666,639
Regulatory assets	264,978	232,697
Other	8,587	2,884
Total deferred income tax liabilities	962,421	902,220
Net long-term deferred income tax liability	$ 642,709	$ 594,712

The realization of deferred income tax assets is dependent upon the ability to generate taxable income in future periods. The Company evaluated available evidence supporting the realization of its deferred income tax assets and determined it is more likely than not that deferred income tax assets will be realized.

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

Status of Internal Revenue Service (IRS) and State Examinations

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

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

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

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

NOTE 13. 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):

	2021	2020	2019
Utility power resources	$ 431,199	$ 324,297	$ 376,769

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):

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

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

The above future contractual commitments for power resources include fixed contractual amounts related to the Company's contracts with certain PUDs to purchase portions of the output of certain generating facilities. Although Avista Utilities has no investment in the PUD generating facilities, the fixed 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, 2021 (principal and interest) was $278.3 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):

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

NOTE 14. COMMITTED LINES OF CREDIT

Avista Corp.

Avista Corp. has a committed line of credit with various financial institutions in the total amount of $400.0 million. In June 2021, the Company entered into an amendment to its committed line of credit that extends the expiration date to June 2026, with the option to extend for an additional one year period (subject to customary conditions). The committed line of credit is secured by non-transferable first mortgage bonds of the Company issued to the agent bank that would only become due and payable in the event, and then only to the extent, that the Company defaults on its obligations under the committed line of credit.

The committed line of credit agreement contains customary covenants and default provisions. The credit agreement has a covenant which does not permit the ratio of "consolidated total debt" to "consolidated total capitalization" of Avista Corp. to be greater than 65 percent at any time. As of December 31, 2021, the Company was in compliance with this covenant.

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

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

As of December 31, 2021 and 2020, the borrowings outstanding under Avista Corp.'s committed line of credit were classified as short-term borrowings on the Consolidated Balance Sheets.

AEL&P

AEL&P has a committed line of credit in the amount of $25.0 million that expires in November 2024. 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, 2021, AEL&P was in compliance with this covenant.

As of December 31, 2021, there were no borrowings under the AEL&P committed line of credit. As of December 31, 2020, there was $1.0 million outstanding with an average interest rate of 1.65 percent.

NOTE 15. CREDIT AGREEMENT

In April 2020, the Company entered into a Credit Agreement with various financial institutions, in the amount of $100 million. The Company borrowed the entire $100 million available under this agreement in April 2020 and repaid the outstanding balance in April 2021.

NOTE 16. LONG-TERM DEBT

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

Maturity Year	Description	Interest Rate	2021	2020
Avista Corp. Secured Long-Term Debt				
2022	First Mortgage Bonds	5.13%	250,000	250,000
2023	Secured Medium-Term Notes	7.18%-7.54%	13,500	13,500
2028	Secured Medium-Term Notes	6.37%	25,000	25,000
2032	Secured Pollution Control Bonds (1)	(1)	66,700	66,700
2034	Secured Pollution Control Bonds (1)	(1)	17,000	17,000
2035	First Mortgage Bonds	6.25%	150,000	150,000
2037	First Mortgage Bonds	5.70%	150,000	150,000
2040	First Mortgage Bonds	5.55%	35,000	35,000
2041	First Mortgage Bonds	4.45%	85,000	85,000
2044	First Mortgage Bonds	4.11%	60,000	60,000
2045	First Mortgage Bonds	4.37%	100,000	100,000
2047	First Mortgage Bonds	4.23%	80,000	80,000
2047	First Mortgage Bonds	3.91%	90,000	90,000
2048	First Mortgage Bonds	4.35%	375,000	375,000
2049	First Mortgage Bonds	3.43%	180,000	180,000
2050	First Mortgage Bonds	3.07%	165,000	165,000
2051	First Mortgage Bonds	3.54%	175,000	175,000
2051	First Mortgage Bonds (2)	2.90%	140,000	—
	Total Avista Corp. secured long-term debt		2,157,200	2,017,200
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		2,232,200	2,092,200
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		2,247,200	2,107,200
Other Long-Term Debt Components				
	Unamortized debt discount		(632)	(710)
	Unamortized long-term debt issuance costs		(14,498)	(14,256)
	Total		2,232,070	2,092,234
	Secured Pollution Control Bonds held by Avista Corporation (1)		(83,700)	(83,700)
	Current portion of long-term debt		(250,000)	—
	Total long-term debt		$ 1,898,370	$ 2,008,534

(1) In December 2010, $66.7 million and $17.0 million of the City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) due in 2032 and 2034, respectively, which had been held by Avista Corp. since 2008 and 2009, respectively, were refunded by new variable rate bond issues (Series 2010A and Series 2010B). The new bonds were not offered to the public and were purchased by Avista Corp. due to market conditions. The Company expects that at a later date, subject to market conditions, these bonds may be remarketed to unaffiliated investors. So long as Avista Corp. is the holder of these bonds, the bonds will not be reflected as an asset or a liability on Avista Corp.'s Consolidated Balance Sheets.

(2) In September 2021, the Company issued and sold $70.0 million of 2.90 percent first mortgage bonds due in 2051 pursuant to a bond purchase agreement with institutional investors in the private placement market. In December 2021, the Company issued and sold the remaining $70.0 million of bonds pursuant to the same agreement. The total net proceeds from the sale of the bonds were used to repay a portion of the outstanding balance under Avista Corp.'s $400.0 million committed line of credit. In connection with the pricing of the first mortgage bonds in September 2021, the Company cash settled four interest rate swap derivatives (notional aggregate amount of $45.0 million) and paid a net amount of $17.2 million. See Note 7 for a discussion of interest rate swap derivatives.

The following table details future long-term debt maturities including long-term debt to affiliated trusts (see Note 17) (dollars in thousands):

	2022	2023	2024	2025	2026	Thereafter	Total
Debt maturities	$ 250,000	$ 13,500	$ 15,000	$ —	$ —	$ 1,936,547	$ 2,215,047

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 (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, 2021, property additions and retired bonds would have allowed, and the net earnings test would not have prohibited, the issuance of $1.8 billion in an aggregate principal amount of additional first mortgage bonds at Avista Utilities and $38.2 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.

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

	2021	2020	2019
Low distribution rate	0.99 %	1.10 %	2.79 %
High distribution rate	1.10 %	2.79 %	3.61 %
Distribution rate at the end of the year	1.05 %	1.10 %	2.79 %

Concurrent with the issuance of the Preferred Trust Securities, Avista Capital II issued $1.5 million of Common Trust Securities to the Company. These Preferred Trust Securities may be redeemed at the option of Avista Capital II at any time and mature on June 1, 2037. In December 2000, the Company purchased $10.0 million of these Preferred Trust Securities.

The Company owns 100 percent of Avista Capital II and has solely and unconditionally guaranteed the payment of distributions on, and redemption price and liquidation amount for, the Preferred Trust Securities to the extent that Avista Capital II has funds available for such payments from the respective debt securities. Upon maturity or prior redemption of such debt securities, the Preferred Trust Securities will be mandatorily redeemed. 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 those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

Level 3 – Pricing inputs include significant inputs that are generally unobservable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value.

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. The determination of the fair values incorporates various factors that not only include the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits and letters of credit), but also the impact of Avista Corp.'s nonperformance risk on its liabilities.

The following table sets forth the carrying value and estimated fair value of the Company's financial instruments not reported at estimated fair value on the Consolidated Balance Sheets as of December 31 (dollars in thousands):

	2021		2020	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Long-term debt (Level 2)	$ 963,500	$ 1,157,651	$ 963,500	$ 1,189,824
Long-term debt (Level 3)	1,200,000	1,366,619	1,060,000	1,235,248
Snettisham finance lease obligation (Level 3)	48,815	54,000	51,750	58,700
Long-term debt to affiliated trusts (Level 3)	51,547	43,299	51,547	43,815

These estimates of fair value of long-term debt and long-term debt to affiliated trusts were primarily based on available market information, which generally consists of estimated market prices from third party brokers for debt with similar risk and terms. The price ranges obtained from the third party brokers consisted of par values of 84.0 to 140.27, where a par value of 100.00 represents the carrying value recorded on the 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, 2021.

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, 2021 at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting (1)	Total
December 31, 2021					
Assets:					
Energy commodity derivatives	$ —	$ 34,119	$ —	$ (31,211)	$ 2,908
Level 3 energy commodity derivatives:					
Natural gas exchange agreements	—	—	143	(143)	—
Interest rate swap derivatives	—	2,319	—	(1,170)	1,149
Deferred compensation assets:					
Mutual Funds:					
Fixed income securities (2)	1,809	—	—	—	1,809
Equity securities (2)	7,594	—	—	—	7,594
Total	$ 9,403	$ 36,438	$ 143	$ (32,524)	$ 13,460
Liabilities:					
Energy commodity derivatives	$ —	$ 41,733	$ —	$ (40,300)	$ 1,433
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	7,914	(143)	7,771
Foreign currency exchange derivatives	—	19	—	—	19
Interest rate swap derivatives	—	25,274	—	(1,170)	24,104
Total	$ —	$ 67,026	$ 7,914	$ (41,613)	$ 33,327

The following table discloses by level within the fair value hierarchy the Company’s assets and liabilities measured and reported on the Consolidated Balance Sheets as of December 31, 2020 at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting (1)	Total
December 31, 2020					
Assets:					
Energy commodity derivatives	$ —	$ 23,645	$ —	$ (22,152)	$ 1,493
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	75	(75)	—
Foreign currency exchange derivatives	—	30	—	—	30
Interest rate swap derivatives	—	952	—	(952)	—
Deferred compensation assets:					
Mutual Funds:					
Fixed income securities (2)	2,471	—	—	—	2,471
Equity securities (2)	6,228	—	—	—	6,228
Total	$ 8,699	$ 24,627	$ 75	$ (23,179)	$ 10,222
Liabilities:					
Energy commodity derivatives	$ —	$ 23,030	$ —	$ (22,768)	$ 262
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	8,485	(75)	8,410
Interest rate swap derivatives	—	51,765	—	(9,002)	42,763
Total	$ —	$ 74,795	$ 8,485	$ (31,845)	$ 51,435

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

(2) 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 7 for additional discussion of derivative netting.

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

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

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

Deferred compensation assets and liabilities represent funds held by the Company in a Rabbi Trust for an executive deferral plan. These funds consist of actively traded equity and bond funds with quoted prices in active markets. The balance disclosed in the table above excludes cash and cash equivalents of $0.1 million as of December 31, 2021 and $0.5 million as of December 31, 2020.

