UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FILED
06/12/26
04:59 PM
A2606009

FORM 10-K

☒ Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the fiscal year ended December 31, 2025

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	Exact name of registrant as specified in its charter; State or other jurisdiction of incorporation or organization	IRS Employer Identification No.
001-14881	**BERKSHIRE HATHAWAY ENERGY COMPANY** **(An Iowa Corporation)** **1615 Locust Street** **Des Moines, Iowa 50309-3037** **515-242-4300**	**94-2213782**
001-05152	**PACIFICORP** **(An Oregon Corporation)** **825 N.E. Multnomah Street** **Portland, Oregon 97232** **888-221-7070**	**93-0246090**
333-90553	**MIDAMERICAN FUNDING, LLC** **(An Iowa Limited Liability Company)** **1615 Locust Street** **Des Moines, Iowa 50309-3037** **515-242-4300**	**47-0819200**
333-15387	**MIDAMERICAN ENERGY COMPANY** **(An Iowa Corporation)** **1615 Locust Street** **Des Moines, Iowa 50309-3037** **515-242-4300**	**42-1425214**
000-52378	**NEVADA POWER COMPANY** **(A Nevada Corporation)** **6226 West Sahara Avenue** **Las Vegas, Nevada 89146** **702-402-5000**	**88-0420104**
000-00508	**SIERRA PACIFIC POWER COMPANY** **(A Nevada Corporation)** **6100 Neil Road** **Reno, Nevada 89511** **775-834-4011**	**88-0044418**
001-37591	**EASTERN ENERGY GAS HOLDINGS, LLC** **(A Virginia Limited Liability Company)** **10700 Energy Way** **Glen Allen, Virginia 23060** **804-613-5100**	**46-3639580**
333-266049	**EASTERN GAS TRANSMISSION AND STORAGE, INC.** **(A Delaware Corporation)** **10700 Energy Way** **Glen Allen, Virginia 23060** **804-613-5100**	**55-0629203**

Registrant	Securities registered pursuant to Section 12(b) of the Act:
BERKSHIRE HATHAWAY ENERGY COMPANY	None
PACIFICORP	None
MIDAMERICAN FUNDING, LLC	None
MIDAMERICAN ENERGY COMPANY	None
NEVADA POWER COMPANY	None
SIERRA PACIFIC POWER COMPANY	None
EASTERN ENERGY GAS HOLDINGS, LLC	None
EASTERN GAS TRANSMISSION AND STORAGE, INC.	None

Registrant	Name of exchange on which registered:
BERKSHIRE HATHAWAY ENERGY COMPANY	None
PACIFICORP	None
MIDAMERICAN FUNDING, LLC	None
MIDAMERICAN ENERGY COMPANY	None
NEVADA POWER COMPANY	None
SIERRA PACIFIC POWER COMPANY	None
EASTERN ENERGY GAS HOLDINGS, LLC	None
EASTERN GAS TRANSMISSION AND STORAGE, INC.	None

Registrant	Securities registered pursuant to Section 12(g) of the Act:
BERKSHIRE HATHAWAY ENERGY COMPANY	None
PACIFICORP	None
MIDAMERICAN FUNDING, LLC	None
MIDAMERICAN ENERGY COMPANY	None
NEVADA POWER COMPANY	Common Stock, $1.00 stated value
SIERRA PACIFIC POWER COMPANY	Common Stock, $3.75 par value
EASTERN ENERGY GAS HOLDINGS, LLC	None
EASTERN GAS TRANSMISSION AND STORAGE, INC.	None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Registrant	Yes	No
BERKSHIRE HATHAWAY ENERGY COMPANY	☐	☒
PACIFICORP	☒	☐
MIDAMERICAN FUNDING, LLC	☐	☒
MIDAMERICAN ENERGY COMPANY	☒	☐
NEVADA POWER COMPANY	☐	☒
SIERRA PACIFIC POWER COMPANY	☐	☒
EASTERN ENERGY GAS HOLDINGS, LLC	☒	☐
EASTERN GAS TRANSMISSION AND STORAGE, INC.	☐	☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Registrant	Yes	No
BERKSHIRE HATHAWAY ENERGY COMPANY	☐	☒
PACIFICORP	☐	☒
MIDAMERICAN FUNDING, LLC	☒	☐
MIDAMERICAN ENERGY COMPANY	☐	☒
NEVADA POWER COMPANY	☐	☒
SIERRA PACIFIC POWER COMPANY	☐	☒
EASTERN ENERGY GAS HOLDINGS, LLC	☐	☒
EASTERN GAS TRANSMISSION AND STORAGE, INC.	☐	☒

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.

Registrant	Yes	No
BERKSHIRE HATHAWAY ENERGY COMPANY	☒	☐
PACIFICORP	☒	☐
MIDAMERICAN FUNDING, LLC	☐	☒
MIDAMERICAN ENERGY COMPANY	☒	☐
NEVADA POWER COMPANY	☒	☐
SIERRA PACIFIC POWER COMPANY	☒	☐
EASTERN ENERGY GAS HOLDINGS, LLC	☒	☐
EASTERN GAS TRANSMISSION AND STORAGE, INC.	☒	☐

Indicate by check mark whether the registrants have 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 registrants were 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.

Registrant	Large accelerated filer	Accelerated filer	Non-accelerated filer	Smaller reporting company	Emerging growth company
BERKSHIRE HATHAWAY ENERGY COMPANY	☐	☐	☒	☐	☐
PACIFICORP	☐	☐	☒	☐	☐
MIDAMERICAN FUNDING, LLC	☐	☐	☒	☐	☐
MIDAMERICAN ENERGY COMPANY	☐	☐	☒	☐	☐
NEVADA POWER COMPANY	☐	☐	☒	☐	☐
SIERRA PACIFIC POWER COMPANY	☐	☐	☒	☐	☐
EASTERN ENERGY GAS HOLDINGS, LLC	☐	☐	☒	☐	☐
EASTERN GAS TRANSMISSION AND STORAGE, INC.	☐	☐	☒	☐	☐

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

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

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

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

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

All shares of outstanding common stock of Berkshire Hathaway Energy Company are held by its parent company, Berkshire Hathaway Inc. As of January 31, 2026, 1 share of common stock, no par value, was outstanding.

All shares of outstanding common stock of PacifiCorp are indirectly held by Berkshire Hathaway Energy Company. As of January 31, 2026, 357,060,915 shares of common stock, no par value, were outstanding.

All of the member's equity of MidAmerican Funding, LLC is held by its parent company, Berkshire Hathaway Energy Company, as of January 31, 2026.

All shares of outstanding common stock of MidAmerican Energy Company are held by its parent company, MHC Inc., which is a direct, wholly owned subsidiary of MidAmerican Funding, LLC. As of January 31, 2026, 70,980,203 shares of common stock, no par value, were outstanding.

All shares of outstanding common stock of Nevada Power Company are held by its parent company, NV Energy, Inc., which is an indirect, wholly owned subsidiary of Berkshire Hathaway Energy Company. As of January 31, 2026, 1,000 shares of common stock, $1.00 stated value, were outstanding.

All shares of outstanding common stock of Sierra Pacific Power Company are held by its parent company, NV Energy, Inc. As of January 31, 2026, 1,000 shares of common stock, $3.75 par value, were outstanding.

All of the member's equity of Eastern Energy Gas Holdings, LLC is held indirectly by its parent company, Berkshire Hathaway Energy Company, as of January 31, 2026.

All shares of outstanding common stock of Eastern Gas Transmission and Storage, Inc. are held by its parent company, Eastern Energy Gas Holdings, LLC, which is an indirect, wholly owned subsidiary of Berkshire Hathaway Energy Company. As of January 31, 2026, 60,101 shares of common stock, $10,000 par value, were outstanding.

Berkshire Hathaway Energy Company, PacifiCorp, MidAmerican Funding, LLC, MidAmerican Energy Company, Nevada Power Company, Sierra Pacific Power Company, Eastern Energy Gas Holdings, LLC and Eastern Gas Transmission and Storage, Inc. meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and are therefore filing portions of this Form 10-K with the reduced disclosure format specified in General Instruction I(2) of Form 10-K.

This combined Form 10-K is separately filed by Berkshire Hathaway Energy Company, PacifiCorp, MidAmerican Funding, LLC, MidAmerican Energy Company, Nevada Power Company, Sierra Pacific Power Company, Eastern Energy Gas Holdings, LLC and Eastern Gas Transmission and Storage, Inc. Information contained herein relating to any individual company is filed by such company on its own behalf. Each company makes no representation as to information relating to the other companies.

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Definition of Abbreviations and Industry Terms

When used in Forward-Looking Statements, Part I - Items 1 through 4, Part II - Items 5 through 7A, and Part III - Items 10 through 14, the following terms have the definitions indicated.

Entity Definitions

BHE	Berkshire Hathaway Energy Company
Berkshire Hathaway	Berkshire Hathaway Inc.
Berkshire Hathaway Energy or the Company	Berkshire Hathaway Energy Company and its subsidiaries
PacifiCorp	PacifiCorp and its subsidiaries
MidAmerican Funding	MidAmerican Funding, LLC and its subsidiaries
MidAmerican Energy	MidAmerican Energy Company
NV Energy	NV Energy, Inc. and its subsidiaries
Nevada Power	Nevada Power Company and its subsidiaries
Sierra Pacific	Sierra Pacific Power Company and its subsidiaries
Nevada Utilities	Nevada Power Company and its subsidiaries and Sierra Pacific Power Company and its subsidiaries
EEGH	Eastern Energy Gas Holdings, LLC
Eastern Energy Gas	Eastern Energy Gas Holdings, LLC and its subsidiaries
EGTS	Eastern Gas Transmission and Storage, Inc. and its subsidiaries
Registrants	Berkshire Hathaway Energy Company, PacifiCorp and its subsidiaries, MidAmerican Funding, LLC and its subsidiaries, MidAmerican Energy Company, Nevada Power Company and its subsidiaries, Sierra Pacific Power Company and its subsidiaries, Eastern Energy Gas Holdings, LLC and its subsidiaries and Eastern Gas Transmission and Storage, Inc. and its subsidiaries
Subsidiary Registrants	PacifiCorp and its subsidiaries, MidAmerican Funding, LLC and its subsidiaries, MidAmerican Energy Company, Nevada Power Company and its subsidiaries, Sierra Pacific Power Company and its subsidiaries, Eastern Energy Gas Holdings, LLC and its subsidiaries and Eastern Gas Transmission and Storage, Inc. and its subsidiaries
Northern Powergrid	Northern Powergrid Holdings Company and its subsidiaries
BHE GT&S	BHE GT&S, LLC and its subsidiaries
Northern Natural Gas	Northern Natural Gas Company
Kern River	Kern River Gas Transmission Company
CGT	Carolina Gas Transmission, LLC
BHE Canada	BHE Canada Holdings Corporation and its subsidiaries
AltaLink	AltaLink, L.P.
BHE U.S. Transmission	BHE U.S. Transmission, LLC and its subsidiaries
HomeServices	HomeServices of America, Inc. and its subsidiaries
BHE Pipeline Group or Pipeline Companies	BHE GT&S, LLC, Northern Natural Gas Company and Kern River Gas Transmission Company
BHE Transmission	BHE Canada Holdings Corporation and BHE U.S. Transmission, LLC
BHE Renewables	BHE Renewables, LLC and its subsidiaries
ETT	Electric Transmission Texas, LLC
Domestic Regulated Businesses	PacifiCorp and its subsidiaries, MidAmerican Energy Company, Nevada Power Company and its subsidiaries, Sierra Pacific Power Company and its subsidiaries, BHE GT&S, LLC and its subsidiaries, Northern Natural Gas Company and Kern River Gas Transmission Company
Regulated Businesses	PacifiCorp and its subsidiaries, MidAmerican Energy Company, Nevada Power Company and its subsidiaries, Sierra Pacific Power Company and its subsidiaries, BHE GT&S, LLC and its subsidiaries, Northern Natural Gas Company, Kern River Gas Transmission Company and AltaLink, L.P.

Utilities	PacifiCorp and its subsidiaries, MidAmerican Energy Company, Nevada Power Company and its subsidiaries and Sierra Pacific Power Company and its subsidiaries
Northern Powergrid Distribution Companies	Northern Powergrid (Northeast) plc and Northern Powergrid (Yorkshire) plc
Topaz	Topaz Solar Farms LLC
Topaz Project	550-megawatt solar project in California
Agua Caliente	Agua Caliente Solar, LLC
Agua Caliente Project	290-megawatt solar project in Arizona
Bishop Hill II	Bishop Hill Energy II LLC
Bishop Hill Project	81-megawatt wind-powered generating facility in Illinois
Pinyon Pines I	Pinyon Pines Wind I, LLC
Pinyon Pines II	Pinyon Pines Wind II, LLC
Pinyon Pines Projects	168-megawatt and 132-megawatt wind-powered generating facilities in California
Jumbo Road	Jumbo Road Holdings, LLC
Jumbo Road Project	300-megawatt wind-powered generating facility in Texas
Solar Star Funding	Solar Star Funding, LLC
Solar Star Projects	A combined 586-megawatt solar project in California
Solar Star I	Solar Star California XIX, LLC
Solar Star II	Solar Star California XX, LLC
Cove Point	Cove Point LNG, LP
Iroquois	Iroquois Gas Transmission System, L.P.
Liquefaction Facility	A natural gas export/liquefaction facility

Certain Industry Terms

2020 Wildfires	Wildfires in Oregon and Northern California that occurred in September 2020
2022 McKinney Fire	A wildfire that began in the Oak Knoll Ranger District of the Klamath National Forest in Siskiyou County, California in July 2022
Wildfires	2020 Wildfires and 2022 McKinney Fire
AESO	Alberta Electric System Operator
AFUDC	Allowance for Funds Used During Construction
AOCI	Accumulated Other Comprehensive Income (Loss)
ARO	Asset Retirement Obligation
ASC	Accounting Standards Codification
AUC	Alberta Utilities Commission
BART	Best Available Retrofit Technology
Bcf	Billion cubic feet
BTER	Base Tariff Energy Rate
California ISO	California Independent System Operator Corporation
CCR	Coal Combustion Residuals
CMO No. 11	Case Management Order No. 11 issued July 28, 2025, by Multnomah County Circuit Court Oregon, which schedules a significant number of James trials in 2026, 2027 and 2028
CPUC	California Public Utilities Commission
CSAPR	Cross-State Air Pollution Rule
D.C. Circuit	U.S. Court of Appeals for the District of Columbia Circuit
DEAA	Deferred Energy Accounting Adjustment
DOE	U.S. Department of Energy
Dodd-Frank Reform Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
DOT	U.S. Department of Transportation

Dth	Decatherm
DSM	Demand Side Management
EAC	Energy Adjustment Clause
EBA	Energy Balancing Account
ECAC	Energy Cost Adjustment Clause
ECAM	Energy Cost Adjustment Mechanism
EEIR	Energy Efficiency Implementation Rate
EEPR	Energy Efficiency Program Rate
EIM	Energy Imbalance Market
EPA	U.S. Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FIP	Federal Implementation Plan
GAAP	Accounting principles generally accepted in the United States of America
GEMA	Gas and Electricity Markets Authority
GHG	Greenhouse Gases
GWh	Gigawatt Hour
ICC	Illinois Commerce Commission
IPUC	Idaho Public Utilities Commission
IRP	Integrated Resource Plan
ITC	Investment Tax Credit
IUC	Iowa Utilities Commission
kV	Kilovolt
LNG	Liquefied Natural Gas
LDC	Local Distribution Company
MATS	Mercury and Air Toxics Standards
MISO	Midcontinent Independent System Operator, Inc.
MW	Megawatt
MWh	Megawatt Hour
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NO_x	Nitrogen Oxides
NRC	Nuclear Regulatory Commission
OATT	Open Access Transmission Tariff
OCI	Other Comprehensive Income (Loss)
Ofgem	Office of Gas and Electric Markets
OPUC	Oregon Public Utility Commission
PCAM	Power Cost Adjustment Mechanism
PGA	Purchased Gas Adjustment Clause
PSPS	Public Safety Power Shutoff
PTAM	Post Test-year Adjustment Mechanism
PTC	Production Tax Credit
PUCN	Public Utilities Commission of Nevada
RCRA	Resource Conservation and Recovery Act
REC	Renewable Energy Credit
RFP	Request for Proposals
RPS	Renewable Portfolio Standards

RTO	Regional Transmission Organization
SCR	Selective Catalytic Reduction
SEC	U.S. Securities and Exchange Commission
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
TAM	Transition Adjustment Mechanism
UPSC	Utah Public Service Commission
WECC	Western Electricity Coordinating Council
WPSC	Wyoming Public Service Commission
WUTC	Washington Utilities and Transportation Commission
ZEC	Zero Emission Credit

Forward-Looking Statements

This report contains statements that do not directly or exclusively relate to historical facts. These statements are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements can typically be identified by the use of forward-looking words, such as "will," "may," "could," "project," "believe," "anticipate," "expect," "estimate," "continue," "intend," "potential," "plan," "forecast" and similar terms. These statements are based upon the relevant Registrant's current intentions, estimates, assumptions, expectations and beliefs and are subject to risks, uncertainties and other important factors. Many of these factors are outside the control of each Registrant and could cause actual results to differ materially from those expressed or implied by such forward-looking statements. These factors include, among others:

- general economic, political and business conditions, as well as changes in, and compliance with, laws and regulations, including trade policy, tariffs and income tax reform, initiatives regarding deregulation and restructuring of the utility industry and reliability and safety standards, affecting the respective Registrant's operations or related industries;
- changes in, and compliance with, environmental laws, regulations, decisions and policies, whether directed towards protection of environmental resources, present and future climate considerations or social justice concerns that could, among other items, increase operating and capital costs, reduce facility output, accelerate or decelerate facility retirements or delay facility construction or acquisition;
- the outcome of regulatory rate reviews and other proceedings conducted by regulatory agencies or other governmental and legal bodies and the respective Registrant's ability to recover costs through rates in a timely manner or at all;
- changes in economic, industry, competition or weather conditions, as well as demographic trends, new technologies and various conservation, energy efficiency and private generation measures and programs, that could affect customer growth and usage, electricity and natural gas supply or the respective Registrant's ability to obtain long-term contracts with customers and suppliers;
- performance, availability and ongoing operation of the respective Registrant's facilities, including facilities not operated by the Registrants, due to the impacts of market conditions, outages and associated repairs, transmission constraints, weather, including wind, solar and hydroelectric conditions, and operating conditions;
- the effects of catastrophic and other unforeseen events, which may be caused by factors beyond the control of each respective Registrant or by a breakdown or failure of the Registrants' operating assets, including severe storms, floods, fires, extreme temperature events, wind events, earthquakes, explosions, landslides, electromagnetic pulses, mining incidents, costly litigation, wars, terrorism, pandemics, embargoes, and cyber security attacks, data security breaches, disruptions, or other malicious acts;
- the risks and uncertainties associated with wildfires that have occurred, are occurring or may occur in the respective Registrant's service territory; the damage caused by such wildfires; the extent of the respective Registrant's liability in connection with such wildfires (including the risk that the respective Registrant may be found liable for damages regardless of fault); investigations into such wildfires; the outcomes of any legal proceedings, demands or similar actions initiated against the respective Registrant; the risk that the respective Registrant is not able to recover losses from insurance or through rates; and the effect of such wildfires, investigations and legal proceedings on the respective Registrant's financial condition and reputation;
- the outcomes of legal or other actions, including the effects of amounts to be paid to complainants as a result of settlements or final legal determinations, bonding requirements related to legal judgments that are being appealed and the impacts of CMO No. 11, including potential collateral triggers, associated with the Wildfires, which could have a material adverse effect on PacifiCorp's financial condition and could limit PacifiCorp's ability to access capital on terms commensurate with historical transactions or at all and could impact PacifiCorp's liquidity, cash flows and capital expenditure plans;
- the respective Registrant's ability to reduce wildfire threats and improve safety, including the ability to comply with the targets and metrics outlined in its wildfire prevention plans; to retain or contract for the workforce necessary to execute its wildfire prevention plans; the effectiveness of its system hardening; ability to achieve vegetation management targets; and the cost of these programs and the timing and outcome of any proceeding to recover such costs through rates;
- the ability to economically obtain insurance coverage, or any insurance coverage at all, sufficient to cover losses arising from catastrophic events, such as wildfires;
- a high degree of variance between actual and forecasted load or generation that could impact a Registrant's hedging strategy and the cost of balancing its generation resources with its retail load obligations;

- changes in prices, availability and demand for wholesale electricity, coal, natural gas, other fuel sources and fuel transportation that could have a significant impact on generating capacity and energy costs;
- the financial condition, creditworthiness and operational stability of the respective Registrant's significant customers and suppliers;
- changes in business strategy or development plans;
- availability, terms and deployment of capital, including reductions in demand for investment-grade commercial paper, debt securities and other sources of debt financing and volatility in interest rates and credit spreads;
- changes in the respective Registrant's credit ratings, changes in rating methodology, placement on negative outlook or credit watch and downgrades to below investment grade;
- risks relating to nuclear generation, including unique operational, closure and decommissioning risks;
- hydroelectric conditions and the cost, feasibility and eventual outcome of hydroelectric relicensing proceedings;
- the impact of certain contracts used to mitigate or manage volume, price and interest rate risk, including increased collateral requirements, and changes in commodity prices, interest rates and other conditions that affect the fair value of certain contracts;
- the impact of inflation on costs and the ability of the respective Registrants to recover such costs in regulated rates;
- fluctuations in foreign currency exchange rates, primarily the British pound and the Canadian dollar;
- increases in employee healthcare costs;
- the impact of investment performance, certain participant elections such as lump sum distributions and changes in interest rates, legislation, healthcare cost trends, mortality, morbidity on pension and other postretirement benefits expense and funding requirements;
- changes in the residential real estate brokerage, mortgage and franchising industries, regulations that could affect brokerage, mortgage and franchising transactions and the outcomes of legal or other actions and the effects of amounts to be paid to complainants as a result of settlements or final legal determinations;
- the ability to successfully integrate future acquired operations into a Registrant's business;
- the impact of supply chain disruptions and workforce availability on the respective Registrant's ongoing operations and its ability to timely complete construction projects;
- unanticipated construction delays, changes in costs, receipt of required permits and authorizations, ability to fund capital projects and other factors that could affect future facilities and infrastructure additions;
- the availability and price of natural gas and LNG in applicable geographic regions and demand for natural gas and LNG supply;
- the impact of new accounting guidance or changes in current accounting estimates and assumptions on the financial results of the respective Registrants; and
- other business or investment considerations that may be disclosed from time to time in the Registrants' filings with the SEC or in other publicly disseminated written documents.

Further details of the potential risks and uncertainties affecting the Registrants are described in the Registrants' filings with the SEC, including Item 1A and other discussions contained in this Form 10-K. Each Registrant undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The foregoing factors should not be construed as exclusive.

PART I

Item 1. Business

GENERAL

BHE, a wholly owned subsidiary of Berkshire Hathaway, is a holding company headquartered in Iowa that has investments in a highly diversified portfolio of locally managed and operated businesses principally engaged in the energy industry. The Company's operations are organized as eight business segments: PacifiCorp, MidAmerican Funding (which primarily consists of MidAmerican Energy), NV Energy (which primarily consists of Nevada Power and Sierra Pacific), Northern Powergrid (which primarily consists of Northern Powergrid (Northeast) plc and Northern Powergrid (Yorkshire) plc), BHE Pipeline Group (which primarily consists of BHE GT&S, Northern Natural Gas and Kern River), BHE Transmission (which consists of BHE Canada (which primarily consists of AltaLink) and BHE U.S. Transmission), BHE Renewables and HomeServices. BHE, through these locally managed and operated businesses, has investments in four utility companies in the U.S. serving customers in 11 states, two electricity distribution companies in Great Britain, five interstate natural gas pipeline companies in the U.S., one of which owns an LNG export, import and storage facility, an electric transmission business in Canada, interests in electric transmission businesses in the U.S., a renewable energy business primarily investing in wind, solar, geothermal and hydroelectric projects, one of the largest residential real estate brokerage firms and a residential real estate brokerage business in the U.S.

BHE's highly diversified portfolio of primarily regulated businesses generate, transmit, store, distribute and supply energy and serve customers and end-users across geographically diverse service territories, including 28 states located throughout the U.S. and in Great Britain and Canada.

- Approximately 80% of the Company's consolidated adjusted earnings on common shares during 2025 was generated from rate-regulated businesses.
- The Utilities serve 5.4 million electric and natural gas customers in 11 states in the U.S., Northern Powergrid serves 4.0 million end-users in northern England and AltaLink serves approximately 85% of Alberta, Canada's population.
- As of December 31, 2025, the Company owns approximately 38,800 MWs of generation capacity in operation and under construction:
  - Approximately 32,400 MWs of generation capacity is owned by its regulated electric utility businesses;
  - Approximately 6,400 MWs of generation capacity is owned by its nonregulated subsidiaries, the majority of which provides power to utilities under long-term contracts;
  - Owned generation capacity in operation and under construction consists of 44% wind and solar, 33% natural gas, 18% coal, 4% hydroelectric and geothermal and 1% nuclear and other; and,
  - Cumulative investments in (i) owned wind, solar and geothermal generation facilities and electric battery storage facilities of $38.0 billion and (ii) wind projects sponsored by third parties, commonly referred to as tax equity investments, of $7.1 billion.
- The Company owns approximately 36,700 miles of electric transmission lines, a 50% interest in ETT that has approximately 2,100 miles of electric transmission lines, approximately 179,600 miles of electric distribution lines and approximately 2,900 substations.
- The BHE Pipeline Group operates approximately 20,900 miles of pipeline with a design capacity of approximately 21.6 Bcf of natural gas per day, transported approximately 15% of the total natural gas consumed in the U.S. during 2025 and owns assets in 27 states. The BHE Pipeline Group also operates 22 natural gas storage facilities with a total working gas capacity of 515.6 Bcf and an LNG export, import and storage facility.
- HomeServices closed approximately $138.5 billion of home sales in 2025 and has brokerage, mortgage and franchise services in all 50 states. HomeServices' franchise business has 250 franchisees primarily in the U.S.

Human Capital

The Registrants are committed to attracting, retaining and developing the highest quality of employees; maintaining a safe, diverse and inclusive work environment; offering competitive compensation and benefit programs; and providing employees with opportunities for growth and development.

Employees

As of December 31, 2025, the Company had approximately 23,900 employees, consisting of approximately 14,800 (62%) electric and natural gas operations employees, approximately 5,200 (22%) real estate services employees and approximately 3,900 (16%) corporate services employees. HomeServices has approximately 35,000 real estate agents who are independent contractors. As of December 31, 2025, approximately 9,100 employees were covered by union contracts. The majority of the union employees are employed by the Utilities and are represented by the International Brotherhood of Electrical Workers, the Utility Workers Union of America, the United Utility Workers Association and the International Brotherhood of Boilermakers.

Safety and Security

Safety and security are integral to the Registrants' culture and will always be a part of the Registrants' top priorities. The Registrants' safety, cyber and physical security programs are built on personal ownership, compliance with standards, accountability for performance, and continuous improvement. The Registrants provide training to ensure that all employees understand the risks and have thorough and specific knowledge to protect themselves, as well as the Registrants' assets, information and operations.

The Registrants use the recordable incident rate to measure employee safety. The recordable incident rate is defined as the number of work-related injuries per 100 full-time workers during a given year. The recordable incident rates for each of the Registrants for the year ended December 31, 2025, are included below:

Recordable Incident Rate:	
PacifiCorp	0.69
MidAmerican Energy	0.66
Nevada Power	0.70
Sierra Pacific	0.75
Eastern Energy Gas	0.39
EGTS	0.32
BHE Overall	0.46

Compensation and Benefits

The Registrants' commitment to employees is further demonstrated through competitive compensation and benefits and by providing opportunities for personal growth and career development. In addition to market-based salary, the Registrants' compensation packages include incentive programs to recognize and reward outstanding performance. The Registrants' benefits programs are designed to meet the diverse needs of employees and their families and include among other benefits:

- A comprehensive and flexible benefits package that includes medical, dental and vision coverage; employee assistance programs; pre-tax flexible spending accounts; and adoption assistance;
- Income protection that includes options for short- and long-term disability coverage and life insurance;
- Retirement planning that includes a retirement savings plan 401(k) and a variety of employee and employer contribution and matching options;
- Family Medical Leave as well as paid time off, bereavement leave and holiday benefits; and
- Career development opportunities that provide access to a variety of learning programs and career development support, including tuition reimbursement or assistance.

BHE was incorporated under the laws of the state of Iowa in 1999 and its principal executive offices are located at 1615 Locust Street, Des Moines, Iowa 50309-3037, its telephone number is (515) 242-4300 and its internet address is www.brkenergy.com.

PACIFICORP

General

PacifiCorp, an indirect wholly owned subsidiary of BHE, is a U.S. regulated electric utility company headquartered in Oregon that serves approximately 2.1 million retail electric customers in portions of Utah, Oregon, Wyoming, Washington, Idaho and California. PacifiCorp is principally engaged in the business of generating, transmitting, distributing and selling electricity. PacifiCorp's combined service territory covers approximately 141,500 square miles and includes diverse regional economies across six states. No single segment of the economy dominates the combined service territory, which helps mitigate PacifiCorp's exposure to economic fluctuations. In the eastern portion of the service territory, consisting of Utah, Wyoming and southeastern Idaho, the principal industries are manufacturing, mining or extraction of natural resources, agriculture, technology, recreation and government. In the western portion of the service territory, consisting of Oregon, southern Washington and northern California, the principal industries are agriculture, manufacturing, forest products, food processing, technology, government and primary metals. In addition to retail sales, PacifiCorp buys and sells electricity on the wholesale market with other utilities, energy marketing companies, financial institutions and other market participants to balance and optimize the economic benefits of electricity generation, retail customer loads and existing wholesale transactions. Certain PacifiCorp subsidiaries support its electric utility operations by providing coal mining services.

PacifiCorp's operations are conducted under numerous franchise agreements, certificates, permits and licenses obtained from federal, state and local authorities. The average term of these franchise agreements is approximately 21 years. Several of these franchise agreements allow the municipality the right to seek amendment to the franchise agreement at a specified time during the term. PacifiCorp generally has an exclusive right to serve electric customers within its service territories and, in turn, has an obligation to provide electric service to those customers. In return, the state utility commissions have established rates on a cost-of-service basis, which are designed to allow PacifiCorp an opportunity to recover its costs of providing services and to earn a reasonable return on its investments.

PacifiCorp was incorporated under the laws of the state of Oregon in 1989. Its principal executive offices are located at 825 N.E. Multnomah Street, Portland, Oregon 97232, its telephone number is (888) 221-7070 and its internet address is www.pacificorp.com. PacifiCorp delivers electricity to customers in Utah, Wyoming and Idaho under the trade name Rocky Mountain Power and to customers in Oregon, Washington and California under the trade name Pacific Power.

All shares of PacifiCorp's common stock are indirectly held by BHE.

Subsequent Event

On February 15, 2026, PacifiCorp and Portland General Electric Company and an affiliate of Portland General Electric Company (together, the "PGE Entities") entered into an Asset Purchase and Service Area Transfer Agreement (the "Sale Agreement") to sell to the PGE Entities certain PacifiCorp assets and liabilities associated with PacifiCorp's Washington operations for a sales price of $1.9 billion in cash plus additional cash consideration for the value of specified assets delivered at closing, subject to customary purchase price adjustments (the "Transaction").

The Transaction assets and liabilities are associated with PacifiCorp's retail service area in Washington and include certain related distribution assets and infrastructure, as well as PacifiCorp's Chehalis combined cycle natural gas-fueled generating facility located in Chehalis, Washington, Goodnoe Hills wind-powered generating facility located in Goldendale, Washington, and Marengo wind-powered generating facility located in Dayton, Washington.

The Transaction has been approved by PacifiCorp's board of directors but is subject to customary closing conditions including (i) the expiration or termination of the waiting period and other required approvals under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, and (ii) the receipt of all necessary approvals, waivers and rulings from the FERC and each of PacifiCorp's six state public utility commissions. The Transaction is expected to close in the first half of 2027. Refer to Note 22 of Notes to the Consolidated Financial Statements of PacifiCorp in Part II, Item 8 of this Form 10-K for additional information.

Regulated Electric Operations

Customers

The GWhs and percentages of electricity sold to PacifiCorp's retail customers by jurisdiction for the years ended December 31 were as follows:

	2025		2024		2023	
Utah	27,665	47 %	27,138	46 %	26,062	46 %
Oregon	14,522	25	13,991	24	13,949	25
Wyoming	8,489	14	8,759	15	8,579	15
Washington	4,003	7	4,112	7	3,850	7
Idaho	3,802	6	3,728	7	3,496	6
California	731	1	747	1	760	1
Total	59,212	100 %	58,475	100 %	56,696	100 %

Electricity sold to PacifiCorp's retail and wholesale customers by class of customer and the average number of retail customers for the years ended December 31 were as follows:

	2025		2024		2023	
GWhs sold:						
Residential	18,270	29 %	18,253	30 %	18,159	31 %
Commercial	22,673	36	21,585	36	20,491	34
Industrial	16,703	26	17,101	28	16,705	28
Other	1,566	2	1,536	2	1,341	2
Total retail	59,212	93	58,475	96	56,696	95
Wholesale	4,354	7	2,280	4	2,911	5
Total GWhs sold	63,566	100 %	60,755	100 %	59,607	100 %
Average number of retail customers (in thousands):						
Residential	1,867	87 %	1,838	87 %	1,806	87 %
Commercial	234	11	230	11	227	11
Industrial	9	1	9	1	9	1
Other	27	1	27	1	27	1
Total	2,137	100 %	2,104	100 %	2,069	100 %

Variations in weather, economic conditions and various conservation, energy efficiency and private generation measures and programs can impact customer energy requirements. Wholesale sales are impacted by market prices for energy relative to the incremental cost to generate electricity.

The annual hourly peak customer demand, which represents the highest demand on a given day and at a given hour, occurs in the summer when air conditioning and irrigation systems are heavily used. During the summer months of 2025, 2024 and 2023, PacifiCorp's hourly peak demand was 11,263, 11,156 and 10,802 MWs, respectively. Peak demand in the winter occurs due to heating requirements. During the winter months of 2025, 2024 and 2023, PacifiCorp's hourly peak demand was 9,302, 9,139 and 8,998 MWs, respectively.

Generating Facilities and Fuel Supply

PacifiCorp has ownership interests in a diverse portfolio of generating facilities. The following table presents certain information regarding PacifiCorp's owned generating facilities as of December 31, 2025:

Generating Facility	Location	Energy Source	Installed / Repowered[1] or Converted[2]	Facility Net Capacity (MWs)[3]	Net Owned Capacity (MWs)[3]
COAL[4]:					
Hunter Nos. 1, 2 and 3	Castle Dale, UT	Coal	1978-1983	1,363	1,158
Huntington Nos. 1 and 2	Huntington, UT	Coal	1974-1977	909	909
Dave Johnston Nos. 1, 2, 3 and 4	Glenrock, WY	Coal	1959-1972	745	745
Jim Bridger Nos. 3 and 4	Rock Springs, WY	Coal	1976-1979	1,049	700
Wyodak	Gillette, WY	Coal	1978	332	266
Craig Nos. 1 and 2	Craig, CO	Coal	1979-1980	837	161
Colstrip Nos. 3 and 4	Colstrip, MT	Coal	1984-1986	1,480	148
Hayden Nos. 1 and 2	Hayden, CO	Coal	1965-1976	441	77
				7,156	4,164
NATURAL GAS:					
Jim Bridger Nos. 1 and 2	Rock Springs, WY	Natural gas	1974-1975 / 2024	1,070	713
Lake Side 2	Vineyard, UT	Natural gas/steam	2014	631	631
Lake Side	Vineyard, UT	Natural gas/steam	2007	546	546
Currant Creek	Mona, UT	Natural gas/steam	2005-2006	524	524
Chehalis	Chehalis, WA	Natural gas/steam	2003	477	477
Naughton No. 3	Kemmerer, WY	Natural gas	1971 / 2020	290	290
Gadsby Steam	Salt Lake City, UT	Natural gas	1951-1955 / 1991	238	238
Hermiston	Hermiston, OR	Natural gas/steam	1996	461	231
Gadsby Peakers	Salt Lake City, UT	Natural gas	2002	119	119
				4,356	3,769
WIND:					
TB Flats	Medicine Bow, WY	Wind	2020-2021	500	500
Rock Creek II	Arlington, WY	Wind	2025	400	400
Ekola Flats	Medicine Bow, WY	Wind	2020	250	250
Pryor Mountain	Bridger, MT	Wind	2020-2021	240	240
Marengo	Dayton, WA	Wind	2007-2008 / 2020	234	234
Cedar Springs II	Douglas, WY	Wind	2020	199	199
Rock Creek I	Arlington, WY	Wind	2024-2025	190	190
Glenrock	Glenrock, WY	Wind	2008-2009 / 2019	139	139
Seven Mile Hill	Medicine Bow, WY	Wind	2008 / 2019	119	119
Dunlap Ranch	Medicine Bow, WY	Wind	2010 / 2020	111	111
Leaning Juniper	Arlington, OR	Wind	2006 / 2019	100	100
Rolling Hills	Glenrock, WY	Wind	2009 / 2019	100	100
High Plains	McFadden, WY	Wind	2009 / 2019	99	99
Goodnoe Hills	Goldendale, WA	Wind	2008 / 2019	94	94
Rock River I	Rock River, WY	Wind	2024	50	50
Foote Creek I	Arlington, WY	Wind	1999 / 2021	43	43
McFadden Ridge	McFadden, WY	Wind	2009 / 2019	28	28
Foote Creek III	Arlington, WY	Wind	2023	25	25
Foote Creek IV	Arlington, WY	Wind	2023	17	17
				2,938	2,938
HYDROELECTRIC:					
Lewis River System	WA	Hydroelectric	1931-1958	578	578
North Umpqua River System	OR	Hydroelectric	1950-1956	204	204
Bear River System	ID, UT	Hydroelectric	1908-1984	105	105
Rogue River System	OR	Hydroelectric	1912-1957	52	52

Generating Facility	Location	Energy Source	Installed / Repowered[1] or Converted[2]	Facility Net Capacity (MWs)[3]	Net Owned Capacity (MWs)[3]
Minor hydroelectric facilities	Various	Hydroelectric	1895-1986	31	31
				970	970
OTHER:					
Blundell	Milford, UT	Geothermal	1984, 2007	32	32
				32	32
Total Available Generating Capacity				15,452	11,873

(1) Repowered dates are associated with component replacements on existing wind-powered generating facilities commonly referred to by the U.S. Internal Revenue Service ("IRS") as repowering. IRS rules provide for re-establishment of the PTCs for an existing wind-powered generating facility upon the replacement of a significant portion of its components. If the degree of component replacement in such projects meets IRS guidelines, PTCs are re-established for 10 years beginning with the date the repowered facility is placed in-service.

(2) Converted dates are associated with the in-service date of coal-fueled generating facilities converted to natural gas-fueled facilities.

(3) Facility Net Capacity represents the lesser of nominal ratings or any limitations under applicable interconnection, power purchase, or other agreements for intermittent resources and the total net dependable capability available during summer conditions for all other units. An intermittent resource's nominal rating is the manufacturer's contractually specified capability (in MWs) under specified conditions. Net Owned Capacity indicates PacifiCorp's ownership of Facility Net Capacity.

(4) PacifiCorp removed Naughton Nos. 1 and 2 from coal-fueled service in December 2025 and will convert them to gas-fueled generation facilities in 2026.

PacifiCorp has a 2 MW battery energy storage system under construction in Oregon with an indeterminate in-service date.

PacifiCorp has entered into multiple electricity contracts from specified resources that it considers part of the total available generating capacity. The following table presents PacifiCorp's contractual right to capacity regarding generation sources of purchased electricity contracts as of December 31, 2025:

Electricity Contract Energy Source	Contractual Capacity MWs
Solar	3,194
Wind	2,217
Hydroelectric	392
Other renewable	134
Total renewable	5,937
Natural gas and other	191
Total contractual capacity	6,128

Additionally, PacifiCorp has contractual rights to a 200 MW energy storage facility located in Utah that reached commercial operation in December 2025.

The following table shows the percentages of PacifiCorp's total energy supplied by energy source for the years ended December 31:

	2025	2024	2023
Coal	34 %	28 %	34 %
Natural gas	22	26	22
Wind[(1)]	12	11	10
Hydroelectric and other[(1)]	4	4	5
Total energy generated	72	69	71
Energy purchased - long-term contracts (renewable)[(1)]	23	19	16
Energy purchased - short-term contracts and other	5	11	12
Energy purchased - long term contracts (non-renewable)	—	1	1
	100 %	100 %	100 %

(1) All or some of the renewable energy attributes associated with generation from these sources may be: (a) used in future years to comply with RPS or other regulatory requirements, (b) sold to third parties in the form of RECs or other environmental commodities, or (c) excluded from energy purchased.