Level 3 Fair Value

For the natural gas commodity exchange agreement, the Company uses the same Level 2 brokered quotes described above; however, the Company also estimates the purchase and sales volumes (within contractual limits) as well as the timing of those transactions. Changing the timing of volume estimates changes the timing of purchases and sales, impacting which brokered quote is used. Because the brokered quotes can vary significantly from period to period, the unobservable estimates of the timing and volume of transactions can have a significant impact on the calculated fair value. The Company currently estimates volumes and timing of transactions based on a most likely scenario using historical data. Historically, the timing and volume of transactions have not been highly correlated with market prices and market volatility.

The following table presents the quantitative information which was used to estimate the fair values of the Level 3 assets and liabilities above as of December 31, 2021 (dollars in thousands):

	Fair Value (Net) at December 31, 2021	Valuation Technique	Unobservable Input	Range
Natural gas exchange	(7,771)	Internally derived weighted average cost of gas	Forward purchase prices	$2.35 - $4.08/mmBTU $2.96 Weighted Average
			Forward sales prices	$2.38 - $9.50/mmBTU $4.51 Weighted Average
			Purchase volumes	130,000 - 310,000 mmBTUs
			Sales volumes	25,000 - 310,000 mmBTUs

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

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

	Natural Gas Exchange Agreement	Power Exchange Agreement	Total
Year ended December 31, 2021:			
Balance as of January 1, 2021	$ (8,410)	$ —	$ (8,410)
Total gains or (losses) (realized/unrealized):			
Included in regulatory assets (1)	4,292	—	4,292
Settlements	(3,653)	—	(3,653)
Ending balance as of December 31, 2021 (2)	$ (7,771)	$ —	$ (7,771)
Year ended December 31, 2020:			
Balance as of January 1, 2020	$ (2,976)	$ —	$ (2,976)
Total gains or (losses) (realized/unrealized):			
Included in regulatory assets (1)	(4,311)	—	(4,311)
Settlements	(1,123)	—	(1,123)
Ending balance as of December 31, 2020 (2)	$ (8,410)	$ —	$ (8,410)
Year ended December 31, 2019:			
Balance as of January 1, 2019	$ (2,774)	$ (2,488)	$ (5,262)
Total gains or (losses) (realized/unrealized):			
Included in regulatory assets (1)	8,175	435	8,610
Settlements	(8,377)	2,053	(6,324)
Ending balance as of December 31, 2019 (2)	$ (2,976)	$ —	$ (2,976)

(1) All gains and losses are included in other regulatory assets and liabilities. There were no gains and losses included in either net income or other comprehensive income during any of the periods presented in the table above.

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

Nonrecurring Fair Value Measurements

The Company holds equity investments without a readily determinable fair value, and these assets are recorded at fair value and adjusted on a nonrecurring basis as a result of observable changes in fair value using the measurement alternative. Amounts recognized in the consolidated financial statements related to equity investments without readily determinable fair value include the following (dollars in thousands):

	December 31, 2021	December 31, 2020
Carrying Value (1)	$ 24,161	$ 15,110
Gains (losses)	8,761	925

(1) Carrying value is adjusted to fair value as of the measurement date when observable changes in fair value occur, such as a transaction involving the underlying asset. These assets are measured using a market approach and are level 2 assets.

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, 2021 was $322.3 million.

See the Consolidated Statements of Equity for dividends declared in the years 2019 through 2021.

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

Common Stock Issuances

The Company issued common stock in 2021 for total net proceeds of $90.0 million. Most of these issuances came through the Company's sales agency agreements under which the sales agents may offer and sell new shares of common stock from time to time. The Company has board and regulatory authority to issue a maximum of 4.3 million shares under these agreements, of which 2.1 million remain unissued as of December 31, 2021. In 2021, 2.2 million shares were issued under these agreements resulting in total net proceeds of $88.5 million.

NOTE 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):

	2021	2020
Unfunded benefit obligation for pensions and other postretirement benefit plans - net of taxes of $2,934 and $3,822, respectively	$ 11,039	$ 14,378

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 2021	2020	2019
Amortization of defined benefit pension items			
Amortization of net prior service cost (a)	$ (793)	$ (794)	$ (794)
Amortization of net loss (a)	38,070	5,586	17,074
Adjustment due to effects of regulation (a)	(33,050)	(10,006)	(19,309)
Total before tax (b)	4,227	(5,214)	(3,029)
Tax expense (b)	(888)	1,095	636
Net of tax (b)	$ 3,339	$ (4,119)	$ (2,393)

(a) These accumulated other comprehensive loss components are included in the computation of net periodic pension cost (see Note 11 for additional details).

(b) Description is also the affected line item on the Consolidated Statements of Income

NOTE 21. EARNINGS PER COMMON SHARE ATTRIBUTABLE TO AVISTA CORPORATION SHAREHOLDERS

The following table presents the computation of basic and diluted earnings per common share attributable to Avista Corp. shareholders for the years ended December 31 (in thousands, except per share amounts):

	2021	2020	2019
Numerator:			
Net income attributable to Avista Corp. shareholders	$ 147,334	$ 129,488	$ 196,979
Denominator:			
Weighted-average number of common shares outstanding-basic	69,951	67,962	66,205
Effect of dilutive securities:			
Performance and restricted stock awards	134	140	124
Weighted-average number of common shares outstanding-diluted	70,085	68,102	66,329
Earnings per common share attributable to Avista Corp. shareholders:			
Basic	$ 2.11	$ 1.91	$ 2.98
Diluted	$ 2.10	$ 1.90	$ 2.97

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 intends to vigorously protect and defend its interests and pursue its rights. However, no assurance can be given as to the ultimate outcome of any particular matter because litigation and other contested proceedings are inherently subject to numerous uncertainties. For matters that affect Avista 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 approximately 40 percent of all of Avista Utilities’ employees. The Company’s largest represented group, representing approximately 90 percent of Avista Utilities' bargaining unit employees in Washington and Idaho, were covered under a three-year agreement which expired in March 2021.

The Company is in the process of negotiating a new agreement with the IBEW. However, there is a risk that if a new agreement is not reached, employees subject to that agreement could strike. Given the number of employees that are covered by the collective bargaining agreement, a strike could result in disruptions to the Company's operations. However, the Company believes that 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 up to $4.4 million for fire suppression and investigation costs and related expenses incurred in connection with a wildfire that occurred in Ferry County, Washington in August 2018. Specifically, the complaint alleges that the fire, which became known as the “Boyds Fire,” was caused by a dead ponderosa pine tree falling into an overhead distribution line, and that Avista Corp. was negligent in failing to identify and remove the tree before it came into contact with the line. Avista Corp. disputes that the tree in question was the cause of the fire and that it was negligent in failing to identify and remove it. Additional lawsuits have subsequently been filed by private landowners seeking property damages, and holders of insurance subrogation claims seeking recovery of insurance proceeds paid.

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

Labor Day Windstorm

General

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

The Company has become aware of instances where, during the course of the storm, otherwise healthy trees and limbs, located in areas outside its maintenance right-of-way, broke under the extraordinary wind conditions and caused damage to its energy delivery system at or near what is believed to be the potential area of origin of a wildfire. Those instances include what has been referred to as: the Babb Road fire (near Malden and Pine City, Washington); the Christensen Road fire (near Airway Heights, Washington); and the Mile Marker 49 fire (near Orofino, Idaho). These wildfires covered, in total, approximately 22,000 acres. The Company currently estimates approximately 230 residential, commercial and other structures were impacted. With respect to the Christensen Road Fire and the Mile Marker 49 Fire, the Company’s investigation determined that the primary cause of the fires was extreme high winds. To date, the Company has not found any evidence that the fires were caused by any deficiencies in its equipment, maintenance activities or vegetation management practices. See further discussion below regarding the Babb Road Fire.

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

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

Babb Road Fire

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

The DNR report concluded, among other things, that

- the fire was ignited when a branch of a multi-dominant Ponderosa Pine tree was broken off by the wind and fell on an Avista Corp. distribution line;

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

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

The DNR report acknowledged that, other than the multi-dominant nature of the tree, the conditions mentioned above would not have been easily visible without close-up inspection of, or cutting into, the tree. The report also acknowledged that, while the presence of multiple tops would have been visible from the nearby roadway, the tree did not fail at a v-fork due to the presence of multiple tops. The Company contends that applicable inspection standards did not require a closer inspection of the otherwise healthy tree, nor was the Company negligent with respect to its maintenance, inspection or vegetation management practices. The Company intends to vigorously defend any such assertion, if made. At this time, no material claims have been asserted against Avista Corp. for damages resulting from the Babb Road Fire.

Colstrip

Colstrip Owners Arbitration and Litigation

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

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

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

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

Burnett et al. v. Talen et al.

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

Westmoreland Mine Permits

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

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

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

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

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

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

Rathdrum, Idaho Natural Gas Incident

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

Other Contingencies

In the normal course of business, the Company has various other legal claims and contingent matters outstanding. The Company believes that any ultimate liability arising from these actions will not have a material impact on its financial condition, results of operations or cash flows. It is possible that a change could occur in the Company's estimates of the probability or amount of a liability being incurred. Such a change, should it occur, could be significant.

The Company routinely assesses, based on studies, expert analysis and legal reviews, its contingencies, obligations and commitments for remediation of contaminated sites, including assessments of ranges and probabilities of recoveries from other responsible parties who either have or have not agreed to a settlement as well as recoveries from insurance carriers. The

Company's policy is to accrue and charge to current expense identified exposures related to environmental remediation sites based on estimates of investigation, cleanup and monitoring costs to be incurred.

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

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

NOTE 23. REGULATORY MATTERS

Regulatory Assets and Liabilities

The following table presents the Company's regulatory assets and liabilities as of December 31, 2021 (dollars in thousands):

		Receiving Regulatory Treatment			2021		2020	
	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)	$ 244,154	$ —	$ —	$ —	$ 244,154	$ —	$ 108,517
Pensions and other postretirement benefit plans	(4)	—	165,696	—	—	165,696	—	198,746
Energy commodity derivatives	(5)	—	15,385	—	12,447	2,938	2,073	5,722
Unamortized debt repurchase costs	(6)	6,768	—	—	—	6,768	—	7,512
Settlement with Coeur d'Alene Tribe	2059	38,926	—	—	—	38,926	—	40,043
Demand side management programs	(3)	—	3,974	—	—	3,974	—	3,814
Decoupling surcharge	2023	24,532	—	—	9,907	14,625	7,123	17,123
Utility plant to be abandoned	(7)	26,771	—	—	—	26,771	—	28,916
Interest rate swaps	(8)	158,082	—	41,672	—	199,754	—	214,851
Deferred power costs	(3)	10,835	—	—	7,334	3,501	1,775	1,562
Deferred natural gas costs	(3)	21,027	—	—	14,095	6,932	2,308	—
AFUDC above FERC allowed rate	(11)	48,455	—	—	—	48,455	—	47,393
COVID-19 deferrals	(12)	—	—	13,591	—	13,591	—	8,166
Advanced meter infrastructure	(13)	36,008	—	—	—	36,008	—	26,379
Other regulatory assets	(3)	37,045	8,563	2,925	—	48,533	394	41,699
Total regulatory assets		$ 652,603	$ 193,618	$ 58,188	$ 43,783	$ 860,626	$ 13,673	$ 750,443
Regulatory Liabilities:								
Deferred natural gas costs	(3)	$ —	$ —	$ —	$ —	$ —	$ 874	$ —
Deferred power costs	(3)	11,891	—	—	6,457	5,434	20,299	17,570
Utility plant retirement costs	(9)	350,190	—	—	—	350,190	—	325,832
Income tax related liabilities	(3) (10)	346,847	24,411	143,862	56,331	458,789	14,952	399,677
Interest rate swaps	(8)	13,589	—	1,473	—	15,062	—	15,046
Decoupling rebate	2022	9,308	—	—	3,049	6,259	1,447	1,519
COVID-19 deferrals	(12)	—	—	12,500	—	12,500	—	10,949
Other regulatory liabilities	(3)	6,905	17,688	—	11,312	13,281	8,863	14,227
Total regulatory liabilities		$ 738,730	$ 42,099	$ 157,835	$ 77,149	$ 861,515	$ 46,435	$ 784,820

(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 that was 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. There are additional smaller projects included in the balance that 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) The majority of 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 32 years. The Company expects the AEL&P amounts to be returned to customers over a period of approximately 40 years. A significant portion of the regulatory liability attributable to non-plant excess deferred taxes was used to offset a portion of the costs associated with accelerating the depreciation of Colstrip based on settlements in Washington and Idaho.

(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 any 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.

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 and defer these differences (over the $4.0 million deadband and sharing bands) for future surcharge or rebate to customers. For 2021, the Company recognized a pre-tax expense of $7.7 million under the ERM in Washington compared to a benefit of $6.2 million for 2020. Total net deferred power costs under the ERM were a liability of $11.9 million as of December 31, 2021 and a liability of $37.9 million as of December 31, 2020. These deferred power cost balances represent amounts due to customers. Pursuant to WUTC requirements, should the cumulative deferral balance exceed $30 million in the rebate or surcharge direction, the Company must make a filing with the WUTC to adjust customer rates to either return the balance to customers or recover the balance from customers. As the cumulative rebate balance exceeded $30 million, the Company’s 2019 filing contained a proposed rate refund. The ERM proceeding was considered with the Company’s 2019 general rate case proceeding and a refund was approved and is being returned to customers over a two-year period that began on April 1, 2020. Avista 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.

Avista Utilities has a PCA mechanism in Idaho that allows it to modify electric rates on October 1 of each year with IPUC approval. Under the PCA mechanism, Avista 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 an asset of $10.8 million as of December 31, 2021 and $2.5 million as of December 31, 2020. Deferred power cost assets represent amounts due from customers and liabilities represent amounts due to customers.

Natural Gas Cost Deferrals and Recovery Mechanisms

Avista 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. Total net deferred natural gas costs were an asset of $21.0 million as of December 31, 2021 and $1.4 million as of December 31, 2020. Asset balances represent amounts due from customers and liabilities represent amounts due to customers.

Decoupling and Earnings Sharing Mechanisms

Decoupling (also known as an FCA in Idaho) is a mechanism designed to sever the link between a utility's revenues and consumers' energy usage. In each of Avista 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 for a five-year period beginning January 1, 2015. In 2019, the WUTC approved an extension of the mechanisms for an additional five-year term through March 31, 2025, with one modification in that new customers added after any test period would not be decoupled until included in a future test period.

Electric and natural gas decoupling surcharge rate adjustments to customers are limited to a 3 percent increase on an annual basis, with any remaining surcharge balance carried forward for recovery in a future period. There is no limit on the level of rebate rate adjustments.

The decoupling mechanisms each include an after-the-fact earnings test. At the end of each calendar year, separate electric and natural gas earnings calculations are made for the calendar year just ended. These earnings tests reflect actual decoupled revenues, normalized power supply costs and other normalizing adjustments. If the Company earns more than its authorized ROR in Washington, 50 percent of excess earnings are rebated to customers through adjustments to decoupling surcharge or rebate balances. See below for a summary of cumulative balances under the decoupling and earnings sharing mechanisms.

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

Idaho FCA and Earnings Sharing Mechanisms

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

Oregon Decoupling Mechanism

In Oregon, the Company has a decoupling mechanism for natural gas. An earnings review is conducted on an annual basis. In the annual earnings review, if the Company earns more than 100 basis points above its allowed 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, 2021 and December 31, 2020, the Company had the following cumulative balances outstanding related to decoupling and earnings sharing mechanisms in its various jurisdictions (dollars in thousands):

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

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

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) attributable to Avista Corp. shareholders. 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 that are 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 any 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, 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 taxes	6,029	2,763	8,792	3,239	—	12,031
Net income from continuing operations attributable to Avista Corp. shareholders	125,558	7,224	132,782	14,552	—	147,334
Capital expenditures (3)	435,887	4,052	439,939	1,270	—	441,209
For the year ended December 31, 2020:						
Operating revenues	$ 1,277,468	$ 42,809	$ 1,320,277	$ 1,614	$ —	$ 1,321,891
Resource costs	396,543	1,966	398,509	—	—	398,509
Other operating expenses	341,709	12,905	354,614	5,344	—	359,958
Depreciation and amortization	213,701	9,806	223,507	716	—	224,223
Income (loss) from operations	220,058	17,088	237,146	(4,446)	—	232,700
Interest expense (2)	98,451	6,272	104,723	524	(186)	105,061
Income taxes	4,921	3,011	7,932	(881)	—	7,051
Net income (loss) from continuing operations attributable to Avista Corp. shareholders	124,810	8,095	132,905	(3,417)	—	129,488
Capital expenditures (3)	397,292	7,014	404,306	1,368	—	405,674
For the year ended December 31, 2019:						
Operating revenues	$ 1,295,873	$ 37,265	$ 1,333,138	$ 12,484	$ —	$ 1,345,622
Resource costs	442,471	(2,654)	439,817	—	—	439,817
Other operating expenses (4)	352,170	12,717	364,887	18,883	—	383,770
Depreciation and amortization	195,697	9,668	205,365	629	—	205,994
Income (loss) from operations	200,994	16,423	217,417	(7,028)	—	210,389
Interest expense (2)	97,866	6,385	104,251	1,032	(929)	104,354
Income taxes	28,363	2,816	31,179	195	—	31,374
Net income from continuing operations attributable to Avista Corp. shareholders	183,977	7,458	191,435	5,544	—	196,979

Capital expenditures (3)		434,077		8,433		442,510		835		—		443,345
Total Assets:												
As of December 31, 2021	$	6,458,244	$	265,422	$	6,723,666	$	132,158	$	(2,241)	$	6,853,583
As of December 31, 2020	$	6,035,340	$	268,971	$	6,304,311	$	109,658	$	(11,872)	$	6,402,097
As of December 31, 2019	$	5,713,268	$	271,393	$	5,984,661	$	113,390	$	(15,595)	$	6,082,456

(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.

(4) Other operating expenses for Avista Utilities for 2019 include merger transaction costs which are separately disclosed on the Consolidated Statements of Income.

NOTE 25. TERMINATION OF PROPOSED ACQUISITION BY HYDRO ONE

In July 2017, Avista Corp. entered into a Merger Agreement that provided for Avista Corp. to become an indirect, wholly-owned subsidiary of Hydro One, subject to the satisfaction or waiver of specified closing conditions, including approval by regulatory agencies.

Termination of the Merger Agreement

Due to the denial of the proposed merger by certain of the Company's regulatory commissions, in January 2019, Avista Corp., Hydro One and certain subsidiaries thereof, entered into a Termination Agreement indicating their mutual agreement to terminate the Merger Agreement. Pursuant to the terms of the Termination Agreement, Hydro One paid Avista Corp. a $103 million termination fee in January 2019. The termination fee was used for reimbursing the Company's transaction costs incurred from 2017 to 2019. The balance of the termination fee remaining after payment of 2019 transaction costs and applicable income taxes was used for general corporate purposes and reduced the Company's need for external financing. The 2019 costs were $19.7 million pre-tax and included financial advisers' fees, legal fees, consulting fees and employee time.

NOTE 26. SALE OF METALfx

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

The purchase price of $17.5 million, as adjusted, was divided among the security holders of METALfx, including the minority shareholder, pro-rata based on ownership (Avista Corp. owned 89.2 percent of the equity of METALfx).

The sales transaction provided cash proceeds to Avista Corp., net of payments to the minority holder, contractually obligated compensation payments and other transaction expenses, of $16.5 million and resulted in a net gain after-tax of $3.3 million. The gross gain is included in "Other income," the transaction expenses paid are included in "Non-utility Other operating expenses" and any taxes associated with the sale are included in "Income tax expense" on the Consolidated Statements of Income.

Prior to the completion of the sales transaction, METALfx was not a reportable business segment and was included in other in the business segment footnote at Note 24. This transaction does not meet the criteria for discontinued operations as it does not represent a strategic shift that will have a major effect on the Company's ongoing operations.

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, 2021.

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, 2021 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, 2021.

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, 2021, 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, 2021, 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, 2021, of the Company and our report dated February 22, 2022, 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 22, 2022

Item 9B. Other Information

None.

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 12, 2022, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 31, 2021, relating to its Annual Meeting of Shareholders held on May 11, 2021.