PacifiCorp is required to have resources available to continuously meet its customer needs and reliably operate its electric system. The percentage of PacifiCorp's energy supplied by energy source varies from year to year and is subject to numerous operational, economic and environmental factors such as planned and unplanned outages; fuel commodity prices; fuel availability; fuel transportation costs; weather, including temperature, hydrologic conditions, wind and sun; legislative and environmental considerations; transmission constraints; wholesale market prices of electricity and other factors. PacifiCorp evaluates these factors continuously in order to facilitate dispatch of its generating facilities. When factors for one energy source are less favorable, PacifiCorp places more reliance on other energy sources. For example, PacifiCorp can generate more electricity using its low-cost wind-powered and hydroelectric generating facilities when factors associated with these facilities are favorable. In addition to meeting its customers' energy needs, PacifiCorp is required to maintain operating reserves on its system to mitigate the impacts of unplanned outages or other disruption in supply, and to meet intra-hour changes in load and resource balance. This operating reserve requirement is dispersed across PacifiCorp's generation portfolio on a least-cost basis based on the operating characteristics of the portfolio. Operating reserves may be held on hydroelectric, coal-fueled, natural gas-fueled or certain types of interruptible load. PacifiCorp manages certain risks relating to its supply of electricity and fuel requirements by entering into various contracts, which may be accounted for as derivatives and may include forwards, options, swaps and other agreements. Refer to "General Regulation" in Item 1 of this Form 10-K for a discussion of energy cost recovery by jurisdiction and to PacifiCorp's Item 7A in this Form 10-K for a discussion of commodity price risk and derivative contracts.

Coal

PacifiCorp has interests in coal mines that support its coal-fueled generating facilities and jointly operates the Bridger surface coal mine. These mines supplied 17%, 18% and 18% of PacifiCorp's total coal requirements during the years ended December 31, 2025, 2024 and 2023, respectively.

Most of PacifiCorp's coal reserves are held through agreements with the federal Bureau of Land Management and certain states and private parties. The agreements generally have multi-year terms that may be renewed or extended and require payment of rents and royalties. In addition, federal and state regulations require that comprehensive environmental protection and reclamation standards be met during the course of mining operations and upon completion of mining activities.

Coal reserve estimates are subject to adjustment as a result of the development of additional engineering and geological data, new mining technology and changes in regulation and economic factors affecting the utilization of such reserves. Recoverability by surface mining methods typically ranges from 90% to 95%.

PacifiCorp believes it will be able to purchase coal under both long- and short-term third-party contracts to supply the remaining coal requirements at its coal-fueled generating facilities over their currently expected remaining useful lives.

Natural Gas

PacifiCorp uses natural gas as fuel for its generating facilities that use combined-cycle, simple-cycle and steam turbines. Oil and natural gas are also used for igniter fuel and standby purposes. These sources are presently in adequate supply and available to meet PacifiCorp's needs.

PacifiCorp enters into forward natural gas purchases at fixed or indexed market prices. PacifiCorp purchases natural gas in the spot market with both fixed and indexed market prices for physical delivery to fulfill any fuel requirements not already satisfied through forward purchases of natural gas and sells natural gas in the spot market for the disposition of any excess supply if the forecasted requirements of its natural gas-fueled generating facilities decrease. When prudent, PacifiCorp also utilizes financial swap contracts to mitigate price risk associated with its forecasted fuel requirements.

Wind

PacifiCorp utilizes wind-powered generating facilities as a prudent means of supplying electricity and to comply with laws and regulations. Wind-powered generating facilities have low to no emissions. The generation from PacifiCorp's wind-powered generating fleet, comprised of newly constructed and recently repowered wind-powered generating facilities, qualifies for federal PTCs for 10 years beginning with the date the new or repowered facility is placed in-service.

Hydroelectric and Other Renewable Resources

The amount of electricity PacifiCorp is able to generate from its hydroelectric generating facilities depends on a number of factors, including snowpack in the mountains upstream of its hydroelectric generating facilities, reservoir storage, precipitation in its watersheds, generating unit availability and restrictions imposed by oversight bodies due to competing water management objectives.

PacifiCorp operates the majority of its hydroelectric generating portfolio under long-term licenses. The FERC regulates 98% of the net capacity of this portfolio through 14 individual licenses, which have terms of 30 to 50 years. The licenses for these hydroelectric generating facilities expire at various dates through 2061. A portion of this portfolio is licensed under the Oregon Hydroelectric Act.

Wholesale Activities

PacifiCorp purchases and sells electricity in the wholesale markets as needed to balance its generation with its retail load obligations. PacifiCorp may also purchase electricity in the wholesale markets when it is more economical than generating electricity from its own facilities and may sell surplus electricity in the wholesale markets when it can do so economically. When prudent, PacifiCorp enters into financial swap contracts and forward electricity sales and purchases for physical delivery at fixed prices to reduce its exposure to changes in electricity prices.

Energy Imbalance Market

PacifiCorp and the California ISO implemented an EIM in November 2014, which delivers customer benefits by leveraging automation and resource diversity to result in more efficient dispatch of a larger and more diverse pool of resources, more effectively integrates renewables and enhances reliability through improved situational awareness and responsiveness. The EIM expands the real-time component of the California ISO's market technology to optimize and balance electricity supply and demand every five minutes across the EIM footprint. The EIM is voluntary and available to all balancing authorities in the western U.S. EIM market participants submit bids to the California ISO market operator before each hour for each generating resource they choose to be dispatched by the market. Each bid is comprised of a dispatchable operating range, ramp rate and prices across the operating range. The California ISO market operator uses sophisticated technology to select the least-cost resources to meet demand and send simultaneous dispatch signals to every participating generator across the EIM footprint every five minutes. In addition to generation resource bids, the California ISO market operator also receives continuous real-time updates of the transmission grid network, meteorological and load forecast information that it uses to optimize dispatch instructions. PacifiCorp is working with the California ISO to join the California ISO Extended Day-Ahead Market ("EDAM") in 2026. The EDAM is a voluntary day-ahead electricity market designed to deliver significant reliability, economic, and environmental benefits to balancing areas and utilities throughout the West. Customer benefits are expected to increase further with renewable resource expansion and as more entities join the EIM, bringing incremental resource diversity. With the development of other day ahead markets scheduled to go live in 2027, there is a risk of future reductions in benefits to PacifiCorp customers if current EIM balancing areas leave the EIM market. A smaller EIM footprint could lead to a reduction in transmission connectivity, resource and load diversity and market transfers between EIM balancing areas, potentially reducing overall EIM benefits.

Transmission and Distribution

PacifiCorp operates one balancing authority area in the western portion of its service territory ("PacifiCorp-West") and one balancing authority area in the eastern portion of its service territory ("PacifiCorp-East"). A balancing authority area is a geographic area with transmission systems that control generation to maintain schedules with other balancing authority areas and ensure reliable operations. In operating the balancing authority areas, PacifiCorp is responsible for continuously balancing electricity supply and demand by dispatching generating resources and interchange transactions so that generation internal to the balancing authority area, plus net imported power, matches customer loads. Deliveries of energy over PacifiCorp's transmission system are managed and scheduled in accordance with the FERC's requirements.

PacifiCorp's transmission system is part of the Western Interconnection, which includes the interconnected transmission systems of 14 western states, two Canadian provinces and parts of Mexico. PacifiCorp's transmission system, together with contractual rights on other transmission systems, enables PacifiCorp to integrate and access generation resources to meet its customer load requirements. PacifiCorp's transmission and distribution systems included approximately 17,500 miles of transmission lines in 10 states, 67,700 miles of distribution lines and 900 substations as of December 31, 2025.

PacifiCorp's transmission and distribution system is managed on a coordinated basis to obtain maximum load-carrying capability and efficiency. Portions of PacifiCorp's transmission and distribution systems are located:

- On property owned or used through agreements by PacifiCorp;
- Under or over streets, alleys, highways and other public places, the public domain and national forests and state and federal lands under franchises, easements or other rights that are generally subject to termination;
- Under or over private property as a result of easements obtained primarily from the title holder of record; or
- Under or over Native American reservations through agreements with the U.S. Secretary of Interior or Native American tribes.

It is possible that some of the easements and the property over which the easements were granted may have title defects or may be subject to mortgages or liens existing at the time the easements were acquired.

Wildfire Prevention

PacifiCorp has developed detailed wildfire mitigation plans for each of the six states in which it operates. Wildfire mitigation plans are filed per required state timelines with the UPSC, the OPUC, the WPSC, the WUTC, the IPUC and the CPUC. These plans include capital investment in asset hardening and meteorological systems, the implementation of risk modeling tools and PacifiCorp's ongoing enhanced safety settings, inspections, vegetation management, PSPS and wildfire encroachment programs and policies.

Asset Hardening

PacifiCorp has and continues to invest in rebuilding overhead lines with covered conductor and in some cases has converted overhead distribution lines to underground. These system hardening efforts reduce the exposure of PacifiCorp's lines to interference from trees and other objects. Covered conductor helps mitigate the risk of fault-caused electrical arcs that could cause an ignition. Overall, mitigated overhead lines help reduce ignition risk and improve reliability during storms or periods of significant wildfire risk.

Approximately 8% of PacifiCorp's service territory and approximately 10% of its customer base are in fire high consequence areas ("FHCA"). Approximately 10,000 miles, or 15%, of PacifiCorp's distribution lines and approximately 1,800 miles, or 10%, of its transmission lines are in the FHCA. In 2024, the process for updating the risk modeling for the identification of the FHCA was completed resulting in an expansion of FHCA.

As of December 31, 2025, all of the approximately 1,800 miles of transmission lines in the FHCA are mitigated by system relay protection schemes. All of the approximately 10,000 miles of distribution lines in the FHCA include some form of mitigation including:

- 5,100 miles, or 51%, with bare conductor mitigated by system relay protection schemes;
- 800 miles, or 8%, with new covered conductor; and
- 4,100 miles, or 41%, underground.

The on-going asset hardening of the FHCA is a priority for PacifiCorp and a key part of the developed wildfire mitigation plans.

Refer to "Future Uses of Cash" in Item 7 of this Form 10-K for further discussion of PacifiCorp's wildfire prevention related capital expenditures, including asset hardening.

Enhanced Safety Settings

Enhanced safety settings are available across PacifiCorp's service territory, including the ongoing installation of new microprocessor relays to detect faults occurring on transmission and distribution lines when wildfire risk is elevated and de-energize the line quickly limiting the arc-energy and potential for wildfire ignition. Field reclosers are being upgraded with similar fault detection capability and are enabled when wildfire risk is elevated.

Meteorology and Risk Modeling

PacifiCorp has installed approximately 650 weather stations that monitor weather conditions and model the impact to the electrical infrastructure. These weather stations utilized by the weather forecasting team servicing PacifiCorp's service territory provide PacifiCorp with the ability to forecast weather and fire risk impact data twice daily. PacifiCorp will continue to install additional weather stations to refine weather modeling in areas where geographic terrain conditions require a dense network of weather stations in order to provide the necessary granular data. In 2025, PacifiCorp upgraded its existing high-powered computer clusters and installed three new high-powered computer clusters to transition to improved forecast models and longer-term forecasting with greater accuracy.

Asset Inspection Program

PacifiCorp conducts an annual inspection of overhead facilities within the FHCA with an accelerated correction timeline for any conditions noted. A detailed inspection of facilities is conducted every five years, which is twice as often as areas outside the FHCA.

Vegetation Management

PacifiCorp's vegetation management program includes annual vegetation inspections and ground clearing of equipment poles in the FHCA along with three-year trimming cycles in place, including in Oregon and California where fire hazard risk is highest.

Public Safety Power Shutoff and Wildfire Encroachment Policy

A PSPS is used as a preventative measure during periods of extreme wildfire risk where the electrical network is de-energized proactively under certain conditions. In determining whether to initiate a PSPS, PacifiCorp works with local public safety authorities in consideration of data from meteorological systems and forecasting tools. PacifiCorp also has a wildfire encroachment policy under which it will de-energize its lines when a known wildfire is within a specified distance of its assets. PSPS is an increasingly common practice for utilities to use as part of wildfire prevention.

Situational Awareness - Wildfire Intelligence Center

PacifiCorp has a dedicated situational awareness team, operating 24 hours a day, seven days a week, that began operation in April 2025 to monitor wildfire related threats and coordinate internal stakeholder action and external engagement. This team supports real-time operations by monitoring for weather, wildfire and other hazards external to the system that could threaten PacifiCorp's assets or community safety. Staffing is comprised of individuals with backgrounds in fire agency dispatch, wildland firefighting and emergency response. During wildfire season, the center's primary focus is to utilize technology for early identification of wildfires within 10 miles of PacifiCorp's transmission and distribution assets. The early detection capabilities allow PacifiCorp to determine the need for encroachment related de-energizations and utilize widely available intelligence to determine the level of threat to assets or communities and to proactively coordinate PacifiCorp's actions and external communications.

Future Generation, Conservation and Energy Efficiency

Energy Supply Planning

As required by certain state regulations, PacifiCorp uses an IRP to develop a long-term resource plan to ensure that PacifiCorp can continue to provide reliable and cost-effective electric service to its customers while maintaining compliance with existing and evolving environmental laws and regulations. The IRP process identifies the amount and timing of PacifiCorp's expected future resource needs, accounting for planning uncertainty, risks, reliability, state energy policies and other factors. The IRP is prepared following a public process, which provides an opportunity for stakeholders to participate in PacifiCorp's resource planning process. PacifiCorp files its IRP biennially with the state commissions in each of the six states where PacifiCorp operates. Five states indicate whether the IRP meets the state commission's IRP standards and guidelines, a process referred to as "acknowledgment" in some states. Acknowledgment by a state commission does not address recovery or prudency of resources ultimately selected.

In March 2025, PacifiCorp filed its 2025 IRP in Utah, Oregon, Wyoming, Washington, Idaho and California. The 2025 IRP highlights a need for investment in transmission infrastructure, renewable solar and wind resources, new energy storage, conversion of coal-fueled generating units to natural gas, demand response and energy efficiency programs and carbon capture technology. In December 2025, the IPUC acknowledged the 2025 IRP.

Requests for Proposals

PacifiCorp issues individual RFPs to procure resources identified in the IRP or resources driven by customer demands and regulatory policy changes. The IRP and the RFPs provide for the identification and staged procurement of resources to meet load and state-specific compliance obligations. Depending upon the specific RFP, applicable laws and regulations may require PacifiCorp to file draft RFPs with the UPSC, the OPUC and the WUTC. Approval by the UPSC, the OPUC or the WUTC may be required depending on the nature of the RFPs.

In April 2025, PacifiCorp filed an expedited application with the OPUC seeking approval to issue to market an RFP for new generating and energy storage resources that will serve Oregon customers and be recovered through Oregon retail rates. In May 2025, the OPUC issued an order for a partial waiver of competitive bidding rules but still requiring PacifiCorp to go through the formal approval process. The OPUC approved the RFP in August 2025, with certain conditions. Those conditions were satisfied in October 2025, when it was issued to market.

In June 2025, PacifiCorp filed an expedited application with the WUTC seeking approval to issue to market an RFP for new generating and energy storage resources that will serve Washington customers and be recovered through Washington retail rates. The WUTC approved the RFP in August 2025, and it was issued to market in September 2025.

Energy Efficiency Programs

PacifiCorp has provided its customers with a comprehensive set of DSM programs since the 1970s. The programs are designed to reduce energy consumption and more effectively manage when energy is used, including management of customer loads. PacifiCorp offers services to customers such as energy engineering audits and information on how to improve the efficiency of their homes and businesses. To assist customers in investing in energy efficiency, PacifiCorp offers rebates or incentives encouraging the purchase and installation of high-efficiency equipment such as lighting, heating and cooling equipment, weatherization, motors, process equipment and systems, as well as incentives for energy project management, efficient building operations and efficient construction. Incentives are also paid to solicit participation in load management programs by residential, business and agricultural customers through programs such as PacifiCorp's residential and small commercial air conditioner load control program, battery control program, electric vehicle programs and irrigation equipment load control programs. Although subject to prudence reviews, state regulations allow for recovery of costs incurred for the DSM programs through state-specific energy efficiency surcharges to retail customers or for recovery of costs through rates through PacifiCorp's general rate case process. During 2025, PacifiCorp spent $245 million on these DSM programs, resulting in an estimated 662,542 MWhs of first-year energy savings and an estimated 428 MWs of peak load management. In addition to these DSM programs, PacifiCorp has load curtailment contracts with a number of large industrial customers that deliver up to 247 MWs of load reduction when needed, depending on the customers' actual operations. Costs associated with the large industrial load curtailment program are captured in the respective customers' retail special contracts.

Human Capital

Employees

As of December 31, 2025, PacifiCorp had approximately 5,200 employees, of which approximately 2,800 (54%) were covered by union contracts, principally with the International Brotherhood of Electrical Workers, the Utility Workers Union of America and the International Brotherhood of Boilermakers. For more information regarding PacifiCorp's human capital disclosures, refer to Item 1. Business - General section of this Form 10-K.

MIDAMERICAN FUNDING AND MIDAMERICAN ENERGY

General

MidAmerican Funding and MHC

MidAmerican Funding, a wholly owned subsidiary of BHE, is a holding company headquartered in Iowa that holds all of the outstanding common stock of MHC Inc. ("MHC"), which is a holding company that holds all of the common stock of MidAmerican Energy and Midwest Capital Group, Inc. ("Midwest Capital"). MidAmerican Funding and MidAmerican Energy are indirect consolidated subsidiaries of Berkshire Hathaway. MidAmerican Funding conducts no business other than activities related to its debt securities and investment in MHC. MHC conducts no business other than its investments in its subsidiaries. MidAmerican Energy is a substantial portion of MidAmerican Funding's and MHC's assets, revenue and earnings.

MidAmerican Funding was formed as a limited liability company under the laws of the state of Iowa in 1999. Its principal executive offices are located at 1615 Locust Street, Des Moines, Iowa 50309-3037 and its telephone number is (515) 242-4300.

MidAmerican Energy

MidAmerican Energy, an indirect wholly owned subsidiary of BHE, is a U.S. regulated electric and natural gas utility company headquartered in Iowa that serves 0.8 million retail electric customers in portions of Iowa, Illinois and South Dakota and 0.8 million retail and transportation natural gas customers in portions of Iowa, South Dakota, Illinois and Nebraska. MidAmerican Energy is principally engaged in the business of generating, transmitting, distributing and selling electricity and in distributing, selling and transporting natural gas. MidAmerican Energy's service territory covers approximately 11,000 square miles. MidAmerican Energy has a diverse customer base consisting of urban and rural residential customers and a variety of commercial and industrial customers. Principal industries served by MidAmerican Energy include electronic data storage; processing and sales of food products; manufacturing, processing and fabrication of primary metals, farm and other non-electrical machinery; cement and gypsum products; and government. In addition to retail sales and natural gas transportation, MidAmerican Energy sells electricity principally to markets operated by RTOs and natural gas to other utilities and market participants on a wholesale basis. MidAmerican Energy is a transmission-owning member of the MISO and participates in its capacity, energy and ancillary services markets.

MidAmerican Energy's regulated electric and natural gas operations are conducted under numerous franchise agreements, certificates, permits and licenses obtained from federal, state and local authorities. The franchise agreements, with various expiration dates, are typically for 20- to 25-year terms. Several of these franchise agreements give either party the right to seek amendment to the franchise agreement at one, two, three or four specified times during the term. MidAmerican Energy generally has an exclusive right to serve electric customers within its service territories and, in turn, has an obligation to provide electricity service to those customers. In return, the state utility commissions have established rates on a cost-of-service basis, which are designed to allow MidAmerican Energy an opportunity to recover its costs of providing services and to earn a reasonable return on its investment. In Illinois, MidAmerican Energy's regulated retail electric customers may choose their energy supplier.

MidAmerican Energy's operating revenue derived from the following business activities for the years ended December 31 were as follows (dollars in millions):

	2025		2024		2023	
Operating revenue:						
Regulated electric	$ 3,124	80 %	$ 2,584	80 %	$ 2,673	79 %
Regulated gas	778	20	658	20	713	21
Other	5	—	9	—	7	—
Total operating revenue	$ 3,907	100 %	$ 3,251	100 %	$ 3,393	100 %

MidAmerican Energy was incorporated under the laws of the state of Iowa in 1995. Its principal executive offices are located at 1615 Locust Street, Des Moines, Iowa 50309-3037, its telephone number is (515) 242-4300 and its internet address is www.midamericanenergy.com.

Regulated Electric Operations

Customers

The GWhs and percentages of electricity sold to MidAmerican Energy's retail customers by jurisdiction for the years ended December 31 were as follows:

	2025		2024		2023	
Iowa	30,810	94 %	27,918	93 %	27,554	93 %
Illinois	1,787	5	1,802	6	1,827	6
South Dakota	316	1	316	1	294	1
	32,913	100 %	30,036	100 %	29,675	100 %

Electricity sold to MidAmerican Energy's retail and wholesale customers by class of customer and the average number of retail customers for the years ended December 31 were as follows:

	2025		2024		2023	
GWhs sold:						
Residential	7,068	15 %	6,691	15 %	6,759	15 %
Commercial	4,064	8	3,926	9	3,992	9
Industrial	20,102	42	17,773	40	17,307	39
Other	1,679	3	1,646	4	1,617	3
Total retail	32,913	68	30,036	68	29,675	66
Wholesale	15,162	32	14,329	32	15,129	34
Total GWhs sold	48,075	100 %	44,365	100 %	44,804	100 %
Average number of retail customers (in thousands):						
Residential	717	86 %	710	86 %	703	86 %
Commercial	103	12	102	12	101	12
Industrial	2	—	2	—	2	—
Other	16	2	15	2	14	2
Total	838	100 %	829	100 %	820	100 %

Variations in weather, economic conditions and various conservation and energy efficiency measures and programs can impact customer energy requirements. Wholesale sales are primarily impacted by market prices for energy.

There are seasonal variations in MidAmerican Energy's electricity sales that are principally related to weather and the related use of electricity for air conditioning. Additionally, electricity sales are priced higher in the summer months compared to the remaining months of the year. As a result, 40% to 50% of MidAmerican Energy's regulated electric retail revenue is reported in the months of June through September.

A degree of concentration of sales exists with certain large electric retail customers. Sales to the 10 largest customers, from a variety of industries, comprised 28%, 27% and 26% of total retail electric sales in 2025, 2024 and 2023, respectively. Sales to electronic data storage customers included in the 10 largest customers comprised 24%, 23% and 20% of total retail electric sales in 2025, 2024 and 2023, respectively.

The annual hourly peak demand on MidAmerican Energy's electric system usually occurs as a result of air conditioning use during the cooling season. Peak demand represents the highest demand on a given day and at a given hour. During 2025, 2024 and 2023, MidAmerican Energy's hourly peak demand was 5,817, 5,623 and 5,851 MWs, respectively. On August 23, 2023, retail customer usage of electricity caused a new record hourly peak demand of 5,851 MWs on MidAmerican Energy's electric distribution system.

Generating Facilities and Fuel Supply

MidAmerican Energy has ownership interests in a diverse portfolio of generating facilities. The following table presents certain information regarding MidAmerican Energy's owned generating facilities as of December 31, 2025:

Generating Facility	Location	Energy Source	Year Installed / Repowered[1]	Facility Net Capacity (MWs)[2]	Net Owned Capacity (MWs)[2]
WIND:					
Ida Grove	Ida Grove, IA	Wind	2016-2019	500	500
Orient	Greenfield, IA	Wind	2018-2019	500	500
Highland	Primghar, IA	Wind	2015	500	500
Rolling Hills	Massena, IA	Wind	2011 / 2022	443	443
Beaver Creek	Ogden, IA	Wind	2017-2018	340	340
North English	Montezuma, IA	Wind	2018-2019	340	340
Palo Alto	Palo Alto, IA	Wind	2019-2020	340	340

Generating Facility	Location	Energy Source	Year Installed / Repowered[1]	Facility Net Capacity (MWs)[2]	Net Owned Capacity (MWs)[2]
Arbor Hill	Greenfield, IA	Wind	2018-2020	316	316
Pomeroy	Pomeroy, IA	Wind	2007-2011 / 2018-2019, 2021	286	286
Diamond Trail	Ladora, IA	Wind	2020	250	250
Lundgren	Otho, IA	Wind	2014 / 2025	250	250
O'Brien	Primghar, IA	Wind	2016	250	250
Southern Hills	Orient, IA	Wind	2020-2021	250	250
Shenandoah Hills	Shenandoah, IA	Wind	2025	214	214
Chickasaw	New Hampton, IA	Wind	2023	200	200
Century	Blairsburg, IA	Wind	2005-2008 / 2017-2018 / 2024-2025	200	200
Eclipse	Adair, IA	Wind	2012 / 2022	200	200
Plymouth	Remsen, IA	Wind	2021	200	200
Intrepid	Schaller, IA	Wind	2004-2005 / 2017 / 2025	176	176
Adair	Adair, IA	Wind	2008 / 2019-2020	175	175
Prairie	Montezuma, IA	Wind	2017-2018	169	169
Carroll	Carroll, IA	Wind	2008 / 2019	150	150
Walnut	Walnut, IA	Wind	2008 / 2019	150	150
Vienna	Gladbrook, IA	Wind	2012-2013 / 2024	150	150
Adams	Lennox, IA	Wind	2015	150	150
Wellsburg	Wellsburg, IA	Wind	2014 / 2025	139	139
Laurel	Laurel, IA	Wind	2011 / 2022	120	120
Macksburg	Macksburg, IA	Wind	2014	119	119
Contrail	Braddyville, IA	Wind	2020	110	110
Morning Light	Adair, IA	Wind	2012 / 2022-2023	100	100
Victory	Westside, IA	Wind	2006 / 2017-2018	99	99
Ivester	Wellsburg, IA	Wind	2018	90	90
Pocahontas Prairie	Pomeroy, IA	Wind	2020 / 2021	80	80
Charles City	Charles City, IA	Wind	2008 / 2018	75	75
				7,631	7,631
COAL:					
Louisa No. 1	Muscatine, IA	Coal	1983	746	657
Walter Scott, Jr. No. 3	Council Bluffs, IA	Coal	1978	709	561
Walter Scott, Jr. No. 4	Council Bluffs, IA	Coal	2007	807	481
George Neal No. 3	Sergeant Bluff, IA	Coal	1975	511	368
Ottumwa No. 1	Ottumwa, IA	Coal	1981	700	364
George Neal No. 4	Salix, IA	Coal	1979	643	261
				4,116	2,692
NATURAL GAS AND OTHER:					
Greater Des Moines	Pleasant Hill, IA	Gas	2003-2004	506	506
Electrifarm	Waterloo, IA	Gas or Oil	1975-1978	189	189
Pleasant Hill	Pleasant Hill, IA	Gas or Oil	1990-1994	151	151
Sycamore	Johnston, IA	Gas or Oil	1974	143	143
River Hills	Des Moines, IA	Gas	1966-1967	119	119
Coralville	Coralville, IA	Gas	1970	63	63
Moline	Moline, IL	Gas	1970	62	62
27 portable power modules	Various	Oil	2000	54	54
Parr	Charles City, IA	Gas	1969	33	33
				1,320	1,320
NUCLEAR:					
Quad Cities Nos. 1 and 2	Cordova, IL	Uranium	1972	1,822	455

Generating Facility	Location	Energy Source	Year Installed / Repowered[1]	Facility Net Capacity (MWs)[2]	Net Owned Capacity (MWs)[2]
SOLAR:					
Holliday Creek	Fort Dodge, IA	Solar	2022	100	100
Arbor Hill	Adair, IA	Solar	2022	24	24
Franklin	Hampton, IA	Solar	2022	7	7
Neal	Salix, IA	Solar	2022	4	4
Waterloo	Waterloo, IA	Solar	2022	3	3
Hills	Hills, IA	Solar	2022	3	3
				141	141
HYDROELECTRIC:					
Moline Unit Nos. 1-4	Moline, IL	Hydroelectric	1941	4	4
Total Available Generating Capacity				15,034	12,243
PROJECTS UNDER CONSTRUCTION:[3]					
Orient Energy Center	Adair County, IA	Gas	Est. 2028	465	465
Triangle	Johnson County, IA	Solar	Est. 2028	150	150
Mills	Mills County, IA	Solar	Est. 2026	50	50
Auburn	Sac County, IA	Solar	Est. 2027	50	50
Nodaway Valley	Page County, IA	Solar	Est. 2027	50	50
Various projects	IA	Solar	Est. 2028	500	500
				1,265	1,265
				16,299	13,508

(1) Repowered dates are associated with component replacements on existing wind-powered generating facilities commonly referred to by the IRS as repowering. IRS rules provide for re-establishment of the PTCs for an existing wind-powered generating facility upon the replacement of a significant portion of its components. If the degree of component replacement in such projects meets IRS guidelines, PTCs are re-established for 10 years beginning with the date the repowered facility is placed in-service.

(2) Facility Net Capacity represents the lesser of nominal ratings or any limitations under applicable interconnection, power purchase, or other agreements for intermittent resources and the total net dependable capability available during summer conditions for all other units. An intermittent resource's nominal rating is the manufacturer's contractually specified capability (in MWs) under specified conditions. Net Owned Capacity indicates MidAmerican Energy's ownership of Facility Net Capacity.

(3) Additional projects under construction as of December 31, 2025, include wind expansion and repowering projects of 1,238 MWs related to generating facilities already included in the table above, with Facility Net Capacity limited by applicable interconnection agreements.

The following table shows the percentages of MidAmerican Energy's total energy supplied by energy source for the years ended December 31:

	2025	2024	2023
Wind, solar and hydroelectric[1]	54 %	59 %	55 %
Coal	24	19	22
Nuclear	8	9	8
Natural gas	4	5	5
Total energy generated	90	92	90
Energy purchased - short-term contracts and other	9	7	9
Energy purchased - long-term contracts (renewable)[1]	1	1	1
	100 %	100 %	100 %

(1) All or some of the renewable energy attributes associated with generation from these sources may be: (a) used in future years to comply with RPS or other regulatory requirements, (b) sold to third parties in the form of RECs or other environmental commodities, or (c) excluded from energy purchased.

MidAmerican Energy is required to have accredited resources available for dispatch by MISO to continuously meet its customer's needs and reliably operate its electric system. The percentage of MidAmerican Energy's energy supplied by energy source varies from year to year and is subject to numerous operational and economic factors such as planned and unplanned outages; fuel commodity prices; fuel availability; fuel transportation costs; weather, including temperature, wind and sun; legislative and environmental considerations; transmission constraints; wholesale market prices of electricity and other factors. MidAmerican Energy evaluates these factors continuously in order to facilitate dispatch of its generating facilities by MISO. When factors for one energy source are less favorable, MidAmerican Energy places more reliance on other energy sources. For example, MidAmerican Energy can generate more electricity using its low cost wind-powered generating facilities when factors associated with these facilities are favorable. When factors associated with wind resources are less favorable, MidAmerican Energy must increase its reliance on more expensive generation or purchased electricity. Refer to "General Regulation" in Item 1 of this Form 10-K for a discussion of energy cost recovery by jurisdiction.

Wind

MidAmerican Energy owns more wind-powered generating capacity than any other U.S. rate-regulated electric utility and believes wind-powered generation offers a viable, economical and environmentally prudent means of supplying electricity and complying with laws and regulations. Pursuant to ratemaking principles approved by the IUC, facilities accounting for 87% of MidAmerican Energy's wind-powered generating capacity in-service at December 31, 2025, are authorized to earn a fixed rate of return on equity over their regulatory lives ranging from 10.75% to 12.3% on the depreciated cost of their original construction, which excludes the cost of later replacements, in any future Iowa rate proceeding. MidAmerican Energy's wind-powered generating facilities, including those facilities where a significant portion of the equipment was replaced, commonly referred to as repowered facilities, are eligible for federal renewable electricity PTCs for 10 years beginning with the date the facilities are placed in-service. PTCs are earned as energy from qualifying wind-powered generating facilities is produced and sold. PTCs for MidAmerican Energy's wind-powered generating facilities currently in-service began expiring in 2014, with final expiration in 2035. MidAmerican Energy has repowered 2,863 MWs of wind-powered generating facilities for which PTCs had expired and plans to repower 1,033 MWs of wind-powered generating facilities for which PTCs have expiration dates from 2024-2026.

Of the 7,854 MWs (nameplate capacity) of wind-powered generating facilities in-service, 7,651 MWs were generating PTCs at some point in 2025, including 2,863 MWs of repowered facilities. MidAmerican Energy earned PTCs from wind-powered generating facilities totaling $751 million, $761 million and $681 million in 2025, 2024 and 2023, respectively.

Coal

All the coal-fueled generating facilities operated by MidAmerican Energy are fueled by low-sulfur, sub-bituminous coal from the Powder River Basin in northeast Wyoming. MidAmerican Energy's coal supply portfolio includes multiple suppliers and mines under short-term and multi-year agreements of varying terms and quantities through 2028. MidAmerican Energy believes supplies from these sources are presently adequate and available to meet MidAmerican Energy's needs. Essentially all of MidAmerican Energy's expected coal supply requirements are covered under fixed-price contracts. MidAmerican Energy regularly monitors the western coal market for opportunities to enhance its coal supply portfolio.

MidAmerican Energy has a multi-year long-haul coal transportation agreement with BNSF Railway Company ("BNSF"), an affiliate company, for the delivery of coal to two MidAmerican Energy-operated coal-fueled generating facilities. Under this agreement, BNSF delivers coal directly to MidAmerican Energy's Walter Scott, Jr. Energy Center and to an interchange point with Canadian Pacific Kansas City Railway Company ("CPKC"). MidAmerican Energy has a single-year contract for short-haul delivery with CPKC from the interchange point to the Louisa Energy Center. MidAmerican Energy has a multi-year long-haul coal transportation agreement with Union Pacific Railroad Company for the delivery of coal to the George Neal Energy Center.

Nuclear

MidAmerican Energy is a 25% joint owner of Quad Cities Generating Station Units 1 and 2 ("Quad Cities Station"), a nuclear generating facility, which is currently licensed by the NRC for operation until December 14, 2032. Constellation Energy Generation, LLC ("Constellation Energy"), is the 75% joint owner and the operator of Quad Cities Station. Approximately one-third of the nuclear fuel assemblies in each reactor core at Quad Cities Station is replaced every 24 months. MidAmerican Energy has been advised by Constellation Energy that it expects to obtain the necessary uranium concentrates, conversion, enrichment and fabrication services to meet the nuclear fuel requirements of Quad Cities Station. In reaction to concerns about the profitability of Quad Cities Station and Constellation Energy's ability to continue its operation, in December 2016, Illinois passed legislation creating a zero-emission standard, which went into effect June 1, 2017. The zero-emission standard requires the Illinois Power Agency to purchase ZECs and recover the costs from certain ratepayers in Illinois, subject to certain limitations. Currently, Quad Cities is operating under agreements to provide Illinois load serving entities ZECs through May 31, 2027. Additionally, on August 16, 2022, the Inflation Reduction Act of 2022 was signed into law which contained numerous provisions, including expanded tax credits for clean energy incentives. As a result of the enactment of the Inflation Reduction Act of 2022, MidAmerican Energy's ownership of the Quad Cities Station qualifies for federal nuclear PTCs which provide a tax credit beginning in 2024 for qualifying production volumes subject to a phase-out based on annual gross receipts. Both the amount of the PTC and the gross receipt thresholds adjust annually for inflation over the duration of the program. MidAmerican Energy earned nuclear PTCs totaling $12 million and $49 million in 2025 and 2024, respectively, of which 88% were included in the Iowa EAC.

Natural Gas and Other

MidAmerican Energy uses natural gas and oil as fuel for intermediate and peak demand electric generation, igniter fuel, transmission support and standby purposes. These sources are presently in adequate supply and available to meet MidAmerican Energy's needs.

Regional Transmission Organizations

MidAmerican Energy sells and purchases electricity and ancillary services related to its generation and load in wholesale markets pursuant to the tariffs in those markets. MidAmerican Energy participates predominantly in the MISO energy and ancillary service markets, which provide MidAmerican Energy with wholesale opportunities over a large market area. MidAmerican Energy can enter into wholesale bilateral transactions in addition to market activity related to its assets. MidAmerican Energy is also authorized to participate in the Southwest Power Pool, Inc. and PJM Interconnection, L.L.C. ("PJM") markets and can contract with several other utilities in the region.

The MISO requires each member to maintain a minimum seasonal reserve margin of its accredited generating capacity over its seasonal peak demand obligation based on the member's seasonal load forecast filed with the MISO each year. Owned and contracted accredited capacity represents the amount of generation available to meet the requirements of MidAmerican Energy's retail customers and consists of MidAmerican Energy-owned generation, interruptible retail customer load, certain customer private generation that MidAmerican Energy is contractually allowed to dispatch and the net amount of capacity purchases and sales, excluding sales into the MISO annual capacity auction. Accredited capacity may vary significantly from the nominal capacity ratings, particularly for wind or solar facilities whose output is dependent upon energy resource availability at any given time. Additionally, the actual amount of generating capacity available at any time may be less than the accredited capacity due to regulatory restrictions, transmission constraints, fuel restrictions and generating units being temporarily out of service for inspection, maintenance, refueling, modifications or other reasons. The MISO's reserve requirements for the 2025-2026 planning year were 7.9% for summer 2025, 14.9% for fall 2025, 18.4% for winter 2025-2026 and 25.3% for spring 2026. For the summer peak demand season, MidAmerican Energy's owned and contracted capacity accredited for the 2025-2026 MISO capacity auction was 6,017 MWs compared to a peak demand obligation of 5,725 MWs. MidAmerican Energy purchased an additional 160 MWs in the MISO Planning Resource Auction to fulfill the MISO summer reserve requirements. MidAmerican Energy has more than adequate reserve margin for the fall, winter and spring peak demand seasons. Some of the excess capacity may be sold through bilateral or MISO capacity auction transactions. The reserve requirements for the 2026-2027 planning year will be 7.9% for summer 2026, 11.6% for fall 2026, 18.9% for winter 2026-2027 and 23.4% for spring 2027. MidAmerican Energy's decisions regarding additions to or reductions of its generation portfolio may be impacted by the MISO's minimum reserve margin requirements.

Transmission and Distribution

MidAmerican Energy's transmission and distribution systems included 4,700 circuit miles of transmission lines in four states, 25,800 circuit miles of distribution lines and 330 substations as of December 31, 2025. Electricity from MidAmerican Energy's generating facilities and purchased electricity is delivered to wholesale markets and its retail customers via the transmission facilities of MidAmerican Energy and others. MidAmerican Energy participates in the MISO capacity, energy and ancillary services markets as a transmission-owning member and, accordingly, operates its transmission assets at the direction of the MISO. The MISO manages its energy and ancillary service markets using reliability-constrained dispatch of the region's generation. For both the day-ahead and real-time (every five minutes) markets, the MISO analyzes generation commitments to provide market liquidity and transparent pricing while maintaining transmission system reliability by minimizing congestion and maximizing efficient energy transmission. Additionally, through its FERC-approved OATT, the MISO performs the role of transmission service provider throughout the MISO footprint and administers the long-term planning function. The MISO costs of the participants are shared among the participants through a number of mechanisms in accordance with the MISO tariff.

Regulated Natural Gas Operations

MidAmerican Energy is engaged in the distribution of natural gas to customers in its service territory and the related procurement, transportation and storage of natural gas for the benefit of those customers. MidAmerican Energy purchases natural gas from various suppliers and contracts with interstate natural gas pipelines for transportation of the gas to MidAmerican Energy's service territory and for storage and balancing services. MidAmerican Energy sells natural gas and delivery services to end-use customers on its distribution system; sells natural gas to other utilities, municipalities and energy marketing companies; and transports natural gas through its distribution system for end-use customers who have independently secured their supply of natural gas. During 2025, 58% of the total natural gas delivered through MidAmerican Energy's distribution system was associated with transportation service.

Natural gas property consists primarily of natural gas mains and service lines, meters, and related distribution equipment, including feeder lines to communities served from natural gas pipelines owned by others. The natural gas distribution facilities of MidAmerican Energy included 25,300 miles of natural gas main and service lines as of December 31, 2025.

Customer Usage and Seasonality

The percentages of natural gas sold to MidAmerican Energy's retail customers by jurisdiction for the years ended December 31 were as follows:

	2025	2024	2023
Iowa	75 %	75 %	75 %
South Dakota	14	14	14
Illinois	10	10	10
Nebraska	1	1	1
	100 %	100 %	100 %

The percentages of natural gas sold to MidAmerican Energy's retail and wholesale customers by class of customer, total Dths of natural gas sold, total Dths of transportation service and the average number of retail customers for the years ended December 31 were as follows:

	2025	2024	2023
Dths sold:			
Residential	48 %	44 %	45 %
Commercial[1]	23	21	21
Industrial[1]	5	5	5
Total retail	76	70	71
Wholesale[2]	24	30	29
	100 %	100 %	100 %
Dths of natural gas sold (in thousands):	104,985	102,186	106,912
Dths of transportation service (in thousands):	111,772	108,667	106,422
Average number of retail customers (in thousands):			
Residential	736	729	723
Commercial	71	70	69
Industrial	1	1	1
Other	3	3	3
Total	811	803	796

(1) Commercial and industrial customers are classified primarily based on the nature of their business and natural gas usage. Commercial customers are non-residential customers that use natural gas principally for heating. Industrial customers are non-residential customers that use natural gas principally for their manufacturing processes.