Information about our Executive Officers

Name	Age	Business Experience
Dennis P. Vermillion	60	Chief Executive Officer since October 2019; President of Avista Corp since January 2018; Director since January 2018; 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.
Mark T. Thies	58	Executive Vice President since October 2019; Treasurer since January 2013; Chief Financial Officer since September 2008; Senior Vice President from September 2008 to October 2019; prior to employment with the Company held the following positions with Black Hills Corporation: Executive Vice President and Chief Financial Officer March 2003 to January 2008; Senior Vice President and Chief Financial Officer March 2000 to March 2003; Controller May 1997 to March 2000.
Kevin J. Christie	54	Senior Vice President, External Affairs and Chief Customer Officer since October 2019; Vice President, External Affairs and Chief Customer Officer January 2018; Vice President of Customer Solutions February 2015 – January 2018; various other management and staff positions with the Company since 2005.
Heather L. Rosentrater	44	Senior Vice President, Energy Delivery and Shared Services since January 2020; Senior Vice President, Energy Delivery from October 2019 to December 2019; Vice President of Energy Delivery December 2015; various other management and staff positions with the Company since 1996.
Jason R. Thackston	52	Senior Vice President since January 2014; Environmental Compliance Officer since May 2018; Vice President of Energy Resources since December 2012; Vice President of Customer Solutions – Avista Utilities June 2012 - December 2012; Vice President of Energy Delivery April 2011 – December 2012; Vice President of Finance June 2009 – April 2011; various other management and staff positions with the Company since 1996.
Bryan A. Cox	52	Vice President, Safety and Human Resources since January 2020; Vice President, Safety and HR Shared Services January 2018 – January 2020; various other management and staff positions with the Company since 1997.
Gregory C. Hesler	44	Vice President, General Counsel, Corporate Secretary and Chief Ethics/Compliance Officer since May 2020; Vice President, General Counsel and Chief Compliance Officer January 2020 – May 2020; various other management and staff positions with the Company since 2015.
Latisha D. Hill	43	Vice President of Community and Economic Vitality since January 2020; various other management and staff positions with the Company since 2005.
James M. Kensok	63	Vice President, Chief Information Officer and Chief Security Officer since January 2013; Vice President and Chief Information Officer January 2007 – January 2013; Chief Information Officer February 2001 – December 2006; various other management and staff positions with the Company since 1996.
Ryan L. Krasselt	52	Vice President, Controller and Principal Accounting Officer since October 2015; various other management and staff positions with the Company since 2001.
David J. Meyer	68	Vice President and Chief Counsel for Regulatory and Governmental Affairs since February 2004; Senior Vice President and General Counsel September 1998 – February 2004.
Edward D. Schlect Jr.	61	Vice President and Chief Strategy Officer since September 2015; prior to employment with the Company, Executive Vice President of Corporate Development at Ecova, Inc.

All of the Company's executive officers, with the exception of David J. Meyer, Kevin J. Christie, and Heather L. Rosentrater, were officers or directors of one or more of the Company's subsidiaries in 2021. 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 also 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 12, 2022, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 31, 2021, relating to its Annual Meeting of Shareholders held on May 11, 2021.

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 12, 2022, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 31, 2021, relating to its Annual Meeting of Shareholders held on May 11, 2021; 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 12, 2022, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 31, 2021, relating to its Annual Meeting of Shareholders held on May 11, 2021.

(c) Changes in control:

None.

(d) Securities authorized for issuance under equity compensation plans as of December 31, 2021:

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)	—	$ —	1,130,521

(1) Excludes unvested restricted shares and performance share awards granted under Avista Corp.'s Long-Term Incentive Plan. At December 31, 2021, 96,127 Restricted Share awards were outstanding. Performance and market-based share awards may be paid out at zero shares at a minimum achievement level; 215,708 shares at target level; or 431,416 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 12, 2022, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 31, 2021, relating to its Annual Meeting of Shareholders held on May 11, 2021.

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 12, 2022, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 31, 2021, relating to its Annual Meeting of Shareholders held on May 11, 2021.

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, 2021, 2020 and 2019

Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2021, 2020 and 2019

Consolidated Balance Sheets as of December 31, 2021, and 2020

Consolidated Statements of Cash Flows for the Years Ended December 31, 2021, 2020 and 2019

Consolidated Statements of Equity for the Years Ended December 31, 2021, 2020 and 2019

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 July 19, 2017)	2.1	Agreement and Plan of Merger, dated as of July 19, 2017, by and among Avista Corporation, Hydro One Limited, Olympus Holding Corp. and Olympus Corp.
2.2	(with Form 8-K filed as of January 23, 2019)	2.1	Termination Agreement, dated as of January 23, 2019, by and among Avista Corporation, Hydro One Limited, Olympus Holding Corp. and Olympus Corp.
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	333-82165	4(a)	Indenture dated as of April 1, 1998 between Avista Corporation and The Bank of New York, as Successor Trustee.
4.68	(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.
4.69	(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.
4.70	(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.

4.71	(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.
4.72	(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.
4.73	(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).
4.74	(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).
4.75	(2)		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 April 18, 2014)	10.2	Bond Delivery Agreement, dated as of April 18, 2014, between Avista Corporation and Union Bank, N.A.
10.4	(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.
10.5	(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).
10.6	(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).
10.7	(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).

10.8	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.*
10.9	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.*
10.10	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.*
10.11	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.*
10.12	(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.*
10.13	(with 1981 Form 10-K)	10(s)-7	Ownership and Operation Agreement for Colstrip Units No. 3 & 4, dated as of May 6, 1981.*
10.14	(with 2019 Form 10-K)	10.14	Avista Corporation Executive Deferral Plan (2020 Component). (3)(5)
10.15	(with 2019 Form 10-K)	10.15	Avista Corporation Supplemental Executive Retirement Plan (Post-2004 Component, Amended in 2018). (3)(6)
10.16	(with 1992 Form 10-K)	10(t)-11	The Company's Unfunded Supplemental Executive Disability Plan. (3)*
10.17	(with 2007 Form 10-K)	10.34	Income Continuation Plan of the Company. (3)
10.18	(with 2018 Form 10-K)	10.21	Avista Corporation Long-Term Incentive Plan. (3)
10.19	(with 2010 Form 10-K)	10.23	Avista Corporation Performance Award Plan Summary. (3)
10.20	(with 2019 Form 10-K)	10.22	Avista Corporation Performance Award Agreement 2019. (3)
10.21	(with 2020 Form 10-K)	10.22	Avista Corporation Performance Award Agreement 2020. (3)
10.22	(2)		Avista Corporation Performance Award Agreement 2021. (3)
10.23	(2)		Avista Corporation Officer Incentive Plan. (3)
10.24	(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)
10.25	(with September 30, 2019 Form 10-Q)	10.1	Form of Change of Control Plan between the Company and its Executive Officers. (3)(7)
10.26	(2)		Avista Corporation Non-Employee Director Compensation.
10.27	(with Form 8-K dated April 6, 2020)	10.1	Credit Agreement, dated as of April 6, 2020, among Avista Corporation, U.S. Bank National Association, as Lender and Administrative Agent, and CoBank, ACB, as 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).

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 Document
101.CAL	(2)	Inline XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF	(2)	Inline XBRL Taxonomy Extension Definition Linkbase Document
101.LAB	(2)	Inline XBRL Taxonomy Extension Label Linkbase Document
101.PRE	(2)	Inline XBRL Taxonomy Extension Presentation Linkbase 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, Gregory C. Hesler, Latisha D. Hill, James M. Kensok, Ryan L. Krasselt, David J. Meyer, Heather L. Rosentrater, Edward D. Schlect, Jason R. Thackston, Mark T. Thies, and Dennis P. Vermillion.

(6) Applies to Kevin J. Christie, Bryan A. Cox, Latisha D. Hill, James M. Kensok, Ryan L. Krasselt, David J. Meyer, Heather L. Rosentrater, Jason R. Thackston, Mark T. Thies, and Dennis P. Vermillion.

(7) Applies to Kevin J. Christie, Bryan A. Cox, Gregory C. Hesler, Latisha D. Hill, James M. Kensok, Ryan L. Krasselt, David J. Meyer, Heather L. Rosentrater, Edward D. Schlect, Jason R. Thackston, Mark T. Thies, 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 22, 2022	By	/s/ Dennis P. Vermillion
Date		Dennis P. Vermillion President and 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 President and Chief Executive Officer	Principal Executive Officer and Director	February 22, 2022
/s/ Mark T. Thies Mark T. Thies Executive Vice President, Chief Financial Officer, and Treasurer	Principal Financial Officer	February 22, 2022
/s/ Ryan L. Krasselt Ryan L. Krasselt Vice President, Controller and Principal Accounting Officer	Principal Accounting Officer	February 22, 2022
/s/ Scott L. Morris Scott L. Morris Chairman of the Board	Director	February 22, 2022
/s/ Julie A. Bentz Julie A. Bentz	Director	February 22, 2022
/s/ Kristianne Blake Kristianne Blake	Director	February 22, 2022
/s/ Donald C. Burke Donald C. Burke	Director	February 22, 2022
/s/ Rebecca A. Klein Rebecca A. Klein	Director	February 22, 2022
/s/ Sena M. Kwawu Sena M. Kwawu	Director	February 22, 2022
/s/ Scott H. Maw Scott H. Maw	Director	February 22, 2022
/s/ Jeffry L. Philipps Jeffry L. Philipps	Director	February 22, 2022
/s/ Heidi B. Stanley Heidi B. Stanley	Director	February 22, 2022
/s/ Janet D. Widmann Janet D. Widmann	Director	February 22, 2022

AVISTA CORPORATION
DESCRIPTION OF COMMON STOCK
(Registered under Section 12(b) of the Securities Exchange Act of 1934, as amended)

General

The authorized capital stock of Avista, as set forth in its Restated Articles of Incorporation (the "Articles"), consists of 10,000,000 shares of Preferred Stock, cumulative, without nominal or par value (the "Preferred Stock"), which is issuable in series, and 200,000,000 shares of Common Stock without nominal or par value (the "Common Stock"). The Common Stock is listed on the New York Stock Exchange and is registered as a class under Section 12(b) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). The Preferred Stock is registered as a class under Section 12(g) of the Exchange Act. As of December 31, 2021, no shares of preferred stock were outstanding. However, subject to the limitations set forth in the Articles and such other limitations as are provided by law, the Board of Directors has the authority to establish series of preferred stock, to determine the relative rights of series of preferred stock so established and to cause the Company to issue and sell the shares of any such series of preferred stock.

The following is a description of certain of the rights and privileges of the Common Stock.

The terms of the Common Stock include those stated in the Articles and Avista's Bylaws (the "Bylaws") and those made applicable thereto by the Washington Business Corporation Act (the "Washington BCA"). The following summary is not complete and is subject in all respects to the provisions of, and is qualified in its entirety by reference to, the Articles, the Bylaws and the Washington BCA. Avista has filed the Articles and the Bylaws as exhibits to its reports filed under the Exchange Act. Whenever particular provisions of the Articles, the Bylaws or the Washington BCA are referred to, the summaries of those provisions set forth herein are qualified in their entirety by reference to the actual provisions set forth in the Articles, the Bylaws or the Washington BCA, as the case may be.