(2) Wholesale sales are generally made to other utilities, municipalities and energy marketing companies for eventual resale to end-use customers.

There are seasonal variations in MidAmerican Energy's regulated natural gas business that are principally due to the use of natural gas for heating. Typically, 50-60% of MidAmerican Energy's regulated retail natural gas revenue is reported in the months of January, February, March and December.

During 2025, 2024 and 2023, MidAmerican Energy's peak-day delivery through its distribution system was 1,372,402, 1,309,874 and 1,119,503 Dths, respectively. On January 20, 2025, MidAmerican Energy recorded its all-time highest peak-day of 1,372,402 Dths. This peak-day delivery consisted of 66% traditional retail sales service and 34% transportation service.

Natural Gas Supply and Capacity

MidAmerican Energy uses several strategies designed to maintain a reliable natural gas supply and reduce the impact of volatility in natural gas prices on its regulated retail natural gas customers. These strategies include the purchase of a geographically diverse supply portfolio from producers and third-party energy marketing companies, the use of interstate pipeline storage services and MidAmerican Energy's LNG peaking facilities, and the use of financial derivatives to fix the price on a portion of the anticipated natural gas requirements of MidAmerican Energy's customers. Refer to "General Regulation" in Item 1 of this Form 10-K for a discussion of the PGAs.

MidAmerican Energy contracts for firm natural gas pipeline capacity to transport natural gas from key production areas and liquid market centers to its service territory through direct interconnects to the pipeline systems of several interstate natural gas pipeline systems, including Northern Natural Gas, an affiliate company. MidAmerican Energy has multiple pipeline interconnections into several larger markets within its distribution system. Multiple pipeline interconnections create competition among pipeline suppliers for transportation capacity to serve those markets, thus reducing costs. In addition, multiple pipeline interconnections increase delivery reliability and give MidAmerican Energy the ability to optimize delivery of the lowest cost supply from the various production areas and liquid market centers into these markets. Benefits to MidAmerican Energy's distribution system customers are shared among all jurisdictions through a consolidated PGA.

At times, the natural gas pipeline capacity available through MidAmerican Energy's firm capacity portfolio may exceed the requirements of retail customers on MidAmerican Energy's distribution system. Firm capacity in excess of MidAmerican Energy's system needs can be released to other companies to achieve optimum use of the available capacity. Past IUC and South Dakota Public Utilities Commission ("SDPUC") rulings have allowed MidAmerican Energy to retain 30% of the revenue on the resold capacity, with the remaining 70% being returned to customers through the PGAs.

MidAmerican Energy utilizes interstate pipeline natural gas storage services to meet retail customer requirements, manage fluctuations in demand due to changes in weather and other usage factors and manage variation in seasonal natural gas pricing. MidAmerican Energy typically withdraws natural gas from storage during the heating season when customer demand is historically at its peak and injects natural gas into storage during off-peak months when customer demand is historically lower. MidAmerican Energy also utilizes its three LNG facilities to meet peak day demands during the winter heating season. Interstate pipeline storage services and MidAmerican Energy's LNG facilities reduce dependence on natural gas purchases during the volatile winter heating season and can deliver a significant portion of MidAmerican Energy's anticipated retail sales requirements on a peak winter day. For MidAmerican Energy's 2025/2026 winter heating season preliminary peak-day of January 23, 2026, supply sources used to meet deliveries to traditional retail sales service customers included 56% from purchases delivered on interstate pipelines, 34% from interstate pipeline storage services and 10% from MidAmerican Energy's LNG facilities.

MidAmerican Energy attempts to optimize the value of its regulated transportation capacity, natural gas supply and interstate pipeline storage services by engaging in wholesale transactions. IUC and SDPUC rulings have allowed MidAmerican Energy to retain 50% of the respective jurisdictional margins earned on certain wholesale sales of natural gas, with the remaining 50% being returned to customers through the PGAs.

MidAmerican Energy is not aware of any factors that would cause material difficulties in meeting its anticipated retail customer demand under normal operating conditions for the foreseeable future.

Energy Efficiency Programs

MidAmerican Energy has provided a comprehensive set of DSM programs to its Iowa electric and natural gas customers since 1990. The programs, collectively referred to as energy efficiency programs, are designed to reduce energy consumption and more effectively manage when energy is used, including management of seasonal peak loads. Current programs offer services to customers such as energy engineering audits and information on how to improve the efficiency of their homes and businesses. To assist customers in investing in energy efficiency, MidAmerican Energy offers rebates or incentives encouraging the purchase and installation of high-efficiency equipment such as lighting, heating and cooling equipment, weatherization, motors, process equipment and systems, as well as incentives for efficient construction. Incentives are also paid to residential customers who participate in the air conditioner load control program and nonresidential customers who participate in the nonresidential load management program. In Iowa, legislation passed in 2018 provides that projected cumulative average annual costs for a natural gas energy efficiency plan cannot exceed 1.5% of expected Iowa natural gas retail revenue and, for an electric demand response plan and separately for an electric energy efficiency plan other than demand response, cannot exceed 2.0% of expected annual Iowa electric retail revenue. Although subject to prudence reviews, state regulations allow for contemporaneous recovery of costs incurred for energy efficiency programs through state-specific energy efficiency service charges paid by all retail electric and natural gas customers. In 2025, $53 million was expensed for MidAmerican Energy's energy efficiency programs, which resulted in estimated first-year energy savings of 232,000 MWhs of electricity and 136,000 Dths of natural gas and an estimated peak load reduction of 262 MWs of electricity and 2,014 Dths per day of natural gas.

Human Capital

Employees

As of December 31, 2025, MidAmerican Funding and MidAmerican Energy had approximately 3,600 employees, of which approximately 1,400 (39%) were covered by union contracts. MidAmerican Energy has three separate contracts with locals of the International Brotherhood of Electrical Workers and the United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied Industrial and Service Workers International Union. A contract with the International Brotherhood of Electrical Workers covering substantially all of the union employees expires April 30, 2027. For more information regarding MidAmerican Funding's and MidAmerican Energy's human capital disclosures, refer to Item 1. Business - General section of this Form 10-K.

NV ENERGY (NEVADA POWER AND SIERRA PACIFIC)

General

NV Energy, an indirect wholly owned subsidiary of BHE, is an energy holding company headquartered in Nevada whose principal subsidiaries are Nevada Power and Sierra Pacific. Nevada Power and Sierra Pacific are indirect consolidated subsidiaries of Berkshire Hathaway. Nevada Power is a U.S. regulated electric utility company serving 1.1 million retail customers primarily in the Las Vegas, North Las Vegas, Henderson and adjoining areas. Sierra Pacific is a U.S. regulated electric and natural gas utility company serving 0.4 million retail electric customers and 0.2 million retail and transportation natural gas customers in northern Nevada. The Nevada Utilities are principally engaged in the business of generating, transmitting, distributing and selling electricity and, in the case of Sierra Pacific, in distributing, selling and transporting natural gas. Nevada Power and Sierra Pacific have electric service territories covering approximately 4,500 square miles and 41,400 square miles, respectively. Sierra Pacific has a natural gas service territory covering approximately 900 square miles in Reno and Sparks. Principal industries served by the Nevada Utilities include gaming, recreation, warehousing, manufacturing and governmental services. Sierra Pacific also serves the mining industry. The Nevada Utilities buy and sell electricity on the wholesale market with other utilities, energy marketing companies, financial institutions and other market participants to balance and optimize economic benefits of electricity generation, retail customer loads and wholesale transactions.

The Nevada Utilities' electric and natural gas operations are conducted under numerous nonexclusive franchise agreements, revocable permits and licenses obtained from federal, state and local authorities. The franchise agreements, with various expiration dates, are typically for 10- to 20-year terms. The Nevada Utilities operate under certificates of public convenience and necessity as regulated by the PUCN, and as such the Nevada Utilities have an obligation to provide electricity service to those customers within their service territory. In return, the PUCN has established rates on a cost-of-service basis, which are designed to allow the Nevada Utilities an opportunity to recover all prudently incurred costs of providing services and an opportunity to earn a reasonable return on their investment.

NV Energy's monthly net income is affected by the seasonal impact of weather on electricity and natural gas sales and seasonal retail electricity prices from the Nevada Utilities'. For 2025, 79% of NV Energy annual net income was recorded in the months of June through September.

Regulated electric utility operations is Nevada Power's only segment while regulated electric utility operations and regulated natural gas operations are the two segments of Sierra Pacific.

Sierra Pacific's operating revenue derived from the following business activities for the years ended December 31 were as follows (dollars in millions):

	2025		2024		2023	
Operating revenue:						
Electric	$ 964	89 %	$ 1,080	86 %	$ 1,194	83 %
Gas	124	11	182	14	237	17
Total operating revenue	$ 1,088	100 %	$ 1,262	100 %	$ 1,431	100 %

Nevada Power was incorporated under the laws of the state of Nevada in 1929. Its principal executive offices are located at 6226 West Sahara Avenue, Las Vegas, Nevada 89146, its telephone number is (702) 402-5000 and its internet address is www.nvenergy.com.

Sierra Pacific was incorporated under the laws of the state of Nevada in 1912. Its principal executive offices are located at 6100 Neil Road, Reno, Nevada 89511, its telephone number is (775) 834-4011 and its internet address is www.nvenergy.com.

Regulated Electric Operations

Customers

The Nevada Utilities' sell electricity to retail customers in a single state jurisdiction. Electricity sold to the Nevada Utilities' retail and wholesale customers by class of customer and the average number of retail customers for the years ended December 31 were as follows:

	2025		2024		2023	
Nevada Power:						
GWhs sold:						
Residential	9,839	40 %	10,535	41 %	9,584	41 %
Commercial	4,894	20	5,045	20	4,807	20
Industrial	6,383	26	6,356	25	5,827	25
Other	176	1	179	1	179	1
Total fully bundled	21,292	87	22,115	87	20,397	87
Distribution only service	2,908	12	2,918	11	2,831	12
Total retail	24,200	99	25,033	98	23,228	99
Wholesale	418	1	465	2	230	1
Total GWhs sold	24,618	100 %	25,498	100 %	23,458	100 %
Average number of retail customers (in thousands):						
Residential	933	89 %	916	89 %	899	89 %
Commercial	118	11	117	11	114	11
Industrial	2	—	2	—	2	—
Total	1,053	100 %	1,035	100 %	1,015	100 %
Sierra Pacific:						
GWhs sold:						
Residential	2,666	22 %	2,726	22 %	2,655	23 %
Commercial	3,095	25	3,108	25	2,998	25
Industrial	2,987	24	2,811	23	2,684	23
Other	9	—	9	—	11	—
Total fully bundled	8,757	71	8,654	70	8,348	71
Distribution only service	2,882	24	2,958	24	2,829	24
Total retail	11,639	95	11,612	94	11,177	95
Wholesale	623	5	683	6	621	5
Total GWhs sold	12,262	100 %	12,295	100 %	11,798	100 %
Average number of retail customers (in thousands):						
Residential	335	87 %	331	87 %	326	87 %
Commercial	51	13	51	13	50	13
Total	386	100 %	382	100 %	376	100 %

Variations in weather, economic conditions, particularly for gaming, mining and wholesale customers and various conservation, energy efficiency and private generation measures and programs can impact customer energy requirements. Wholesale sales are impacted by market prices for energy relative to the incremental cost to generate power.

There are seasonal variations in the Nevada Utilities' electric business that are principally related to weather and the related use of electricity for air conditioning. Typically, 47-52% of Nevada Power's and 38-40% of Sierra Pacific's regulated electric revenue is reported in the months of June through September.

The annual hourly peak customer demand on the Nevada Utilities' electric systems occurs as a result of air conditioning use during the cooling season. Peak demand represents the highest demand on a given day and at a given hour. During the summer months of 2025, 2024 and 2023, customer usage of electricity caused an hourly peak demand on Nevada Power's electric system of 6,168, 6,656 and 6,311 MWs, respectively, and on Sierra Pacific's electric system of 2,073, 2,113 and 1,825 MWs, respectively.

Generating Facilities and Fuel Supply

The Nevada Utilities have ownership interests in a diverse portfolio of generating facilities. The following table presents certain information regarding the Nevada Utilities' owned generating facilities as of December 31, 2025:

Generating Facility	Location	Energy Source	Installed	Facility Net Capacity (MWs)[1]	Net Owned Capacity (MWs)[1]
Nevada Power:					
NATURAL GAS:					
Lenzie	Las Vegas, NV	Natural gas	2006	1,218	1,218
Clark	Las Vegas, NV	Natural gas	1973-2008	1,144	1,144
Silverhawk[2]	Las Vegas, NV	Natural gas	2004-2024	1,034	1,034
Harry Allen	Las Vegas, NV	Natural gas	1995-2011	680	680
Higgins	Primm, NV	Natural gas	2004	602	602
Las Vegas	Las Vegas, NV	Natural gas	1994-2003	272	272
Sun Peak	Las Vegas, NV	Natural gas/oil	1991	231	231
				5,181	5,181
RENEWABLES:					
Dry Lake	Dry Lake, NV	Solar	2024	150	150
Nellis	Las Vegas, NV	Solar	2015	15	15
Goodsprings	Goodsprings, NV	Waste heat	2010	5	5
				170	170
Total Nevada Power Available Generating Capacity				5,351	5,351
Sierra Pacific:					
NATURAL GAS:					
Tracy	Sparks, NV	Natural gas	1974-2008	776	776
Ft. Churchill	Yerington, NV	Natural gas	1968-1971	196	196
Clark Mountain	Sparks, NV	Natural gas	1994	138	138
Valmy Unit No. 1[3]	Valmy, NV	Natural gas	1981-2025	254	127
				1,364	1,237
RENEWABLES:					
Ft. Churchill	Yerington, NV	Solar	2015	20	20
Total Sierra Pacific Available Generating Capacity				1,384	1,257
Total NV Energy Available Generating Capacity				6,735	6,608
PROJECTS UNDER CONSTRUCTION:					
Sierra Solar[4]	Fernley, NV	Solar	Est. 2027	400	400
				7,135	7,008

(1) Facility Net Capacity represents the lesser of nominal ratings or any limitations under applicable interconnection, power purchase, or other agreements for intermittent resources and the total net dependable capability available during summer conditions for all other units. An intermittent resource's nominal rating is the manufacturer's contractually specified capability (in MWs) under specified conditions. Net Owned Capacity indicates Nevada Power or Sierra Pacific's ownership of Facility Net Capacity.

(2) Additional generating units at the Silverhawk generating facility in Clark County, Nevada were placed into commercial operation in July 2024 creating an additional 444 MW of peaking combustion turbines.

(3) Valmy Unit No. 1 completed its conversion from coal to natural gas in December 2025. Conversion of Valmy Unit No. 2 will start in early 2026 and will add 134 MWs of net owned natural gas generation capacity when the unit is completed by mid-2026.

(4) In addition to the 400 MW solar photovoltaic facility, Sierra Solar has 400 MW of co-located battery energy storage that will be developed in Fernley, Nevada with commercial operation expected in 2026. The solar photovoltaic portion is expected to be operational in 2027. The facility ownership share is allocated 90% to Sierra Pacific and 10% to Nevada Power Company.

Additionally, as of December 31, 2025, Nevada Power has two battery energy storage systems in-service; Reid Gardner located in Moapa, Nevada, having total Facility Net Capacity and Net Owned Capacity of 220 MWs and Dry Lake located in Dry Lake, Nevada, having total Facility Net Capacity and Net Owned Capacity of 100 MWs.

The Nevada Utilities have entered into multiple long-term electricity contracts that it considers part of the total available generating capacity. The following table presents facility net capacity regarding generation sources of the Nevada Utilities' long-term purchased electricity contracts as of December 31, 2025:

Electricity Contract Energy Source	Capacity MWs
Solar	2,851
Geothermal	405
Hydroelectric	246
Wind	152
Other renewable	15
Total renewable	3,669
Other	11
Total contract capacity	3,680

Additionally, the Nevada Utilities have contractual rights to 553 MW's of co-located battery energy storage facilities of which 454 MW are located in southern Nevada service territory and 99 MW are located in northern Nevada service territory.

The following table shows the percentages of the Nevada Utilities' total energy supplied by energy source for the years ended December 31:

	2025	2024	2023
Nevada Power:			
Natural gas	64 %	65 %	65 %
Renewable [1]	2	2	—
Total energy generated	66	67	65
Energy purchased - long-term contracts (renewable)[2]	32	29	24
Energy purchased - long-term contracts (non-renewable)	—	1	5
Energy purchased - short-term contracts and other	2	3	6
	100 %	100 %	100 %
Sierra Pacific:			
Natural gas	49 %	49 %	44 %
Coal	9	10	8
Total energy generated[1]	58	59	52
Energy purchased - long-term contracts (renewable)[2]	35	35	32
Energy purchased - long-term contracts (non-renewable)	4	4	9
Energy purchased - short-term contracts and other	3	2	7
	100 %	100 %	100 %

(1) Energy generated from renewable generating facilities mainly comprised of the solar resources related to the Dry Lake solar generating facility that was placed into service in May 2024.

(2) All or some of the renewable energy attributes associated with generation from these sources may be: (a) used in future years to comply with RPS or other regulatory requirements, (b) sold to third parties in the form of RECs or other environmental commodities, or (c) excluded from energy purchased.

The Nevada Utilities are required to have resources available to continuously meet their customer needs and reliably operate their electric systems. The percentage of the Nevada Utilities' energy supplied by energy source varies from year-to-year and is subject to numerous operational and economic factors such as planned and unplanned outages; fuel commodity prices; fuel availability; fuel transportation costs; weather, including temperature, wind and sun; legislative and environmental considerations; transmission constraints; wholesale market prices of electricity and other factors. The Nevada Utilities evaluate these factors continuously in order to facilitate dispatch of their generating facilities. When factors for one energy source are less favorable, the Nevada Utilities place more reliance on other energy sources. As long as the Nevada Utilities' purchases are deemed prudent by the PUCN, through their annual prudency review, the Nevada Utilities are permitted to recover the cost of fuel and purchased power. The Nevada Utilities also have the ability to reset quarterly the BTERs, with PUCN approval, based on the last 12 months fuel costs and purchased power and to reset the quarterly DEAA.

The Nevada Utilities have adopted an approach to managing the energy supply function that has three primary elements. The first element is a set of management guidelines for procuring and optimizing the supply portfolio that is consistent with the requirements of a load serving entity with a full requirements obligation, and with the growth of private generation serving a small but growing group of customers with partial requirements. The second element is an energy risk management and control approach that ensures clear separation of roles between the day-to-day management of risks and compliance monitoring and control and ensures clear distinction between planning and execution. Lastly, the Nevada Utilities pursue a process of ongoing regulatory involvement and acknowledgment of the resource portfolio management plans.

The Nevada Utilities have entered into multiple long-term power purchase contracts (three or more years) with suppliers that generate electricity utilizing renewable resources and natural gas. Nevada Power has entered into contracts with a total capacity of 3,902 MWs with contract termination dates ranging from 2026 to 2067. Included in these contracts are 2,874 MWs of capacity from renewable energy, of which 150 MWs of capacity are owned, and 1,028 MWs of capacity are under development or construction and not currently available. Sierra Pacific has entered into contracts with a total capacity of 1,172 MWs with contract termination dates ranging from 2026 to 2053. Included in these contracts are 1,160 MWs of capacity from renewable energy, of which 215 MWs of capacity are under development or construction and not currently available.

The Nevada Utilities manage certain risks relating to their supply of electricity and fuel requirements by entering into various contracts, which may be accounted for as derivatives, including forwards, futures, options, swaps and other agreements. Refer to NV Energy's "General Regulation" section in Item 1 of this Form 10-K for a discussion of energy cost recovery by jurisdiction and Nevada Power's Item 7A and Sierra Pacific's Item 7A in this Form 10-K for a discussion of commodity price risk and derivative contracts.

Natural Gas

The Nevada Utilities rely on indexed physical gas purchases for the majority of natural gas needed to operate their generating facilities. To secure natural gas supplies for the generating facilities, the Nevada Utilities execute purchases pursuant to a PUCN approved four-season laddering strategy. In 2025, natural gas supply net purchases averaged 319,859 and 148,892 Dths per day with the winter period contracts averaging 302,161 and 175,031 Dths per day and the summer period contracts averaging 332,346 and 130,449 Dths per day for Nevada Power and Sierra Pacific, respectively. The Nevada Utilities believe supplies from these sources are presently adequate and available to meet its needs.

The Nevada Utilities contract for firm natural gas pipeline capacity to transport natural gas from production areas to their service territory through direct interconnects to the pipeline systems of several interstate natural gas pipeline systems, including Nevada Power who contracts with Kern River, an affiliated company. Sierra Pacific utilizes natural gas storage contracted from interstate pipelines to meet retail customer requirements and to manage the daily changes in demand due to changes in weather and other usage factors. The stored natural gas is typically replaced during off-peak months when the demand for natural gas is historically lower than during the heating season.

Coal

Sierra Pacific relied on spot market solicitations for coal supplies and regularly monitored the western coal market for opportunities to meet these needs. Sierra Pacific had a transportation services contract with Union Pacific Railroad Company to ship coal from various origins in central Utah, western Colorado and Wyoming that expired December 31, 2025. Sierra Pacific had a transportation services contract with BNSF, an affiliate company, to ship coal from western Montana that expired October 31, 2025. The Valmy generating facility, Sierra Pacific's remaining facility requiring coal, had an approved retirement date of December 2025. Sierra Pacific proposed in its Fifth Amendment to the 2021 Joint Integrated Resource Plan to convert the existing coal-fueled plant to a cleaner natural gas-fueled plant which was approved by the PUCN in April 2024 as delineated in the final modified order. Nevada Power has no coal requirements.

Energy Imbalance Market

The Nevada Utilities participate in the EIM operated by the California ISO, which reduces costs to serve customers through more efficient dispatch of a larger and more diverse pool of resources, more effectively integrates renewables and enhances reliability through improved situational awareness and responsiveness. The EIM expands the real-time component of the California ISO's market technology to optimize and balance electricity supply and demand every five minutes across the EIM footprint. The EIM is voluntary and available to all balancing authorities in the western U.S. EIM market participants submit bids to the California ISO market operator before each hour for each generating resource they choose to be dispatched by the market. Each bid is comprised of a dispatchable operating range, ramp rate and prices across the operating range. The California ISO market operator uses sophisticated technology to select the least-cost resources to meet demand and send simultaneous dispatch signals to every participating generator across the EIM footprint every five minutes. In addition to generation resource bids, the California ISO market operator also receives continuous real-time updates of the transmission grid network, meteorological and load forecast information that it uses to optimize dispatch instructions. The EIM delivers customer benefits by leveraging automation and resource diversity to result in more efficient dispatch, more effective integration of renewables and improved situational awareness. Benefits are expected to increase further with renewable resource expansion and as more entities join the EIM bringing incremental diversity.

Transmission and Distribution

The Nevada Utilities' transmission system is part of the Western Interconnection, a regional grid in the U.S. The Western Interconnection includes the interconnected transmission systems of 14 western states, two Canadian provinces and parts of Mexico. The Nevada Utilities' transmission system, together with contractual rights on other transmission systems, enables the Nevada Utilities to integrate and access generation resources to meet their customer load requirements. Nevada Power's transmission and distribution systems included approximately 1,700 miles of transmission lines, 14,800 miles of distribution lines and 220 substations as of December 31, 2025. Sierra Pacific's transmission and distribution systems included approximately 4,300 miles of transmission lines, 9,600 miles of distribution lines and 200 substations as of December 31, 2025.

ON Line is a 231-mile, 500-kV transmission line connecting Nevada Power's and Sierra Pacific's service territories. ON Line provides the ability to jointly dispatch energy throughout Nevada and provide access to renewable energy resources in parts of northern and eastern Nevada, which enhances the Nevada Utilities' ability to manage and optimize their generating facilities. ON Line provides between 600 MWs northbound and 900 MWs southbound of transfer capability with interconnection between the Robinson Summit substation on the Sierra Pacific system and the Harry Allen substation on the Nevada Power system. ON Line was a joint project between the Nevada Utilities and Great Basin Transmission, LLC. The Nevada Utilities own a 25% interest in ON Line and have entered into a long-term transmission use agreement with Great Basin Transmission, LLC for its 75% interest in ON Line until 2054. The Nevada Utilities share of its 25% interest in ON Line and the long-term transmission use agreement is split 75% for Nevada Power and 25% for Sierra Pacific.

The PUCN has approved the Nevada Utilities' Greenlink Nevada transmission expansion program, with an estimated cost of approximately $4.2 billion, which builds a foundation for the Nevada Utilities to accommodate existing and future transmission network customers, increase transmission system reliability, create access to diversified resources and facilitate development of conventional generation. The Greenlink program consists of a 350-mile, 525-kV transmission line, known as Greenlink West, connecting the Walker River substation, near Yerington, Nevada to the Northwest substation, near Las Vegas, Nevada to the Harry Allen substation, near Las Vegas, Nevada; a 235-mile, 525-kV transmission line, known as Greenlink North, connecting the new Walker River substation, near Yerington, Nevada to the Robinson Summit substation, near Ely, Nevada; and various interconnections, known as Greenlink Common Ties that primarily include a 46-mile, 345-kV transmission line from the new Walker River substation, near Yerington, Nevada to the Mira Loma substations, near Yerington, Nevada; and a 38-mile, 345-kV transmission line from the new Walker River substation, near Yerington, Nevada to the Comstock Meadows substations, near Reno, Nevada. The Greenlink program will be constructed in stages that are estimated to be placed in-service between May 2027 and December 2028. The Nevada Utilities will jointly own and operate the Greenlink transmission lines with Nevada Power having a 70% ownership share in Greenlink West and North and Sierra Pacific having a 30% ownership share. Sierra Pacific will have a 100% ownership share in the Greenlink Common Ties. Through December 31, 2025, $1.2 billion had been spent.

Wildfire Prevention

The Nevada Utilities have developed detailed natural disaster protection plans for its service territory and areas in which it owns and operates assets. Natural disaster protection plans are filed with the PUCN on or before March 1 of every third year with annual updates to be filed on or before September 1 of the second and third years of the plan. These plans include capital investment in asset hardening and meteorological systems, the implementation of risk modeling tools and the Nevada Utilities' ongoing enhanced safety settings, inspections, vegetation management, enhancement to situational awareness to include implementation of wildfire alert cameras and weather stations in extreme fire-risk areas. In addition, NV Energy has an active power shutoff program referred to as public safety outage management ("PSOM") as well as an emergency de-energization policy in response to active wildfires encroaching the company's infrastructure.

Asset Hardening

The Nevada Utilities have and continue to invest in rebuilding overhead transmission and distribution lines with covered conductor and fire mesh and in some cases have converted overhead distribution lines to underground. These system hardening efforts reduce the exposure of the Nevada Utilities' lines to interference from trees and other objects. Covered conductor helps mitigate the risk of fault-caused electrical arcs that could cause an ignition. Overall, mitigated overhead lines help reduce ignition risk and improve reliability during storms or periods of significant wildfire risk.

The Nevada Utilities compiled an assessment of heightened threat areas ("HTAs") for wildfires that are presented as different tiers to characterize wildfire risk and potential catastrophic wildfire risk. The different tiers that the Nevada Utilities use to categorize their HTAs are Tier 1, Tier1E - Elevated ("Tier 1E"), Tier 2 (high) and Tier 3 (extreme).

Approximately 2,720 miles, or 9%, of the Nevada Utilities' transmission and distribution lines are in Tier 1E, Tier 2 and Tier 3 HTAs, covering approximately 6% of its service territory and approximately 0.2% of its customer base.

As of December 31, 2025, the 2,720 miles of transmission and distribution lines in Tier 1E, Tier 2 and Tier 3 HTAs were as follows:

- 1,930 miles, or 71%, with bare conductor miles, a portion of which in Tier 3 is fully mitigated by system relay fast trip protection schemes that are expanding into Tiers 2 and 1E with estimated completion by the end of 2026;
- 20 miles, or 1%, with new covered conductor miles; and
- 770 miles, or 28%, with underground miles.

The on-going asset hardening of the HTAs is a priority for the Nevada Utilities and a key part of the developed natural disaster protection plans.

Refer to "Future Uses of Cash" in Item 7 of this Form 10-K for further discussion of the Nevada Utilities' natural disaster protection plan related capital expenditures, including asset hardening.

Enhanced Safety Settings

Enhanced safety settings are available across the HTAs in the Nevada Utilities' service territory. Upon declaration of wildfire season, the Nevada Utilities place all Tier 3 circuits and certain Tier 2 and Tier 1E circuits into seasonal fire mode with no circuit reclosing which reduces the potential for sparking on multiple reclosing events when faults occur. Additionally, Fast Trip Fire Mode is an instantaneous lockout setting available at most HTA substations that is enabled when certain fire danger conditions are present to provide an enhanced level of protection to limit the potential for wildfire ignition.

Meteorology and Risk Modeling

The Nevada Utilities have installed 65 weather stations that monitor weather conditions and model the impact to the electrical infrastructure. These weather stations combined with the Nevada Utilities' dedicated two full-time meteorologists provide the Nevada Utilities with the ability to forecast weather and fire risk impact data twice daily. The Nevada Utilities will continue to install additional weather stations to refine weather modeling in areas where geographic terrain conditions require a dense network of weather stations in order to provide the necessary granular data. The Nevada Utilities have also installed 25 fire cameras equipped with artificial intelligence that provide around-the-clock monitoring and alerts of new fire starts.

Asset Inspection Program

Within the identified HTAs, the Nevada Utilities conduct an annual inspection of overhead facilities with an accelerated correction timeline for any conditions noted. A detailed inspection of facilities located in HTAs is conducted every three to 10 years based on the identified risk level.

Vegetation Management

The Nevada Utilities follow industry best management practices, internal protocols and the standards outlined in the International Wildland-Urban Interface Code. The Nevada Utilities' vegetation management program consists of prioritized patrols and inspections, prescribed tree pruning and removal and strategic ground clearing of equipment poles and right-of -way ground fuels reduction in all HTAs. The Nevada Utilities collaborate with state and federal agencies along with private property owners where vegetation clearing creates rights-of-way that deters fire spread.

Public Safety Outage Management and Wildfire Encroachment Policy

A PSOM is used as a preventative measure prior to extreme fire weather conditions that may pose threats to the public, customers, infrastructure or the environment where the electrical network is de-energized proactively under certain conditions. This program includes areas of wildfire risk system-wide where proactive de-energization zones are identified. In determining whether to initiate a PSOM, the Nevada Utilities evaluate conditions that may create an unacceptable level of risk of electric infrastructure being damaged and causing an ignition using data from meteorological systems and forecasting tools. During 2025, the Nevada Utilities continued to actively utilize the PSOM program to address extreme-risk weather conditions. PSOM is an increasingly common practice for utilities to use as part of wildfire prevention. The Nevada Utilities' also have an emergency de-energization policy under which it will de-energize its lines when a known wildfire that is unpredictable and uncontrollable is within a specified distance of its assets.

Future Generation, Conservation and Energy Efficiency

Energy Supply Planning

Within the energy supply planning process, there are four key components covering different time frames:

- IRPs are filed by the Nevada Utilities for approval by the PUCN every three years and the Nevada Utilities may, as necessary, file amendments to their IRPs. IRPs are prepared in compliance with Nevada laws and regulations and cover a 20-year period. Nevada law governing the IRP process was modified in 2017 and now requires joint filings by Nevada Power and Sierra Pacific. IRPs develop a comprehensive, integrated plan that considers customer energy requirements and propose the resources to meet those requirements in a manner that is consistent with prevailing market fundamentals. The ultimate goal of the IRPs is to balance the objectives of minimizing costs and reducing volatility while reliably meeting the electric needs of the Nevada Utilities' customers. Costs incurred to complete projects approved through the IRP process still remain subject to review for reasonableness by the PUCN.
- Energy Supply Plans ("ESP") are filed with the PUCN for approval and operate in conjunction with the PUCN-approved 20-year IRP. The ESP has a one- to three-year planning horizon and is an intermediate-term resource procurement and risk management plan that establishes the supply portfolio strategies within which intermediate-term resource requirements will be met with PUCN approval required for executing contracts of longer than three years.
- Distributed Resource Plans ("DRP") are filed with the PUCN for approval and operate in conjunction with the PUCN-approved 20-year IRP. The DRP establishes a formal process to aid in the cost-effective integration of distributed resources into the Nevada Utilities' distribution and transmission process and ultimately the NV Energy utilities' electricity grid.
- Action plans are filed with the PUCN for approval and operate in conjunction with the PUCN-approved 20-year IRP and PUCN-approved ESP. The action plan establishes tactical execution activities with a three-year focus.

In August 2023, the Nevada Utilities filed its Joint Application for approval of the Fifth Amendment to the 2021 Joint Integrated Resource Plan. The Fifth Amendment sought, in part (1) to convert the existing coal-fueled generating facility at North Valmy Generating Station to a cleaner natural gas-fueled generating facility (2) to purchase, install, and operate a company-owned 400 MW solar plant along with a 400 MW, four-hour battery storage system in Northern Nevada; (3) to continue operation of Tracy units 4 and 5 to 2049; (4) to purchase development assets for the 149 MW photovoltaic and 149 MW battery energy storage system Crescent Valley Solar project; (5) to construct the Esmeralda and Sagebrush substations transformers; and (6) to construct the necessary infrastructure in the APEX Area Master Plan. The Nevada Utilities sought approval of approximately $1.8 billion in total costs of new projects. An order was issued in March 2024 in which the Nevada Utilities filed a motion for clarification and petition for reconsideration. In April 2024, a modified final order was issued, which granted in part and denied in part including the denial of the 149 MW photovoltaic and 149 MW battery energy storage system Crescent Valley Solar project as delineated in the final modified order.

In May 2024, the Nevada Utilities filed its joint Application for approval of the 2024 Joint Integrated Resources Plan. The 2024 joint Application sought, in part (1) the addition of three power purchase agreements for solar generating resources totaling more than 1,000 MW, each with co-located battery storage systems; (2) the addition of 400 MW of company-owned hydrogen-capable natural gas simple cycle combustion turbine peakers at the North Valmy generation station; (3) to approve an update of the Greenlink Nevada Transmission project costs; and (4) to construct the necessary transmission infrastructure to support growing customer demand. In December 2024, the PUCN largely accepted the filing as filed but denied opining on the additional costs associated with the Greenlink Nevada project as all costs expended to construct the previously approved Greenlink Nevada project are subject to a prudency review in the GRC as delineated in the final 2024 Joint Integrated Resource Plan order.

In October 2025, the Nevada Utilities submitted a Joint Application for approval of the First Amendment to the 2024 Joint Integrated Resource Plan. The First Amendment seeks approval to enter into a 20-year power purchase agreement with the developer for an additional 150-MW battery energy storage system that will reduce the Nevada Utilities' open position beginning in the summer of 2027. The battery energy storage system will be co-located with existing Dodge Flat solar and battery facility in Washoe County, Nevada. In January 2026, the Nevada Utilities filed a stipulation with the PUCN that reflected a settlement among participating parties and largely accepted the First Amendment as filed, including approval of the 150-MW battery energy storage system power purchase agreement. A final order approving the stipulation was received in February 2026.

Energy Efficiency Programs

The Nevada Utilities have provided a comprehensive set of DSM programs which include energy efficiency, demand response, and conservation programs to their Nevada electric customers. The programs are designed to reduce energy consumption and more effectively manage when energy is used, including management of seasonal peak loads. Current programs offer services to customers such as energy audits and customer education and awareness efforts that provide information on how to improve the efficiency of their homes and businesses. To assist customers in investing in energy efficiency, the Nevada Utilities have offered rebates or incentives encouraging the purchase and installation of high-efficiency equipment such as lighting, heating and cooling equipment, electric water heating, weatherization, motors, process equipment and systems, as well as incentives for efficient construction. Incentives are also paid to residential customers who participate in the air conditioner load control program and nonresidential customers who participate in the smart thermostat and energy storage demand response program and nonresidential load management program. Energy efficiency program costs are recovered through annual rates set by the PUCN and adjusted based on the Nevada Utilities' annual filing to recover current program costs and any over or under collections from the prior filing, subject to prudence review. During 2025, Nevada Power spent $43 million on energy efficiency programs, resulting in an estimated 206,435 MWhs of electric energy savings and an estimated 157 MWs of electric peak load management. During 2025, Sierra Pacific spent $14 million on energy efficiency programs, resulting in an estimated 56,219 MWhs of electric energy savings and an estimated 31 MWs of electric peak load management.

Regulated Natural Gas Operations

Sierra Pacific is engaged in the distribution of natural gas to customers in its service territory and the related procurement, transportation and storage of natural gas for the benefit of those customers. Sierra Pacific purchases natural gas from various suppliers and contracts with interstate natural gas pipelines for transportation of the natural gas from the production areas to Sierra Pacific's service territory and for storage services to manage fluctuations in system demand and seasonal pricing. Sierra Pacific sells natural gas and delivery services to end-use customers on its distribution system; sells natural gas to other utilities, municipalities and energy marketing companies; and transports natural gas through its distribution system for a number of end-use customers who have independently secured their supply of natural gas. During 2025, 7% of the total natural gas delivered through Sierra Pacific's distribution system was for transportation service.

Natural gas property consists primarily of natural gas mains and service lines, meters, and related distribution equipment, including feeder lines to communities served from natural gas pipelines owned by others. The natural gas distribution facilities of Sierra Pacific included 3,700 miles of natural gas mains and service lines as of December 31, 2025.

Sierra Pacific specifically provided a Demand-Side Management "DSM" Gas Energy Education Program that delivers information, educational tools, tips, and personalized recommendations for gas customers who want to learn about their usage behavior and ways they can improve their energy efficiency practices. The Program utilizes engagement, outreach, and education as pathways to inform customers about access and use of energy. During 2025, Sierra Pacific spent $0.3 million on the DSM Gas Energy Education Program, resulting in an estimated 476,400 Dths in deemed therm savings. Sierra bases its estimated 2025 deemed therm savings on previously verified gas savings reported by Measurement and Verification reports from 2019. A deemed savings approach involves using stipulated savings for energy conservation measures for which savings values are well known and documented. Deemed savings are estimates of natural gas savings based on the actual reported savings for a similar program measure or action from previous years.

In October 2025, Sierra Pacific filed its 2025 Natural Gas Triennial Integrated Resource Plan (the "2025 NGIRP") with the PUCN, covering the 2026 through 2028 action plan period. The filling seeks approval of forecasted natural gas demand, ten significant operational and capital projects, the 2025 DSM Plan, and related findings regarding the reasonableness of the forecast methodology, projected demand, cost-effectiveness of proposed investments, resource mix, greenhouse gas considerations, and impacts on low-income and historically underserved communities. The application also requests authorization to establish a regulatory asset account to record costs associated with a proposed Plexco Service Tee Cap Replacement Program addressing premature failures of certain service tee caps installed between 1990 and 1996, with recovery of amounts recorded in the regulatory asset account to be sought in a future general rate case. In January 2026, Sierra Pacific filed a stipulation with the PUCN that reflected a settlement among participating parties and largely accepted the NGIRP as filed with removal of the requested regulatory asset account to record costs associated with the Plexco Service Tee CAP Replacement Program. A final order approving the stipulation was received in February 2026.

Customer Usage and Seasonality

The percentages of natural gas sold to Sierra Pacific's retail and wholesale customers by class of customer, total Dths of natural gas sold, total Dths of transportation service and the average number of retail customers for the years ended December 31 were as follows:

	2025	2024	2023
Dths sold:			
Residential	50 %	54 %	52 %
Commercial[1]	26	27	26
Industrial[1]	11	12	12
Total retail	87	93	90
Wholesale[2]	13	7	10
	100 %	100 %	100 %
Dths of natural gas sold (in thousands):	20,811	20,379	23,613
Dths of transportation service (in thousands):	1,468	1,267	1,453
Average number of retail customers (in thousands):			
Residential	173	171	169
Commercial	15	14	14
Total	188	185	183

(1) Commercial and industrial customers are classified primarily based on the nature of their business and natural gas usage. Commercial customers are non-residential customers with monthly gas usage less than 12,000 therms during five consecutive winter months. Industrial customers are non-residential customers that use natural gas in excess of 12,000 therms during one or more winter months.

(2) Wholesale sales are generally made to other utilities, municipalities and energy marketing companies for eventual resale to end-use customers.