Dividend Rights; Rights upon Liquidation; No Pre-Emptive Rights

After full provision for all Preferred Stock dividends declared or in arrears, the holders of Common Stock are entitled to receive such dividends as may be lawfully declared from time to time by the Board of Directors.

In the event of any liquidation or dissolution of Avista, after satisfaction of the preferential liquidation rights of the Preferred Stock (including accumulated dividends), the holders of Common Stock would be entitled to share ratably in all assets of Avista available for distribution to shareholders.

No holder of Common Stock has any pre-emptive rights.

Voting Rights

General; Quorum

The holders of the Common Stock have sole voting power, except as indicated below or as otherwise provided by law. Each holder of Common Stock is entitled to one vote per share.

Under the Washington BCA, a majority of the votes entitled to be cast on a corporate action by a voting group constitutes a quorum of that group for that corporate action. If a quorum exists, a corporate action, other than the election of directors, is approved by the voting group if the votes cast within the voting group favoring the corporate action exceed the votes cast within the voting group opposing the corporate action.

Election of Directors

In an uncontested election of directors, each vote may be cast “for” or “against” one or more candidates, or a shareholder may “abstain” with respect to one or more candidates. A candidate is elected to the Board of Directors only if the number of votes “for” such candidate exceeds the number of votes “against” such candidate. Shares otherwise present at the meeting but for which there is an “abstention” or as to which no authority or direction is given or specified with respect to a candidate are not counted as votes “for” or “against”. If an incumbent director does not receive a majority of votes cast, he or she would continue to serve a term that would terminate on the date that is the earliest of (a) the date of the commencement of the term of a new director selected by the Board to fill the office held by such director, (b) the effective date of the resignation of such director and (c) the later of (i) the last day of the sixth calendar month commencing after the election and (ii) December 31 of the calendar year in which the election occurred. In a contested election — that is, an election in which the number of candidates exceeds the total number of directors to be elected — shareholders would be allowed to vote “for” one or more candidates (not to exceed the number of directors to be elected) or “withhold” votes with respect to one or more candidates. The candidates elected would be those receiving the largest number of votes (up to the number of directors to be elected). Shareholders are not allowed to cumulate their votes in any election of directors (whether or not contested).

Senior Class of Stock; Major Corporate Transaction

Under the Articles, the approval of the holders of the majority of the outstanding shares of Common Stock is required to create a new class of stock, including, for example, preference stock or any other class of stock senior to the Common Stock. In addition, in any circumstance in which the Washington BCA would require the approval of shareholders to authorize (1) the merger of the Company with or into another entity or a statutory share exchange with another entity, (2) a sale, lease, exchange or other disposition of property of the Company or (3) the dissolution of the Company, the requisite shareholder approval (in addition to any required approval by the holders of Preferred Stock) is the affirmative vote of the holders of a majority of the outstanding shares of Common Stock, unless the Washington BCA requires a higher standard.

Voting Rights of Preferred Stock

Under the Articles, whenever and as often as, at any date, dividends payable on any shares of Preferred Stock shall be in arrears in an amount equal to the aggregate amount of dividends accumulated on such shares of Preferred Stock over the eighteen (18) month period ended on such date, the holders of the Preferred Stock, voting separately and as a single class, are entitled to elect a majority of the Board of Directors, and the holders of the Common Stock, voting separately and as a single class, are entitled to elect the remaining directors. Such voting rights of the holders of the Preferred Stock cease when all defaults in the payment of dividends on the Preferred Stock have been cured.

In addition, the consent of various proportions of the Preferred Stock at the time outstanding is required to adopt any amendment to the Articles which would authorize any new class of stock ranking prior to or on a parity with the Preferred Stock as to certain matters, to increase the authorized number of shares of the Preferred Stock, to change any of the rights or preferences of outstanding Preferred Stock or to issue additional shares of Preferred Stock unless an earnings test is satisfied.

Under the Washington BCA, the approval of the holders of a majority of the outstanding shares of Preferred Stock is required in connection with certain changes in the capital structure of Avista or in certain rights and preferences of the Preferred Stock, including certain of the changes referred to in the preceding paragraph. In addition, the Washington BCA requires approval of certain mergers, share exchanges and other major corporate transactions by the holders of two-thirds of the outstanding Preferred Stock.

Board of Directors

The Articles provide that the number of directors of the Company will be the number, not to exceed eleven, that the Board of Directors specifies from time to time in the Bylaws, subject to the rights of holders of the Preferred Stock to elect directors in certain circumstances. Both the Articles and the Bylaws provide that all directors will be elected at each annual meeting for a term that will expire at the next succeeding annual meeting.

Vacancies occurring in the Board of Directors may be filled by the Board. Directors may be removed only for cause and only if the number of votes cast by holders of Common Stock for the removal of a director exceeds the number of votes cast against such removal.

The Articles and the Bylaws further require an affirmative vote of the holders of at least 80% of the outstanding shares of Common Stock to alter, amend or repeal the provisions relating to the Board of Directors and the filling of vacancies on, and the removal of members from, the Board of Directors.

Advance Notice of Shareholder Nominations for Director and Proposals of Other Business

Under the Bylaws, at an annual meeting of shareholders only such nominations of individuals for election to the Board of Directors shall be made as shall have been properly made and only such other business shall be transacted as shall be properly brought before the meeting, in accordance with the timing and information requirements set forth in the Bylaws. In general, a shareholder's notice of intention to nominate a candidate for director or bring other business before the meeting must be delivered in writing not less than 90 nor more than 180 days prior to the first anniversary date of the preceding year's annual meeting, and the information contained in or accompanying such notice shall be updated periodically up to the time of the meeting. Only shareholders of record (as of the date of the notice and the date of the meeting) who have complied with the procedures set forth in the Bylaws and appear at the meeting in person or by qualified representative are eligible to nominate a candidate for director or bring other business before the meeting.

A shareholder notice must contain information regarding the proponent, the nominee (if any) and their respective shareholdings and derivative transactions and, in addition, information as to:

- persons associated, affiliated or acting in concert with, the shareholder and the nominee (if any);
- purchases and sales by the shareholder of Avista's stock during the 24 month period preceding the shareholder notice;
- agreements, arrangements or understandings between or among the shareholder, any shareholder associated person or any other person that relates to the proposed business or proposal; and
- additional information about a shareholder's nominee, including (i) the nominee's occupation, and (ii) any related person transactions between the nominating shareholder and shareholder associated persons, and the nominee and nominee associated persons.

A shareholder proposing to nominate an individual for election as a director must submit a questionnaire (similar to Avista's directors' and officers' questionnaire) completed and signed by the nominee, which also includes representations by the nominee concerning (i) the absence of certain voting commitments and compensation or indemnification arrangements and (ii) the nominee's compliance with the applicable law and Avista's policies.

Proposed business will not be transacted and proposed nominations will not be made if the shareholder (or qualified representative) does not appear at the meeting and satisfy the other requirements of the Bylaws.

These procedures and information requirements apply to any nomination to be made at, or other business to be brought before, a shareholder meeting, including any proposal that is to be included in Avista's Proxy Statement pursuant to Rule 14a-8 under the Exchange Act.

Proxy Access

General

Subject to the conditions, limitations and exceptions set forth in the Bylaws, each Eligible Access Shareholder (as defined) may designate one nominee to election as a director of the Company (an “Access Nominee”) for inclusion in the proxy statement and proxy card of the Board of Directors used for each annual meeting of shareholders.

In order to so designate an Access Nominee, an Eligible Access Shareholder shall comply with all requirements relating to the nomination of a candidate for election as a director and shall deliver, no later than the Access Notice Date (as defined), the notice and accompanying documentation required for the nomination of such candidate, as described above under “Advance Notice of Shareholder Nominations for Director and Proposals of Other Business.” In addition, no later than the Access Notice Date, the Eligible Access Shareholder shall deliver:

- a request that the Access Nominee be included in the Board of Director’s proxy statement and proxy card, together with the written consent of such Access Nominee to be so included and to serve if elected;
- agreements and instruments, specified in the Bylaws, containing various representations and warranties as to such Eligible Access Shareholder and such Access Nominee and various agreements on the part of each of them;
- any statement (not to exceed 500 words) that the Eligible Access Shareholder requests to be included in such proxy statement.

Number of Nominees

Each Eligible Access Shareholder (including, for this purpose, its affiliates) has the right to designate one, but no more than one, Access Nominee, except that the Board of Directors is not required to include in its proxy statement or on its proxy card more than the Maximum Number of Access Nominees. If there are more than the Maximum Number of Access Nominees for any annual meeting of shareholders, the Access Nominees will be included in the order of the number (largest to smallest) of shares of the Common Stock Owned of the Eligible Access Shareholders proposing such nominees.

Exceptions and Limitations

Anything in the Bylaws to the contrary notwithstanding, if, among other things:

- the Company receives proper notice that any shareholder intends to nominate a candidate for director at the annual meeting and not request the inclusion of such candidate in the proxy statement of the Board of Directors;
- the Board of Directors determines that (i) any Access Nominee's nomination or election to the Board of Directors would result in the Company violating or failing to be in compliance with any applicable law, rule or regulation or the Articles or Bylaws or (ii) any Access Nominee would not be independent under various applicable standards, is the subject of a pending criminal proceeding or has been convicted in such a proceeding within the past ten years, or, without authorization of the Federal Energy Regulatory Commission, would upon election to the Board of Directors, be in violation of the Federal Power Act;
- any Access Nominee was included in the proxy statement and proxy card of the Board of Directors and nominated for election to the Board of Directors at one of the Company's two preceding annual meetings of shareholders and received a vote of less than 25% of the shares of Common Stock;
- any of the representations or warranties made, or any of the other information provided, by any Eligible Access Shareholder or any Access Nominee in any of the documents delivered to the Company contains any misstatement or omission of a material fact or if there occurs a material breach of any of the agreements or other obligations contained in such documents; or
- any Eligible Access Shareholder, or a qualified representative, fails to appear at the annual meeting of shareholders and nominate an Access Nominee;
- then, in any such case, among other things,
- the Board of Directors will not be required to include such Access Nominee (any Access Nominee in the case of the first bullet point above) in its proxy statement and proxy card;
- the nomination (if made) of such Access Nominee will be disregarded; and/or
- in any event, such Access Nominee will not be voted on at the annual meeting of shareholders, whether or not such Access Nominee was included in the proxy

statement and proxy card of the Board of Directors and whether or not proxies in respect of a vote on such Access Nominee have been solicited or received by the Board of Directors.

Anything in the Bylaws to the contrary notwithstanding, the Board of Directors may omit from its proxy statement, or may supplement or correct, any information, including all or any portion of the statement in support of any Access Nominee, if the Board of Directors determines, among other things, that such information contains misstatements or omissions of material facts or that the inclusion of such information would violate applicable law.