There are seasonal variations in Sierra Pacific's regulated natural gas business that are principally due to the use of natural gas for heating. Typically, 47-58% of Sierra Pacific's regulated natural gas revenue is reported in the months of December through March.

During the winter months of 2025, 2024 and 2023, Sierra Pacific's peak-day natural gas delivery through its gas distribution system was 151,018, 140,157 and 160,974 Dths, respectively.

Fuel Supply and Capacity

The purchase of natural gas for Sierra Pacific's regulated natural gas operations is done in combination with the purchase of natural gas for Sierra Pacific's regulated electric operations. In response to energy supply challenges, Sierra Pacific has adopted an approach to managing the energy supply function that has three primary elements, as discussed earlier under Generating Facilities and Fuel Supply. Similar to Sierra Pacific's regulated electric operations, as long as Sierra Pacific's purchases of natural gas are deemed prudent by the PUCN, through its annual prudency review, Sierra Pacific is permitted to recover the cost of natural gas. Sierra Pacific also has the ability, with PUCN approval, to reset quarterly the BTERs, based on the last 12 months fuel costs, and to reset quarterly DEAA.

Human Capital

Employees

As of December 31, 2025, Nevada Power had approximately 1,500 employees, of which approximately 800 (49%) were covered by a union contract with the International Brotherhood of Electrical Workers.

As of December 31, 2025, Sierra Pacific had approximately 1,100 employees, of which approximately 600 (52%) were covered by a union contract with the International Brotherhood of Electrical Workers.

For more information regarding Nevada Power's and Sierra Pacific's human capital disclosures, refer to Item 1. Business - General section of this Form 10-K.

NORTHERN POWERGRID

Northern Powergrid, an indirect wholly owned subsidiary of BHE, is a holding company with investments in two companies that distribute electricity in Great Britain, Northern Powergrid (Northeast) plc and Northern Powergrid (Yorkshire) plc. In addition to the Northern Powergrid Distribution Companies, Northern Powergrid also has investments in a meter asset rental business that leases meters to energy suppliers in the United Kingdom, an engineering contracting business that provides electrical infrastructure contracting services primarily to third parties, an upstream gas exploration and production business that is focused on developing integrated projects in Europe and Australia and two solar generation facilities in Australia having a total net owned capacity of 260 MWs.

The Northern Powergrid Distribution Companies serve 4.0 million end-users and operate in the north-east of England from North Northumberland through Tyne and Wear, County Durham and Yorkshire to North Lincolnshire, an area covering 10,000 square miles. The principal function of the Northern Powergrid Distribution Companies is to build, maintain and operate the electricity distribution network through which the end-user receives a supply of electricity.

The Northern Powergrid Distribution Companies receive electricity from the national grid transmission system and from generators that are directly connected to the distribution network and distribute it to end-users' premises using their networks of transformers, switchgear and distribution lines and cables. Substantially all of the end-users in the Northern Powergrid Distribution Companies' distribution service areas are directly or indirectly connected to the Northern Powergrid Distribution Companies' networks and electricity can only be delivered to these end-users through their distribution systems, thus providing the Northern Powergrid Distribution Companies with distribution volumes that are relatively stable from year to year. The Northern Powergrid Distribution Companies charge fees for the use of their distribution systems to the suppliers of electricity.

The suppliers purchase electricity from generators, sell the electricity to end-user customers and use the Northern Powergrid Distribution Companies' distribution networks pursuant to an industry standard "Distribution Connection and Use of System Agreement." During 2025, E.ON and certain of its affiliates, British Gas Trading Limited and Octopus Energy Group Limited represented 16%, 15% and 12%, respectively, of the total combined distribution revenue of the Northern Powergrid Distribution Companies. Variations in demand from end-users can affect the revenues that are received by the Northern Powergrid Distribution Companies in any year, but such variations have no effect on the total revenue that the Northern Powergrid Distribution Companies are allowed to recover in a price control period. Under- or over-recoveries against price-controlled revenues are carried forward into prices for future years.

The Northern Powergrid Distribution Companies' combined service territory features a diverse economy with no dominant sector. The mix of rural, agricultural, urban and industrial areas covers a broad customer base ranging from domestic usage through farming and retail to major industry including automotives, chemicals, mining, steelmaking and offshore marine construction. The industry within the area is concentrated around the principal centers of Newcastle, Middlesbrough, Sheffield and Leeds.

The price-controlled revenue of the Northern Powergrid Distribution Companies is set out in the special conditions of the licenses of those companies. The licenses are enforced by the regulator, GEMA, through Ofgem, and limit increases to allowed revenues (or may require decreases) based upon the rate of inflation, other specified factors and other regulatory action. The current electricity distribution price control became effective April 1, 2023 and will continue through March 31, 2028.

GWhs and percentages of electricity distributed to the Northern Powergrid Distribution Companies' end-users and the total number of end-users as of and for the years ended December 31 were as follows:

	2025		2024		2023	
GWhs distributed:						
Residential	12,322	39 %	12,045	38 %	11,638	38 %
Commercial	3,350	11	3,391	11	3,534	11
Industrial	15,611	49	15,508	50	15,655	50
Other	279	1	280	1	279	1
	31,562	100 %	31,224	100 %	31,106	100 %
Number of end-users (in thousands):	3,956		3,952		3,954	

As of December 31, 2025, the combined electricity distribution network of the Northern Powergrid Distribution Companies included approximately 17,000 miles of overhead lines, 44,700 miles of underground cables and 860 major substations.

BHE PIPELINE GROUP (EASTERN ENERGY GAS AND EGTS)

The BHE Pipeline Group consists of BHE GT&S, Northern Natural Gas and Kern River, each an indirect wholly owned subsidiary of BHE. The BHE Pipeline Group operates approximately 20,900 miles of pipeline with a design capacity of approximately 21.6 Bcf of natural gas per day, transported approximately 15% of the total natural gas consumed in the U.S. during 2025 and owns assets in 27 states. The BHE Pipeline Group also operates 22 natural gas storage facilities with a total working gas capacity of 515.6 Bcf and an LNG export, import and storage facility. BHE Pipeline Group, LLC's operations also include a company specializing in environmentally clean, low-emission, large-horsepower contract compression services. As of December 31, 2025, the BHE Pipeline Group had approximately 2,800 employees, consisting of approximately 2,300 natural gas operations employees and 500 corporate services employees.

The Pipeline Companies compete with other pipelines on the basis of cost, flexibility, reliability of service and overall customer service, with the customer's decision being made primarily on the basis of delivered price, which includes both the natural gas commodity cost and transmission costs. The Pipeline Companies also compete with midstream operators and gas marketers seeking to provide or arrange transmission, storage and other services to meet customer needs. Natural gas competes with alternative energy sources, including coal, nuclear energy, wind, geothermal, solar and fuel oil and the electricity generated from these alternative energy sources. The Pipeline Companies generate a substantial portion of their revenue from long-term firm contracts for transmission and storage services and are therefore insulated from competitive factors during the terms of the contracts. When these long-term contracts expire, the Pipeline Companies face competitive pressures from other natural gas pipeline facilities.

Subject to regulatory requirements, the Pipeline Companies attempt to recontract or remarket capacity at the maximum rates allowed under their tariffs, although at times the Pipeline Companies discount these rates to remain competitive. Historically, the Pipeline Companies have been able to provide competitively priced services because of access to a variety of relatively low cost supply basins, cost control measures and the relatively high level of firm entitlement that is sold on a seasonal and annual basis, which lowers the per unit cost of transmission. To date, the Pipeline Companies have avoided significant pipeline system bypasses.

BHE GT&S

BHE GT&S' operations, through its investment in Eastern Energy Gas, includes three interstate natural gas pipeline systems, one of the nation's largest underground natural gas storage systems and one LNG export, import and storage facility. BHE GT&S' operations also include smaller LNG facilities and natural gas liquid gathering and processing facilities.

Eastern Energy Gas' principal wholly owned subsidiaries are EGTS and CGT. EGTS' operations include natural gas transmission system assets located in Maryland, New York, Ohio, Pennsylvania, Virginia and West Virginia. EGTS also operates one of the nation's largest underground natural gas storage systems located in New York, Pennsylvania and West Virginia. CGT's operations include an interstate natural gas transmission system located in South Carolina and Georgia. Eastern Energy Gas also holds a 50% equity interest in Iroquois. Iroquois owns and operates an interstate natural gas transmission system located in the states of New York and Connecticut.

Eastern Energy Gas' LNG operations involve the export, import and storage of LNG at the Cove Point LNG Facility that is owned by Cove Point, located in Maryland, as well as the transmission of regasified LNG to the interstate pipeline grid and mid-Atlantic markets and the liquefaction of natural gas for export as LNG. Cove Point's LNG Facility has an operational peak regasification daily send-out capacity of approximately 1.8 million Dths and an aggregate LNG storage capacity of approximately 14.6 billions of cubic feet equivalent ("Bcfe"). In addition, Cove Point has a small liquefier that has the potential to produce approximately 15,000 Dth/day. The Liquefaction Facility consists of one LNG train with a nameplate outlet capacity of 5.25 million tonnes per annum ("Mtpa"). Cove Point has authorization from the DOE to export up to 0.77 Bcfe/day (approximately 5.75 Mtpa) should the Liquefaction Facility perform better than expected. Cove Point's 36-inch diameter underground interstate natural gas pipelines are approximately 139 miles, with interconnections to Transcontinental Gas Pipeline, LLC in Fairfax County, Virginia, and with Columbia Gas Transmission, LLC and EGTS in Loudoun County, Virginia. Eastern Energy Gas operates, as the general partner, and holds 75% of the limited partner interests in the Cove Point export, import and storage facility. BHE GT&S also operates and has interests in three smaller LNG facilities in Alabama, Florida and Pennsylvania.

In total, Eastern Energy Gas operates approximately 5,400 miles of natural gas transmission, gathering and storage pipelines, of which approximately 5,200 miles are owned by Eastern Energy Gas, with a design capacity of 12.9 Bcf per day as well as approximately 100 miles of natural gas liquids pipelines operated by BHE GT&S. EGTS operates approximately 3,900 miles of natural gas transmission and storage pipelines with a design capacity of 10.1 Bcf per day. EGTS also operates 17 underground storage fields with a total working gas capacity of approximately 420 Bcf, of which approximately 307 Bcf relates to natural gas storage field capacity that EGTS owns. BHE GT&S' pipeline system is configured with approximately 370 active receipt and delivery points. In 2025, BHE GT&S delivered over 2.3 trillion cubic feet ("Tcf") of natural gas to its customers. BHE GT&S also operates two natural gas liquid gathering and processing facilities in West Virginia.

BHE GT&S' natural gas transmission and storage earnings primarily result from rates established by FERC. Revenues derived from BHE GT&S' pipeline operations are primarily from reservation charges for firm transmission and storage services as provided for in their FERC-approved tariffs. Reservation charges are required to be paid regardless of volumes transported or stored. The profitability of these businesses is dependent on their ability, through the rates they are permitted to charge, to recover costs and earn a reasonable return on their capital investments. As of December 31, 2025, 86% of Eastern Energy Gas' transmission capacity is subscribed, including 78% under long-term contracts and 8% on a year-to-year basis, and 100% of EGTS' storage capacity is subscribed, including 99% under long-term contracts. As of December 31, 2025, the weighted average remaining contract term for Eastern Energy Gas' and EGTS' firm transmission contracts is six years and five years, respectively, and EGTS' storage contracts is three years. Additionally, BHE GT&S receives revenue from firm fee-based contractual arrangements, including negotiated rates, for certain pipeline transmission and LNG storage and terminal services. Variability in BHE GT&S' earnings results from changes in operating and maintenance expenditures, as well as changes in rates and the demand for services, which are dependent on weather, changes in commodity prices and the economy.

BHE GT&S' operating revenue for the year ended December 31 was as follows (in millions):

	2025		2024		2023	
Transmission	$ 892	41 %	$ 885	40 %	$ 881	39 %
LNG	789	36	798	37	796	36
Storage	305	14	312	14	329	15
Gas, liquids and other sales	187	9	189	9	233	10
Total operating revenue	$ 2,173	100 %	$ 2,184	100 %	$ 2,239	100 %

Except for quantities of natural gas owned and managed for operational and system balancing purposes, BHE GT&S does not own the natural gas that is transported through its system.

During 2025, BHE GT&S had two customers that each accounted for greater than 15% of its operating revenue and its 10 largest customers accounted for 50% of its total operating revenue. BHE GT&S has agreements with terms through 2038 to retain the majority of its two largest customers' volumes. The loss of any of these significant customers, if not replaced, could have a material adverse effect on BHE GT&S.

Eastern Energy Gas was formed as a limited liability company under the laws of the state of Virginia in 2013. Its principal executive offices are located at 10700 Energy Way, Glen Allen, Virginia 23060, its telephone number is (804) 613-5100 and its internet address is www.bhegts.com.

EGTS was incorporated under the laws of the state of Delaware in 1980. Its principal executive offices are located at 10700 Energy Way, Glen Allen, Virginia 23060, its telephone number is (804) 613-5100 and its internet address is www.bhegts.com.

Human Capital

As of December 31, 2025, Eastern Energy Gas had approximately 1,500 employees, consisting of approximately 1,300 natural gas operations employees and 200 corporate services employees. As of December 31, 2025, approximately 600 (37%) employees were covered by a union contract with the Utility Workers Union of America.

As of December 31, 2025, EGTS had approximately 1,200 employees, consisting of approximately 1,000 natural gas operations employees and 200 corporate services employees. As of December 31, 2025, approximately 600 (46%) employees were covered by a union contract with the Utility Workers Union of America.

For more information regarding Eastern Energy Gas' and EGTS' human capital disclosures, refer to Item 1. Business - General section of this Form 10-K.

Northern Natural Gas

Northern Natural Gas owns the largest interstate natural gas pipeline system in the U.S., as measured by pipeline miles, which reaches from west Texas to Michigan's Upper Peninsula. Northern Natural Gas primarily transports and stores natural gas for utilities, municipalities, gas marketing companies and industrial and commercial users. Northern Natural Gas' pipeline system consists of two commercial segments. Its traditional end-use and distribution market area in the northern part of its system, referred to as the Market Area, includes points in Iowa, Nebraska, Minnesota, Wisconsin, South Dakota, Michigan and Illinois. Its natural gas supply and delivery service area in the southern part of its system, referred to as the Field Area, includes points in Kansas, Texas, Oklahoma and New Mexico. The Market Area and Field Area are separated at a Demarcation Point ("Demarc"). Northern Natural Gas' pipeline system consists of 14,100 miles of natural gas pipelines, including 5,700 miles of mainline transmission pipelines and 8,400 miles of branch and lateral pipelines, with a Market Area design capacity of 6.5 Bcf per day, a Field Area delivery capacity of 1.7 Bcf per day to the Market Area and 1.5 Bcf per day to the West Texas area and 95.6 Bcf of working gas capacity in five storage facilities. Northern Natural Gas' pipeline system is configured with approximately 2,339 active receipt and delivery points which are integrated with the facilities of LDCs. Many of Northern Natural Gas' LDC customers are part of combined utilities that also use natural gas as a fuel source for electric generation. Northern Natural Gas delivered over 1.4 Tcf of natural gas to its customers in 2025.

Northern Natural Gas' transmission rates and most of its storage rates are cost-based. These rates are designed to provide Northern Natural Gas with an opportunity to recover its costs of providing services and earn a reasonable return on its investments. Substantially all of Northern Natural Gas' Market Area transmission revenue is generated from reservation charges, with the balance from usage charges. Most of Northern Natural Gas' transmission capacity in the Market Area is committed to customers under firm transmission contracts, where customers pay Northern Natural Gas a monthly reservation charge for the right to transport natural gas through Northern Natural Gas' system. Reservation charges are required to be paid regardless of volumes transported or stored. As of December 31, 2025, approximately 64% of Northern Natural Gas' customers' entitlement in the Market Area have terms beyond 2027 and approximately 38% beyond 2029. As of December 31, 2025, the weighted average remaining contract term for Northern Natural Gas' Market Area firm transmission contracts is five years. Northern Natural Gas' Field Area customers consist primarily of energy marketing companies, midstream companies and power generators that are connected to Northern Natural Gas' system in Texas and New Mexico that are contracted on a long-term basis with a weighted average remaining contract term of five years. Northern Natural Gas' storage services are provided through the operation of one underground natural gas storage field in Iowa and two underground natural gas storage facilities in Kansas. Additionally, Northern Natural Gas has two LNG storage peaking units, one in Iowa and one in Minnesota, that support its transmission service. The three underground natural gas storage facilities and two LNG storage peaking units have a total working gas capacity of over 95.6 Bcf and approximately 2.2 Bcf per day of peak delivery capability. The average remaining contract term for firm storage contracts is four years.

Northern Natural Gas' operating revenue for the years ended December 31 was as follows (in millions):

	2025		2024		2023	
Transmission:						
Market Area	$ 862	66 %	$ 832	64 %	$ 815	65 %
Field Area	290	22	281	22	249	22
Total transmission	1,152	88	1,113	86	1,064	87
Storage	112	9	113	8	113	9
Total transmission and storage revenue	1,264	97	1,226	94	1,177	96
Gas, liquids and other sales	38	3	73	6	49	4
Total operating revenue	$ 1,302	100 %	$ 1,299	100 %	$ 1,226	100 %

Except for quantities of natural gas owned and managed for operational and system balancing purposes, Northern Natural Gas does not own the natural gas that is transported through its system. The sale of natural gas for operational and system balancing purposes accounts for the majority of the remaining operating revenue.

During 2025, Northern Natural Gas had two customers that each accounted for greater than 10% of its transmission and storage revenue and its 10 largest customers accounted for 60% of its system-wide transmission and storage revenue. Northern Natural Gas has agreements with terms through 2027 and 2034 to retain the majority of its two largest customers' volumes. The loss of either of these significant customers, if not replaced, could have a material adverse effect on Northern Natural Gas.

Kern River

Kern River owns an interstate natural gas pipeline system that extends from supply areas in the Rocky Mountains to consuming markets in Utah, Nevada and California. Kern River's pipeline system consists of 1,700 miles of natural gas pipelines, including 1,400 miles of mainline section and 300 miles of common facilities, with a year-round design capacity of 2,166,575 Dths, or 2.2 Bcf, per day. Additional seasonal design capacity (Bell-Curve) is contracted in all months except July, August and September. Kern River owns the entire mainline section, which extends from the system's point of origination near Opal, Wyoming, through the Central Rocky Mountains to Daggett, California. The mainline section consists of 1,300 miles of primarily 36-inch diameter pipeline and 100 miles of various laterals that connect to the mainline. The common facilities are jointly owned by Kern River and Mojave Pipeline Company as tenants-in-common and are operated by Mojave Pipeline Operating Company.

Kern River's rates are designed to provide Kern River with an opportunity to recover its costs of providing services and earn a reasonable return on its investments and are based on a levelized rate design that assumes recovery of 70% of the original investment during the initial long-term contracts ("Period One rates"). After expiration of the initial term, eligible customers have the option to elect service at rates ("Period Two rates") that are lower than Period One rates because they are designed to recover the remaining 30% of the original investment. To the extent that eligible customers do not contract for service at Period Two rates, the volumes are turned back to Kern River, and it resells capacity at market rates for varying terms. As of December 31, 2025, Kern River's design capacity, including seasonal Bell-Curve, totaled 2,345,381 Dths per day and approximately 95% is contracted pursuant to long-term firm natural gas transmission service agreements, whereby Kern River receives natural gas on behalf of customers at designated receipt points and transports the natural gas on a firm basis to designated delivery points. In return for this service, each customer pays Kern River a fixed monthly reservation fee based on each customer's maximum daily quantity, which represents nearly 94% of total operating revenue, and a commodity charge based on the actual amount of natural gas transported pursuant to its long-term firm natural gas transmission service agreements and Kern River's tariff. These long-term firm natural gas transmission service agreements expire between February 2026 and December 2045 and have a weighted-average remaining contract term of approximately six years. As of December 31, 2025, 67% of the year-round design capacity of 2,166,575 Dths under firm contract has primary delivery points in California, with the flexibility to access secondary delivery points in Nevada and Utah.

Kern River primarily transports natural gas for utilities, municipalities, energy marketing companies, electric generating companies and other industrial and commercial users. Except for quantities of natural gas owned for operational purposes, Kern River does not own the natural gas that is transported through its system. Kern River's transmission rates are cost-based.

During 2025, Kern River had two customers, including Nevada Power Company, an affiliated company, that each accounted for greater than 10% of its revenue. The loss of these significant customers, if not replaced, could have a material adverse effect on Kern River.

BHE TRANSMISSION

BHE Transmission consists of BHE Canada, an indirect wholly owned subsidiary of BHE, BHE U.S. Transmission, a wholly owned subsidiary of BHE, interests in generating facilities and 300 MWs of long-term northbound transmission rights on the Montana Alberta Tie Line (commencing April 30, 2026). BHE Canada and BHE U.S. Transmission together own and operate the Montana Alberta Tie Line, which is a 214-mile, 230-kV transmission line that runs from Lethbridge, Alberta, Canada, to Great Falls, Montana, U.S., and connects power grids in the two jurisdictions. BHE Canada also owns AlbertaEx, a cross-border operations center to optimize in real-time the value of BHE Transmission's existing physical generation assets on the Montana Alberta Tie Line. Operations for AlbertaEx commenced in January 2025.

AltaLink

BHE Canada primarily consists of AltaLink, a regulated electric transmission utility company headquartered in Alberta, Canada, serving approximately 85% of Alberta's population. AltaLink's high voltage transmission lines and related facilities transmit electricity from generating facilities to major load centers, cities and large industrial plants throughout its 87,000 square mile service territory, which covers a diverse geographic area including most major urban centers in central and southern Alberta. AltaLink's transmission facilities, consisting of approximately 8,300 miles of transmission lines and approximately 310 substations as of December 31, 2025, are an integral part of the Alberta Interconnected Electric System ("AIES").

The AIES is a network or grid of transmission facilities operating at high voltages ranging from 69 kV to 500 kV. The grid delivers electricity from generating units across Alberta, Canada, through approximately 16,000 miles of transmission lines. The AIES is interconnected to British Columbia's transmission system and to Montana's transmission system that link Alberta with the North American western interconnected system. The AIES is also interconnected with Saskatchewan's transmission system that links Alberta with the North American eastern interconnection.

AltaLink is a transmission facility owner within the electricity industry in Alberta and is permitted to charge a tariff rate for the use of its transmission facilities. Such tariff rates are established on a cost-of-service regulatory model, which is designed to allow AltaLink an opportunity to recover its costs of providing services and to earn a reasonable return on its investments. Transmission tariff rates are approved by the AUC and are collected from the AESO.

The electricity industry in Alberta consists of four principal segments. Generators sell wholesale power into the power pool operated by the AESO and through direct contractual arrangements. Alberta's transmission system or grid is composed of high voltage power lines and related facilities that transmit electricity from generating facilities to distribution networks and directly connected end-users. Distribution facility owners are regulated by the AUC and are responsible for arranging for, or providing, regulated rate and regulated default supply services to convey electricity from transmission systems and distribution-connected generators to end-use customers. Retailers can procure energy through the power pool, through direct contractual arrangements with energy suppliers or ownership of generation facilities and arrange for its distribution to end-use customers.

The AESO mandate, defined in the *Electric Utilities Act* (Alberta) and its regulations, requires the AESO to assess both current and future needs of the AIES. In January 2025, the AESO released its 2025 Long-Term Transmission Plan ("LTP"). The LTP identifies three areas of planning: load growth, generation growth and intertie development. The LTP was developed under Alberta's current zero-congestion policy and acknowledges that the current workstream to develop and implement the AESO's Optimal Transmission Planning ("OTP") Framework will impact generation growth driven transmission projects. The OTP Framework seeks to optimize the use of the existing transmission system while planning the development of new transmission; altogether it ensures a safe and reliable electricity system that enables a fair, efficient, and openly competitive electricity market. The OTP Framework is not anticipated to impact transmission system projects driven by load growth and by intertie development. The LTP identifies approximately C$2.1 billion of generation driven projects and C$150 million of intertie driven projects in AltaLink's service territory.

In May 2024, the AESO released its 2024 Long-Term Outlook. The reference case was consistent with the Government of Alberta's target to achieve decarbonization by 2050. The alternatives focused on the following three scenarios:

- Decarbonization by 2035: a scenario which assumes a linear decline in emissions from 2030 to 2035 based on federal Clean Electricity Regulations;
- Alternative Decarbonization: a scenario which explores the effect of increasing intertie connections in 2035 and anticipates technological cost declines as well as delays in development of carbon capture, utilization and storage, nuclear small modular reactors and hydrogen; and
- High Electrification: a scenario which anticipates higher load growth from increased electric vehicles, electrification of building heating and cooling as well as additional industrial load due to electrification and carbon capture, utilization and storage adoption.

The scenarios allowed the AESO to consider possible future states of the Alberta market.

Wildfire Prevention

AltaLink has developed and implemented detailed wildfire mitigation plans ("WMPs") for its service territory since 2019. AltaLink submits these plans to the AUC for approval as part of its General Tariff Application ("GTA") process. AltaLink received approval for its wildfire mitigation plan in the 2019-2021, 2022-2023, and 2024-2025 GTA periods. AltaLink's 2026-2027 WMP is currently under review by the AUC in the regulatory approval process for AltaLink's 2026-2027 GTA. In the 2026-2027 WMP, AltaLink introduced a new Wildfire Risk Model that responds to the AUC's directives from the 2024-2025 GTA decision. The Wildfire Risk Model attempts to quantify wildfire risk and estimate net benefits from wildfire risk mitigation measures. AltaLink's 2026-2027 WMP includes improvements in situational awareness, meteorological systems, and risk modeling; investments in asset hardening and vegetation management; and AltaLink's ongoing elevated wildfire risk operating practices and policies, which include inspections, recloser blocking procedures, wildfire encroachment procedures, and public safety power shutoff ("PSPS") procedures.

Asset Hardening and Vegetation Management

AltaLink developed a new Wildfire Risk Model that quantifies the risk at every transmission structure in AltaLink's system to target specific asset investments. These hardening efforts reduce the likelihood of AltaLink's transmission lines igniting a wildfire at locations of high fire risk. Investments are primarily focused on targeted transmission structure or transmission line upgrades or identified right-of-way improvements to remove hazardous vegetation to reduce fire ignition risk.

Situational Awareness, Meteorology, and Risk Modeling

AltaLink uses available integrated meteorology, fire monitoring and camera systems available from the Government of Alberta. Additionally, AltaLink installed incremental weather and camera stations in support of improvements to its situational awareness. This weather information, combined with expert third-party assessment, provides daily weather and fire risk forecasting for AltaLink's service territory. AltaLink also established a Daily Hazard Forecast Report, which is provided to the organization and field crews, and implemented an information portal in the control room. AltaLink implemented further enhancements to its fire weather modeling tools in 2024. AltaLink provides regular training to field operations and contractor crews regarding fire management and preventive practices. AltaLink completed its fire risk modeling and high-risk fire area ("HRFA") mapping in 2020, implemented dynamic modeling as well as further enhancements to its fire weather modeling tools in 2024, implemented the Wildfire Risk Model to quantify wildfire risk in 2025, and will complete updates to the Wildfire Risk Model in 2026 aligned with the AUC's upcoming decision for the 2026-2027 GTA.

Asset Inspection Program

AltaLink completes asset inspections for all its facilities at least annually. For lines located in HRFAs, inspection frequencies are twice per year to review structure and vegetation conditions.

Public Safety Power Shutoff and Wildfire Encroachment Policy

A PSPS is an operating protocol used as a preventative measure of last resort during periods of extreme wildfire risk. It involves de-energizing a transmission line or lines proactively under certain conditions to reduce the risk of wildfire ignition. PSPS is an increasingly common practice for utilities to use as part of wildfire prevention.

In determining whether to initiate a PSPS, AltaLink works with local public safety authorities and considers data from its wildfire risk forecasting tools and meteorological systems. If the forecast exceeds thresholds, escalating action is taken proactively starting from the seven-day forecast outlook. AltaLink continues to conduct stakeholder and Indigenous engagement and exercises related to its PSPS process. To mitigate the risk of secondary ignitions from fires on the landscape as well as safety risks to fire fighters on scene, AltaLink also has a wildfire encroachment policy to either disable reclosers or proactively de-energize transmission lines. These measures aim to reduce the risk to public safety.

BHE U.S. Transmission

BHE U.S. Transmission is engaged in various joint ventures to develop, own and operate transmission assets and is pursuing additional investment opportunities in the U.S. Currently, BHE U.S. Transmission has two joint ventures with transmission assets that are operational: ETT, a 50% owned joint venture with subsidiaries of American Electric Power Company, Inc. ("AEP"), and Prairie Wind Transmission, LLC, a 25% owned joint venture with AEP and Evergy, Inc. ETT owns and operates electric transmission assets in the ERCOT and, as of December 31, 2025, had total assets of $4.4 billion. ETT's transmission system includes approximately 2,100 miles of transmission lines and 51 substations as of December 31, 2025. Prairie Wind Transmission, LLC, owns and operates a 108-mile, 345-kV transmission project in Kansas having total assets of $125 million as of December 31, 2025.

In response to MISO's Tranche 2 competitive bid process, BHE U.S. Transmission in partnership with AEP and Evergy, Inc, submitted a $1.2 billion bid on a 765 kV line in Wisconsin that was awarded on January 6, 2026. The line must be operational by June 1, 2034.

Generating Facilities

BHE Transmission has ownership interests in the following generating facilities as of December 31, 2025 that provide support to its transmission business, and how it operates:

Generating Facility	Location	Energy Source	Year Installed	Power Purchase Agreement Expiration	Power Purchaser	Facility Net Capacity (MWs)[1]	Net Owned Capacity (MWs)[1]
WIND:							
Rattlesnake	Alberta	Wind	2022	2042/2032	Telus, RBC, Bullfrog, Shopify	130	130
Rim Rock [2]	Montana	Wind	2012	2026	Morgan Stanley	189	189
Glacier 1 [2]	Montana	Wind	2008	2026	Morgan Stanley	106	106
Glacier 2 [2]	Montana	Wind	2009	2026	Morgan Stanley	103	103
						528	528
NATURAL GAS:							
Nat-1	Alberta	Natural gas	2015	N/A	N/A	20	20
						20	20
Total Available Generating Capacity						548	548
PROJECTS UNDER CONSTRUCTION:							
Glacier Solar Park	Montana	Solar	Est. 2026	N/A	N/A	130	130
						678	678

(1) Facility Net Capacity represents the lesser of nominal ratings or any limitations under applicable interconnection, power purchase, or other agreements for intermittent resources and the total net dependable capability available during summer conditions for all other units. An intermittent resource's nominal rating is the manufacturer's contractually specified capability (in MWs) under specified conditions. Net Owned Capacity indicates BHE Transmission' ownership of Facility Net Capacity.

(2) In January 2026, the Glacier Battery System connected at the Marias substation, servicing the three Montana wind farms, was put into service, having total Facility Net Capacity and Net Owned Capacity of 75 MWs.

BHE RENEWABLES

The subsidiaries comprising the BHE Renewables reportable segment own interests in several independent power projects in the U.S. and has invested $7.1 billion in 38 wind projects sponsored by third parties, commonly referred to as tax equity investments. The following table presents certain information concerning the owned independent power projects as of December 31, 2025:

Generating Facility	Location	Energy Source	Year Installed	Power Purchase Agreement Expiration	Power Purchaser[1]	Facility Net Capacity (MWs)[2]	Net Owned Capacity (MWs)[2]
WIND:							
Grande Prairie	Nebraska	Wind	2016	2036	OPPD	400	400
Jumbo Road	Texas	Wind	2015	2033	AE	300	300
Santa Rita	Texas	Wind	2018	2029-2038	KC & CODTX	300	300
Rio Bravo	Texas	Wind	2019	N/A	N/A	238	238
Mariah Del Norte	Texas	Wind	2016	2030	OPS	230	230
Walnut Ridge	Illinois	Wind	2018	2028	USGSA	212	212
Flat Top	Texas	Wind	2019	2030-2038	OPS & Shaw	200	200
Pinyon Pines I	California	Wind	2012	2035	SCE	168	168
Fluvanna II	Texas	Wind	2019	2034	Heinz	158	158
Pinyon Pines II	California	Wind	2012	2035	SCE	132	132
Bishop Hill II	Illinois	Wind	2012	2032	Ameren	81	81

Marshall	Kansas	Wind	2016	2036	MJMEC, KPP, KMEA & COIMO	72	72
Independence	Iowa	Wind	2021	2041	CIPCO	54	54
						2,545	2,545
SOLAR:							
Topaz	California	Solar	2013-2014	2039	PG&E	550	550
Solar Star 1	California	Solar	2013-2015	2035	SCE	310	310
Solar Star 2	California	Solar	2013-2015	2035	SCE	276	276
Agua Caliente	Arizona	Solar	2012-2013	2039	PG&E	290	142
Alamo 6	Texas	Solar	2017	2042	CPS	110	110
Community Solar Gardens[5]	Minnesota	Solar	2016-2018	2041-2043	(4)	98	98
Pearl	Texas	Solar	2017	2042	CPS	50	50
						1,684	1,536
NATURAL GAS:							
Cordova	Illinois	Natural Gas	2001	N/A	N/A	512	512
Power Resources	Texas	Natural Gas	1988	N/A	N/A	140	140
Saranac	New York	Natural Gas	1994	N/A	N/A	245	196
Yuma	Arizona	Natural Gas	1994	N/A	N/A	50	50
						947	898
GEOTHERMAL:							
Imperial Valley Projects	California	Geothermal	1982-2000	(3)	(3)	345	345
						345	345
HYDROELECTRIC:							
Wailuku	Hawaii	Hydroelectric	1993	2028	HELCO	10	10
						10	10
Total Available Generating Capacity						5,531	5,334
PROJECTS UNDER CONSTRUCTION							
Solar Star 3 & 4[6]	California	Solar	Est. 2026	(7)	CPA	48	48
Ravenswood[8]	West Virginia	Solar	Est. 2027	(9)	TIMET	106	106
						5,685	5,488

(1) Omaha Public Power District ("OPPD"); Austin Energy ("AE"); Kimberly-Clark Corporation ("KC"); City of Denton, TX ("CODTX"); Occidental Power Services ("OPS"); U.S. General Services Administration ("USGSA"); Shaw Industries Group, Inc ("Shaw"); Southern California Edison ("SCE"); Kraft Heinz Food Company ("Heinz"); Ameren Illinois Company ("Ameren"); Missouri Joint Municipal Electric Commission ("MJMEC"); Kansas Power Pool ("KPP"); Kansas Municipal Energy Agency ("KMEA"); City of Independence, MO ("COIMO"); Central Iowa Power Cooperative ("CIPCO"); Pacific Gas and Electric Company ("PG&E"); CPS Energy ("CPS"); Hawaii Electric Light Company, Inc. ("HELCO"); Clean Power Alliance of Southern California ("CPA"); and Titanium Metals Corporation ("TIMET").

(2) Facility Net Capacity represents the lesser of nominal ratings or any limitations under applicable interconnection, power purchase, or other agreements for intermittent resources and the total net dependable capability available during summer conditions for all other units. An intermittent resource's nominal rating is the manufacturer's contractually specified capability (in MWs) under specified conditions. Net Owned Capacity indicates BHE Renewables' ownership of Facility Net Capacity.

(3) Approximately 24% of the Company's interests in the Imperial Valley Projects' Contract Capacity are currently sold to Southern California Edison Company and Imperial Irrigation District under power purchasing agreements expiring in 2026. Certain long-term power purchase agreement renewals for 252 MWs have been entered into with other parties at fixed prices that expire from 2028 to 2039, of which 202 MWs mature in 2039.

(4) The power purchasers are commercial, industrial and not-for-profit organizations.

(5) The community solar gardens project is consolidated in the table above for convenience as it consists of 98 distinct entities that each own an approximately 1-MW solar garden with independent but substantially similar terms and conditions.

(6) In addition to the 48-MW solar photovoltaic facility, Solar Star 3 & 4 has 46 MWs of co-located battery energy storage that will be developed in Kern County, California with commercial operation expected in 2026.

(7) Solar Star 3 & 4 entered into a 20-year power purchase agreement effective on the commercial operation date.

(8) In addition to the 106-MW solar photovoltaic facility, Ravenswood has 20 MWs of co-located battery energy storage that will be developed in Jackson County, West Virginia with commercial operation expected in 2027.

(9) Pending outcome of negotiations with TIMET.

BHE Renewables' operating revenue derived from the following business activities for the years ended December 31 were as follows (dollars in millions):

	2025		2024		2023	
Solar	$ 475	43 %	$ 451	31 %	$ 427	26 %
Wind	259	23	267	18	276	16
Geothermal	190	17	138	9	210	12
Hydro	1	—	7	—	4	—
Natural gas	162	15	97	7	105	6
Retail energy services	26	2	515	35	688	40
Total operating revenue	$ 1,113	100 %	$ 1,475	100 %	$ 1,710	100 %

HOMESERVICES

HomeServices, a wholly owned subsidiary of BHE, is one of the largest residential real estate brokerage firms in the U.S. In addition to providing traditional residential real estate brokerage services, HomeServices offers other integrated real estate services, including mortgage originations and mortgage banking; title and closing services; property and casualty insurance; home warranties; relocation services; and other home-related services. HomeServices' real estate brokerage business is subject to seasonal fluctuations because more home sale transactions tend to close during the second and third quarters of the year. As a result, HomeServices' operating results and profitability are typically higher in the second and third quarters relative to the remainder of the year. HomeServices' owned brokerages currently operate in over 770 offices in 35 states and the District of Columbia with nearly 35,000 real estate agents under 46 brand names. The U.S. residential real estate brokerage business is subject to the general real estate market conditions, is highly competitive and consists of numerous local brokers and agents in each market seeking to represent sellers and buyers in residential real estate transactions.

HomeServices' franchise business currently includes over 250 franchisees and nearly 1,400 brokerage offices with approximately 39,700 real estate agents under two brand names, primarily in the U.S. In exchange for certain fees, HomeServices provides franchisees the right to use the Berkshire Hathaway HomeServices or Real Living brand names and other related service marks, as well as providing orientation programs, training and consultation services, advertising programs and other services.

GENERAL REGULATION

BHE's regulated subsidiaries and certain affiliates are subject to comprehensive governmental regulation, which significantly influences their operating environment, prices charged to customers, capital structure, costs and, ultimately, their ability to recover costs and earn a reasonable return on invested capital. In addition to the discussion contained herein regarding general regulation, refer to "Regulatory Matters" in Item 1 of this Form 10-K for further discussion regarding certain regulatory matters.

Domestic Regulated Public Utility Subsidiaries

The Utilities are subject to comprehensive regulation by various state, federal and local agencies. The more significant aspects of this regulatory framework are described below.

State Regulation

Historically, state regulatory commissions have established retail electric and natural gas rates on a cost-of-service basis, which are designed to allow a utility the opportunity to recover what each state regulatory commission deems to be the utility's reasonable costs of providing services, including the opportunity to earn a fair and reasonable return on its investments based on its cost of debt and equity. In addition to return on investment, a utility's cost of service generally reflects a representative level of prudent expenses, including cost of sales, operating expense, depreciation and amortization and income and other tax expense, reduced by wholesale electricity and other revenue. The allowed operating expenses are typically based on actual historical costs adjusted for known and measurable or forecasted changes. State regulatory commissions may adjust cost of service for various reasons, including pursuant to a review of: (a) the utility's revenue and expenses during a defined test period, (b) the utility's level of investment and (c) changes in income tax laws. State regulatory commissions typically have the authority to review and change rates on their own initiative; however, they may also initiate reviews at the request of a utility, utility customers or organizations representing groups of customers. In certain jurisdictions, the utility and such parties, however, may agree with one another not to request a review of or changes to rates for a specified period of time.

The retail electric rates of the Utilities are generally based on the cost of providing traditional bundled services, including generation, transmission and distribution services. The Utilities have established ECAMs and other cost recovery mechanisms in certain states, which help mitigate their exposure to changes in costs from those assumed in establishing base rates.

With certain limited exceptions, the Utilities have an exclusive right to serve retail customers within their service territories and, in turn, have an obligation to provide service to those customers. In some jurisdictions, certain classes of customers may choose to purchase all or a portion of their energy from alternative energy suppliers, and in some jurisdictions retail customers can generate all or a portion of their own energy. In Utah, a law signed in March 2025 (Senate Bill 132) establishes an alternative process to provide electric service to customers with new loads of 100 MW or greater, which includes the ability for the customer to take service from an independent power producer if the utility is unable to meet certain service provisions or reach a mutually agreeable service agreement with the customer. Under Oregon law, PacifiCorp has the exclusive right and obligation to provide electricity distribution services to all residential and nonresidential customers within its allocated service territory; however, nonresidential customers have the right to choose an alternative provider of energy supply. The impact of this right on PacifiCorp's consolidated financial results has not been material. In Washington, state law does not provide for exclusive service territory allocation. PacifiCorp's service territory in Washington is surrounded by other public utilities with whom PacifiCorp has from time to time entered into service area agreements under the jurisdiction of the WUTC. Under California law, PacifiCorp has the exclusive right and obligation to provide electricity distribution services to all residential and nonresidential customers within its allocated service territory; however, cities, counties and certain other public agencies have the right to choose to generate energy supply or elect an alternative provider of energy supply through the formation of a Community Choice Aggregator ("CCA"). To date, no CCA activity has occurred in PacifiCorp's California service territory. If a CCA is formed, PacifiCorp would continue to provide CCA customers transmission, distribution, metering and billing services and the CCA would provide generation supply. In addition, PacifiCorp would likely be able to collect costs from CCA customers for the generation-related costs that PacifiCorp incurred while they were customers of PacifiCorp. PacifiCorp would remain the electricity provider of last resort for these customers. In Illinois, state law has established a competitive environment so that all Illinois customers are free to choose their retail service supplier. For customers that choose an alternative retail energy supplier, MidAmerican Energy continues to have an ongoing obligation to deliver the supplier's energy to the retail customer. MidAmerican Energy bills the retail customer for such delivery services. MidAmerican Energy also has an obligation to serve customers at regulated cost-based rates and has a continuing obligation to serve customers who have not selected a competitive electricity provider. The impact of this right on MidAmerican Energy's financial results has not been material. In Nevada, Chapter 704B of the Nevada Revised Statutes allows retail electric customers with an average annual load of one MW or more to file a letter of intent and application with the PUCN to acquire electric energy and ancillary services from another energy supplier. The law requires customers wishing to choose a new supplier to receive the approval of the PUCN to meet public interest standards. In particular, departing customers must secure new energy resources that are not under contract to the Nevada Utilities, the departure must not burden the Nevada Utilities with increased costs or cause any remaining customers to pay increased costs and the departing customers must pay their portion of any deferred energy balances, all as determined by the PUCN. SB 547 revised Chapter 704B to establish limits on the amount of load eligible to take service under Chapter 704B and to set those limits as a part of the IRP filed by the Nevada Utilities. Also, the Utilities and the state regulatory commissions are individually evaluating how best to integrate private generation resources into their service and rate design, including considering such factors as maintaining high levels of customer safety and service reliability, minimizing adverse cost impacts and fairly allocating costs among all customers.

In Nevada, large natural gas customers using 12,000 therms per month with fuel switching capability are allowed to participate in the incentive natural gas rate tariff. Once a service agreement has been executed, a customer can compare natural gas prices under this tariff to alternative energy sources and choose its source of natural gas. In addition, natural gas customers using greater than 1,000 therms per day have the ability to secure their own natural gas supplies under the gas transportation tariff.

PacifiCorp

Rate Filings

Under Utah law, the UPSC must issue a written order within 240 days of a public utility's application for a general rate change. Absent an order, the proposed rates go into effect as filed and are not subject to refund. The UPSC may allow interim rates to take effect within 45 days of an application, subject to refund or surcharge, if an adequate prima facie showing is established in hearing that the interim rate change is justified.

In Oregon, the OPUC has the authority to suspend proposed new rates for a period of up to 10 months, beyond the 30-day time period when the new rates would otherwise go into effect. Absent suspension or other action from the OPUC, new rates automatically go into effect 30 days from filing by the utility. Upon suspension by the OPUC, the OPUC is authorized to allow the collection of an interim rate, subject to refund, during the pendency of the OPUC's review of the rate request. In July 2025, Oregon House Bill 3179, the "FAIR Energy Act" (Fairness & Affordability in Residential Energy Regulation), was signed into law. Among other changes, the FAIR Energy Act prohibits any increase in residential rates from taking effect during the high-demand winter months, November 1 to March 31.

In Wyoming, the WPSC can allow interim rates to go into effect 30 days after the initial application but may require a bond to secure a refund for the amount. The WPSC may suspend the rates for final approval for a period not to exceed 10 months.

In Washington, the WUTC has the authority to suspend proposed new rates, subject to hearing, for a period not to exceed 10 months beyond the 30-day time period when the new rate would otherwise go into effect.

Under Idaho law, the IPUC can suspend a filing for an initial period not to exceed five months and an additional extension of 60 days with a showing of good cause.

In California, the CPUC has the authority to suspend proposed new rates, subject to hearing, for a period not to exceed 18 months. The CPUC may extend the suspension period on a case-by-case basis.

Potential Wildfire Related Funds

In Wyoming and Idaho, PacifiCorp is pursuing a self-insurance reserve fund for wildfire liability instead of acquiring commercial excess liability insurance. If approved by the state commissions, the reserve fund that would be funded through rates would allow PacifiCorp to recover the costs associated with third-party claims and external legal costs incurred as a result of wildfires occurring in the respective states. Additionally, in Utah, PacifiCorp is pursuing a catastrophic wildfire fund that is supported by Utah statute and which would differ from the reserve funds being pursued in Wyoming and Idaho in that commercial excess liability insurance for wildfires would be maintained.

Adjustment Mechanisms

In addition to recovery through base rates, PacifiCorp also achieves recovery of certain costs through various adjustment mechanisms as summarized below.

State Regulator	Base Rate Test Period	Adjustment Mechanism
UPSC	Forecasted or historical with known and measurable changes[(1)]	EBA under which 100% of the difference between base net power costs set during a general rate case and actual net power costs is deferred and reflected in future rates. Wheeling revenue and PTCs are also included in the mechanism with a true-up at 100%. Balancing account to provide for 90% refund of REC revenues to customers (10% REC incentive authorized by the UPSC). Recovery mechanism for single capital investments that in total exceed 1% of existing rate base when a general rate case has occurred within the preceding 18 months. Wildland Fire Mitigation Balancing Account to recover operating expenses and capital expenditures incurred to implement PacifiCorp's Utah Wildland Fire Protection Plan incremental to those included in base rates.

State Regulator	Base Rate Test Period	Adjustment Mechanism
OPUC	Forecasted	PCAM under which 90% of the difference between forecasted net variable power costs and PTCs established under the annual TAM and actual net variable power costs and PTCs is deferred and reflected in future rates. The difference between the forecasted and actual net variable power costs and PTCs must fall outside of an established asymmetrical deadband, with a negative annual power cost variance deadband of $15 million; and a positive annual power cost variance deadband of $30 million and is subject to an earnings test of +/- 1% on PacifiCorp's allowed return on equity. Annual TAM based on forecasted net variable power costs and PTCs. Renewable Adjustment Clause to recover the revenue requirement of new renewable resources and associated transmission costs that are not reflected in general rates. Balancing account for recovery of costs associated with the purchase of RECs necessary to meet Oregon's RPS requirements. Vegetation Management Cost Recovery Adjustment to recover vegetation management costs, incremental to those included in base rates. Recovery is subject to performance metrics and earnings tests. Wildfire Mitigation Plan Automatic Adjustment Clause was approved to recover the capital and operations and maintenance costs associated with implementation and operation of PacifiCorp's Oregon Wildfire Mitigation Plan.
WPSC	Forecasted or historical with known and measurable changes[(1)]	ECAM under which 80% of the difference between base net power costs set during a general rate case and actual net power costs is deferred and reflected in future rates. Within the mechanism, chemical costs and start-up fuel costs are also included at the 80% symmetrical sharing band and PTCs are included at 100% symmetrical sharing. REC and SO_2 revenue adjustment mechanism to provide for refund of 100% of actual REC and SO_2 revenues.
WUTC	Historical with known and measurable changes	PCAM under which the difference between base net power costs set during a general rate case and actual net power costs is deferred and reflected in future rates after applying a $4 million deadband for positive or negative net power cost variances. For net power cost variances between $4 million and $10 million, amounts to be recovered from customers are allocated 50/50 and amounts to be credited to customers are allocated 75/25 (customers/PacifiCorp). Positive or negative net power cost variances in excess of $10 million are allocated 90/10 (customers/PacifiCorp). The mechanism includes a true-up of PTCs at 100%. Deferral mechanism of costs for up to 24 months of new base load generation resources and eligible renewable resources and related transmission that qualify under the state's emissions performance standard and are not reflected in base rates. REC revenue tracking mechanism to provide credit of 100% of REC revenues to customers. Decoupling mechanism under which the difference between actual annual revenues and authorized revenues per customer per specified rate schedules is deferred and reflected in future rates. To trigger a rate adjustment, the deferral balance must exceed plus or minus 2.5% of the authorized revenue at the end of each deferral period by rate class. Rate adjustments must not exceed a surcharge of 5% of the actual normalized revenue by class.
IPUC	Historical with known and measurable changes	ECAM under which 90% of the difference between base net power costs set during a general rate case and actual net power costs is deferred and reflected in future rates. Also provides for recovery or refund of 100% of the difference in actual PTCs compared to the amount in base rates. REC revenues will be deferred to be returned to customers in a future filing.
CPUC	Forecasted	PTAM for major capital additions that allows for rate adjustments outside of the context of a traditional general rate case for the revenue requirement associated with capital additions exceeding $50 million on a total-company basis. Filed as eligible capital additions are placed into service. ECAC that allows for an annual update to actual and forecasted net power costs. PTAM for attrition, a mechanism that allows for an annual adjustment to costs other than net power costs. Catastrophic Events Memorandum Account for catastrophic events, allows for deferral and cost recovery of reasonable costs incurred as the result of catastrophic events, which are events for which a state or federal agency has declared a state of emergency. Fire Risk Mitigation Memorandum Account to track costs related to wildfire mitigation activities incremental to what is in base rates and Wildfire Mitigation Plan Memorandum Account to track costs associated with the implementation of PacifiCorp's approved wildfire mitigation plan.

State Regulator	Base Rate Test Period	Adjustment Mechanism
		Wildfire Expense Memorandum Account allows for tracking of incremental wildfire-related liability costs such as third-party claims, legal expenses and insurance costs, subject to certain limitations.

(1) PacifiCorp has relied on both historical test periods with known and measurable adjustments, as well as forecasted test periods.

MidAmerican Energy

Rate Filings

Under Iowa law, a utility may implement temporary rates, without IUC review and subject to refund, on or after 10 days of filing a request for higher base rates. If the IUC has not issued a final order within 10 months after the filing date, the temporary rates become final. Under Illinois law, new base rates may become effective 45 days after the filing of a request with the ICC, or earlier with ICC approval. The ICC has authority to suspend the proposed new rates, subject to hearing, for a period not to exceed approximately 11 months after filing. South Dakota law authorizes the SDPUC to suspend new base rates for up to six months during the pendency of rate proceedings; however, a utility may implement all or a portion of the proposed new rates six months after the filing of a request for a rate increase subject to refund pending a final order in the proceeding.

Iowa law also permits rate-regulated utilities to seek ratemaking principles with the IUC prior to the construction of certain types of new generating facilities. Pursuant to this law, MidAmerican Energy has applied for and obtained IUC ratemaking principles orders for a 484-MW (MidAmerican Energy's share) coal-fueled generating facility, a 495-MW combined cycle natural gas-fueled generating facility and 7,055 MWs (nominal ratings) of wind-powered generating facilities in-service as of December 31, 2025. These ratemaking principles established cost caps for the projects, below which such costs are deemed prudent by the IUC and authorized a fixed rate of return on equity for the respective generating facilities over the regulatory life of the facilities in any future Iowa rate proceeding. As of December 31, 2025, the generating facilities in-service totaled $7.4 billion, or 31%, of MidAmerican Energy's regulated property, plant and equipment, net and were subject to these ratemaking principles at a weighted average return on equity of 11.3% with a weighted average remaining life of 31 years.

Ratemaking principles for several wind-powered generation projects have established mechanisms in Iowa where electric rate base may be reduced. The current revenue sharing mechanism is in accordance with Wind PRIME ratemaking principles and reduces rate base for Iowa electric returns on equity exceeding an established benchmark. Sharing is triggered by MidAmerican Energy's actual equity return being above a threshold calculated annually. The threshold, not to exceed 11%, is the weighted average equity return of rate base with returns authorized via ratemaking principles proceedings and all other rate base. For all other rate base, the return is based on interest rates on 30-year A-rated utility bond yields plus 400 basis points, with a minimum return of 9.5%. MidAmerican Energy shares with customers 90% of the revenue in excess of the trigger. A second mechanism, the retail customer benefit mechanism, reduces electric rate base for the value of higher cost retail energy displaced by covered wind-powered production and applies to the wind-powered generating facilities constructed under the Wind X and Wind XII projects, and wind-powered generating facilities placed in service in 2023 and future projects yet to be constructed under the Wind PRIME project that was approved by the IUC in December 2023. Rate base reductions under these mechanisms are applied to coal and other generation facilities in specified orders. A third mechanism, the Iowa EAC rate mitigation mechanism, provides EAC rate stability to customers by allocating revenue sharing amounts as required to reduce retail electric energy cost recoveries to a targeted amount.

Adjustment Mechanisms

Under its current Iowa, Illinois and South Dakota electric tariffs, MidAmerican Energy is allowed to recover fluctuations in electric energy costs for its retail electric sales through fuel, or energy, cost adjustment mechanisms. Additionally, MidAmerican Energy has transmission adjustment clauses to recover certain transmission charges related to retail customers in all jurisdictions. The transmission adjustment mechanisms recover costs billed by the MISO for regional transmission service. The Illinois adjustment mechanism additionally recovers MidAmerican Energy's entire transmission revenue requirement attributable to Illinois. The adjustment mechanisms reduce the regulatory lag for the recovery of energy and transmission costs related to retail electric customers in these jurisdictions and accomplish, with limited timing differences, a pass-through of the related costs to these customers. Recoveries through these adjustment mechanisms are reflected in operating revenue, and the related costs are reflected in cost of fuel and energy or operations and maintenance expense, as applicable.

Of the wind-powered generating facilities placed in-service as of December 31, 2025, 5,451 MWs (nominal ratings) have not been included in the determination of MidAmerican Energy's Iowa retail electric base rates. In accordance with related ratemaking principles, until such time as these generation assets are reflected in base rates and ceasing thereafter, MidAmerican Energy will continue to reduce its revenue from Iowa EAC recoveries by $12 million each calendar year.

MidAmerican Energy's cost of natural gas purchased for resale is collected for each jurisdiction through a uniform PGA, which is updated monthly to reflect changes in actual costs. Subject to prudence reviews, the PGA accomplishes a pass-through of MidAmerican Energy's cost of natural gas purchased for resale to its customers and, accordingly, has no direct effect on net income.

MidAmerican Energy's electric and natural gas energy efficiency program costs are collected through bill riders that are adjusted annually based on actual and expected costs in accordance with the energy efficiency plans filed with and approved by the respective state regulatory commission. As such, the energy efficiency program costs, which are reflected in operations and maintenance expense, and related recoveries, which are reflected in operating revenue, have no direct impact on net income.

MidAmerican Energy has income tax rider mechanisms in Iowa and Illinois that were established in response to significant changes to the Internal Revenue Code enacted in 2017, including, among other things, a reduction in the U.S. federal corporate income tax rate from 35% to 21%. As a result of these changes, MidAmerican Energy re-measured its accumulated deferred income tax balances at the 21% rate and increased regulatory liabilities pursuant to the approved mechanisms. In December 2018, the IUC approved in final form a tax expense revision mechanism that reduces customer electric rates for the impact of the lower income tax rate on current operations, as calculated annually, and defers the amortization of excess accumulated deferred income taxes created by their re-measurement at the 21% income tax rate to a regulatory liability, the disposition of which will be determined in MidAmerican Energy's next rate case. In 2018, Iowa Senate File 2417 was signed into law, with updates made in 2022 with the enactment of Iowa House File 2317, which, among other items, reduced the state of Iowa corporate tax rate in stages from 12% to its current 7.1%, and the impacts of such changes are included in the Iowa tax expense revision mechanism.

NV Energy (Nevada Power and Sierra Pacific)

Rate Filings

Nevada statutes require the Nevada Utilities to file electric general rate cases at least every three years with the PUCN and prohibit the Nevada Utilities from filing another general rate application until all pending general rate applications filed have been decided by the Commission unless, after application and hearing, the Commission determines that a substantial financial emergency would exist if the public utility or its affiliate is not permitted to file another general rate case sooner. Sierra Pacific may also file natural gas general rate cases with the PUCN. The Nevada Utilities are also subject to a two-part fuel and purchased power adjustment mechanism. The Nevada Utilities make quarterly filings to reset the BTERs, based on the last 12 months of fuel and purchased power costs. The difference between actual fuel and purchased power costs and the revenue collected in the BTERs is deferred into a balancing account. The DEAA rate clears amounts deferred into the balancing account. Nevada regulations allow an electric or natural gas utility that adjusts its BTERs on a quarterly basis to request PUCN approval to make quarterly changes to its DEAA rate if the request is in the public interest. During required annual DEAA proceedings, the prudence of fuel and purchased power costs is reviewed, and if any costs are disallowed on such grounds, the disallowances will be incorporated into the next quarterly BTERs change. Also, on an annual basis, the Nevada Utilities (a) seek a determination that energy efficiency program expenditures were reasonable, (b) request that the PUCN reset base and amortization EEPR, and (c) request that the PUCN reset base and amortization EEIR.

EEPR and EEIR

EEPR was established to allow the Nevada Utilities to recover the costs of implementing energy efficiency programs and EEIR was established to offset the negative impacts on revenue associated with the successful implementation of energy efficiency programs. These rates change once a year in the utility's annual DEAA application based on energy efficiency program budgets prepared by the Nevada Utilities and approved by the PUCN in the IRP proceedings. When the Nevada Utilities' regulatory earned rate of return for a calendar year exceeds the regulatory rate of return used to set base tariff general rates, they are obligated to refund energy efficiency implementation revenue previously collected for that year.

Net Metering

Nevada enacted Assembly Bill 405 ("AB 405") on June 15, 2017. The legislation, among other things, established net metering crediting rates for private generation customers with installed net metering systems less than 25 kilowatts. Under AB 405, private generation customers will be compensated for excess energy on a monthly basis at 95% of the rate the customer would have paid for a kilowatt-hour of electricity supplied by the Nevada Utilities for the first 80 MWs of cumulative installed capacity of all net metering systems in Nevada, 88% of the rate for the next 80 MWs, 81% of the rate for the next 80 MWs and 75% of the rate for any additional private generation capacity.

The Public Utilities Commission of Nevada approved a new 2025 net metering rate schedule ("NMR-2025") effective October 1, 2025, for only Sierra customers whose generation capacity is less than 25 kilowatts. Nevada Power customers remain on the NMR-405 rate. The new NMR-2025 rate does not change the compensation amounts established by AB 405 law, but it increases the frequency at which the net metering bill equations are calculated from once a month to every 15 minutes.

As of December 31, 2025, the cumulative installed and applied-for capacity of net metering systems under NMR-405 and NMR-2025 in Nevada was 957 megawatts.

Natural Disaster Protection Plan ("NDPP")

Senate Bill 329 ("SB 329"), Natural Disaster Mitigation Measures, was signed into law on May 22, 2019. The legislation requires the Nevada Utilities to submit an NDPP to the PUCN. The PUCN adopted NDPP regulations on January 29, 2020, that require the Nevada Utilities to file their NDPP for approval on or before March 1 of every third year. The regulations also require annual updates to be filed on or before September 1 of the second and third years of the plan. The plan must include procedures, protocols and other certain information as it relates to the efforts of the Nevada Utilities to prevent or respond to a fire or other natural disaster. The expenditures incurred by the Nevada Utilities in developing and implementing the NDPP are held in a regulatory asset account. Historically, these costs were recovered through an annual application filed on or before March 1, with 2025 representing the final year of that recovery mechanism. Beginning in 2026, NDPP related costs will continue to be deferred as a regulatory asset and will be recovered through the Nevada Utilities' General Rate Case recovery mechanism.

Federal Regulation

The FERC is an independent agency with broad authority to implement provisions of the Federal Power Act, the Natural Gas Act ("NGA"), the Energy Policy Act of 2005 ("Energy Policy Act") and other federal statutes. The FERC regulates rates for wholesale sales of electricity; transmission of electricity, including pricing and regional planning for the expansion of transmission systems; electric system reliability; utility holding companies; accounting and records retention; securities issuances; construction and operation of hydroelectric facilities; and other matters. The FERC also has the enforcement authority to assess civil penalties for violation of rules, regulations and orders issued under the Federal Power Act. The Utilities have implemented programs and procedures that facilitate and monitor compliance with the FERC's regulations described below. MidAmerican Energy is also subject to regulation by the NRC pursuant to the Atomic Energy Act of 1954, as amended ("Atomic Energy Act"), with respect to its interest in the Quad Cities Station.

Wholesale Electricity and Capacity

The FERC regulates the Utilities' rates charged to wholesale customers for electricity and transmission capacity and related services. Much of the Utilities' wholesale electricity sales and purchases occur under market-based pricing allowed by the FERC and are therefore subject to market volatility. The Utilities are precluded from selling at market-based rates in the PacifiCorp-East, PacifiCorp-West, and Nevada Utilities balancing authority areas. Wholesale electricity sales in those specific balancing authority areas are permitted at cost-based rates. PacifiCorp and the Nevada Utilities have been granted the authority to bid into the California EIM at market-based rates.

The Utilities' authority to sell electricity in wholesale electricity markets at market-based rates is subject to triennial reviews conducted by the FERC. Accordingly, the Utilities are required to submit triennial filings to the FERC that demonstrate a lack of market power over sales of wholesale electricity and electric generation capacity in their respective market areas. PacifiCorp, the Nevada Utilities and certain affiliates, representing the BHE Northwest Companies, file together for market power study purposes. The BHE Northwest Companies' most recent triennial filing was made in June 2025 and is pending acceptance by the FERC. MidAmerican Energy and certain affiliates file together for market power study purposes of the FERC-defined Northeast Region. The most recent triennial filing for the Northeast Region was made in June 2023, and it remains under review by the FERC. MidAmerican Energy and certain affiliates file together for market power study purposes of the FERC-defined Central Region. The most recent triennial filing for the Central Region was made in December 2023, and it remains pending under review. Under the FERC's market-based rules, the Utilities must also file with the FERC a notice of change in status when there is a change in the conditions that the FERC relied upon in granting market-based rate authority. PacifiCorp filed its most recent notice of non-material change in status in October 2025. MidAmerican Energy filed a notice of non-material change in status in July 2022, and the filing is currently under review by the FERC. In January 2024, MidAmerican Energy filed a change in status filing due to the addition of the Chickasaw wind farm generation, and the filing is currently under review by the FERC.

Transmission

PacifiCorp's and the Nevada Utilities' wholesale transmission services are regulated by the FERC under cost-based regulation subject to PacifiCorp's and the Nevada Utilities' OATTs. These services are offered on a non-discriminatory basis, which means that all potential customers are provided an equal opportunity to access the transmission system. PacifiCorp's and the Nevada Utilities' transmission business is managed and operated independently from its wholesale marketing business in accordance with the FERC's Standards of Conduct. PacifiCorp and the Nevada Utilities have made several required compliance filings in accordance with these rules.

In December 2011, PacifiCorp adopted a cost-based formula rate under its OATT for its transmission services. Cost-based formula rates are intended to be an effective means of recovering PacifiCorp's investments and associated costs of its transmission system without the need to file rate cases with the FERC, although the formula rate results are subject to discovery and challenges by the FERC and intervenors. A significant portion of these services are provided to PacifiCorp's energy supply management function.

MidAmerican Energy participates in the MISO as a transmission-owning member. Accordingly, the MISO is the transmission provider under its FERC-approved OATT. While the MISO is responsible for directing the operation of MidAmerican Energy's transmission system, MidAmerican Energy retains ownership of its transmission assets and, therefore, is subject to the FERC's reliability standards discussed below. MidAmerican Energy's transmission business is managed and operated independently from its wholesale marketing business in accordance with the FERC's Standards of Conduct.

MidAmerican Energy constructed and owns four Multi-Value Projects ("MVPs") located in Iowa and Illinois that added approximately 250 miles of 345-kV transmission line to MidAmerican Energy's transmission system since 2012. The MISO's OATT allows for broad cost allocation for MidAmerican Energy's MVPs, including similar MVPs of other MISO participants. Accordingly, a significant portion of the revenue requirement associated with MidAmerican Energy's MVP investments is shared with other MISO participants based on the MISO's cost allocation methodology, and a portion of the revenue requirement of the other participants' MVPs is allocated to MidAmerican Energy, which MidAmerican Energy recovers from customers via a rider mechanism. The transmission assets and financial results of MidAmerican Energy's MVPs are excluded from the determination of its base retail electric rates.

The FERC has established an extensive number of mandatory reliability standards developed by the NERC and the WECC, including planning and operations, critical infrastructure protection and regional standards. Compliance, enforcement and monitoring oversight of these standards is carried out by the FERC; the NERC; and the WECC for PacifiCorp, Nevada Power, and Sierra Pacific; and the Midwest Reliability Organization for MidAmerican Energy.

Hydroelectric

The FERC licenses and regulates the operation of hydroelectric systems, including license compliance and dam safety programs. Most of PacifiCorp's hydroelectric generating facilities are licensed by the FERC as major systems under the Federal Power Act, and certain of these systems are licensed under the Oregon Hydroelectric Act. Under the Federal Power Act, 16 of PacifiCorp's hydroelectric developments are classified as "high hazard potential," meaning it is probable in the event of a dam failure that loss of human life in the downstream population could occur. PacifiCorp uses the FERC's guidelines to develop public safety programs consisting of a dam safety program and emergency action plans.

Nuclear Regulatory Commission

General

MidAmerican Energy is subject to the jurisdiction of the NRC with respect to its license and 25% interest in Quad Cities Station. Constellation Energy, the operator and 75% owner of Quad Cities Station, is under contract with MidAmerican Energy to secure and keep in effect all necessary NRC licenses and authorizations.

The NRC regulates the granting of permits and licenses for the construction and operation of nuclear generating stations and regularly inspects such stations for compliance with applicable laws, regulations and license terms. Current licenses for Quad Cities Station provide for operation until December 14, 2032. The NRC review and regulatory process covers, among other things, operations, maintenance, environmental and radiological aspects of such stations. The NRC may modify, suspend or revoke licenses and impose civil penalties for failure to comply with the Atomic Energy Act, the regulations under such Act or the terms of such licenses.

Federal regulations provide that any nuclear operating facility may be required to cease operation if the NRC determines there are deficiencies in state, local or utility emergency preparedness plans relating to such facility, and the deficiencies are not corrected. Constellation Energy has advised MidAmerican Energy that an emergency preparedness plan for Quad Cities Station has been approved by the NRC. Constellation Energy has also advised MidAmerican Energy that state and local plans relating to Quad Cities Station have been approved by the Federal Emergency Management Agency.

The NRC also regulates the decommissioning of nuclear-powered generating facilities, including the planning and funding for the eventual decommissioning of the facilities. In accordance with these regulations, MidAmerican Energy submits a biennial report to the NRC providing reasonable assurance that funds will be available to pay its share of the costs of decommissioning Quad Cities Station. MidAmerican Energy has established a trust for the investment of funds collected for nuclear decommissioning of Quad Cities Station.

Under the Nuclear Waste Policy Act of 1982 ("NWPA"), the DOE is responsible for the selection and development of repositories for, and the permanent disposal of, spent nuclear fuel and high-level radioactive wastes. Constellation Energy, as required by the NWPA, signed a contract with the DOE under which the DOE was to receive spent nuclear fuel and high-level radioactive waste for disposal beginning not later than January 1998. The DOE did not begin receiving spent nuclear fuel on the scheduled date and remains unable to receive such fuel and waste. The costs to be incurred by the DOE for disposal activities were previously being financed by fees charged to owners and generators of the waste. In accordance with a 2013 ruling by the D.C. Circuit, the DOE, in May 2014, provided notice that, effective May 16, 2014, the spent nuclear fuel disposal fee would be zero. In 2004, Constellation Energy, reached a settlement with the DOE concerning the DOE's failure to begin accepting spent nuclear fuel in 1998. As a result, Quad Cities Station has been billing the DOE, and the DOE is obligated to reimburse the station for all station costs incurred due to the DOE's delay. Constellation Energy has constructed an interim spent fuel storage installation ("ISFSI") at Quad Cities Station consisting of two pads to store spent nuclear fuel in dry casks to free space in the storage pool. The first dry cask was placed in-service in 2005. As of December 31, 2021, the first pad at the ISFSI is full, and the second pad is in operation. The first and second pads at the ISFSI are expected to facilitate storage of casks to support operations at Quad Cities Station through the end of its current operating licenses, which is 2032.

Nuclear Insurance

MidAmerican Energy maintains financial protection against catastrophic loss associated with its interest in Quad Cities Station through a combination of insurance purchased by Constellation Energy, insurance purchased directly by MidAmerican Energy, and the mandatory industry-wide loss funding mechanism afforded under the Price-Anderson Amendments Act of 1988 ("Price-Anderson"), which was amended and extended by the Energy Policy Act. The general types of coverage maintained are: nuclear liability, property damage or loss and nuclear worker liability, as discussed below.

Constellation Energy purchases private market nuclear liability insurance for Quad Cities Station in the maximum available amount of $500 million, which includes coverage for MidAmerican Energy's ownership. In accordance with Price-Anderson, excess liability protection above that amount is provided by a mandatory industry-wide Secondary Financial Protection program under which the licensees of nuclear generating facilities could be assessed for liability incurred due to a serious nuclear incident at any commercial nuclear reactor in the U.S. Currently, MidAmerican Energy's aggregate maximum potential share of an assessment for Quad Cities Station is approximately $83 million per incident, payable in installments not to exceed $12 million annually.

The insurance for nuclear property damage losses covers property damage, stabilization and decontamination of the facility, disposal of the decontaminated material and premature decommissioning arising out of a covered loss. For Quad Cities Station, Constellation Energy purchases primary property insurance protection for the combined interests in Quad Cities Station, with coverage limits for nuclear damage losses up to $1.5 billion for nuclear perils and $500 million for non-nuclear perils. MidAmerican Energy also directly purchases extra expense coverage for its share of replacement power and other extra expenses in the event of a covered accidental outage at Quad Cities Station. The property and related coverages purchased directly by MidAmerican Energy and by Constellation Energy, which includes the interests of MidAmerican Energy, are underwritten by an industry mutual insurance company and contain provisions for retrospective premium assessments to be called upon based on the industry mutual board of directors' discretion for adverse loss experience. Currently, the maximum retrospective amounts that could be assessed against MidAmerican Energy from industry mutual policies for its obligations associated with Quad Cities Station total $9.8 million.

The master nuclear worker liability coverage, which is purchased by Constellation Energy for Quad Cities Station, is an industry-wide guaranteed-cost policy with an aggregate limit of $500 million for the nuclear industry as a whole, which is in effect to cover tort claims of workers in nuclear-related industries.

U.S. Mine Safety

PacifiCorp's surface mining operations are regulated by the Federal Mine Safety and Health Administration, which administers federal mine safety and health laws and regulations, and state regulatory agencies. The Federal Mine Safety and Health Administration has the statutory authority to institute a civil action for relief, including a temporary or permanent injunction, restraining order or other appropriate order against a mine operator who fails to pay penalties or fines for violations of federal mine safety standards. Information regarding PacifiCorp's mine safety violations and other legal matters disclosed in accordance with Section 1503(a) of the Dodd-Frank Reform Act is included in Exhibit 95 to this Form 10-K.

Interstate Natural Gas Pipeline Subsidiaries

The Pipeline Companies are regulated by the FERC, pursuant to the NGA and the Natural Gas Policy Act of 1978. Under this authority, the FERC regulates, among other items, (a) rates, charges, terms and conditions of service, (b) the construction and operation of interstate pipelines, storage and related facilities, including the extension, expansion or abandonment of such facilities and (c) the construction and operation of LNG export/import facilities. The Pipeline Companies hold certificates of public convenience and necessity and LNG facility authorizations issued by the FERC, which authorize them to construct, operate and maintain their pipeline and related facilities and services.

In February 2022, the FERC updated its certificate policy that guides the authorization of natural gas projects and issued an interim policy providing guidance on how the FERC will review a natural gas project for its impact on climate change. The policies apply to pending and future natural gas projects. On September 12, 2025, the FERC terminated the proceedings to update its certificate policy without modification.

FERC regulations and the Pipeline Companies' tariffs allow each of the Pipeline Companies to charge approved rates for the services set forth in their respective tariffs. Generally, these rates are a function of the cost of providing services to customers, including prudently incurred operations and maintenance expenses, taxes, depreciation and amortization and a reasonable return on invested capital. Tariff rates for each of the Pipeline Companies have been developed under a rate design methodology whereby substantially all fixed costs, including a return on invested capital and income taxes, are collected through reservation charges, which are paid by firm transportation and storage customers regardless of volumes shipped. Commodity charges, which are paid only with respect to volumes actually shipped, are designed to recover the remaining, primarily variable, costs. Kern River's reservation rates have historically been approved using a "levelized" cost-of-service methodology so that the rate remains constant over the levelization period. This levelized cost of service has been achieved by using a FERC-approved depreciation schedule in which depreciation increases as the cost of capital decreases on declining rate base. Each of the Pipeline Companies also hold authority to negotiate rates for their services, subject to requirements to offer cost-based rate alternatives, and to publish such negotiated rates. In addition, for services that are not subject to FERC rate jurisdiction pursuant to Section 3 of the Natural Gas Act, Cove Point charges rates that are established by contract.

The Pipeline Companies' rates are subject to change in future general rate proceedings. Rates for natural gas pipelines are changed by filings under either Section 5 or Section 4 of the Natural Gas Act. Section 5 proceedings are initiated by the FERC or the pipeline's customers for a potential reduction to rates that the FERC finds are no longer just and reasonable. In a Section 5 proceeding, the initiating party has the burden of demonstrating that the currently effective rates of the pipeline are no longer just and reasonable, and of demonstrating alternative just and reasonable rates. Any rate decrease as a result of a Section 5 proceeding is implemented prospectively upon the issuance of a final FERC order adopting the new just and reasonable rates. Section 4 rate proceedings are initiated by the natural gas pipeline, who must demonstrate that the new proposed rates are just and reasonable. The new rates as a result of a Section 4 proceeding are typically implemented six months after the Section 4 filing if higher than prior rates and are subject to refund upon issuance of a final order by the FERC.

The FERC-regulated natural gas companies may not grant undue preference to any customer. FERC regulations require that certain information be made public for market access, through standardized internet websites. These regulations also restrict each pipeline's marketing affiliates' access to certain non-public information that could affect price or availability of service.

Interstate natural gas pipelines are also subject to regulations administered by the Office of Pipeline Safety within the Pipeline and Hazardous Materials Safety Administration, an agency of the DOT. Federal pipeline safety regulations are issued pursuant to the Natural Gas Pipeline Safety Act of 1968, as amended ("NGPSA"), which establishes safety requirements in the design, construction, operation and maintenance of interstate natural gas facilities, and requires an entity that owns or operates pipeline facilities to comply with such plans. Major amendments to the NGPSA include the Pipeline Safety Improvement Act of 2002 ("2002 Act"), the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 ("2006 Act"), the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 ("2011 Act") the Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2016 ("2016 Act") and the Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2020 ("2020 Act").

The 2002 Act established additional safety and pipeline integrity regulations for all natural gas pipelines in high-consequence areas. The 2002 Act imposed major new requirements in the areas of operator qualifications, risk analysis and integrity management. The 2002 Act mandated more frequent periodic inspection or testing of natural gas pipelines in high-consequence areas, which are locations where the potential consequences of a natural gas pipeline accident may be significant or may do considerable harm to persons or property. Pursuant to the 2002 Act, the DOT promulgated regulations that require natural gas pipeline operators to develop comprehensive integrity management programs, to identify applicable threats to natural gas pipeline segments that could impact high-consequence areas, to assess these segments and to provide ongoing mitigation and monitoring. The regulations require recurring inspections of high-consequence area segments every seven years after the initial baseline assessment.

The 2006 Act required pipeline operators to institute human factors management plans for personnel employed in pipeline control centers. DOT regulations published pursuant to the 2006 Act required development and implementation of written control room management procedures.

The 2011 Act was a response to natural gas pipeline incidents, most notably the San Bruno natural gas pipeline explosion that occurred in September 2010 in California. The 2011 Act increased the maximum allowable civil penalties for violations, directs operator assistance for Federal authorities conducting investigations and authorized the DOT to hire additional inspection and enforcement personnel. The 2011 Act also directed the DOT to study several topics, including the definition of high-consequence areas, the use of automatic shutoff valves in high-consequence areas, expansion of integrity management requirements beyond high-consequence areas and cast iron pipe replacement. The studies are complete, and a number of notices of proposed rulemaking have been issued. The Pipeline and Hazardous Materials Safety Administration ("PHMSA") issued the Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements and Other Related Amendments final rule in October 2019. The primary change was the expansion of the pipeline integrity assessment requirements to cover moderate-consequence areas and reconfirming maximum allowable operating pressures. Pipeline operators were required to develop procedures to address assessment requirements by July 2021 and complete 50% of the required MAOP reconfirmation actions by 2028 and the remaining by 2035. The BHE Pipeline Group has updated procedures, identified pipeline segments subject to the rule and has planned projects to complete required assessments. PHMSA sent Part 2 of the rule to the Federal Register for publishing August 4, 2022, and it was published in the Federal Register August 24, 2022. The rule initially had an effective date of May 2023, but has been extended to February 2024. The third part of the rule, the gas gathering rule, has also been issued, but has minimal impact on the BHE Pipeline Group.

The 2016 Act required the Pipeline and Hazardous Materials Safety Administration to set federal minimum safety standards for underground natural gas storage facilities and authorized emergency order authority. In February 2020, the Pipeline and Hazardous Materials Safety Administration issued a final rule regarding underground natural gas storage facilities that incorporates by reference the American Petroleum Institute's Recommended Practice 1171, "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs," clarifies certain aspects of the mandatory nature of the standard and defines regulatory completion dates for underground storage facility risk assessments. The BHE Pipeline Group has 20 total underground natural gas storage fields at EGTS and Northern Natural Gas that fall under this regulation and is complying with the final rule. The BHE Pipeline Group underground storage fields have had several audits under the Final Rule with no notices of probable violations issued. Kern River, Carolina Gas and Cove Point do not have underground natural gas storage facilities.

The 2020 Act required operations to review and update their inspection and maintenance plans to address how the plans contribute to eliminate hazardous leaks of natural gas, reduction of fugitive emissions and replacement or remediation of pipelines that are known to leak based on the material, design or past operating maintenance history. BHE Pipeline Group has completed the review and update of its inspection and maintenance plans. To assist in this effort, Kern River participated in a non-punitive pilot inspection with the Pipeline and Hazardous Materials Safety Administration.

The DOT and related state agencies routinely audit and inspect the pipeline facilities for compliance with their regulations. The Pipeline Companies conduct periodic internal audits of their facilities with more frequent reviews of those deemed higher risk. The Pipeline Companies also conduct preliminary audits in advance of agency audits. Compliance issues that arise during these audits or during the normal course of business are addressed on a timely basis. The Pipeline Companies believe their pipeline systems comply in all material respects with the NGPSA and with DOT regulations issued pursuant to the NGPSA.

Northern Powergrid Distribution Companies

The Northern Powergrid Distribution Companies, as holders of electricity distribution licenses, are subject to regulation by GEMA. GEMA regulates distribution network operators ("DNOs") within the terms of the Electricity Act 1989 and the terms of DNO licenses, which are revocable with 25 years notice. Under the Electricity Act 1989, GEMA has a duty to ensure that DNOs can finance their regulated activities and DNOs have a duty to maintain an investment grade credit rating. GEMA discharges certain of its duties through its staff within Ofgem. Each of fourteen licensed DNOs distributes electricity from the national grid transmission system and distribution-connected generators to end users within its respective distribution services area.

DNOs are subject to price controls, enforced by Ofgem, that limit the revenue that may be recovered and retained from their electricity distribution activities. The regulatory regime that has been applied to electricity distributors in Great Britain encourages companies to look for efficiency gains in order to improve profits. The distribution price control formula also adjusts the revenue received by DNOs to reflect a number of factors, including, but not limited to, the rate of inflation (as measured by the United Kingdom's Retail Prices Index) and the quality of service delivered by the licensee's distribution system. The current price control, Electricity Distribution 2 ("ED2"), has been set for a period of five years, starting April 1, 2023. The procedure and methodology adopted at a price control review are at the reasonable discretion of Ofgem. Ofgem's judgment of the future allowed revenue of licensees is likely to take into account, among other things:

- the actual operating and capital costs of each of the licensees;
- the operating and capital costs that each of the licensees would incur if it were as efficient as, in Ofgem's judgment, the more efficient licensees;
- the actual value of certain costs which are judged to be beyond the control of the licensees;
- the taxes that each licensee is expected to pay;
- the regulatory value ascribed to the expenditures that have been incurred in the past and the efficient expenditures that are to be incurred in the forthcoming regulatory period;
- the rate of return to be allowed on expenditures that make up the regulatory asset value;
- the financial ratios of each of the licensees and the license requirement for each licensee to maintain investment grade status;
- an allowance in respect of the repair of the pension deficits in the defined benefit pension schemes sponsored by each of the licensees; and
- any under- or over-recoveries of revenues, relative to allowed revenues, in the previous price control period.