Nothing in the Bylaws limits the Company's right to solicit against and include in its proxy statement its own statements relating to, any Access Nominee.

Definitions

As used in this section:

"*Access Notice Date*" means the thirtieth (30th) day following the earliest date on which a shareholder notice of a proposed nomination of a candidate for director may be made under the applicable provision of the Bylaws, as generally described above under "Advance Notice of Shareholder Nominations for Director and Proposals of Other Business."

"*Eligible Access Shareholder*" means, subject to the specific provisions of the Bylaws, a shareholder who (1) is eligible under the Bylaws to nominate a candidate for director (or a group of not more than 20 such shareholders) and (2)(a) has continuously Owned at least the Minimum Number of shares of the Common Stock throughout the preceding three-year period and through the date of the annual meeting of shareholders and (b) otherwise satisfies the conditions and complies with the provisions of the Bylaws.

"*Maximum Number*" means, except as otherwise set forth in the Bylaws, the number of members of the Board of Directors that constitutes 20% of the total number of such members as of the Access Notice Date (rounded down to the nearest whole number); provided, however, that the Maximum Number for a particular annual meeting shall be reduced as set forth in the Bylaws.

"*Minimum Number*" means the number of shares of the Common Stock that constitutes 3% of the total number of shares outstanding as of the most recent date prior to the Access Notice Date as of which such number is given in any document filed by the Company pursuant to the Exchange Act.

"*Own*," with respect to shares of the Common Stock, means, except as otherwise set forth in the Bylaws, to possess both the full voting and investment rights pertaining to, and the full economic interest in, such shares; provided, however, that the number of shares so Owned shall not include, or shall be reduced by, any shares purchased or sold in an unsettled transaction, sold short, borrowed or subject to any derivative or similar agreement that reduces the holder's voting rights in respect of such shares or hedges or offsets the economic interest otherwise attributable to such shares.

Special Meetings of Shareholders

The Articles provide that a special meeting of shareholders may be called by certain corporate officers and shall be called by the President at the request of the holders of two-thirds of the outstanding shares of Common Stock.

“Fair Price” Provision

The Articles contain a “fair price” provision which requires the affirmative vote of the holders of at least 80% of the outstanding shares of Common Stock for the consummation of certain business combinations, including mergers, consolidations, recapitalizations, certain dispositions of assets, certain issuances of securities, liquidations and dissolutions involving Avista and a person or entity who is or, under certain circumstances, was, a beneficial owner of 10% or more of the outstanding shares of Common Stock (an “Interested Shareholder”) unless

- such business combination has been approved by a majority of the directors unaffiliated with the Interested Shareholder, or
- certain minimum price and procedural requirements are met. The Articles provide that the “fair price” provision may be altered, amended or repealed only by the affirmative vote of the holders of at least 80% of the outstanding shares of Common Stock.

Statutory Limitation on “Significant Business Transactions”

General

The Washington BCA contains provisions that limit our ability to engage in “significant business transactions” with an “acquiring person”, each as defined below. Avista has no right to waive the applicability of these provisions.

Significant Business Transactions Within Five Years of Share Acquisition Time

Subject to certain exceptions, for five years after an "acquiring person's" "share acquisition time," Avista may not engage in any "significant business transaction" with such "acquiring person" unless:

- before such "share acquisition time", a majority of the Board of Directors approves either:
  - such "significant business transaction"; or
  - the purchase of shares made by such "acquiring person"; or
- at or subsequent to such "share acquisition time", such "significant business transaction" has been approved by:
  - a majority of the Board of Directors; and
  - the holders of 2/3 of the outstanding shares of Common Stock (except shares beneficially owned by or under the voting control of the "acquiring person").

Significant Business Transactions More Than Five Years After Share Acquisition Time

Avista may not engage in certain "significant business transactions" (including mergers, share exchanges and consolidations) with any "acquiring person" unless:

- the transaction complies with certain "fair price" provisions specified in the statute; or
- no earlier than five years after the "acquiring person's" "share acquisition time", the "significant business transaction" is approved at an annual or special meeting of shareholders by holders of a majority of the outstanding shares of common stock by or under the voting control of the "acquiring person" may not be counted in determining whether the "significant business transaction" has been approved.

Definitions

As used in this section:

"Significant business transaction" means any of various specified transactions involving an "acquiring person", including:

- a merger, share exchange, or consolidation of Avista or any of its subsidiaries with an "acquiring person" or its affiliate;
- a sale, lease, transfer or other disposition to an "acquiring person" or its affiliate of assets of Avista or any of its subsidiaries having an aggregate market value equal to 5% or more of all of the assets determined on a consolidated basis, or all the outstanding shares of Avista, or representing 5% or more of its earning power or net income determined on a consolidated basis;
- termination, at any time over the five-year period following the "share acquisition time", of 5% or more of the employees of Avista as a result of the "acquiring person's" acquisition of 10% or more of the shares of Avista; and
- the issuance or redemption by Avista or any of its subsidiaries of shares (or of options, warrants, or rights to acquire shares) of Avista or any of its subsidiaries to or beneficially owned by an "acquiring person" or its affiliate except pursuant to an offer, dividend distribution or redemption paid or made *pro rata* to all shareholders (or holders of options, warrants or rights).

"Acquiring person" means, with certain exceptions, a person (or group of persons) other than Avista or its subsidiaries who beneficially owns 10% or more of the outstanding Common Stock of Avista.

"Share acquisition time" means the time at which a person first becomes an "acquiring person" of Avista.

Regulatory Approvals Required for An Acquisition of Avista

General

As a public utility company, Avista is subject to the jurisdiction of the federal and state utility regulatory commissions listed below. Although there is specific statutory language in each jurisdiction that defines the transactions that would require commission approval, in general any acquisition of direct or indirect control over, or other direct or indirect transfer or acquisition of the utility facilities of, Avista by any means (any such transaction being called, for convenience, an *"Acquisition"*), would be subject to the approval of such commissions. The following is an outline of the primary standards for approval in each jurisdiction, but it is not a complete list of all approvals that would be required.

Washington

As a condition to its approval of a proposed Acquisition, the Washington Utilities and Transportation Commission would have to conclude, among other things, that the Acquisition would provide a "net benefit" to Avista's customers and would otherwise be "consistent with the public interest."

Idaho

As a condition to its approval of a proposed Acquisition, the Idaho Public Utilities Commission (the *"IPUC"*) would have to conclude, among other things, that the Acquisition would be "consistent with the public interest". In addition, because any Acquisition would include hydropower water rights used in the generation of electric power, the Idaho Department of Water Resources would have to issue conditions protecting the public interest and holders of existing water rights with respect to the hydropower water rights to be transferred.

In addition, a separate Idaho statute, on its face, provides, subject to certain exceptions, that no interest in any electric public utility property may be transferred to or acquired by, directly or indirectly, (1) any government or governmental or political entity organized or existing under the laws of any other state, or any corporation or other organization whose capital stock or other evidence of ownership is owned or controlled, directly or indirectly, by any of the foregoing or (2) any corporation or other organization that (a) is organized under the laws of any other state and (b) is not an "electric public utility" or "electrical corporation" subject to the jurisdiction of the IPUC.

Montana

As a condition to its approval of a proposed Acquisition, the Public Service Commission of the State of Montana (the *"MPSC"*) would have to conclude, among other things, that the Acquisition would satisfy any of three standards – the "public interest" standard, the "no-harm-to-consumers" standard or the "net-benefit-to-consumers" standard. The MPSC has not enunciated a specific standard, applicable in every case, because of the variety of situations that can arise.

Oregon

In addition to requiring approval by the Public Utility Commission of Oregon (the *"OPUC"*) of any Acquisition, Oregon law separately requires OPUC approval of any transaction whereby any person, directly or indirectly, would "acquire the power to exercise any substantial influence over the policies and actions of a public utility" if such person is, or would become, an "affiliated interest" with such public utility (defined to include a person owning or holding, directly or indirectly, 5% or more of the voting securities of a public utility). As a condition to its approval of the acquisition of such a "substantial influence", as described above, the OPUC would have to conclude, among other things, that the proposed transaction would "serve the public utility's customers and [be] in the public interest" (which the OPUC interprets as a "net benefits" test).

Alaska

Alaska law would require the approval by the Regulatory Commission of Alaska (the *"RCA"*) for any Acquisition since such a transaction would constitute an indirect acquisition of a controlling interest in Alaska Electric Light and Power Company, which is an indirect, wholly owned subsidiary of Avista. As a condition to its approval of a proposed Acquisition, the RCA would have to conclude, among other things, that the proposed acquiror is "fit, willing and able" and that the proposed transaction is "consistent with the convenience and necessity of the public."

Federal

As a condition to its approval of a proposed Acquisition, the Federal Energy Regulatory Commission would have to conclude, among other things, that the Acquisition would be "consistent with the public interest", considering, among other things, the effect of the transaction on competition in wholesale electric power markets and the rates for wholesale power sales or electric transmission services.

Anti-Takeover Effect

Certain provisions of the Articles and the Bylaws described above under "Board of Directors", the provisions of the Bylaws described above under "Advance Notice of Shareholder Nominations for Director and Proposals of Other Business" and the provisions of the Articles described above under "Special Meetings of Shareholders" and "'Fair Price' Provision", together with the provisions of the Washington BCA described above under "Statutory Limitations on 'Significant Business Transactions'", considered either individually or in the aggregate, may have an "anti-takeover" effect. These provisions could discourage a future takeover attempt which is not approved by Avista's Board of Directors, but which individual shareholders might deem to be in their best interests or in which shareholders would receive a premium for their shares over current market prices.

In addition, the provisions of federal and state utility law described under "Regulatory Approval Required for an Acquisition of Avista" could discourage any future takeover attempt or other business combination, even if it were approved by the Company's Board of Directors and even if individual shareholders might deem it to be in their best interests.

Miscellaneous

The outstanding shares of Common Stock are fully paid and non-assessable. The holders of shares of Common Stock are not and will not be subject to liability for further calls or assessment by, or for liabilities of, Avista.

The outstanding shares of Common Stock are listed on the New York Stock Exchange under the symbol "AVA." Any new shares of Common Stock will also be listed on that Exchange subject to official notice of issuance.

The Transfer Agent and Registrar for the Common Stock is Computershare Shareowner Services LLC, P.O. Box 505000, Louisville, KY 40233.

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 **«Employee_First_Name» «Employee_Last_Name»**

b. The "Grant Date" is **February 4, 2021**.

c. The total target number of eligible "Performance Awards" shall be (# of) 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, 2021 and ending on December 31, 2023.