A number of incentive schemes also operate within the current price control period to encourage DNOs to provide an appropriate quality of service to end users. This includes specified payments to be made for failures to meet prescribed standards of service. The aggregate of these guaranteed standards payments is uncapped but may be excused in certain prescribed circumstances that are generally beyond the control of the DNOs.

The current electricity distribution price control became effective April 1, 2023 and is due to terminate on March 31, 2028, and will be immediately replaced with a new price control. Although it has been the convention in Great Britain for regulators to conduct periodic regulatory reviews before making proposals for any changes to the price controls, a new price control can be implemented by GEMA without the consent of the DNOs. If a licensee disagrees with a change to its license, it can appeal the matter to the United Kingdom's CMA, as can certain other parties. Any appeals must be notified within 20 working days of the license modification by GEMA. If the CMA determines that the appellant has relevant standing, then the statute requires that the CMA complete its process within six months, or in some exceptional circumstances seven months. The Northern Powergrid Distribution Companies appealed Ofgem's proposals for the resetting of the formula that commenced April 1, 2023, the CMA remitted the matter back to Ofgem to determine and implement a remedy.

Ofgem completed the price control review that resulted in a new price control effective April 1, 2023. The license modifications that give effect to the price control were published by Ofgem on February 3, 2023 and were subject to appeal to the CMA, if an appeal is filed by March 3, 2023. Many aspects of the prior price control were maintained and the changes made generally follow the template that was set by the price controls implemented in April 2021 for transmission and gas distribution in Great Britain. Specific changes include new service standard incentives and mechanisms to adjust cost allowances in specific circumstances, particularly related to investment required to support decarbonization efforts, and partially updating the allowed return on equity within the period for changes in the interest rate on government bonds. Ofgem's final determinations also included an allowed cost of equity of 5.23% plus inflation (calculated using the United Kingdom's consumer prices index including owner occupiers' housing costs) and cost allowances representing a 20% real-term increase compared to the current regulatory period annual average. The base allowed revenue, excluding the effects of incentive schemes, pass-through costs and any deferred revenues from the prior price control, will decrease approximately 4.0% at Northern Powergrid (Northeast) plc and will increase approximately 2.5% at Northern Powergrid (Yorkshire) plc, respectively, in 2023-24 before the addition of inflation.

Ofgem also monitors DNO compliance with license conditions and enforces the remedies resulting from any breach of condition. License conditions include the prices and terms of service, financial strength of the DNO, the provision of information to Ofgem and the public, as well as maintaining transparency, non-discrimination and avoidance of cross-subsidy in the provision of such services. Ofgem also monitors and enforces certain duties of a DNO set out in the Electricity Act 1989, including the duty to develop and maintain an efficient, coordinated and economical system of electricity distribution. Under changes to the Electricity Act 1989 introduced by the Utilities Act 2000, GEMA is able to impose financial penalties on DNOs that contravene any of their license duties or certain of their duties under the Electricity Act 1989, as amended, or that are failing to achieve a satisfactory performance in relation to the individual standards prescribed by GEMA. Any penalty imposed must be reasonable and may not exceed 10% of the licensee's revenue.

AltaLink

AltaLink is regulated by the AUC, pursuant to the *Electric Utilities Act* (Alberta), the *Public Utilities Act* (Alberta), the *Alberta Utilities Commission Act* (Alberta) and the *Hydro and Electric Energy Act* (Alberta). The AUC is an independent, quasi-judicial agency established by the province of Alberta, Canada, which is responsible for, among other things, approving the tariffs of transmission facility owners, including AltaLink, acquisitions of such transmission facility owners or utilities, and construction and operation of new transmission projects in Alberta. The AUC also investigates and rules on regulated rate disputes, system access, and market participant conduct. The AUC regulates and oversees Alberta's electricity transmission sector with broad authority that may impact many of AltaLink's activities, including its tariffs, rates, construction, operations and financing.

The AUC has various core functions in regulating the Alberta electricity transmission sector, including the following:

- regulating and adjudicating issues related to the operation of electric utilities within Alberta;
- processing and approving general tariff applications relating to revenue requirements, capital expenditure prudency and rates of return including deemed capital structure for regulated utilities, while ensuring that utility rates are just and reasonable;
- approving the transmission tariff rates of regulated transmission providers paid by the AESO, which is the independent transmission system operator in Alberta, Canada, that controls the operation of AltaLink's transmission system;

- approving the need for new electricity transmission facilities and permits to build and licenses to operate electricity transmission facilities;
- reviewing operations and accounts from electric utilities and conducting on-site inspections to ensure compliance with industry regulation and standards;
- adjudicating enforcement issues including the imposition of administrative penalties that arise when market participants violate the rules of the AESO or contravene legislation; and
- collecting, storing, analyzing, appraising and disseminating information to effectively fulfill its duties as an industry regulator.

In addition, AUC approval is required in connection with new energy and regulated utility initiatives in Alberta, amendments to existing approvals and financing proposals by designated utilities.

AltaLink's tariffs are regulated by the AUC under the provisions of the *Electric Utilities Act* (Alberta) in respect of rates and terms and conditions of service. In regulating transmission tariffs, the AUC must facilitate sufficient investment to ensure the timely upgrade, enhancement or expansion of transmission facilities, and foster a stable investment climate and a continued stream of capital investment for the transmission system.

Under the *Electric Utilities Act* (Alberta), AltaLink prepares and files applications with the AUC for approval of tariffs to be paid by the AESO for the use of its transmission facilities, and the terms and conditions governing the use of those facilities. The AUC reviews and approves such tariff applications based on a cost-of-service regulatory model under a forward test year basis. Under this model, the AUC provides AltaLink with a reasonable opportunity to (i) earn a fair return on equity; and (ii) recover its forecast costs, including operating expenses, depreciation, borrowing costs and taxes (including deemed income taxes) associated with its regulated transmission business. The AUC must approve tariffs that are just, reasonable and not unduly preferential, arbitrary or unjustly discriminatory. AltaLink's transmission tariffs are not dependent on the price or volume of electricity transported through its transmission system.

The AESO is an independent system operator in Alberta, Canada, that oversees the Alberta Interconnected Electric System ("AIES") and wholesale electricity market. The AESO is responsible for directing the safe, reliable and economic operation of the AIES, including long-term transmission system planning. AltaLink and the other transmission facility owners receive substantially all of their transmission tariff revenues from the AESO. The AESO, in turn, charges wholesale tariffs, approved by the AUC, in a manner that promotes fair and open access to the AIES and facilitates a competitive market for the purchase and sale of electricity. The AESO monitors compliance with approved reliability standards, which are enforced by the Market Surveillance Administrator, which may impose penalties on transmission facility owners for non-compliance with the approved reliability standards.

The AESO determines the need and plans for the expansion and enhancement of the transmission system in Alberta in accordance with applicable law and reliability standards. The AESO's responsibilities include long-term transmission planning and management, including assessing the current and future transmission system capacity needs of market participants. When the AESO determines an expansion or enhancement of the transmission system is needed, with limited exceptions, it submits an application to the AUC for approval of the proposed expansion or enhancement. The AESO then determines which transmission provider should submit an application to the AUC for a permit and license to construct and operate the designated transmission facilities. Generally, the transmission provider operating in the geographic area where the transmission facilities expansion or enhancement is to be located is selected by the AESO to build, own and operate the transmission facilities. In addition, Alberta law provides that certain transmission projects may be subject to a competitive process open to qualified bidders.

Independent Power Projects

The Yuma, Cordova, Saranac, Power Resources, Topaz, Agua Caliente, Solar Star 1, Solar Star 2, Solar Star 3, Solar Star 4 Bishop Hill II, Jumbo Road, Marshall, Grande Prairie, Walnut Ridge, Pinyon Pines I, Pinyon Pines II, Santa Rita, Independence, Fluvanna II, Flat Top, Mariah del Norte, Rio Bravo, Alamo 6 and Pearl independent power projects are Exempt Wholesale Generators ("EWGs") under the Energy Policy Act, while the Community Solar Gardens, Imperial Valley and Wailuku independent power projects are currently each certified as a Qualifying Facility ("QF") under the Public Utility Regulatory Policies Act of 1978. Both EWGs and QFs generally are exempt from compliance with extensive federal and state regulations that control the financial structure of an electric generating plant and the prices and terms at which electricity may be sold by the facilities.

The Yuma, Cordova, Saranac, Imperial Valley, Topaz, Agua Caliente, Solar Star 1, Solar Star 2, Solar Star 3, Solar Star 4, Bishop Hill II, Marshall, Grande Prairie, Walnut Ridge, Independence, Pinyon Pines I and Pinyon Pines II independent power projects have obtained authority from the FERC to sell their power at market-based rates. This authority to sell electricity in wholesale electricity markets at market-based rates is subject to triennial reviews conducted by the FERC. Accordingly, the respective independent power projects are required to submit triennial filings to the FERC that demonstrate a lack of market power over sales of wholesale electricity and electric generation capacity in their respective market areas. The Pinyon Pines I, Pinyon Pines II, Solar Star 1, Solar Star 2, Solar Star 3, Solar Star 4, Topaz and Yuma independent power projects and power marketers CalEnergy, LLC and BHER Market Operations, LLC file together for market power study purposes of the FERC-defined Southwest Region. The most recent triennial filing for the Southwest Region was made in June 2025, and is awaiting FERC action. The Cordova and Saranac independent power projects and power marketer CalEnergy, LLC file together with MidAmerican Energy and certain affiliates for market power study purposes of the FERC-defined Northeast Region. The most recent triennial filing for the Northeast Region was made in June 2023 and is awaiting FERC action. The Bishop Hill II and Walnut Ridge independent power projects and power marketer CalEnergy, LLC file together with MidAmerican Energy and certain affiliates for market power study purposes of the FERC-defined Central Region. The most recent triennial filing for the Central Region was made in December 2023 and is awaiting FERC action. The Marshall and Grande Prairie independent power projects and power marketer CalEnergy, LLC file together for market power study purposes in the FERC-defined Southwest Power Pool Region. The most recent triennial filing for the Southwest Power Pool Region was made in December 2024 and is awaiting FERC action. Power marketers CalEnergy LLC and BHER Market Operations, LLC also file for market power study purposes in the FERC-defined Northwest Region together with PacifiCorp, Nevada Power Company, Sierra Power Company and certain affiliates. The most recent triennial filing for the Northwest Region was made in June 2025, and is awaiting FERC action.

The entire output of Jumbo Road, Santa Rita, Fluvanna II, Flat Top, Mariah del Norte, Rio Bravo, Alamo 6, Pearl and Power Resources is within ERCOT and market-based authority is not required for such sales solely within ERCOT as the ERCOT market is not a FERC-jurisdictional market. Similarly, Wailuku sells its output solely to the Hawaii Electric Light Company within the Hawaii electric grid, which is not a FERC-jurisdictional market and therefore, Wailuku does not require market-based rate authority.

EWGs are permitted to sell capacity and electricity only in the wholesale markets, not to end users. Additionally, utilities are required to purchase electricity produced by QFs at a price that does not exceed the purchasing utility's "avoided cost" and to sell back-up power to the QFs on a non-discriminatory basis, unless they have successfully petitioned the FERC for an exemption from this purchase requirement. Avoided cost is defined generally as the price at which the utility could purchase or produce the same amount of power from sources other than the QF on a long-term basis. The Energy Policy Act eliminated the purchase requirement for utilities with respect to new contracts under certain conditions. New QF contracts are also subject to FERC rate filing requirements, unlike QF contracts entered into prior to the Energy Policy Act. FERC regulations also permit QFs and utilities to negotiate agreements for utility purchases of power at rates other than the utility's avoided cost.

Residential Real Estate Brokerage Company

HomeServices and its operating subsidiaries are regulated by the U.S. Consumer Financial Protection Bureau which enforces the Truth In Lending Act ("TILA"), the Equal Credit Opportunity Act ("ECOA") and the Real Estate Settlement Procedures Act ("RESPA"); by the U.S. Federal Trade Commission with respect to certain franchising activities; by the U.S. Department of Housing and Urban Development, which enforces the Fair Housing Act ("FHA"); and by state agencies where its subsidiaries operate. TILA and ECOA regulate lending practices. FHA prohibits housing-related discrimination on the basis of race, color, national origin, religion, sex, familial status, and disability. RESPA regulates real estate settlement services including real estate closing practices, lender servicing and escrow account practices and business relationships among settlement service providers and third parties to the transaction.

REGULATORY MATTERS

In addition to the discussion contained herein regarding regulatory matters, refer to "General Regulation" in Item 1 of this Form 10-K for further information regarding the general regulatory framework.

PacifiCorp

Utah

In May 2024, PacifiCorp filed its EBA application to recover deferred net power costs from 2023. In June 2024, the UPSC approved an interim rate increase of $256 million, or 11.6%, effective July 1, 2024, allowing for recovery of $432 million of deferred net power costs. In February 2025, the UPSC issued a final order reducing the total final EBA recovery by $24 million, primarily for costs related to the Washington Cap and Invest program. The reductions from the final order were reflected in the 2024 EBA filing made in May 2025. In March 2025, PacifiCorp filed a request for review or rehearing regarding the disallowed costs that was denied by the UPSC in April 2025. After the UPSC denied the rehearing, PacifiCorp filed for review with the Utah Supreme Court.

In June 2024, PacifiCorp filed a general rate case requesting a rate increase over two years that included increased net power costs, capital investments in transmission and wind-powered generating facilities and higher insurance premiums for third-party liability coverage. In August 2024, PacifiCorp filed an amended application that removed the second rate increase that was associated with net power costs and updated costs associated with insurance premiums. In November and December 2024, PacifiCorp filed updated testimony that further revised the requested rate increase to $330 million, or 14.0%, effective February 23, 2025. In April 2025, the UPSC issued a final order approving a rate increase of $87 million, or 3.7%, effective April 25, 2025. Most significantly, the final order substantially limited PacifiCorp's recovery of costs associated with insurance premiums, lowered PacifiCorp's authorized return on equity and equity component of its capital structure, reduced forecast base net power costs, substantially limited recovery for amounts previously deferred under the wildland fire mitigation balancing account and disallowed recovery of Utah's share of PacifiCorp's investment in certain assets on the Klamath River hydroelectric system. In May 2025, PacifiCorp filed a request for rehearing that the UPSC denied in June 2025, except for a partial reconsideration of a mathematical error that granted an additional $7 million related to excess liability insurance premiums. PacifiCorp has filed for review of these decisions with the Utah Supreme Court.

In May 2025, PacifiCorp filed its EBA application to recover deferred net power costs from 2024. The filing requests recovery of $472 million of deferred net power costs, effective on an interim basis July 1, 2025. The request would result in a rate increase of $40 million, or 1.6%. In June 2025, the UPSC approved the interim rate change, effective July 1, 2025. In December 2025, a settlement stipulation was filed that updated recovery to $467 million of deferred net power costs. In February 2026, the UPSC approved the settlement stipulation.

In November 2025, PacifiCorp filed an application to create a catastrophic wildfire fund authorized by Utah statute. The fire fund would serve as a supplement to other forms of insurance to manage liabilities associated with catastrophic fire events in Utah that are not otherwise covered by insurance.

Oregon

In February 2024, PacifiCorp filed a general rate case requesting a rate increase that included new capital investments in transmission and wind-powered generating facilities, higher insurance premiums for third-party liability coverage and proposed funding for a catastrophic fire fund. In July 2024, PacifiCorp filed updated testimony that removed the proposed funding for a catastrophic fire fund and included a reduction in the requested return on equity and in August 2024, PacifiCorp filed updated testimony that further revised the requested rate increase to $208 million, or 11.2%, effective January 1, 2025. In December 2024, the OPUC issued an order in the general rate case that resulted in a rate increase of $140 million, or 7.5%, effective January 1, 2025. In February 2025, PacifiCorp filed an application for reconsideration or rehearing with the OPUC regarding the level of recovery provided for Oregon's share of wildfire mitigation investments and PacifiCorp's return on investment in its 416-mile, 500-kV high voltage transmission line set forth in the December 2024 general rate case order. In April 2025, the OPUC denied reconsideration, and PacifiCorp is pursuing review of this decision with the Oregon Court of Appeals.

In April 2025, PacifiCorp filed a renewable adjustment clause application with the OPUC to recover the full costs of certain wind-powered generating facilities and associated transmission lines that are being only partially recovered as a result of the December 2024 general rate case order or that were placed into service subsequent to the rate effective date of the last general rate case. The application sought a rate increase of $51 million, or 2.5%, effective January 1, 2026. In December 2025, the OPUC approved recovery of the wind-powered generating facilities but not the associated transmission lines, resulting in a rate increase of $40 million, which is a 2.2% increase for non-residential customers effective January 1, 2026, and a 1.7% increase, for residential customers effective April 1, 2026. In February 2026, PacifiCorp filed an application for reconsideration with the OPUC regarding the decision to exclude recovery of the transmission lines.

In August 2025, PacifiCorp filed an application to defer the costs of certain wind-powered generating facilities and associated transmission lines not already in rates as of August 15, 2025 through December 31, 2025, when these projects would be included in rates through the renewable adjustment clause.

In February 2026, PacifiCorp filed an application to defer 90% of the incremental costs associated with insurance coverage commencing in February 2026.

Wyoming

In March 2023, PacifiCorp filed a general rate case requesting a rate increase of $140 million, or 21.6%, to become effective January 1, 2024. The requested rate increase included recovery of increases in net power costs and new major capital investments in transmission and wind-powered generating facilities. In September 2023, PacifiCorp filed updated testimony that included updated net power costs and increased insurance premium costs associated with third-party liability coverage. In November 2023, the WPSC approved a rate increase of $54 million, or 8.3%, effective January 1, 2024. In January 2024, PacifiCorp filed an application for rehearing requesting the WPSC consider three items, including the WPSC's adjustment to net power costs related to third-party wholesale reserves, costs associated with the Washington Cap and Invest program and the opportunity to revise PacifiCorp's initial revenue requirement request for updates, corrections and revisions reflected in rebuttal testimony. In April 2024, the WPSC denied a rehearing in an open meeting. PacifiCorp is pursuing review of this decision in federal and Wyoming state courts. In September 2025, the U.S. District Court for the District of Wyoming granted PacifiCorp's motion for summary judgment ruling that the WPSC's net power costs adjustment intruded on the FERC's jurisdiction over third-party wholesale reserves. The WPSC and another intervening party have appealed the decision to the Tenth Circuit Court of Appeals.

In August 2024, PacifiCorp filed a general rate case requesting a rate increase of $124 million, or 14.7%, to become effective June 1, 2025. The request included new capital investments in transmission and wind-powered generating facilities, a new insurance cost adjustment mechanism and proposed adjustments to the ECAM. In January 2025, PacifiCorp filed updated testimony that reduced the requested rate increase to $110 million, or 13.1%. In March 2025, a multi-party settlement stipulation was filed that requested a rate increase of $86 million, or 10.2%. In April 2025, the WPSC approved the stipulation as filed, with rates effective June 1, 2025.

In April 2025, PacifiCorp filed its ECAM and its REC and SO_2 revenue adjustment mechanism to recover deferred net power costs from 2024. The combined filing requests a rate decrease of $47 million, or 5.8%, to be effective on an interim basis on July 1, 2025. In June 2025, the WPSC approved the interim rate change, effective July 1, 2025. In December 2025, the WPSC approved an all-party settlement stipulation that reduced the interim rate change by $3 million, effective January 1, 2026.

In January 2026, PacifiCorp filed an application to establish a temporary balancing account to track the excess liability insurance premium expenses currently included in rates and 80% of the cost of claims and outside legal defense costs related to wildfires that occur in Wyoming while pursuing a self-insurance reserve fund for wildfire liability.

Washington

In March 2023, PacifiCorp filed a general rate case requesting a two-year rate plan with a rate increase that included recovery of increases in net power costs and new major capital investments in transmission and wind-powered generating facilities. In March 2024, the WUTC accepted the multi-party settlement stipulation for which the first-year rate increase went into effect April 3, 2024. In March 2025, PacifiCorp submitted a compliance filing for the second year of the two-year rate plan, resulting in a rate increase of $16 million, or 3.8%, effective April 3, 2025. The compliance filing included updated net power cost forecasts that resulted in a $5 million decrease to the stipulated second year increase. In April 2025, the WUTC approved the second year increase as filed, effective April 3, 2025.

As part of the stipulation in the above two-year general rate case, PacifiCorp agreed to file a review and potential refund of provisional capital not placed in-service. After the determination of any refund under the capital review process, PacifiCorp's restated actual rate of return will be compared against the authorized rate of return to determine if any deferral is necessary under Washington's multiyear rate plan legislation. In July 2024, PacifiCorp submitted a provisional capital report for calendar year 2023. During review of the provisional capital report in February 2025, the WUTC ordered a refund of $64,000 related to specific wind-powered generating facilities.

In August 2023, PacifiCorp filed a deferral application with the WUTC for costs associated with increased insurance premium costs associated with third-party liability coverage. In September 2025, the WUTC approved the request to defer these costs.

In April 2025, PacifiCorp filed a power cost only rate case, as directed by the WUTC in the 2023 general rate case, to reset the baseline net power costs to remove coal-fueled resources from rates under the Washington 2026 Protocol also proposed in the filing. The filing requested a $34 million, or 7.9%, rate increase effective January 1, 2026. In September 2025, PacifiCorp submitted rebuttal testimony which reflected a lower proposed rate increase of $12 million, or 2.8%. The update is primarily due to Washington Engrossed House Bill 1329, enacted into law in May 2025, that updated types of wholesale power purchases allowed by electric utilities under Washington's Clean Energy Transformation Act. In December 2025, the WUTC approved the 2026 Protocol and PacifiCorp's request to update its baseline net power costs. The final rates that went into effect January 1, 2026, incorporated cost updates and resulted in a rate increase of $2 million, or 0.5%, for customers.

In June 2025, PacifiCorp filed its PCAM requesting recovery of deferred net power costs from 2024. The filing requested a rate increase of $56 million, or 10.0%, effective October 1, 2025. In September 2025, the WUTC approved recovery of $57 million, with an updated effective date of February 1, 2026, for most customer classes. Since the 2024 PCAM effective date coincides with the expiration of the larger 2023 PCAM surcharge, customers will experience an overall decrease in rates.

Idaho

In April 2024, PacifiCorp filed its ECAM to recover deferred net power costs from 2023. The filing requested a rate increase of $33 million, or 10.5%, effective June 1, 2024. In May 2024, the IPUC approved a rate increase of $30 million, or 9.7%, effective June 1, 2024, that excluded costs associated with the Washington Cap and Invest program. In June 2024, PacifiCorp filed a petition for reconsideration of the disallowed costs, and in July 2024, the IPUC granted the request for reconsideration. PacifiCorp filed comments in September 2024, and in October 2024, the IPUC issued a decision denying reconsideration of its May order. Subsequently, in November 2024, PacifiCorp filed an appeal with the Idaho Supreme Court regarding the IPUC's order that was denied in November 2025. Per the 2024 Idaho general rate case settlement approved in January 2025 by the IPUC, the rate increase approved for the ECAM will be spread over a two-year period.

In March 2025, PacifiCorp filed its ECAM to recover deferred net power costs from 2024. The filing requested a rate increase of $8 million, or 2.2%, effective June 1, 2025, that the IPUC approved in May 2025. The filing excluded costs associated with the Washington Cap and Invest program.

In January 2026, PacifiCorp filed an application to establish a temporary balancing account to track the excess liability insurance premium expenses currently included in rates and 80% of the cost of claims and outside legal defense costs related to wildfires that occur in Idaho while pursuing a self-insurance reserve fund for wildfire liability.

California

In May 2022, PacifiCorp filed a general rate case requesting an overall rate change to become effective January 1, 2023. In November 2022, the CPUC granted the requested rate effective date and directed PacifiCorp to establish a memorandum account to track the change in rates beginning January 1, 2023, until the new rates become effective. In February 2023, the CPUC issued a ruling requesting additional information on PacifiCorp's wildfire and risk analyses and requested additional information regarding wildfire memorandum accounts and in March 2023, the CPUC split the general rate case into two tracks. The first track addressed the general rate case and the second track addressed the wildfire memorandum accounts. In December 2023, the CPUC issued an order for the first track approving a rate increase effective January 12, 2024 and recovery of the aforementioned memorandum account over three years. In the second track of the general rate case, PacifiCorp filed the independent audit of the wildfire memorandum accounts in January 2024, indicating no findings. In January 2025, the CPUC issued a proposed decision authorizing PacifiCorp to recover $36 million related to historic wildfire mitigation costs. In February 2025, the CPUC issued a final decision authorizing PacifiCorp to recover these costs over six years, effective April 15, 2025.

In June 2023, PacifiCorp filed an application with the CPUC for authority to establish a Wildfire Expense Memorandum Account to track for future cost recovery incremental, unreimbursed wildfire liability-related expenses, including increased insurance premium costs and legal expenses, to be applied to expenses incurred on or after June 21, 2023, for wildfires occurring on or after June 21, 2020. In September 2025, the CPUC approved the request to track California claims for unreimbursed wildfire liability-related expenses, including third-party liability expenses and legal expenses for wildfires occurring between June 21, 2020, and June 30, 2026, and for incremental, unreimbursed wildfire insurance premiums incurred on or after June 21, 2023, subject to certain limitations.

In September 2024, PacifiCorp filed to recover costs associated with an event that occurred in 2023 recorded in the catastrophic events memorandum account requesting recovery of $30 million over a two-year period, resulting in an annual rate increase of $15 million, or 10.2%, effective March 1, 2025. In August 2025, parties filed a motion for the CPUC to adopt a joint settlement agreement for $29 million amortized over three years.

In June 2025, the CPUC issued a proposed administrative enforcement order against PacifiCorp for its 2020 wildfire mitigation plan compliance. The order alleges that PacifiCorp did not meet targets in the approved wildfire mitigation plan and did not provide sufficient data to support PacifiCorp's compliance or corrective actions. The order proposes a $27 million penalty. In July 2025, PacifiCorp filed a request for hearing which will take place in May 2026.

FERC

PacifiCorp's wholesale transmission rates are set annually using formula rates approved by the FERC and are updated annually. In May 2024, PacifiCorp published the 2024 annual update of its transmission formula rate in FERC Docket No. ER24-2004-000 pursuant to its formula rate implementation protocols. The 2024 formula rate update included the impacts of approximately $1,677 million of accrued losses, net of expected insurance recoveries associated with the Wildfires recognized during the year ended December 31, 2023, among other adjustments. Pursuant to the formula rate implementation protocols, PacifiCorp transmission customers are permitted to lodge "preliminary challenges" to the formula rate updates, which provides an informal basis upon which PacifiCorp and the transmission customers may exchange certain information and engage in discussions in order to provide further context to the rates resulting from the updates. Transmission customers are ultimately permitted to lodge "formal challenges" to the formula rate update with the FERC in the event preliminary discussions are not fruitful or do not resolve outstanding issues, and the FERC has an established process to resolve formal challenges. In June 2025, several PacifiCorp transmission customers filed formal challenges with the FERC, largely seeking to disallow PacifiCorp's recovery of the portion of losses associated with the Wildfires allocable to transmission customers through the formula rate and other, less substantive expenses. In August 2025, PacifiCorp filed a response and procedural motion with the FERC to dismiss the formal challenges on the basis that the formal challenges lack merit and do not support finding that PacifiCorp's Wildfires losses were imprudently incurred. In September 2025, those transmission customers who filed the formal challenges filed responses to PacifiCorp's filing. In October 2025, PacifiCorp filed an additional response with the FERC. PacifiCorp will continue to utilize the FERC-established process to resolve all outstanding issues related to its 2024 annual update. The matter is pending before the FERC.

In May 2025, PacifiCorp published the 2025 annual update of its transmission formula rate in FERC Docket No. ER25-2221-000, which included the impacts of approximately $346 million of accrued losses associated with the Wildfires recognized during the year ended December 31, 2024, among other adjustments. In January 2026, several PacifiCorp transmission customers filed preliminary challenges to the 2025 formula rate update. Formal challenges with the FERC are due June 25, 2026.

2026 PacifiCorp Inter-Jurisdictional Allocation Protocol

In August 2025, PacifiCorp filed applications with the UPSC, the OPUC, the WPSC and the IPUC for approval of PacifiCorp's 2026 Inter-Jurisdictional Cost Allocation Protocol ("2026 Protocol"). The 2026 Protocol is intended to supersede the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol for Utah, Oregon, Wyoming, Idaho and California, and align with the changes proposed in the Washington 2026 Protocol, filed with the April 2025 power cost only rate case. This filing is the first phase in a multi-phased process to transition PacifiCorp's cost-allocation methodology to accommodate diverging resource portfolios and changes to operations needed to address individual state energy policies. If approved, the 2026 Protocol will be effective for new regulatory filings beginning January 1, 2026. The CPUC will consider the 2026 Protocol as part of PacifiCorp's next general rate case filed in California. In December 2025, PacifiCorp filed deferral applications with the UPSC, the OPUC, the WPSC and the IPUC for net impacts of the reallocation of resources required to implement the 2026 Protocol as of January 1, 2026, while approval of the 2026 Protocol is pending in the respective states.

MidAmerican Energy

2025 Solar Reliability Project

In February 2025, MidAmerican Energy filed an application with the IUC for advance ratemaking principles for MidAmerican Energy's 2025 Solar Reliability Project. The application asks the IUC to approve installation of up to 800 MWs of new solar generation in Iowa to meet capacity needs driven by load growth and regional capacity requirements. In July 2025, MidAmerican Energy filed a unanimous settlement with all parties. On September 11, 2025, the IUC issued its final order, approving the unanimous settlement without modification. MidAmerican Energy accepted the ratemaking principles on September 12, 2025, and began construction in 2025 and expects to place the project's facilities in-service in 2026 through 2028.

Iowa Transmission Legislation

In 2020, Iowa enacted legislation that grants incumbent electric transmission owners the right to construct, own and maintain electric transmission lines that have been approved for construction in a federally registered planning authority's transmission plan and that connect to the incumbent electric transmission owner's facility. This Right of First Refusal ("ROFR") law gave MidAmerican Energy, as an incumbent electric transmission owner, the legal right to construct, own and maintain transmission lines in MidAmerican Energy's service territory that have been approved by the MISO (or another federally registered planning authority) and are eligible to receive regional cost allocation. In October 2020, national transmission interests filed a lawsuit that challenged the law on state constitutional grounds. After an appeal in which the Iowa Supreme Court held the national transmission interests had standing to challenge the law and remanded the case to the Iowa district court for a decision on the merits, the district court, in December 2023, found the legislature impermissibly "log-rolled" the ROFR law into a state appropriations bill in violation of the title and single-subject provisions of the Iowa Constitution and held that the law was unconstitutional and unenforceable. The district court issued an injunction that enjoins MidAmerican Energy and ITC Midwest from further developing the Long Range Transmission Projects ("LRTP") Tranche 1 projects to the extent authority to construct was claimed pursuant to, under, or in reliance on the invalid ROFR law, but allows either company to proceed with projects assigned in a manner not relying on the claimed existence of the law.

In April 2024, MidAmerican Energy and ITC Midwest filed an appeal to the Iowa Supreme Court that challenged the application of the injunction to the LRTP Tranche 1 projects; MISO filed an amicus brief that supports the positions taken by MidAmerican Energy and ITC Midwest.

In May 2024, while the appeal was pending, MISO initiated a variance analysis under its tariff to assess actions that could be taken to mitigate the obstacle to construct posed by the district court injunction. In August 2024, MISO announced the outcome of its variance analysis, which implemented a mitigation plan under the MISO tariff. As part of the mitigation plan, MISO's Competitive Transmission Executive Committee determined the projects should be assigned to the incumbent transmission owners under the transmission owners agreement, which results in no change to the project assignments. MISO affirmed that, pursuant to its tariff, MidAmerican Energy and ITC Midwest remain obligated to construct the projects assigned to each company.

On May 30, 2025, the Iowa Supreme Court issued its opinion on the scope of the injunction. The Iowa Supreme Court held that the district court's injunction properly restricted the parties from taking any additional action, or relying on prior actions, related to any and all electric transmission line projects in Iowa that were claimed pursuant to, under or in reliance on Iowa's ROFR law. However, the Iowa Supreme Court advised that any relief related to the application of the MISO tariff or the assignment of projects under MISO's variance analysis should be sought from the FERC.

Following the Iowa Supreme Court's opinion, the IUC requested additional briefing in a docket involving an LRTP Tranche 1 project to be constructed by ITC Midwest. The IUC advised that it needed to address "existing barriers to resolution of this and other proposed transmission projects," noting that the Iowa Supreme Court "provided acute clarity with respect to Iowa law and how the Commission should act, or not act, in regard to projects tainted by ROFR" but left unresolved "the impact of federal determinations on these proceedings." MidAmerican Energy filed comments that support the right to proceed with projects assigned under MISO's variance analysis and mitigation plan. At a July 22, 2025 hearing in the ITC Midwest docket, the IUC held that the variance analysis and mitigation plan allowed the project to proceed and encouraged any party that disagreed to "seek appropriate relief from MISO or FERC". The IUC issued a franchise and opinion on December 1, 2025, finding that the variance analysis assigning Tranche 1 projects relies on grounds other than Iowa's ROFR law. No petition for judicial review was filed, rendering the IUC's favorable decision final. MidAmerican Energy continues to progress with a franchise petition for its first LRTP Tranche 1 project, consistent with the IUC ruling.

Litigation regarding the ROFR law would only affect the manner in which MidAmerican Energy would secure the right to construct transmission lines that are eligible for regional cost allocation and are otherwise subject to competitive bidding under the MISO tariff; it does not negatively affect or implicate MidAmerican Energy's ongoing rights to construct any other transmission lines, including lines required to serve new or expanded retail load, connect new generators or meet reliability criteria.

NV Energy (Nevada Power and Sierra Pacific)

Regulatory Rate Review

In February 2025, Nevada Power filed an electric regulatory rate review with the PUCN that requested an annual revenue increase of $215 million, or 9.0%. Nevada Power filed its certification filing in April 2025 that updated the requested annual revenue increase to $224 million, or 9.4%. In May 2025, a settlement was reached in the cost of capital phase, resulting in the return on equity remaining at 9.5% and the capital structure as well as the cost of debt being approved as filed. Hearings for the revenue requirement and rate design phases were held in July 2025. In September 2025, the PUCN issued an order approving an increase in the revenue requirement of $118 million, which includes 50% of construction work in progress in rate base for the Greenlink project, with rates effective October 1, 2025. In October, 2025, Nevada Power filed a petition for reconsideration and clarification of certain aspects of the PUCN's order, including recovery of the Flex Pay Program implementation costs. In November 2025, the PUCN issued a final modified order largely reaffirming its original order.

Wildfire Self-Insurance Policy Filing

In January 2025, the Nevada Utilities filed applications for approval of the establishment and associated cost recovery of a Wildfire Self-Insurance Policy. The applications request that the PUCN issue an order determining that it is reasonable and prudent for the Nevada Utilities to establish a $500 million wildfire self-insurance policy (the "Policy") in order to have additional wildfire liability insurance in place in the event that a catastrophic wildfire in Nevada is alleged to be caused or exacerbated by utility equipment. The Policy would provide $500 million in additional coverage for the Nevada Utilities for third-party claims, and it would be in excess to the commercial wildfire liability insurance the Nevada Utilities possess. In addition, the applications request approval to collect the costs for the Policy in rates over a ten-year period. Hearings before the Commission concluded in June 2025. In July 2025, the PUCN issued an order that approved the application in part and denied the application in part. The PUCN found that $1.0-$1.5 billion in insurance coverage is a prudent range for the Nevada Utilities based on its wildfire risk profile and that the Nevada Utilities sufficiently supported its initial request for an additional $500 million of excess insurance. However, the PUCN also determined that additional information is necessary to assess whether the self-insurance policy proposed by the Nevada Utilities is prudent under the circumstances and reasonable considering other options, if any. The Nevada Utilities filed the additional information requested by the PUCN in October 2025. The PUCN has set a hearing in April 2026 to assess the prudency of self-insurance.

BHE Pipeline Group

Northern Natural Gas

In July 2025, Northern Natural Gas filed a general rate case that proposed an overall annual cost-of-service of $1.6 billion. This is an increase of $286 million above the cost-of-service filed in its 2022 rate case of $1.3 billion, largely due to higher depreciation expense and return allowance of $165 million from increased rate base and an increase in depreciation and negative salvage rates, and increased operations and maintenance expenses of $96 million. Northern Natural Gas requested increases in various rates, including transportation and storage reservation rates. In January 2026, the FERC approved Northern Natural Gas' filing to implement interim rates effective January 1, 2026, subject to refund and the outcome of hearing procedures.

BHE Transmission

AltaLink

In May 2025, AltaLink filed its 2026-2027 General Tariff Application and 2023-2024 Deferral Accounts Reconciliation Application with the AUC. AltaLink amended its application in July 2025. In August 2025, AltaLink advised the AUC that it reached a negotiated settlement with customer groups for substantially all its 2026-2027 GTA revenue and the entirety of the 2023-2024 Deferral Accounts Reconciliation Application. AltaLink filed its revised GTA reflecting the terms of the negotiated settlement agreement with total amended revenue requirements of C$919 million and C$960 million for 2026 and 2027, respectively. Under the agreement, AltaLink reduced its applied-for operating expenses by C$4 million and sustaining capital expenditures by C$67 million for the 2026-2027 test period. In September 2025, the AUC approved the negotiated settlement agreement. The approved negotiated settlement marks AltaLink's fourth successful negotiated settlement over the past decade.

The negotiated settlement agreement does not include, among other items, AltaLink's 2026-2027 Wildfire Mitigation Plan and the execution and costs of the 2024-2025 Wildfire Mitigation Plan, insurance premiums, depreciation on certain asset classes, the regulatory accounting and income tax treatment of certain costs and the proposal of two deferral accounts. These items were heard in an AUC hearing in November 2025, with a decision expected in the first quarter of 2026. A decision is expected in March 2026.

BHE U.S. Transmission

In January 2025, ETT filed a request with the Public Utilities Commission of Texas ("PUCT") for a $57 million annual base rate increase over its adjusted test year revenues which includes interim transmission rate updates. The rate case sought a prudence review determination on cumulative capital additions included in interim rates since the initial base regulatory review in 2007. In June 2025, ETT filed a unanimous and unopposed settlement with the PUCT with a base rate increase of approximately $20 million, based on an ROE of 9.6% and a capital structure of 59% debt and 41% equity. The settlement also included a determination that ETT's invested capital and rate base are prudent and properly included in rates. A motion to approve interim rates was granted in June 2025. In October 2025, the PUCT issued an order approving the June 2025 settlement. The rates approved by the order are identical to the rates approved on an interim basis.

Northern Powergrid

Ofgem is currently consulting on its framework for the five-year RIIO-ED3 price control, which will become effective April 1, 2028. Ofgem plans to publish its decision on the framework in Q2 2026. Northern Powergrid will be required to submit its final business plan in December 2026, ahead of Ofgem's Final Determination scheduled for December 2027.

ENVIRONMENTAL LAWS AND REGULATIONS

Each Registrant is subject to federal, state, local and foreign laws and regulations regarding air quality, climate change, emissions performance standards, water quality, coal ash disposal and other environmental matters that have the potential to impact each Registrant's current and future operations. In addition to imposing continuing compliance obligations, these laws and regulations provide regulators with the authority to levy substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. These laws and regulations are administered by various federal, state, local and international agencies. Each Registrant believes it is in material compliance with all applicable laws and regulations, although many laws and regulations are subject to interpretation that may ultimately be resolved by the courts.

The Company has cumulative investments in (i) owned wind, solar and geothermal generating facilities and electric battery storage facilities of $38.0 billion and (ii) wind tax equity investments of $7.1 billion and has ceased coal operations at 22 coal-fueled generation facilities. As a result, as of December 31, 2025, the Company reduced its annual GHG emissions by 30% as compared to 2005 levels. To the extent it is beneficial for customers and consistent with regulatory provisions, the Company plans to continue investing in wind, solar and other low-carbon generation and storage in the future, including (i) $4.9 billion on the construction of renewable generating facilities and repowering certain existing wind-powered generating facilities through 2028 and (ii) $197 million on the construction of electric battery storage facilities through 2028, and to cease coal operations at additional coal-fueled generation facilities in a reliable and cost-effective manner. Refer to "Liquidity and Capital Resources" of each respective Registrant in Item 7 of this Form 10-K for discussion of each Registrant's renewable generation-related capital expenditures.