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.

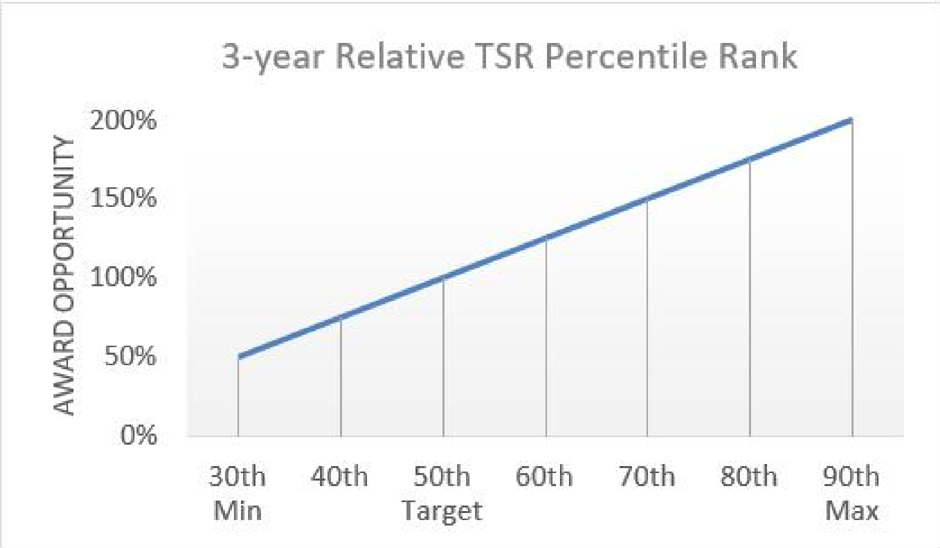
AVISTA CORPORATION

By: Dennis Vermillion
President and Chief Executive Officer

EXHIBIT 1

Performance Award Plan
Relative Total Shareholder Return Metric and Goals
2021 - 2023 Performance Cycle

The following graph and table represent the relationship between the Company's relative three-year Total Shareholder Return ("TSR") commencing January 1, 2021 and ending December 31, 2023 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, 2018 – December 31, 2020 as the Performance Cycle.

Date	**Closing Price**	Date	Closing Price
12/29/2017	51.49	12/31/2020	40.14
12/28/2017	51.56	12/30/2020	39.66
12/27/2017	51.53	12/29/2020	39.74
12/26/2017	51.47	12/28/2020	40.42
12/22/2017	51.51	12/24/2020	39.92
12/21/2017	51.45	12/23/2020	39.68
12/20/2017	51.27	12/22/2020	39.34
12/19/2017	51.25	12/21/2020	38.3
12/18/2017	51.47	12/18/2020	38.85
12/15/2017	51.48	12/17/2020	39.52
12/14/2017	51.42	12/16/2020	39.61
12/13/2017	51.61	12/15/2020	39.78
12/12/2017	51.4	12/14/2020	39.11
12/11/2017	51.58	12/11/2020	38.96
12/8/2017	51.58	12/10/2020	38.86
12/7/2017	51.55	12/9/2020	38.57
12/6/2017	51.67	12/8/2020	37.75
12/5/2017	51.71	12/7/2020	37.8
12/4/2017	51.83	12/4/2020	37.38
12/1/2017	51.94	12/3/2020	37.42
Average	51.5385	Average	39.0405

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.

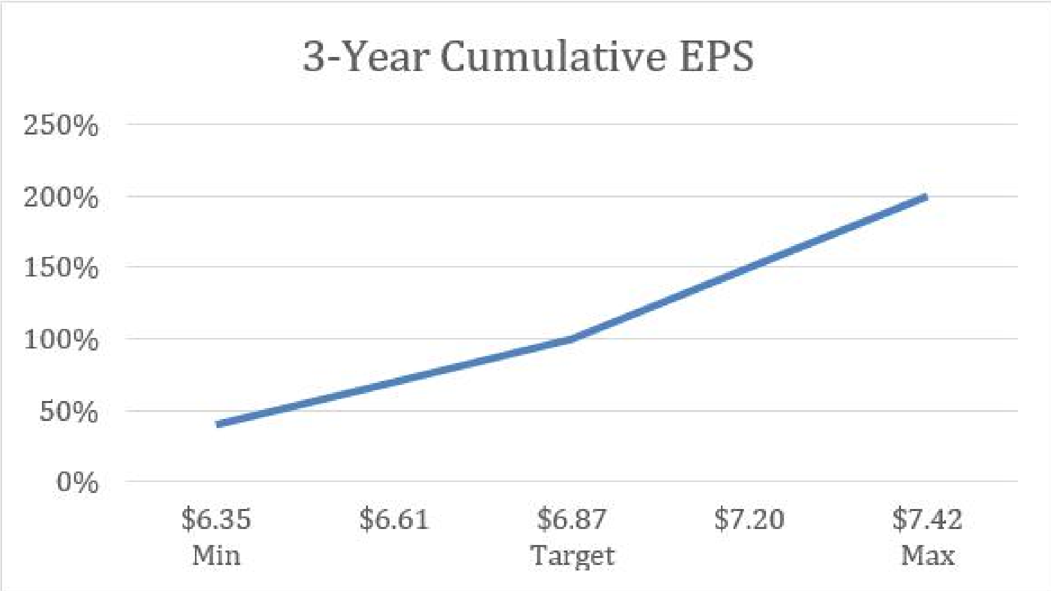
Date	Closing Price	Dividend	Daily TSR
11/19/2019	47.03	0	NA
11/20/2019	46.92	0.388	0.5911%*
11/21/2019	46.65	0	(0.5609%)
11/22/2019	46.41	0	(0.5190%)
11/25/2019	46.80	0	0.8392%
11/26/2019	46.91	0	0.2427%
Cumulative TSR 11/19/2019 to 11/26/2019			0.5978%

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

EXHIBIT 2

Performance Award Plan
Cumulative Earnings Per Share Metric and Goals
–2021-2023 Performance Period

The following graph and table represent the relationship between the Company’s Cumulative Earnings Per Share (“CEPS”) commencing January 1, 2021 and ending December 31, 2023 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 $6.87 over the three-year cycle. To receive 200% of the Award, Avista must achieve CEPS of $7.42. If Avista’s CEPS is less than $6.35, 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	$7.52	200%
Target	$6.87	100%
Threshold	$6.35	40%
	<$6.35	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 $7.03 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

2021 EXECUTIVE OFFICER
ANNUAL CASH INCENTIVE PLAN – Revised
February 2022

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, 2021 – December 31, 2021

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.

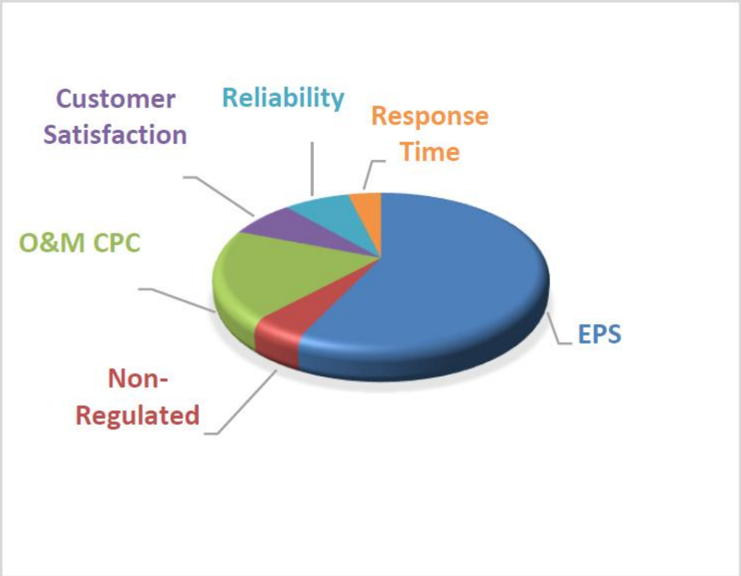
Non-Regulated Activity – This is a measure that identifies the Company's non-regulated business for continued focus on innovation and development of the new business pipeline ultimately with the intent to positively impact EPS. The metric is based on achieving a set of activity based milestones.

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, non-regulated activity is 5 percent, customer satisfaction and reliability each 8 percent, and response time 4 percent.



Non-financial metrics: The non-financial pieces of the award (customer satisfaction, reliability, and 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 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.

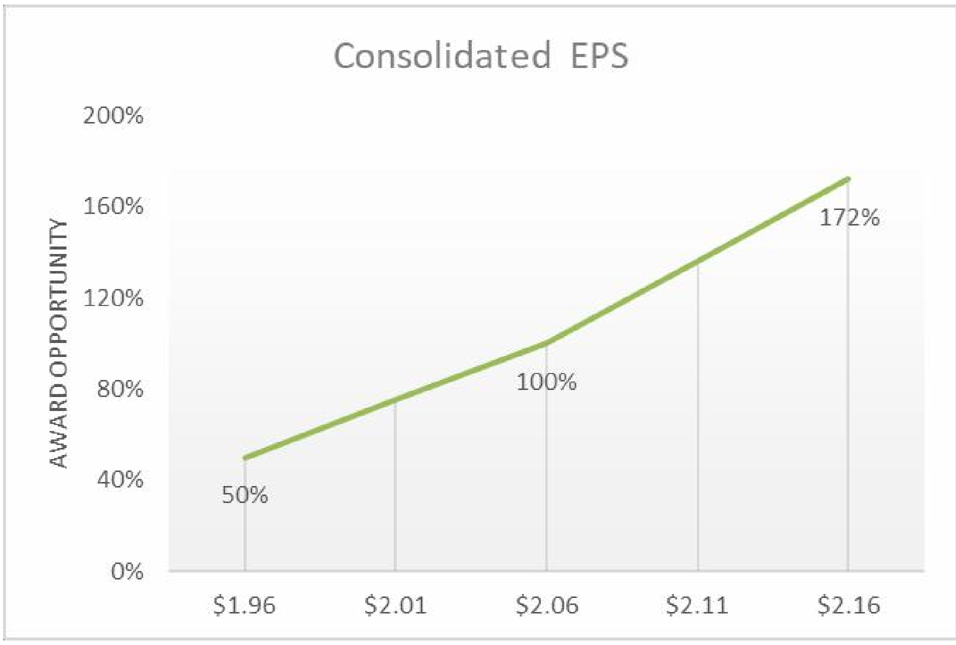


Figure 1

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 3

The non-regulated activity metric is based on the achievement of two milestones, each of which awards 50% of the incentive goal. If the Company achieves both milestones, employees receive 100% of the incentive award percentage related to the metric, or 5%. Achievement of only one of the two milestones would result in a 50% payout of the non-regulated activity metric, or 2.5%