On January 20, 2025, President Trump issued a series of U.S. federal executive orders, including a memorandum establishing a regulatory freeze pending review. The memo prohibits submission of rules and guidance documents to the Federal Register without direct review, requires immediate withdrawal of rules and guidance documents submitted to the Federal Register but not yet published, and, for rules and guidance documents published but not yet having taken effect, consideration of a 60-day delay and possible additional comment period. Additional executive orders direct the heads of all administrative agencies to review all existing regulations, orders, guidance documents, policies, settlements, consent orders and any other agency actions and develop action plans to suspend, revise or rescind all agency actions identified as unduly burdensome. Until the agencies complete reviews and take final action consistent with these directives, the relevant Registrant cannot determine the impact and whether additional action will be necessary.

Climate Change

In December 2015, an international agreement was negotiated by 195 nations to create a universal framework for coordinated action on climate change in what is referred to as the Paris Agreement. The Paris Agreement reaffirms the goal of limiting global temperature increase well below 2 degrees Celsius, while urging efforts to limit the increase to 1.5 degrees Celsius and reaching a global peak of GHG emissions as soon as possible to achieve climate neutrality by mid-century; establishes commitments by all parties to make nationally determined contributions and pursue domestic measures aimed at achieving the commitments; commits all countries to submit emissions inventories and report regularly on their emissions and progress made in implementing and achieving their nationally determined commitments; and commits all countries to submit new commitments every five years, with the expectation that the commitments will get more aggressive. After more than 55 countries representing more than 55% of global GHG emissions submitted their ratification documents, the Paris Agreement became effective November 4, 2016; however, the U.S. completed its first withdrawal from the Paris Agreement on November 4, 2020. The U.S. accepted the terms of the climate agreement on January 20, 2021, and the U.S. completed its reentry February 19, 2021. In January 2025, the U.S. announced its second departure from the Paris Agreement, which was finalized in January 2026.

Environmental Deregulation

On March 12, 2025, the EPA announced a significant deregulatory effort focused on climate change and measures that impact the energy sector. At the core of the deregulatory effort is the plan to reconsider the EPA's 2009 endangerment finding on greenhouse gases. That finding gives the EPA its authority to regulate greenhouse gas emissions by finding they threaten public health. In addition to the endangerment finding, the EPA announced it will review the following rules and policies relevant to the Registrants: greenhouse gas standards for power plants; methane standards for the oil and natural gas sector; greenhouse gas reporting rule; mercury and air toxics standards; steam electric effluent limitation guidelines; oil and natural gas effluent limitation guidelines; risk management program; hydrofluorocarbon phase-out rule; National Ambient Air Quality Standards for fine particulate matter; regional haze program; state and tribe implementation plans for a variety of air quality rules; exceptional events policy; coal combustion residuals rule; and the definition of waters of the U.S. The EPA has taken the following actions to implement the announcement:

- On June 11, 2025, the EPA issued a proposal to rescind the 2024 rules establishing greenhouse gas emissions limits for existing coal-fueled power plants and new natural gas-fueled power plants. The rule contains two co-proposals: The lead proposal would exclude the power sector from Clean Air Act regulation for greenhouse gas emissions on the grounds that the sector does not significantly contribute to dangerous air pollution; the secondary proposal would eliminate the carbon capture and sequestration-based standards and other requirements from the 2024 rules. The effect of the secondary proposal for new natural gas-fueled plants is to leave in place the efficiency-based Phase 1 standards while removing the carbon capture and sequestration-based Phase 2 standards. For existing coal-fueled plants, the removal of carbon capture and sequestration-based and natural gas co-firing-based requirements means that no greenhouse gas emissions requirements would be in place. The proposed rescission could affect facilities at BHE Renewables, MidAmerican Energy, NV Energy and PacifiCorp. The EPA accepted comments on the proposal through August 7, 2025. Until the rulemaking process is complete and litigation exhausted, full impacts to the affected Registrants cannot be determined.
- On June 11, 2025, the EPA issued a proposal to repeal the 2024 amendments to the Mercury and Air Toxics Standards, specifically addressing the residual risk and technology review that informed the amendments. The repeal includes the filterable particulate matter emission standard as a surrogate for non-mercury hazardous air pollutants; the requirement to use continuous emission monitoring systems for measuring and reporting particulate matter emissions; and the mercury emissions standard for existing lignite-fueled electric generating units. The rescission of the first two limits would affect facilities at MidAmerican Energy and PacifiCorp. The EPA accepted comments on the proposal through August 11, 2025. Until the rulemaking process is complete and litigation exhausted, full impacts to the affected Registrants cannot be determined.

- On July 17, 2025, the EPA issued a direct final rule and companion proposal that would extend the compliance deadlines for coal combustion residual management units set forth in the legacy CCR rule. The rule would (1) establish an additional option that will allow the part one and part two facility evaluation reports to be prepared concurrently so long as both reports are submitted no later than February 8, 2027; (2) extend by 15 months the deadline for CCR management units to comply with the groundwater monitoring provisions; and (3) make conforming changes to the remaining CCR management unit deadlines that will be impacted by the extended facility evaluation report deadline. The EPA accepted comments on the direct final rule and co-proposal through September 15, 2025. Because adverse comments were submitted, the direct final rule was withdrawn and the EPA proceeded to consider comments on the co-proposal. The EPA signed the final CCRMU Deadline Extension Rule on February 6, 2026, and it took effect February 9, 2027. The deadline extensions in the final rule provide owners and operators of CCR management units with an additional year to complete both the part one and part two facility evaluation reports, which are now due February 9, 2027, and February 8, 2028, respectively. Because these reports and deadlines serve as prerequisites for all other sequential deadlines for CCR management units, the EPA made conforming changes to extend deadlines for these requirements, including implementation of groundwater monitoring, preparing closure and post-closure care plans and initiating closure of the CCR management unit. Owners and operators of CCR management units will have a total of 36 months (i.e., February 10, 2031) from the completion of the part 2 facility evaluation report to design and install groundwater monitoring systems and initiate monitoring. Closure and post-closure care plans are now due August 11, 2031, and initial groundwater monitoring and corrective action reports for CCR management units are now due January 31, 2032. Until the rulemaking process is complete and litigation exhausted, full impacts to the affected Registrants cannot be determined.
- On July 29, 2025, the EPA extended several compliance deadlines for the 2024 methane regulation, which covers new and modified oil and gas facilities, including transmission and storage assets. The interim rule was effective immediately. Most compliance deadlines for newly regulated sources, including equipment leaks, tank controls, pneumatic controllers, and super-emitter programs, have been extended by 18 months. Monitoring requirements for flares and enclosed combustion have a shorter, 120-day extension. States were given an additional 10 months to submit plans, now due November 9, 2026. The extension rule provides short-term operational relief for the Registrant BHE Pipeline Group, with additional time to plan and implement compliance measures for new and modified sources affected by the rule. However, the extension rule does not alter the substance of obligations under the methane rule. Additional rulemaking to address the substantive elements of the rule is anticipated in 2026.
- On July 29, 2025, the EPA released a proposed rule titled "Reconsideration of 2009 Endangerment Finding and Greenhouse Gas Vehicle Standards." This proposal would repeal the EPA's 2009 Endangerment Finding, a determination that greenhouse gas emissions qualify as air pollution that endangers human health or the environment. The proposed rescission offered several differing and potentially exclusive approaches to reach a new conclusion. The lead proposal would find that Clean Air Act section 202(a) (the section that authorizes regulation of motor vehicle emissions) does not authorize the EPA to prescribe emission standards based on global climate change concerns. The first alternative proposal would repeal the Endangerment Finding by casting doubt on the underlying record and scientific evidence. A second alternative proposal would not withdraw or repeal the Endangerment Finding but instead would reopen the standards the EPA established in 2024 for greenhouse gas emissions from light, medium, and heavy-duty motor vehicles and would find that there are no requisite emissions control technologies for motor vehicle greenhouse emissions that would meaningfully address global climate change without imposing a greater public health burden by presumed economic loss. The EPA finalized the Endangerment Finding Rescission on February 11, 2026. The EPA said that Section 202(a) of the Clean Air Act does not allow the agency to enact emissions regulations for vehicles in a way that addresses climate change, so there is no legal basis to issue the endangerment finding and any resulting regulations. In the final rule, the EPA argues that the Clean Air Act was never intended to allow for regulation of greenhouse gases because climate change is a global phenomenon. Such a limitation, however, is not expressed in the law itself. The final rule is expected to be challenged in the D.C. Circuit and ultimately appealed to the U.S. Supreme Court for final adjudication. The legal process could take several years, with significant uncertainty in the short term. Until the rulemaking process is complete and litigation has been exhausted, impacts on the relevant Registrants cannot be determined.

- On September 12, 2025, the EPA issued a proposed rule to rescind its greenhouse gas reporting requirements for nearly all industrial sectors currently subject to its Greenhouse Gas Reporting Program and to suspend until 2034 most oil and gas sector rules, while also repealing mandates for gas distribution operations. If finalized, the proposal would remove reporting obligations for most large facilities; all fuel and industrial gas suppliers; and carbon dioxide injection sites. The agency said that no sector would need to submit reports with 2025 data. However, the proposal would extend the March 31, 2026, deadline for such reports until June 10, 2026, which would "allow the EPA time to issue a final rule prior to the regulatory deadline for reporting year 2025." While power plants would no longer be subject to reporting emissions under the greenhouse gas reporting program, Section 821 of the Clean Air Act Amendments of 1990 established a separate statutory requirement that sources subject to the Title IV Acid Rain Program, principally power plants, must monitor and report carbon dioxide. That obligation is carried out through separate regulations that are not affected by the current proposal. Until the rulemaking process is complete and litigation has been exhausted, impacts on the relevant Registrants cannot be determined.
- On November 20, 2025, the EPA and the U.S. Army Corps of Engineers ("Corps") proposed a revised waters of the U.S. definition limiting the scope of waters that receive federal Clean Water Act protections. An estimate in a regulatory impact analysis conducted by the EPA and the Corps said 19% of wetlands in the contiguous U.S. that have been mapped by the federal government would be protected under the draft definition. The agencies said the proposal conforms with *Sackett v. EPA*, a 2023 U.S. Supreme Court ruling that found only wetlands that directly touched a relatively permanent waterway – like a river or lake – fell under the scope of the Clean Water Act and the regulatory powers of the federal government. The agencies proposed a more restrictive interpretation of the ruling than prior iterations of the definitional rule. In addition to having a physical surface connection to a waterway, wetlands would need to contain surface water at least for the duration of the wet season to be considered jurisdictional waters. The relevant Registrants most commonly encounter the need to evaluate potential impacts to waters of the U.S. with infrastructure construction projects. The revised definition may reduce the companies' regulatory burden under programs like the Nationwide Permit program, due to the narrower definition of what constitutes a water of the U.S. The agencies accepted comments on the proposed rule through January 5, 2026. Until rulemaking is complete and litigation is exhausted, impacts on the relevant Registrants cannot be determined.
- On December 31, 2025, the EPA finalized its rule extending by six years certain compliance deadlines in a rule governing coal-fired power plants' effluent limitations guidelines, while also providing assurances that officials will not enforce facilities violating permit conditions in the rule if they face an upcoming deadline to do so. The final rule extends the deadline for the Notice of Plan Participation for permanent cessation of coal by 2034 to December 31, 2031; extends the deadline for compliance with zero-liquid discharge technologies for bottom ash transport water, flue gas desulfurization wastewater, and combustion residual leachate from 2029 to 2034; and provides flexibilities for compliance with deadlines for bottom ash transport water and flue gas desulfurization wastewater from the 2020 rule. The final rule includes a provision granting sources that demonstrate unexpected changes in energy demand or supply the ability to obtain site-specific extensions of the discharge limit requirements on an as-needed basis. In addition to the deadline extensions, the EPA's Office of Enforcement and Compliance Assurance provided a no action assurance regarding certain coal plants that are subject to effluent limitations guidelines in both the 2020 rule and 2024 rule. The no action assurance establishes that the EPA will exercise its enforcement discretion to not pursue enforcement actions for certain permit violations by coal-fired power plants not yet in compliance with limitations from the 2020 and 2024 final rules where those limitations are required by the permit to be met on dates between December 31, 2025, through December 31, 2026, as long as the entities involved meet the conditions of the no action assurance. Facilities must submit to the permitting authority a timely and complete initial request letter to receive an alternative applicability date and provide a copy to the EPA; permitting authorities must find that the initial request letter factually supports the facility meeting one of the circumstances that warrant an alternative applicability date; and facilities must meet all applicable reporting and recordkeeping requirements. The extension rule takes effect March 2, 2026. MidAmerican and PacifiCorp own or operate facilities impacted by the 2024 rule's requirements and are evaluating the final extension rule's impacts on operations. Environmental groups opposing the changes are expected to file suit over the rule. Until litigation has been exhausted, impacts on the relevant Registrants cannot be determined.
- On January 15, 2026, the EPA finalized changes to New Source Performance Standards for stationary combustion turbines. The rule applies to affected sources constructed, modified or reconstructed after December 13, 2024. The rule establishes nitrogen oxide emissions limits for affected turbines based on size, rates of utilization, design efficiency and fuel type. The final rule now requires selective catalytic reduction only for new, large gas-fueled turbines. The EPA included a new subcategory for small and medium temporary stationary combustion turbines which can only be used in a single location for up to 24 months. Such units must utilize combustion controls to meet applicable fuel-based emissions limits. The rule took effect upon publication in the Federal Register. Until anticipated litigation is exhausted, impacts on the relevant Registrants cannot be determined.

Air Quality Regulations

The Clean Air Act, as well as state laws and regulations impacting air emissions, provides a framework for protecting and improving the nation's air quality and controlling sources of air emissions. These laws and regulations continue to be promulgated and implemented and will impact the operation of BHE's generating facilities and require them to reduce emissions at those facilities to comply with the requirements. In addition, the potential adoption of state or federal clean energy standards, which include low-carbon, non-carbon and renewable electricity generating resources, may also impact electricity generators and natural gas providers.

National Ambient Air Quality Standards

Under the authority of the Clean Air Act, the EPA sets minimum NAAQS for six principal pollutants, consisting of carbon monoxide, lead, NO_x, particulate matter, ozone and SO_2, considered harmful to public health and the environment. Areas that achieve the standards, as determined by ambient air quality monitoring, are characterized as being in attainment, while those that fail to meet the standards are designated as being nonattainment areas. Generally, sources of emissions in a nonattainment area that are determined to contribute to the nonattainment are required to reduce emissions. Currently, with the exceptions described in the following paragraphs, air quality monitoring data indicates that all counties where the relevant Registrant's major emission sources are located are in attainment of the current NAAQS.

On June 4, 2018, the EPA published final ozone designations for much of the U.S. Relevant to the Registrants, these designations include classifying Yuma County, Arizona; Clark County, Nevada; and the Northern Wasatch Front, Southern Wasatch Front and Duchesne and Uintah counties in Utah as nonattainment-marginal with the 2015 ozone standard. These areas were required to meet the 2015 standard three years from the August 3, 2018, effective date. All other areas relevant to the Registrants were designated attainment/unclassifiable with this same action. However, on January 29, 2021, the D.C. Circuit vacated several provisions of the 2018 implementing rules for the 2015 ozone standards for contravening the Clean Air Act. The EPA and environmental groups finalized a consent decree in January 2022 that sets deadlines for the agency to approve or disapprove the "good neighbor" provisions of interstate ozone plans of dozens of states. Relevant to the Registrants, the EPA must, by April 30, 2022, propose to approve or disapprove the interstate ozone SIPs of Alabama, Iowa, Maryland, Michigan, Minnesota, New York, Ohio, Pennsylvania, Texas, West Virginia and Wisconsin. On February 22, 2022, the EPA published a series of proposed decisions to disapprove the SIPs for interstate ozone transport of 19 states. Relevant to the Registrants, these states include Alabama, Maryland, Michigan, Minnesota, New York, Ohio, West Virginia and Wisconsin. The EPA also proposed to approve Iowa's SIP after re-analyzing the state's data. In addition, the EPA must approve or disapprove the interstate plans of Arizona, California, Nevada and Wyoming. On April 15, 2022, the EPA issued its final rule approving Iowa's SIP as meeting the good neighbor provisions for the 2015 ozone standard. On May 24, 2022, the EPA disapproved the Utah and Wyoming interstate ozone SIPs. On January 30, 2023, the EPA entered into a stipulated extension to the deadline for action on the Wyoming SIP, setting a new deadline of December 15, 2023. The EPA explained that the extra time is needed to fully consider updated air quality information and public comments. The EPA published its proposed approval of Wyoming's SIP on August 14, 2023 and finalized the approval December 19, 2023. As a result, Wyoming is not subject to the Good Neighbor Rule, discussed below, and litigation over Wyoming's SIP was terminated after the effective date of the rule on January 18, 2024. The EPA also reevaluated SIPs for Tennessee and Arizona. On January 31, 2023, the EPA issued final disapproval of the 19 SIPs proposed in April 2022, setting the stage to include those states in the federal implementation plan described under the Cross-State Air Pollution Rule. Separately, on March 28, 2022, the EPA proposed determinations as to whether certain areas have achieved levels of ground-level ozone pollution that meet the 2008 and 2015 ozone NAAQS. Relevant to Registrants, the Southern Wasatch Front in Utah and Yuma, Arizona are proposed to have met the 2015 ozone standard; and the Cincinnati area of Ohio and Kentucky and the Northern Wasatch Front in Utah are proposed to have not met the 2015 ozone standard and to be reclassified as Moderate Non-Attainment, and have until August 3, 2024, to meet the standard. In June 2022, the EPA took final action to redesignate the Ohio portion of the Cincinnati area to attainment status and no further action is required. In November 2022, the EPA finalized the redesignations of the Southern Wasatch Front area in Utah and Yuma, Arizona to attainment, and also finalized a finding of failure to attain and redesignation to marginal nonattainment for the Kentucky portion of the Cincinnati area. In September 2022, after achieving acceptable levels of the ozone NAAQS, the Commonwealth of Kentucky requested that the EPA redesignate the Kentucky portion of the Cincinnati area to attainment for the 2015 ozone standard. The EPA took final action in September 2023 to approve Kentucky's plan and to redesignate the Kentucky portion of the Cincinnati area to attainment for the 2015 ozone standard. In December 2024, the EPA finalized findings of failure to attain and reclassification of the Northern Wasatch Front area in Utah and the Las Vegas Valley area of Clark County, Nevada, as "serious" for the 2015 ozone standard. As a result, Utah and Nevada must submit to the EPA certain SIP revisions and may require permitting changes for the relevant Registrants' facilities. In October 2024, the EPA proposed to set a deadline of 18 months from the effective date of the reclassification, or no later than January 1, 2026. Also in October 2024, the EPA entered into a settlement agreement with environmental groups concerning the agency's delay in reviewing and revising, if necessary, the primary health-based NAAQS for NOx. Under the agreement, the EPA must sign a proposed NOx NAAQS update by January 17, 2028, and finalize it by November 10, 2028. On December 27, 2024, consistent with the terms of a separate settlement agreement, the EPA finalized action to revise the secondary NAAQS for SO2 and to retain the existing secondary standards for NOx and PM. Any action may be subject to further review by the new administration. Until the EPA takes final action to address implementation deadlines for newly reclassified areas and the affected states submit any required SIPs, the relevant Registrants cannot determine the impacts of these actions.

On February 7, 2024, the EPA released final standards for fine particulate matter, PM2.5. The EPA strengthened the primary, health-based annual PM2.5 standard from 12 micrograms per cubic meter to 9 micrograms per cubic meter. The standards were last updated in 2012. Most PM2.5 particles form in the atmosphere as a result of chemical reactions of substances, such as sulfur dioxide and nitrogen oxides, that are emitted from power plants, industrial sources and automobiles. National ambient air quality standards are implemented through compliance plans submitted by states and tribes that are then approved by the EPA. The EPA stated that 119 counties in the 48 contiguous states do not meet the revised standard but predicted that that number would be reduced to 52 counties by 2032, the earliest year by which a compliance requirement is anticipated. A coalition of two dozen states challenged the final PM2.5 rule in the D.C Circuit Court of Appeals. The EPA initially defended the rule in briefing and at oral argument, but signaled a likely policy change with a request to abate litigation in 2025. The court granted the EPA's motion to stay litigation while the agency reconsidered the rule. In November 2025, the EPA asked the court to vacate the PM2.5 air standard because the agency determined it had not conducted a "thorough review" and it failed to evaluate compliance costs. The court has not yet ruled on the motion to vacate, and the EPA has not proposed a replacement rule. The EPA did not meet a February 6, 2026, deadline for designating attainment status with the current PM2.5 NAAQS. The agency is expected to extend the designation deadline by one year. Until additional rulemaking and litigation is exhausted, the relevant Registrants cannot determine the full impacts of the revised standard.

Cross-State Air Pollution Rule

On June 18, 2025, the U.S. Supreme Court issued a unanimous decision in favor of Utah and PacifiCorp in the ozone transport case titled *Oklahoma v. U.S. Environmental Protection Agency*, in which the state and company were parties. The case addressed the proper court venue for the EPA's disapproval of Oklahoma and Utah state ozone transport plans. The court's ruling provides needed clarity and confirms that while SIPs require a careful balance of federal and state collaboration, the Clean Air Act clearly directs that regional courts are the proper court venue for disagreements over the details of those plans. By recognizing that state plans are "undisputedly locally or regionally applicable actions," the court preserved important legal rights for states to have disagreements over their plans heard in the appropriate regional federal circuit court. This enables regional court consideration of the plans and arguments rather than grouping multiple state plans under a national review in the D.C. Circuit. The cases have been transferred back to the Tenth Circuit Court of Appeals, the regional court where they were originally filed. The Tenth Circuit Court of Appeals agreed to abate further litigation while the EPA reconsiders both its earlier disapproval of the state plans and the federal plan it promulgated. On November 10, 2025, the EPA approved a portion of Utah's SIP addressing interstate transport for the 2008 8-hour ozone standard.

On January 27, 2026, the EPA signed a proposal to reconsider the Good Neighbor Plan. In the proposed rule, the EPA finds that it wrongly disallowed state implementation plans that relied on earlier guidance to show that they meet the Clean Air Act's good neighbor provision with respect to the 2015 ozone national ambient air quality standard. Relevant to the Registrants, the EPA is proposing to approve the SIP submissions of Arizona, Minnesota and Nevada and to withdraw previously proposed error-correction action related to interstate transport obligations for Iowa. The currently approved Iowa Plan will therefore stay in place. The EPA will accept public comments on the proposed reconsideration through March 2, 2026. It is the first of a two-part effort to establish a new interstate ozone policy, and the EPA intends to take a subsequent action to address interstate transport obligations for the 2015 8-hour ozone standard for other states covered by the Good Neighbor Plan, including Utah, Texas, Illinois, Michigan, Maryland, Pennsylvania, New York, Ohio, Virginia and West Virginia. The Good Neighbor Plan required nitrogen oxides emissions cuts from power plants, but also - for the first time - additional industry sectors, including oil and natural gas pipelines. Enforcement of the Good Neighbor Plan remains suspended pending full reconsideration. Until rulemaking is complete and litigation is exhausted, the potential impacts to the relevant Registrants cannot be determined.

Regional Haze

First Planning Period

The EPA's Regional Haze Rule, finalized in 1999, requires states to develop and implement plans to improve visibility in designated federally protected areas ("Class I areas"). In accordance with the federal requirements, states are required to submit SIPs that address emissions from sources subject to visibility requirements and demonstrate progress towards achieving natural visibility requirements in Class I areas by 2064.

On January 30, 2014, the EPA disapproved Wyoming's first planning period regional haze SIP for Dave Johnston Unit 3 and imposed a federal plan that effectively required Unit 3 to shut down by the end of 2027. On September 25, 2025, PacifiCorp and Wyoming filed petitions for reconsideration, requesting that the EPA reconsider the specific part of the SIP disapproval that resulted in the federal plan's shutdown requirement. The EPA granted the petitions for reconsideration and PacifiCorp continues to coordinate with Wyoming and the EPA on this action. On August 7, 2025, the EPA finalized approval of Wyoming's revision of its first planning period regional haze implementation plan for Jim Bridger Units 1 and 2.

The state of Colorado first planning period regional haze SIP requires SCR equipment at Craig Unit 2 and Hayden Units 1 and 2, in which PacifiCorp has interests. Each of those regional haze compliance projects are in-service. In addition, in February 2015, the state of Colorado finalized an amendment to its regional haze SIP relating to Craig Unit 1, in which PacifiCorp has an interest, to require the installation of SCR controls by 2021. In September 2016, the owners of Craig Units 1 and 2 reached an agreement with state and federal agencies and certain environmental groups that were parties to the previous settlement requiring SCR to retire Unit 1 by December 31, 2025, in lieu of SCR installation, or alternatively to remove the unit from coal-fueled service by August 31, 2021 with an option to convert the unit to natural gas by August 31, 2023, in lieu of SCR installation. The terms of the agreement were approved by the Colorado Air Quality Board in December 2016, incorporated into an amended Colorado regional haze SIP in 2017 and approved by the EPA in August 2018. PacifiCorp retained a December 31, 2025, retirement date for Craig Unit 1 in its 2023 IRP, which will satisfy its regional haze obligations in the state of Colorado. On December 30, 2025, the DOE issued an emergency order requiring the operators of Craig Generating Station to "take all measures necessary to ensure that Craig Unit 1 is available to operate" until at least March 30, 2026. The operators and owners are reviewing the order to determine its impact and assess compliance with the order and with other regulatory requirements.

Second Planning Period

Nevada, Utah and Wyoming each submitted regional haze SIPs for the regional haze second planning period to the EPA and received completeness determinations in August 2022. The EPA was required to make final determinations on the SIPs by August 2023. The states of Utah and Wyoming filed deadline suits in the Utah and Wyoming federal district courts in October and November 2023, respectively, asking the court to require the EPA to perform its statutory duty to approve or disapprove the states' regional haze second planning period SIPs. PacifiCorp also filed a deadline suit in both courts. Three environmental groups filed similar deadline suits in the federal district court in Washington, D.C. for seven different states on June 15, 2023. The environmental groups amended their lawsuit on November 10, 2023, after Wyoming and PacifiCorp's suits were filed, to include Utah's and Wyoming's state plans. PacifiCorp intervened in the D.C. district court case and asked that court to stay the Utah and Wyoming cases in that court while they proceed in the relevant federal courts in Utah and Wyoming. On August 1, 2024, the EPA proposed to partially approve and partially disapprove Wyoming's SIP for the second planning period and accepted comments on the proposal through September 3, 2024. On August 19, 2024, the EPA proposed to partially approve and partially disapprove Utah's SIP for the second planning period and accepted comments on the proposal through September 18, 2024. On December 2, 2024, the EPA finalized the partial approval and partial disapproval of Utah's and Wyoming's SIPs. The EPA finalized its approval of West Virginia's second planning period regional haze plan in July 2025, setting a precedent for other states seeking to meet haze reduction goals for 156 national parks and wilderness areas using a more gradual reduction timeline, which often means new pollution control requirements are not necessary. The EPA's approval hinges on a reframing of what states need to do to make reasonable progress toward the objective of restoring natural visibility to those lands by 2064. If states meet what is known as the "uniform rate of progress" on the way to that target, they would be deemed in compliance. The EPA believes that the policy meshes with the purpose of regional haze program regulations to achieve reasonable progress towards Congress' natural visibility goal. Several states have regional haze implementation plans pending with the EPA that are expected to be impacted by this policy which are applicable to the relevant Registrants, including Texas, Arizona, Utah, Wyoming and Nevada. Two environmental groups filed a lawsuit in the Fourth Circuit Court of Appeals in September 2025, challenging the EPA's decision in its approval of West Virginia's plan to incorporate the uniform rate of progress policy. The outcome of that litigation may affect other SIPs that incorporate the uniform rate of progress policy. Based on the uniform rate of progress policy, the EPA approved Texas' SIP for the second planning period on December 5, 2025. The EPA partially disapproved SIPs for Arizona, Utah and Wyoming in December 2024. Arizona petitioned for reconsideration of the EPA's partial disapproval and the EPA granted the state's petition in September 2025. Wyoming and PacifiCorp filed petitions for reconsideration in January 2025 and remain in coordination with the EPA. PacifiCorp filed a petition for reconsideration of the Utah plan denial in January 2025 and remains in coordination with Utah and the EPA. On April 30, 2025, the EPA granted PacifiCorp's petition for reconsideration on its disapproval of the Utah Regional Haze SIP for the second planning period, as well as PacifiCorp's and Wyoming's petitions for reconsideration on the EPA's disapproval of the second planning period Wyoming Regional Haze SIP. Both the Utah and Wyoming plan denials were also petitioned to the Tenth Circuit Court of Appeals; the suits are held in abeyance while the EPA reviews the underlying decisions. The EPA proposed to approve portions of the second round regional haze SIP for Nevada in October 2025 and finalized the action February 6, 2026. The EPA determined Nevada's SIP meets the requirements related to the uniform rate of progress. The EPA plans to address reasonable progress determinations for the North Valmy Station's Units 1 and 2 and Tracy Generating Station Unit 7 (Pinyon Pine Unit 4) that were part of a 2025 SIP supplement, issued on May 28, 2025, as a separate action to allow sufficient time for the EPA's full consideration. Until rulemaking is complete and litigation exhausted, impacts on the relevant Registrants cannot be determined.

On August 25, 2022, the EPA promulgated a finding of failure to submit a SIP for the regional haze second planning period for 15 states, including Iowa. The finding establishes a two-year deadline for the agency to promulgate FIPs to address the requirements, unless prior to promulgating a FIP, the state submits, and the agency approves, a SIP meeting the requirements. The Iowa Department of Natural Resources issued a SIP in August 2023 that requires operational improvements to existing control equipment at MidAmerican Energy's Louisa Generation Station and Walter Scott, Jr. Energy Center - Unit 3. Iowa submitted that plan to the EPA in fall 2023. The operational improvements were implemented beginning January 1, 2024. On August 2, 2024, the EPA proposed a rule to approve Iowa's SIP as submitted. The EPA accepted comment on the proposal through September 3, 2024. On August 5, 2025, the EPA approved Iowa's SIP for the regional haze second planning period.

Third Planning Period

On January 6, 2026, the EPA issued a final rule that moves the deadline for states to submit state implementation plans for the regional haze rule's third implementation period from July 31, 2028, to July 31, 2031. The rule pushes back the deadline in response to persistent delays by states in submitting state implementation plans, and by the EPA in approving them, for the first and second implementation periods. The second implementation phase currently underway is focused on ensuring reasonable further progress in restoring visibility to natural conditions in Class I areas – national parks and wilderness areas. The EPA deferred action on other elements including the September 2025 proposed rule, including whether to keep or extend the existing deadline of 2064 for states to attain natural visibility conditions for their Class I areas. Until the rulemaking process is complete and litigation has been exhausted, impacts on the relevant Registrants cannot be determined.

Coal Ash Disposal

In April 2015, the EPA released a final rule to regulate the management and disposal of CCR under the RCRA. The rule regulates coal combustion residuals as non-hazardous waste under RCRA Subtitle D and establishes minimum nationwide standards for the disposal of CCR. Under the final rule, surface impoundments and landfills utilized for coal combustion residuals will need to be closed unless they can meet the more stringent regulatory requirements.

On August 28, 2025, the EPA proposed to approve Wyoming's coal combustion residuals permit program. A final determination is expected in early 2026. If finalized as proposed, the state will have authority to manage disposal of coal combustion residuals in surface impoundments and landfills in Wyoming, replacing the current federal self-implementing program and bringing PacifiCorp coal ash units at Jim Bridger, Dave Johnston and Naughton under the state program. The pending approval excludes provisions related to legacy CCR units, suspension of groundwater monitoring and alternate groundwater protection standards for constituents without maximum contaminant levels. As a result, facilities must comply with both Wyoming's rules and applicable federal requirements for these excluded provisions. PacifiCorp submitted comments in support of the EPA's proposed approval of the state of Wyoming's Coal Combustion Residuals permit program by the November 3, 2025, deadline. Until the rule is finalized and litigation is exhausted, impacts on the relevant Registrants cannot be determined.

On November 28, 2025, the EPA issued a proposed rule to extend the closure deadline for certain coal combustion residuals surface impoundments operating under alternative closure provisions. The rule would defer the deadline from October 17, 2028, to October 17, 2031, to cease operation of coal-fueled boilers and complete the closure of unlined coal combustion residual surface impoundments larger than 40 acres. The subset of impoundments affected by the proposed rule are those that submitted alternative closure demonstrations in 2020 under the Part A rule. The EPA has not taken final action on the Part A demonstrations at issue in this proposed extension rule. PacifiCorp's Naughton Plan submitted a Part A demonstration in November 2020 for its South Ash Pond, which is identified as one of the potentially affected surface impoundments in the proposed rule. The EPA accepted comments on the proposed rule through February 6, 2026. Until rulemaking is complete and litigation is exhausted, impacts on the relevant Registrants cannot be determined.

Notwithstanding the status of the final CCR rule, citizens' suits have been filed against regulated entities seeking judicial relief for contamination alleged to have been caused by releases of coal combustion residuals. Some of these cases have been successful in imposing liability upon companies if coal combustion residuals contaminate groundwater that is ultimately released or connected to surface water. In addition, actions have been filed against regulated entities seeking to require that surface impoundments containing CCR be subject to closure by removal rather than being allowed to effectuate closure in place as provided under the final rule. The Registrants are not a party to these lawsuits and until they are resolved, the Registrants cannot predict the impact on overall compliance obligations.

Mandatory Climate Change Disclosures

In October 2023, California enacted three climate-related disclosure laws. Because Berkshire Hathaway Energy does business in California and exceeds certain applicability thresholds, it is subject to all three laws. Reporting under all three statutes covers Berkshire Hathaway Energy's global operations, including operating companies that otherwise do not do business in California. Under California's Voluntary Market Disclosure Act, authorized by Assembly Bill 1305, companies must make certain disclosures if they make claims in California regarding greenhouse gas emissions reductions or if they market, sell, purchase or use voluntary carbon offsets. Berkshire Hathaway Energy posted its disclosure on December 31, 2024 on its company website, with the required information concerning statements about its greenhouse gas emissions reductions. Berkshire Hathaway Energy is preparing consolidated disclosures of its scopes 1 and 2 greenhouse gas emissions and the financial risks of climate change to the business. Under California's Corporate Greenhouse Gas Reporting Program, authorized by Senate Bill 253, as amended, Scope 1 and Scope 2 emissions must be reported to California beginning in 2026. While the reporting timeline has not been finalized, the Company anticipates a compliance deadline of August 10, 2026. Scope 3 emissions are not required to be reported until 2027. Under California's Climate-Related Financial Risk Disclosure Program, authorized by Senate Bill 261, as amended, a report discussing the financial impacts of climate change to the business, consistent with the Task Force on Climate-Related Financial Disclosures (TCFD) framework, must be posted to the Company's public website by January 1, 2026. The Company is monitoring litigation challenging both SB 253 and SB 261 to assess impacts on compliance obligations. On November 18, 2025, the Ninth Circuit Court of Appeals issued an order staying enforcement of SB 261, but denied requests to stay enforcement of SB 253. The court heard oral argument in the case on January 9, 2026, and is expected to issue a decision by summer 2026.

Federal Permitting Moratoria for Renewable Energy

On January 20, 2025, the Trump Administration released a Presidential Memorandum temporarily placing a halt on offshore wind leasing and on federal permitting for onshore wind facilities. The memorandum calls for a "temporary cessation and immediate review" of federal wind permitting for onshore wind. This directive covers "new or renewed approvals, rights of way, permits, leases, or loans for onshore or offshore wind projects" pending the completion of a comprehensive assessment and review of federal wind leasing and permitting practices. The memorandum does not provide a timeline for the Secretary of the Interior to complete its review. It also does not provide any guidance on the alleged deficiencies in the permitting process that are to be addressed. Between January and August 2025, the U.S. Department of Interior ("DOI') issued a number of orders to implement the Presidential Memorandum and enact a significant federal policy shift concerning renewable energy. Seventeen states, the District of Columbia, and the Alliance for Clean Energy New York challenged the Presidential Memorandum in U.S. District Court for the District of Massachusetts. On December 8, 2025, the court found the memorandum to be arbitrary and capricious and contrary to law and directed that it be vacated in full, meaning the ruling applies nationwide. However, the various directives issued by federal agencies limited access to federal permits or increasing the regulatory requirements for wind and solar projects do not rely on the Presidential Memorandum, so the district court's order is not expected to directly affect them. On December 23, 2025, eight regional renewable energy trade associations filed suit in Massachusetts district court challenging six actions by federal agencies that have blocked or curtailed permitting for renewable energy projects and have requested a preliminary injunction of these actions. Applicable to the relevant Registrants, the challenged administrative actions include the DOI's policy requiring review and approval by three of the department's most senior officials for each discretionary action related to wind and solar projects; a memorandum from the Corps requiring consideration of capacity density when reviewing applications for individual permits under Section 404 of the Clean Water Act and Section 10 of the Rivers and Harbors Act; and the U.S. Fish and Wildlife Service's prohibition on wind facilities obtaining permits authorizing the take of eagles under the Bald and Golden Eagle Protection Act. Until litigation is exhausted, impacts on the relevant Registrants cannot be determined.

Other

Other laws, regulations and agencies to which the relevant Registrants are subject include, but are not limited to:

- The federal Comprehensive Environmental Response, Compensation and Liability Act and similar state laws may require any current or former owners or operators of a disposal site, as well as transporters or generators of hazardous substances sent to such disposal site, to share in environmental remediation costs. Certain Registrants have been identified as potentially responsible parties in connection with certain disposal sites. The relevant Registrants have completed several cleanup actions and are participating in ongoing investigations and remedial actions. Costs associated with these actions are not expected to be material and are expected to be found prudent and included in rates.

- The Nuclear Waste Policy Act of 1982, under which the DOE is responsible for the selection and development of repositories for, and the permanent disposal of, spent nuclear fuel and high-level radioactive wastes. Refer to Note 14 of the Notes to Consolidated Financial Statements of Berkshire Hathaway Energy in Item 8 of this Form 10-K and Note 11 of the Notes to Financial Statements of MidAmerican Energy in Item 8 of this Form 10-K for additional information regarding MidAmerican Energy's nuclear decommissioning obligations.
- The federal Surface Mining Control and Reclamation Act of 1977 and similar state statutes establish operational, reclamation and closure standards that must be met during and upon completion of PacifiCorp's mining activities.
- The FERC evaluates hydroelectric systems to ensure environmental impacts are minimized, including the issuance of environmental impact statements for licensed projects both initially and upon relicensing. The FERC monitors the hydroelectric facilities for compliance with the license terms and conditions, which include environmental provisions. Refer to Note 14 of the Notes to Consolidated Financial Statements of PacifiCorp in Item 8 of this Form 10-K for information regarding PacifiCorp's Klamath River hydroelectric system.

The Registrants expect they will be allowed to recover their respective prudently incurred costs to comply with the environmental laws and regulations discussed above. The Registrants' planning efforts take into consideration the complexity of balancing factors such as: (a) pending environmental regulations and requirements to reduce emissions, address waste disposal, ensure water quality and protect wildlife; (b) avoidance of excessive reliance on any one generation technology; (c) costs and trade-offs of various resource options including energy efficiency, demand response programs and renewable generation; (d) state-specific energy policies, resource preferences and economic development efforts; (e) additional transmission investment to reduce power costs and increase efficiency and reliability of the integrated transmission system; and (f) keeping rates affordable. Due to the number of generating units impacted by environmental regulations, deferring installation of compliance-related projects is often not feasible or cost effective and places the Registrants at risk of not having access to necessary capital, material, and labor while attempting to perform major equipment installations in a compressed timeframe concurrent with other utilities across the country. Therefore, the Registrants have established installation schedules with permitting agencies that coordinate compliance timeframes with construction and tie-in of major environmental compliance projects as units are scheduled off-line for planned maintenance outages; these coordinated efforts help reduce costs associated with replacement power and maintain system reliability.

Item 1A. Risk Factors

Each Registrant is subject to numerous risks and uncertainties, including, but not limited to, those described below. Careful consideration of these risks, together with all of the other information included in this Form 10-K and the other public information filed by the relevant Registrant, should be made before making an investment decision. Additional risks and uncertainties not presently known or which each Registrant currently deems immaterial may also impair its business operations. Unless stated otherwise, the risks described below generally relate to each Registrant.

Liquidity, Capital Requirements and Corporate Structure Risks

BHE and EEGH are holding companies and depend on distributions from subsidiaries, including joint ventures, to meet their obligations.

BHE and EEGH are holding companies with no material assets other than the investment interests in their subsidiaries and joint ventures, collectively referred to as subsidiaries. Accordingly, the cash flows of BHE and EEGH and the ability to meet their obligations are largely dependent upon the earnings of their respective subsidiaries and the payment of such earnings to BHE or EEGH in the form of dividends or other distributions. As a result of material wildfire litigation at PacifiCorp, no dividends will be paid to BHE by PacifiCorp over the next several years, which could impact BHE's ability to fund its operations, make interest payments, fund debt maturities and increase BHE's reliance on debt.