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:

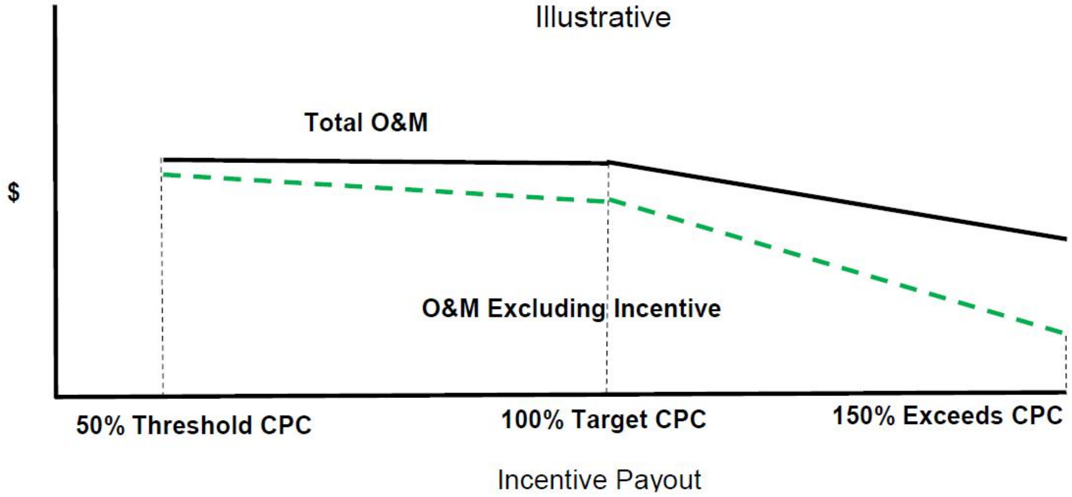
Consolidated Earnings per Share: To determine the Consolidated EPS goal for the Plan, the Committee, in conjunction with the Finance Committee of the Board and management, considered and incorporated the EPS target range contained in the Company's original publicly disclosed earnings guidance and reviewed 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 2021 guidance for EPS is $1.96 to $2.16.

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 10,193. Variability in the final customer count will impact the amount of O&M savings necessary to achieve an incentive payment.

Non-Regulated Activity: The purpose of this metric is to align the Officers with our core value of Invent, and to facilitate non-utility growth. The three milestones that are measured are New Business Launches, completion of Startup Avista exercises, and Avista Edge Total Customer Metric. A New Business Launch is defined as the creation of a new distinct entity (tax id) that has dedicated staff (at least 2 FTE) and an Officer approved business plan. A Startup Avista exercise is a business ideation process which must include Design Thinking Training, a customer engagement exercise, completion of a Business Model Canvas, development of a prototype if applicable, and opportunity evaluation culminating in a presentation to the Officers of the potential for a New Business Launch. This process is also referred to as the Startup Avista exercise. The third milestone is for Avista Edge to reach 1,953 total retail customers in 2021. In this Plan, the target is set at achieving two milestones. Each milestone (a New Business Launch, completion of two Startup Avista events, or Avista Edge achieving the target number of retail customers) results in a 50% payout of the award opportunity, and completion of two or more milestones would result in 100% payout of the 5% award opportunity.

Examples of this calculation methodology would be:

New Business Launch (50%) + 2 Startup Avista Exercises (50%) = 100% payout

Startup Avista Exercises (50%) + 0 New Business Launches = 50% payout

2 Startup Avista Exercises (50%) + 2 Startup Avista Exercises (50%) = 100% payout

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 (CEMI3)*. CEMI3 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.

$$\text{Index} = \frac{\text{CAIDI Target / CAIDI Actual}}{3} + \frac{\text{SAIFI Target / SAIFI Actual}}{3} + \frac{\text{CEMI3 Target / CEMI3 Actual}}{3}$$

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 34 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 1.05 outages per customer.
- Customers Experiencing Multiple Sustained Interruptions more than 3 (CEMI3): *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 5.99% 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 2021:

	Earnings Per Share	O&M Cost per Customer	Customer Satisfaction Rating	Reliability Index	Average Response Time Minutes	Non Regulated Activity
% of Total Opportunity	55%	20%	8%	8%	4%	5%
Threshold 50%	$1.96	$419.87				
Target 100%	$2.06	$417.26	90%	1.00	<55 Min	≥ 2 milestones achieved
Maximum 172%	$2.16					
Maximum 150%		$407.52				

*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
100%	65%	60%	40%

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) Non-Regulated Activity = 100% = 2 milestones met

Non-CEO Average Earnings = $314,335 Average Target Opportunity = 48% or $150,881							
Goal	Opportunity		Weighting		% Results		Amount
Consolidated EPS	$ 150,880.58	x	55%	x	166.666666%	=	$ 138,307.20
Cost per Customer	$ 150,880.58	x	20%	x	148.6468%	=	$ 44,855.83
Customer Satisfaction	$ 150,880.58	x	8%	x	100%	=	$ 12,070.45
Reliability	$ 150,880.58	x	8%	x	100%	=	$ 12,070.45
Response Time	$ 150,880.58	x	4%	x	100%	=	$ 6,035.22
Non-Regulated	$ 150,880.58	x	5%		100%		$ 7,544.03
Total Payout = $220,883 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 12/21/2020 – 1/3/2021 which is paid on pay date 1/8/2021. Changes effective during this pay period will count towards the 2021 plan since the earnings and pay date are part of 2021. Changes effective during the dates 12/20/2021 – 1/2/2022 are not included in the 2021 Plan because the earnings and pay date are part of 2022.

Pay Period Schedule for 2021:

Pay Period	Date Range	Pay Date	Pay Period	Date Range	Pay Date
1	12/21/20 – 01/03/2021	1/8	14	6/21 – 7/4	7/9
2	1/4 – 1/17	1/22	15	7/5 – 7/18	7/23
3	1/18 – 1/31	2/5	16	7/19 – 8/1	8/6
4	2/1 – 2/14	2/19	17	8/2 – 8/15	8/20
5	2/15 – 2/28	3/5	18	8/16 – 8/29	9/3
6	3/1 – 3/14	3/19	19	8/30 – 9/12	9/17
7	3/15 – 3/28	4/2	20	9/13 – 9/26	10/1
8	3/29 – 4/11	4/16	21	9/27 – 10/10	10/15
9	4/12 – 4/25	4/30	22	10/11 – 10/24	10/29
10	4/26 – 5/9	5/14	23	10/25 – 11/7	11/12
11	5/10 – 5/23	5/28	24	11/8 – 11/21	11/26
12	5/24 – 6/6	6/11	25	11/22 – 12/5	12/10
13	6/7 – 6/20	6/25	26	12/6 – 12/19	12/23

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 5/7 and remains employed through the end of the year. The date 5/7 falls in the date range associated with pay period 10 which is paid on pay date 5/14. 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 9/22 and remains employed through the end of the year. Her date falls in pay period 20 and is associated with pay date 10/1. 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 5/20 and returns to his regular union position on 12/4. The transfer date of 5/20 falls within pay period 11 which is associated with pay date 5/28. The returning date of 12/4 falls within pay period 25 which is associated with pay date 12/10. Count the number of pay dates starting with 5/28 and end with 11/26 which is the pay date prior to the next COS date of 12/4. He receives 14 pay periods of credit towards the non-union portion of his incentive award. Remember you 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	4/26 – 5/9	5/14	1		
11	5/10 – 5/23	5/28	1		1
12	5/24 – 6/6	6/11	1		1
13	6/7 – 6/20	6/25	1		1
14	6/21 – 7/4	7/9	1		1
15	7/5 – 7/18	7/23	1		1
16	7/19 – 8/1	8/6	1		1
17	8/2 – 8/15	8/20	1		1
18	8/16 – 8/29	9/3	1		1
19	8/30 – 9/12	9/17	1		1
20	9/13 – 9/26	10/1	1	1	1
21	9/27 – 10/10	10/15	1	1	1
22	10/11 – 10/24	10/29	1	1	1
23	10/25 – 11/7	11/12	1	1	1
24	11/8 – 11/21	11/26	1	1	1
25	11/22 – 12/5	12/10	1	1	
26	12/6 – 12/19	12/23	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, 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, 34C, 61
Short-term Disability 100% & 60%	18, 80
Workers Compensation	19, 19A, 85, 85C, 86, 87, 88
Holiday	25, 26, 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

Avista Corporation
Non-Employee Director Compensation - 2021

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	2021 Compensation		
Annual Retainer (cash and stock)	Board Members: (Directors receive an annual retainer of $190,000, with $110,000 automatically paid in stock. Directors have the option of taking the remaining $80,000 in cash, stock or a combination of both cash and stock.)	**$**	**190,000**
Committee Chair Retainers (Cash)	Audit Committee:	**$**	**20,000**
	Compensation Committee:	**$**	**15,000**
	Environmental Committee:	**$**	**15,000**
	Finance Committee:	**$**	**15,000**
	Governance Committee:	**$**	**15,000**
	Lead Director:	**$**	**25,000**
	Non-Executive Chairman:	**$**	**100,000**
Meeting Fees (Cash)	Board and Committee Meetings	**$**	**1,500**

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. Within five years of becoming a Board member, outside directors are expected to achieve a minimum investment of five times the minimum stock portion of their retainer (currently, five times $110,000 = $550,000), 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. All directors currently comply or are making adequate progress towards compliance based on their years of service completed on the Board.

There were no annual stock option grants or non-stock incentive plan compensation payments to directors for services in 2021 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. 333-231431 on Form S-3 of our reports dated February 22, 2022, 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, 2021.

/s/ DELOITTE & TOUCHE LLP

Portland, Oregon
February 22, 2022

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 22, 2022

/s/ Dennis P. Vermillion

Dennis P. Vermillion

President and Chief Executive Officer

(Principal Executive Officer)

Exhibit 31.2

CERTIFICATION

I, Mark T. Thies, 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 22, 2022

/s/ Mark T. Thies

Mark T. Thies
Executive Vice President,
Chief Financial Officer, and Treasurer
(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, President and Chief Executive Officer of Avista Corporation (the "Company"), and Mark T. Thies, Executive 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, 2021 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 22, 2022

/s/ Dennis P. Vermillion
Dennis P. Vermillion
President and Chief Executive Officer

/s/ Mark T. Thies
Mark T. Thies
Executive Vice President,
Chief Financial Officer, and Treasurer