Prior to funding the obligations of BHE or EEGH, their respective subsidiaries, including the Subsidiary Registrants, have financial obligations and certain regulatory restrictions that must be satisfied. Each respective subsidiary is a separate and distinct legal entity and has no obligation, contingent or otherwise, to pay amounts due pursuant to BHE's or EEGH's debt or other obligations, or to make funds available, whether by dividends or other payments, for the payment of amounts due pursuant to BHE's or EEGH's debt or other obligations, and do not guarantee the payment of any of BHE's or EEGH's obligations. Distributions from subsidiaries may also be limited by:

- PacifiCorp's liquidity concerns resulting from wildfire litigation (described below);
- their respective earnings, capital requirements, and required debt payments;
- the satisfaction of certain terms contained in financing, ring-fencing or organizational documents; and
- regulatory restrictions that limit the ability of BHE's regulated utility subsidiaries to distribute profits.

The Registrants are substantially leveraged, the terms of their existing debt do not restrict the incurrence of additional debt by BHE or its subsidiaries, including the Subsidiary Registrants, and BHE's debt is structurally subordinated to the debt of its subsidiaries, including the Subsidiary Registrants, and each of such factors could adversely affect the Registrants' financial results.

A significant portion of BHE's capital structure is comprised of debt, and BHE expects to incur additional debt in the future to fund items such as, among others, acquisitions, capital investments and the development and construction of new or expanded facilities. As of December 31, 2025, BHE had the following outstanding obligations:

- senior unsecured debt of $11.5 billion;
- commercial paper borrowings of $— million; and
- guarantees, letters of credit and surety bonds in respect of subsidiaries, equity method investments and other related parties aggregating $3.9 billion.

BHE's consolidated subsidiaries, including the Subsidiary Registrants, also have significant amounts of outstanding debt, which totaled $47.8 billion as of December 31, 2025, and expect to incur additional debt in the future to fund items such as, among others, acquisitions, capital investments and the development and construction of new or expanded facilities. These amounts exclude (a) trade debt, (b) preferred stock obligations, (c) letters of credit in respect of subsidiary debt, and (d) BHE's share of the outstanding debt of its own or its subsidiaries' equity method investments. PacifiCorp may also incur additional debt in the future in response to impacts associated with wildfire litigation as described under "PacifiCorp Wildfire Litigation Related Risks" below.

Given each Registrant's substantial leverage, a Registrant may not have sufficient cash to service its debt, which could limit its ability to finance future acquisitions, develop and construct additional projects, or operate successfully under difficult conditions, including those brought on by adverse national and global economies, unfavorable financial markets or growth

conditions where its capital needs may exceed its ability to fund them. Each Registrant's leverage could also impair its credit quality or the credit quality of its subsidiaries, making it more difficult to finance operations or issue future debt on favorable terms, and could result in a downgrade in debt ratings by credit rating agencies. Refer to "PacifiCorp Wildfire Litigation Risks" below for additional information regarding PacifiCorp.

The terms of BHE's and its subsidiaries' debt, including the Subsidiary Registrants, do not limit BHE's ability or the ability of its subsidiaries to incur additional debt or issue preferred stock. Accordingly, BHE or its subsidiaries could enter into acquisitions, new financings, refinancings, recapitalizations, leases or other highly leveraged transactions that could significantly increase BHE's or its subsidiaries' total amount of outstanding debt. The interest payments needed to service this increased level of debt could adversely affect BHE's or its subsidiaries' financial results. Many of BHE's subsidiaries' debt agreements contain covenants, or may in the future contain covenants, that restrict or limit, among other things, such subsidiaries' ability to create liens, sell assets, make certain distributions, incur additional debt or miss contractual deadlines or requirements, and BHE's ability to comply with these covenants may be affected by events beyond its control. Further, if an event of default accelerates a repayment obligation and such acceleration results in an event of default under some or all of BHE's other debt, BHE may not have sufficient funds to repay all of the accelerated debt simultaneously, and the other risks described under "Corporate and Financial Structure Risks" may be magnified as well.

Because BHE is a holding company, the claims of its debt holders are structurally subordinated with respect to the assets and earnings of its subsidiaries. Therefore, the rights of its creditors to participate in the assets of any subsidiary in the event of a liquidation or reorganization are subject to the prior claims of the subsidiary's creditors and preferred shareholders, if any. In the event of default due to the bankruptcy, insolvency, or reorganization of a significant subsidiary, all of BHE's debt will become immediately due. In addition, pursuant to separate financing agreements, substantially all of PacifiCorp's electric utility properties, MidAmerican Energy's electric utility properties in the state of Iowa, Nevada Power's and Sierra Pacific's properties in the state of Nevada, AltaLink's transmission properties, the equity interest of MidAmerican Funding's subsidiary and substantially all of the assets of the subsidiaries of BHE Renewables that are direct or indirect owners of solar and wind generation projects, are directly or indirectly pledged to secure their financings and, therefore, may be unavailable as potential sources of repayment of BHE's debt.

A downgrade in BHE's credit ratings or the credit ratings of its subsidiaries, could negatively affect BHE's or its subsidiaries' access to capital, increase the cost of borrowing or raise energy transaction credit support requirements.

BHE's senior unsecured debt and its subsidiaries' long-term debt, including the Subsidiary Registrants, are rated by various rating agencies. BHE cannot give assurance that its senior unsecured debt rating or any of its subsidiaries' long-term debt ratings will not be reduced in the future. Although none of the Registrants' outstanding debt has rating-downgrade triggers that would accelerate a repayment obligation, a credit rating downgrade would increase any such Registrant's borrowing costs and commitment fees on its revolving credit agreements and other financing arrangements, perhaps significantly. In addition, such Registrant would likely be required to pay a higher interest rate in future financings, the potential pool of investors would likely decrease and depending on the rating, require some investors to sell the Registrants' bonds. Further, access to the commercial paper market could be significantly limited, resulting in higher interest costs.

Similarly, any downgrade, change in rating methodology impacting subsidiaries credit rating, placement on negative outlook or credit watch or other event negatively affecting the credit ratings of BHE's subsidiaries could make their costs of borrowing higher or access to funding sources more limited, which in turn could cause BHE to provide liquidity in the form of capital contributions or loans to such subsidiaries, thus reducing its and its subsidiaries' liquidity and borrowing capacity; however BHE is not obligated to provide liquidity to its subsidiaries.

Most of the Registrants' large wholesale customers, suppliers and counterparties require such Registrant to have sufficient creditworthiness in order to enter into transactions, particularly in the wholesale energy markets. If the credit ratings of a Registrant were to decline, especially below investment grade, the relevant Registrant's financing costs and borrowings would likely increase because certain counterparties may require collateral in the form of cash, a letter of credit or some other form of security for existing transactions and as a condition to entering into future transactions with such Registrant. Amounts could be material and could adversely affect such Registrant's liquidity and cash flows.

Refer to "PacifiCorp Wildfire Litigation Related Risks" section below for additional information regarding PacifiCorp.

Disruptions in the financial markets could affect each Registrant's ability to obtain debt financing or to draw upon or renew existing credit facilities and have other adverse effects on each Registrant.

Disruptions in the financial markets could affect each Registrant's ability to obtain debt financing or to draw upon or renew existing credit facilities and have other adverse effects on each Registrant. Significant dislocations and liquidity disruptions in the U.S., Great Britain, Canada and global credit markets, such as those that occurred in 2008, 2009 and 2020, may materially impact liquidity in the bank and debt capital markets, making financing terms less attractive for borrowers that are able to find financing and, in other cases, may cause certain types of debt financing, or any financing, to be unavailable. Additionally, economic uncertainty in the U.S. or globally may adversely affect the U.S. credit markets and could negatively impact each Registrant's ability to access funds on favorable terms or at all. If a Registrant is unable to access the bank and debt markets to meet liquidity and capital expenditure needs, it may adversely affect the timing and amount of its capital expenditures, acquisition financing and its financial results.

Poor performance of plan and fund investments and other factors impacting the pension and other postretirement benefit plans and nuclear decommissioning and mine reclamation trust funds could unfavorably impact each Registrant's cash flows, liquidity and financial results.

Costs of providing each Registrant's defined benefit pension and other postretirement benefit plans and costs associated with the joint trustee plan to which PacifiCorp contributes depend upon a number of factors, including the rates of return on plan assets, the level and nature of benefits provided, discount rates, mortality assumptions, the interest rates used to measure required minimum funding levels, the funded status of the plans, changes in benefit design, tax deductibility and funding limits, changes in laws and government regulation and each Registrant's required or voluntary contributions made to the plans. Furthermore, the timing of recognition of unrecognized gains and losses associated with the Registrants' defined benefit pension plans is subject to volatility due to events that may give rise to settlement accounting. Settlement events resulting from lump sum distributions offered by certain of the Registrants' defined benefit pension plans are influenced by the interest rates used to discount a participant's lump sum distribution. When the applicable interest rates are low, lump sum distributions in a given year tend to increase resulting in a higher likelihood of triggering settlement accounting.

If the Registrant's pension or other postretirement benefit plans are in underfunded positions, the respective Registrant may be required to make cash contributions to fund such underfunded plans in the future. Additionally, each Registrant's plans have investments in domestic and foreign equity and debt securities and other investments that are subject to the risk of loss. Losses from investments could add to the volatility, size and timing of future contributions.

Furthermore, the funded status of the UMWA 1974 Pension Plan multiemployer plan to which PacifiCorp's subsidiary previously contributed is considered critical and declining. PacifiCorp's subsidiary involuntarily withdrew from the UMWA 1974 Pension Plan in June 2015 when the UMWA employees ceased performing work for the subsidiary. PacifiCorp has recorded its best estimate of the withdrawal obligation.

In addition, MidAmerican Energy is required to fund over time the projected costs of decommissioning Quad Cities Station, a nuclear generating facility, and Bridger Coal Company, a joint venture of PacifiCorp's subsidiary, Pacific Minerals, Inc., is required to fund projected mine reclamation costs. The funds that MidAmerican Energy has invested in a nuclear decommissioning trust and a subsidiary of PacifiCorp has invested in a mine reclamation trust are invested in debt and equity securities and poor performance of these investments will reduce the amount of funds available for their intended purpose, which could require MidAmerican Energy or PacifiCorp's subsidiary to make additional cash contributions. As contributions to the trust are being made over the operating life of the respective facility, reductions in the expected operating life of the facility could also require MidAmerican Energy and PacifiCorp's subsidiary to make additional contributions to the related trust. Such cash funding obligations, which are also impacted by the other factors described above, could have a material impact on MidAmerican Energy's or PacifiCorp's liquidity by reducing their available cash. Additionally, PacifiCorp's mine reclamation obligation for Bridger Coal Company is secured by a surety bond. Refer to "PacifiCorp Wildfire Litigation Related Risks" below for additional information regarding PacifiCorp.

BHE's shareholder, Berkshire Hathaway, could exercise control over BHE in a manner that would benefit Berkshire Hathaway to the detriment of BHE's creditors and BHE could exercise control over the Subsidiary Registrants in a manner that would benefit BHE to the detriment of the Subsidiary Registrants' creditors.

Berkshire Hathaway holds all of the common stock of BHE and has control over all decisions requiring shareholder approval. In circumstances involving a conflict of interest between Berkshire Hathaway and BHE's creditors, Berkshire Hathaway could exercise its control in a manner that would benefit Berkshire Hathaway to the detriment of BHE's creditors.

BHE indirectly holds all of the common stock of PacifiCorp, Nevada Power, Sierra Pacific and EGTS and the membership interest in Eastern Energy Gas. BHE is also the sole member of MidAmerican Funding and, accordingly, indirectly holds all of MidAmerican Energy's common stock. As a result, BHE has control over all decisions requiring shareholder approval, including the election of directors. In circumstances involving a conflict of interest between BHE and the creditors of the Subsidiary Registrants, BHE could exercise its control in a manner that would benefit BHE to the detriment of the Subsidiary Registrants' creditors.

PacifiCorp Wildfire Litigation Related Risks

PacifiCorp's litigation risk associated with the Wildfires and the potential impacts of CMO NO. 11 are inherently uncertain and the ultimate outcomes of the associated claims and the James appeals could materially and adversely affect PacifiCorp's financial condition and results of operations and its ability to obtain financing, to fund its operations, capital investments and settlements arising from the Wildfires.

Wildfire Litigation

A substantial number of complaints and demands associated with the 2020 Wildfires have been filed in Oregon and California, including the *James* class action complaint, for which a June 2023 Jury verdict found PacifiCorp's conduct grossly negligent, reckless and willful. Additionally, multiple complaints associated with the 2022 McKinney Fire have been filed in California. PacifiCorp may be subject to additional complaints and demands (collectively "actions") associated with the Wildfires and additional plaintiffs may be added to the *James* class action complaint. The amounts specified in the original filed actions do not limit the amount of damages that ultimately may be awarded in a court proceeding; therefore PacifiCorp's liability for damages could be substantially greater than the original amounts specified and its estimated losses. While certain settlements associated with the Wildfires have occurred, PacifiCorp cannot be certain that additional settlements can be achieved on terms it finds reasonable, if at all.

PacifiCorp has and intends to appeal adverse decisions associated with the Wildfires, and while final determination of its liability could take several years, the Multnomah County Circuit Court Oregon granted PacifiCorp's motion for expedited oral argument in the *James* appeal. Refer to Item 3. Legal Proceedings, BHE's Note 16 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K and PacifiCorp's Note 14 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information on the Wildfires, including settlement activities, *James* verdicts, CMO No. 11 and the pending *James* appeals.

Liquidity and Potential Impacts of CMO No. 11

As a result of the litigation risk and estimated losses recorded to date associated with the Wildfires, PacifiCorp's liquidity has been materially impacted and its credit ratings have been downgraded. Based on the volume of *James* damages phase trials scheduled under Multnomah County Circuit Court Oregon in CMO No. 11, combined with the requirement to bond judgments for each verdict and potential additional impacts on PacifiCorp's credit rating, PacifiCorp may be unable to obtain the necessary funding to meet its liquidity needs.

While judgments awarded in *James* to date have been supported by surety bonds, they can also be supported by posting letters of credit or cash. PacifiCorp estimates damages awarded in additional *James* jury verdicts will exceed its available surety bond and letter of credit capacity, requiring cash bonding thereafter. PacifiCorp expects additional debt financings, including potential borrowings under its $2.0 billion credit facility to the extent available, or other sources of funding will be needed to provide liquidity to post cash for judgments. These bonding requirements will weaken PacifiCorp's credit metrics, which could result in a downgrade of PacifiCorp's senior secured debt to below investment grade. Such a downgrade may result in the loss of surety bond and letter of credit capacity, trigger cash collateral calls for surety bonds posted and trigger cash collateral calls or other forms of security for wholesale energy agreements that contain credit risk-related contingent features or rights to demand adequate assurance in the event of a material adverse change in PacifiCorp's creditworthiness. Additionally, a downgrade of PacifiCorp's senior secured debt below investment grade would require new regulatory applications and approvals due to certain authorizations or exemptions currently in place with certain regulatory commissions for the issuance of securities. PacifiCorp may also be subject to borrowing limitations under its long-term debt covenants.

In the event of a downgrade below investment grade and the caseload under CMO No. 11 progresses as scheduled, PacifiCorp may be unable to secure sufficient debt financings or alternative funding sources to support ongoing operations, including the ability to absorb wholesale power volatility, pay suppliers and meet debt obligations, and such liquidity issues may impact transmission and generation development, purchasing power in the market, building and upgrading substations, connecting new customers, addressing outages and maintaining system resilience. Investors in PacifiCorp's first mortgage bonds may be unable

to hold existing bonds or to invest in new bonds, and perceived risks associated with the Wildfires may limit PacifiCorp's ability to attract investors. At a minimum, the cost of any short- or long-term financing is expected to be higher as a result of the wildfire litigation risks and decline in PacifiCorp's credit ratings.

Refer to Item 7 "Liquidity and Capital Resources" for further information regarding the liquidity impacts arising from the Wildfires.

Regulatory, Legislative and Legal Risks

Each Registrant may be subject to extensive federal, state, local and foreign legislation and regulation, including numerous environmental, health, safety, reliability, data privacy and other laws and regulations that may affect its operations and costs. These laws and regulations are complex, dynamic and subject to new interpretations or change. In addition, new laws and regulations, including, but not limited to, initiatives regarding deregulation and restructuring of the utility industry, are continually being proposed and enacted that may impose new or revised requirements or standards on each Registrant.

Each Registrant is required to comply with numerous federal, state, local or foreign laws and regulations as described in "General Regulation" and "Environmental Laws and Regulations" in Item 1 of this Form 10-K that have broad application to each Registrant and limits the respective Registrant's ability to independently make and implement management decisions regarding, among other items, acquiring businesses; constructing, acquiring, disposing or retiring operating assets; operating and maintaining generating facilities and transmission and distribution system assets; complying with pipeline safety and integrity and environmental requirements; setting rates charged to customers; establishing capital structures and issuing debt or equity securities; managing and reporting transactions between subsidiaries and affiliates; and paying dividends or similar distributions. These laws and regulations, which are followed in developing the Registrants' safety and compliance programs and procedures, are implemented and enforced by federal, state and local regulatory agencies, such as the Occupational Safety and Health Administration, the FERC, the EPA, the DOT, the NRC, the Federal Mine Safety and Health Administration and various state regulatory commissions in the U.S., and by foreign regulatory agencies, such as GEMA, which discharges certain of its powers through its staff within Ofgem, in Great Britain and the AUC in Alberta, Canada.

Compliance with applicable laws and regulations generally requires each Registrant to obtain and comply with a wide variety of licenses, permits, inspections, audits and other approvals. Further, compliance with laws and regulations can require significant capital and operating expenditures, including expenditures for new equipment, inspection, cleanup costs, removal and remediation costs and damages arising out of contaminated properties. Compliance activities pursuant to existing or new laws and regulations could be prohibitively expensive or otherwise uneconomical. As a result, each Registrant could be required to shut down some facilities or materially alter its operations. Further, each Registrant may not be able to obtain or maintain all required environmental or other regulatory approvals and permits for its operating assets or development projects. Delays in, or active opposition by third parties to, obtaining any required environmental or regulatory authorizations or failure to comply with the terms and conditions of the authorizations may increase costs or prevent or delay each Registrant from operating its facilities, developing or favorably locating new facilities or expanding existing facilities. If any Registrant fails to comply with any environmental or other regulatory requirements, such Registrant may be subject to penalties and fines or other sanctions, including changes to the way its electricity generating facilities are operated that may adversely impact generation or how the Pipeline Companies are permitted to operate their systems that may adversely impact throughput. The costs of complying with laws and regulations could adversely affect each Registrant's financial results. Not being able to operate existing facilities or develop new generating facilities to meet customer electricity needs could require such Registrant to increase its purchases of electricity on the wholesale market, which could increase market and price risks and adversely affect such Registrant's financial results.

Existing laws and regulations, while comprehensive, are subject to changes and revisions from ongoing policy initiatives by legislators and regulators and to interpretations that may ultimately be resolved by the courts. For example, changes in laws and regulations could result in, but are not limited to, increased competition and decreased revenue within each Registrant's service territories; new environmental or climate-related requirements; RPS and GHG emissions reduction goals; the issuance of new or stricter air quality standards; the implementation of energy efficiency mandates; the issuance of regulations governing the management and disposal of coal combustion byproducts; changes in forecasting requirements; changes to each Registrant's service territories as a result of condemnation or takeover by municipalities or other governmental entities, particularly where it lacks the exclusive right to serve its customers; the inability of each Registrant to recover its costs on a timely basis, if at all; new pipeline safety requirements; or a negative impact on each Registrant's current cost recovery arrangements. In addition to changes in existing legislation and regulation, new laws and regulations are likely to be enacted from time to time that impose additional or new requirements or standards on each Registrant. Adverse rulings in GHG-related cases could result in increased or changed regulations and could increase costs for GHG emitters, including the Registrants' generating facilities. The GHG

rules, changes to those rules, and the Registrants' compliance requirements are subject to potential outcomes from proceedings and litigation challenging the rules.

New federal, regional, state and international accords, legislation, regulation, or judicial proceedings limiting GHG emissions could have a material adverse impact on the Registrants, the U.S. and the global economy. Companies and industries with higher GHG emissions, such as utilities with significant coal-fueled generating facilities, will be subject to more direct impacts and greater financial and regulatory risks. The impact is dependent on numerous factors, none of which can be meaningfully quantified at this time. These factors include, but are not limited to, the magnitude and timing of GHG emissions reduction requirements; the design of the requirements; the cost, availability and effectiveness of emissions control technology; the price, distribution method and availability of offsets and allowances used for compliance; government-imposed compliance costs; and the existence and nature of incremental cost recovery mechanisms. Examples of how new requirements may impact the Registrants include:

- Additional costs may be incurred to purchase required emissions allowances under any market-based cap-and-trade system in excess of allocations that are received at no cost. These purchases would be necessary until new technologies could be developed and deployed to reduce emissions or lower carbon generation is available;
- Acquiring and renewing construction and operating permits for new and existing generating facilities may be costly and difficult;
- Additional costs may be incurred to purchase and deploy new generating technologies;
- Costs may be incurred to retire existing coal-fueled generating facilities before the end of their otherwise useful lives or to convert them to burn fuels, such as natural gas or biomass, that result in lower emissions;
- Operating costs may be higher and generating unit outputs may be lower;
- Higher interest and financing costs and reduced access to capital markets may result to the extent that financial markets view climate change and GHG emissions as a greater business risk; and
- The relevant Registrant's natural gas pipeline operations and capacity sales, electric transmission and retail sales may be impacted in response to changes in customer demand and requirements to reduce GHG emissions.

The impact of events or conditions caused by climate change, whether from natural processes or human activities, are uncertain and could vary widely, from highly localized to worldwide, and the extent to which a utility's operations may be affected is uncertain. Climate change may cause physical and financial risks through, among other things, sea level rise, changes in precipitation and extreme weather events. Consumer demand for energy may increase or decrease, based on overall changes in weather and as customers promote lower energy consumption through the continued use of energy efficiency programs or other means. Availability of resources to generate electricity, such as water for hydroelectric production and cooling purposes, may also be impacted by climate change and could influence the Registrants' existing and future electricity generating portfolio. These issues may have a direct impact on the costs of electricity production and increase the price customers pay or their demand for electricity.

Implementing actions required under, and otherwise complying with, new federal and state laws and regulations and changes in existing ones are among the most challenging aspects of managing utility operations. The Registrants cannot accurately predict the type or scope of future laws and regulations that may be enacted, changes in existing ones or new interpretations by agency orders or court decisions, nor can each Registrant determine their impact on it at this time; however, any one of these could adversely affect each Registrant's financial results through higher capital expenditures and operating costs, early closure of generating facilities or lower tax benefits or restrict or otherwise cause an adverse change in how each Registrant operates its business. To the extent that each Registrant is not allowed by its regulators to recover or cannot otherwise recover the costs to comply with new laws and regulations or changes in existing ones, the costs of complying with such additional requirements could have a material adverse effect on the relevant Registrant's financial results. Additionally, even if such costs are recoverable in rates, if they are substantial and result in rates increasing to levels that substantially reduce customer demand, this could have a material adverse effect on the relevant Registrant's financial results.

Recovery of costs and certain activities by each Registrant is subject to regulatory review and approval, and the inability to recover costs or undertake certain activities may adversely affect each Registrant's financial results.

State Regulatory Rate Review Proceedings

The Utilities establish rates for their regulated retail services through state regulatory proceedings. These proceedings typically involve multiple parties, including government bodies and officials, consumer advocacy groups and various consumers of energy, who have differing concerns but generally have the common objective of limiting rate increases or requesting rate decreases while also requiring the Utilities to ensure system reliability. Decisions are subject to judicial appeal, potentially leading to further uncertainty associated with the approval proceedings.

States set retail rates for consumers within their jurisdiction based in part upon the state regulatory commission's acceptance of an allocated share of total utility costs. When states adopt different methods to calculate interjurisdictional cost allocations, some costs may not be incorporated into rates of any state or other jurisdiction. Ratemaking is also generally done on the basis of estimates of normalized costs, so if a given year's realized costs are higher than normalized costs, rates may not be sufficient to cover those costs. In some cases, actual costs are lower than the normalized or estimated costs recovered through rates and from time-to-time may result in a state regulator requiring refunds to customers. Each state regulatory commission generally sets rates based on a test year established in accordance with that commission's policies. The test year data adopted by each state regulatory commission may create a lag between the incurrence of a cost and its recovery in rates. Each state regulatory commission also decides the allowed levels of expense, investment and capital structure that it deems are prudently incurred in providing the service and may disallow recovery in rates for any costs that it believes do not meet such standard. Additionally, each state regulatory commission establishes the allowed rate of return the Utilities will be given an opportunity to earn on their sources of capital. While rate regulation is premised on providing a fair opportunity to earn a reasonable rate of return on invested capital, the state regulatory commissions do not guarantee that each Registrant will be able to realize the allowed rate of return or recover all of its costs even if it believes such costs to be prudently incurred.

Some state regulatory commissions have authorized recovery of certain costs above the level assumed in establishing base rates through adjustment mechanisms, which may be subject to customer sharing. Any significant increase in fuel costs for electricity generation or purchased electricity costs could have a negative impact on the Utilities, despite efforts to minimize this impact through the use of hedging contracts and adjustment mechanisms or through future general regulatory rate reviews. Further, interjurisdictional cost allocation constraints could limit PacifiCorp's ability to recover such costs despite the adjustment mechanisms. Any of these consequences could adversely affect each Registrant's financial results.

FERC and Other Jurisdictions

The FERC authorizes cost-based rates associated with transmission services provided by the Utilities' transmission facilities. Under the Federal Power Act, the Utilities, or MISO as it relates to MidAmerican Energy, may voluntarily file, or may be obligated to file, for changes, including general rate changes, to their system-wide transmission service rates. General rate changes implemented may be subject to refund. The FERC also has responsibility for approving both cost- and market-based rates under which the Utilities sell electricity in the wholesale market, has jurisdiction over most of PacifiCorp's hydroelectric generating facilities and has broad jurisdiction over energy markets. The FERC may impose price limitations, bidding rules and other mechanisms to address some of the volatility of these markets or could revoke or restrict the ability of the Utilities to sell electricity at market-based rates, which could adversely affect each Registrant's financial results. The FERC also maintains rules concerning standards of conduct, affiliate restrictions, interlocking directorates and cross-subsidization. As a transmission owning member of MISO, MidAmerican Energy is also subject to MISO-directed modifications of market rules, which are subject to FERC approval and operational procedures. As participants in EIM, PacifiCorp, Nevada Power and Sierra Pacific are also subject to applicable California ISO rules, which are subject to FERC approval and operational procedures. The FERC may also impose substantial civil penalties for any non-compliance with the Federal Power Act and the FERC's rules and orders.

The NERC has standards in place to ensure the reliability of the electric generation system and transmission grid. The Utilities are subject to the NERC's regulations and periodic audits to ensure compliance with those regulations. The NERC may carry out enforcement actions for non-compliance and administer significant financial penalties, subject to the FERC's review.

The FERC has jurisdiction over, among other things, the construction, abandonment, modification and operation of natural gas pipelines and related facilities used in the transportation, storage and sale of natural gas in interstate commerce, including all rates, charges and terms and conditions of service. The FERC also has market transparency authority and has adopted additional reporting and internet posting requirements for natural gas pipelines and buyers and sellers of natural gas.

Rates for the interstate natural gas transmission and storage operations at the Pipeline Companies, which include reservation, commodity, surcharges, fuel and gas lost and unaccounted for charges, are authorized by the FERC. In accordance with the FERC's ratemaking principles, the Pipeline Companies' current maximum tariff rates are designed to recover prudently incurred costs included in their pipeline systems' regulatory cost of service that are associated with the construction, operation and maintenance of their pipeline systems and to afford the Pipeline Companies an opportunity to earn a reasonable rate of return. Nevertheless, the rates the FERC authorizes the Pipeline Companies to charge their customers may not be sufficient to recover the costs incurred to provide services in any given period. Moreover, from time to time, the FERC may change, alter or refine its policies or methodologies for establishing pipeline rates and terms and conditions of service. In addition, the FERC has the authority under Section 5 of the NGA to investigate whether a pipeline may be earning more than its allowed rate of return and, when appropriate, to institute proceedings against such pipeline to prospectively reduce rates. Any such proceedings, if instituted, could result in significantly adverse rate decreases.

Under FERC policy, interstate pipelines and their customers may execute contracts at negotiated rates, which may be above or below the maximum tariff rate for that service or the pipeline may agree to provide a discounted rate, which would be a rate between the maximum and minimum tariff rates. In a rate proceeding, rates in these contracts are generally not subject to adjustment. It is possible that the cost to perform services under negotiated or discounted rate contracts will exceed the cost used in the determination of the negotiated or discounted rates, which could result either in losses or lower rates of return for providing such services. Under certain circumstances, FERC policy allows interstate natural gas pipelines to design new maximum tariff rates to recover such costs in regulatory rate reviews. However, with respect to discounts granted to affiliates, the interstate natural gas pipeline must demonstrate that the discounted rate was necessary in order to meet competition.

The Northern Powergrid Distribution Companies, as DNOs and holders of electricity distribution licenses, are subject to regulation by GEMA. Most of the revenue of a DNO is controlled by a distribution price control formula set out in the electricity distribution license. The price control formula does not directly constrain profits from year-to-year but is a control on revenue that operates independent of a significant portion of the DNO's actual costs. A resetting of the formula does not require the consent of the DNO, but if a licensee disagrees with a change to its license, it can appeal the matter to the United Kingdom's CMA. GEMA is able to impose financial penalties on DNOs that contravene any of their electricity distribution license duties or certain of their duties under British law or fail to achieve satisfactory performance of individual standards prescribed by GEMA. Any penalty imposed must be reasonable and may not exceed 10% of the DNO's revenue. During the term of any price control, additional costs have a direct impact on the financial results of the Northern Powergrid Distribution Companies.

The AUC is an independent, quasi-judicial agency established by the province of Alberta, Canada, which is responsible for, among other things, approving the tariffs of transmission facility owners, including AltaLink, and distribution utilities, acquisitions of such transmission facility owners or utilities, and construction and operation of new transmission projects in Alberta. The AUC also investigates and rules on regulated rate disputes, system access problems and market participant conduct.

The AUC regulates and oversees Alberta's electricity transmission sector with broad authority that may impact many of AltaLink's activities, including its tariffs, rates, construction, operations and financing. In addition, AUC approval is required in connection with new energy and regulated utility initiatives in Alberta, amendments to existing approvals and financing proposals by designated utilities.

Each Registrant is involved in a variety of legal proceedings, the outcomes of which are uncertain and could adversely affect its financial results.

Each Registrant is, and in the future may become, a party to a variety of legal proceedings. Litigation is subject to many uncertainties, and the Registrants cannot predict the outcome of individual matters with certainty. It is possible that the final resolution of some of the matters in which each Registrant is involved could result in additional material payments substantially in excess of established liabilities or in terms that could require each Registrant to change business practices and procedures or divest ownership of assets. Further, litigation could result in the imposition of operational or financial penalties or injunctions and adverse regulatory consequences, any of which could limit each Registrant's ability to take certain desired actions or the denial of needed permits, licenses or regulatory authority to conduct its business, including the siting, operation or permitting of facilities. Unfavorable judgments could also require posting of surety bonds as security until the amounts awarded to plaintiffs are paid or the judgment is overturned in the appeals process. To the extent the Registrant or affected subsidiary is unable to post such a bond, other forms of security may be required such as cash or letters of credit that could reduce borrowing capacity under credit facility agreements. Any of these outcomes could have a material adverse effect on such Registrant's or BHE's financial results. Refer to "PacifiCorp Wildfire Litigation Related Risks" above for additional information regarding PacifiCorp's wildfire litigation risks.

Operational and Development Risks

The Registrants are subject to operating uncertainties and events beyond each respective Registrant's control that impact the costs to operate, maintain, repair and replace utility and interstate natural gas pipeline systems and the ability to self-insure many risks, which could adversely affect each respective Registrant's financial results.

The operation of complex utility systems or interstate natural gas pipeline and storage systems that are spread over large geographic areas involves many operating uncertainties and events beyond each respective Registrant's control. These potential events include the breakdown or failure of the Registrants' thermal, nuclear, hydroelectric, solar, wind and other electricity generating facilities and related equipment, compressors, pipelines, transmission and distribution lines and associated electric operations equipment or other equipment or processes, which could lead to catastrophic events; unscheduled outages; coal supply challenges occurring as a result of the transition away from coal-fueled resources; strikes, lockouts, other labor-related actions or shortages of qualified labor, including with respect to the Registrants' suppliers and vendors; transmission and distribution system constraints; failure to obtain, renew or maintain rights-of-way, easements and leases on U.S. federal, Native American, First Nations or tribal lands; terrorist activities or military or other actions, including physical or cyber attacks; fuel shortages or interruptions; unavailability of critical equipment, materials and supplies; low water flows and other weather-related impacts; performance below expected levels of output, capacity or efficiency; operator error; third-party excavation errors; unexpected degradation of transmission lines, pipeline systems or storage reservoirs; design, construction or manufacturing defects; and catastrophic events such as severe storms, floods, fires, extreme temperature events, wind events, earthquakes, explosions, landslides, an electromagnetic pulse, mining incidents, costly litigation, wars, terrorism, pandemics and embargoes. A catastrophic event might result in injury or loss of life, extensive property damage, environmental or natural resource damages or excessive economic loss. For example, in the event of an uncontrolled release of water at one of PacifiCorp's high hazard potential hydroelectric dams, it is probable that loss of human life, disruption of lifeline facilities and property damage could occur in the downstream population and civil or other penalties could be imposed by the FERC. The extent of that liability would be determined by the applicable state law where any such damage occurred. Any of these events or other operational events could significantly reduce or eliminate the relevant Registrant's revenue or significantly increase its expenses, thereby reducing the availability of distributions to BHE. For example, if the relevant Registrant cannot operate its electricity or natural gas facilities at full capacity due to damage caused by a catastrophic event or due to supply constraints, its revenue could decrease and its expenses could increase due to the need to obtain energy from more expensive sources.

The Registrants self-insure many risks, and current and future insurance coverage may not be sufficient to replace lost revenue or cover repair and replacement costs or other damages. Further, third-party liability insurance coverage may be costly or unavailable as a result of increasing risks associated with catastrophic wildfires as discussed below. The scope, cost and availability of each Registrant's insurance coverage may change, including the portion that is self-insured.

Any reduction of each Registrant's revenue or increase in its expenses resulting from the risks described above, could adversely affect the relevant Registrant's financial results. Refer also to "PacifiCorp Wildfire Litigation Related Risks" above for additional information regarding PacifiCorp's wildfire insurance risks.

The Registrants are subject to increasing risks from catastrophic wildfires and may be unable to obtain enough third-party liability insurance coverage at a reasonable cost or at all and insurance coverage on existing wildfire claims could be insufficient to cover all losses, all of which could materially affect the Registrants financial results and liquidity.

The risk of catastrophic and severe wildfires has increased in the western U.S. giving rise to the potential for large damage claims against utilities for fire-related losses. Catastrophic and severe wildfires can occur in PacifiCorp, Nevada Power and Sierra Pacific's ("Western Domestic Utilities") service territories even when the Western Domestic Utilities effectively implement their wildfire mitigation plans and prudently manage their systems.

In California, for example, where PacifiCorp operates, "inverse condemnation" currently exposes utilities to potential liability for property damages where the utility's electrical equipment was a substantial cause of the wildfire. California courts have held that utilities can be held liable under inverse condemnation without being found negligent and regardless of fault. California law also permits inverse condemnation plaintiffs to recover attorney's fees. As a result of inverse condemnation being applied to utilities and wildfire damages, recent losses recorded by insurance companies, and the risk of an increase in the frequency, duration and size of wildfires, insurance for wildfire liabilities may not be available or may be available only at rates that are prohibitively expensive. In addition, even if insurance for wildfire liabilities is available, it may not be available in amounts necessary to cover potential losses.

Certain Registrants have experienced material increases in the cost of third-party liability insurance as a result of worsening damage claims in the utility industry associated with catastrophic wildfires in the geographic regions in which they operate.

Such costs may continue to increase materially to the point of being prohibitively expensive, and it is possible that the Registrants may be unable to obtain third-party liability insurance. Increases in the cost of insurance may be challenged when Registrants seek cost recovery and such amounts may not be recoverable in customer rates. To the extent third-party liability insurance costs continue to increase, becomes cost prohibitive or is unavailable and such increased costs are not recoverable in customer rates, the Registrant's financial condition and results of operations could be materially adversely affected and its liquidity position further negatively impacted.

The Western Domestic Utilities monitor weather conditions with specific thresholds for designated high fire consequence areas to help ensure the safe and reliable operation of their systems during periods of elevated wildfire ignition risk. Should weather conditions become extreme, the Western Domestic Utilities may de-energize certain sections of their transmission and distribution facilities as a last resort to minimize risk to the public. These "public safety power shutoffs" could be subject to increased scrutiny by regulators and policy makers. And, although "public safety power shutoffs" are intended to minimize risk of wildfire ignition, de-energization may cause other damages for which the Western Domestic Utilities could be held liable.

Each Registrant is actively pursuing, developing and constructing new or expanded facilities, the completion and expected costs of which are subject to significant risk, and each Registrant has significant funding needs related to its planned capital expenditures.

Each Registrant actively pursues, develops and constructs new or expanded facilities. Each Registrant expects to incur significant annual capital expenditures over the next several years. Such expenditures may include construction and other costs for new electricity generating facilities, electric transmission or distribution projects, environmental control and compliance systems, natural gas storage facilities, new or expanded pipeline and local distribution systems, and continued maintenance and upgrades of existing assets.

Development and construction of major facilities are subject to substantial risks, including fluctuations in the price and availability of commodities, manufactured goods, equipment, and the imposition of tariffs thereon when sourced by foreign providers, labor, siting and permitting and changes in environmental and operational compliance matters, load forecasts and other items over a multi-year construction period, as well as counterparty risk and the economic viability of the Registrants' suppliers, customers and contractors. Certain of the Registrants' construction projects are substantially dependent upon a single supplier or contractor and replacement of such supplier or contractor may be difficult and cannot be assured. These risks may result in the inability to timely complete a project or higher than expected costs to complete an asset and place it in-service and, in extreme cases, the loss of the power purchase agreements or other long-term off-take contracts underlying such projects. Such costs may not be recoverable in the regulated rates or market or contract prices each Registrant is able to charge its customers. Delays in construction of renewable projects may result in delayed in-service dates which may result in the loss of anticipated revenue or income tax benefits. It is also possible that additional generation needs may be obtained through power purchase agreements, which could increase long-term purchase obligations and force reliance on the operating performance of a third party. The inability to successfully and timely complete a project, avoid unexpected costs or recover any such costs could adversely affect such Registrant's financial results.

Furthermore, each Registrant depends upon both internal and external sources of liquidity to provide working capital and to fund capital requirements. If BHE does not provide needed funding to its subsidiaries and the subsidiaries are unable to obtain funding from external sources, they may need to postpone or cancel planned capital expenditures. Refer to "PacifiCorp Wildfire Litigation Related Risks" above for additional information regarding the impact of wildfire litigation risks on PacifiCorp's ability to fund capital expenditures.

A significant sustained decrease in demand for electricity or natural gas in the markets served by each Registrant would decrease its operating revenue, could impact its planned capital expenditures and could adversely affect its financial results.

A significant sustained decrease in demand for electricity or natural gas in the markets served by each Registrant would decrease its operating revenue, could impact its planned capital expenditures and could adversely affect its financial results. Factors that could lead to a decrease in market demand include, among others:

- a depression, recession or other adverse economic condition that results in a lower level of economic activity or reduced spending by consumers on electricity or natural gas;
- an increase in the market price of electricity or natural gas or a decrease in the price of other competing forms of energy;
- shifts in competitively priced natural gas supply sources away from the sources connected to the Pipeline Companies' systems, including shale gas sources;

- efforts by customers, legislators and regulators to reduce the consumption of electricity generated or distributed by each Registrant through various existing laws and regulations, as well as, deregulation, conservation, energy efficiency and private generation measures and programs;
- laws or policy pronouncements mandating or encouraging renewable energy sources, which may decrease the demand for electricity and natural gas or change the market prices of these commodities;
- higher fuel taxes or other governmental or regulatory actions that increase, directly or indirectly, the cost of natural gas or other fuel sources for electricity generation or that limit the use of natural gas or the generation of electricity from fossil fuels;
- a shift to more energy-efficient or alternative fuel machinery or an improvement in fuel economy, whether as a result of technological advances by manufacturers, legislation mandating higher fuel economy or lower emissions, price differentials, incentives or otherwise;
- a reduction in the state or federal subsidies or tax incentives that are provided to agricultural, industrial or other customers, or a significant sustained change in prices for commodities such as ethanol or corn for ethanol manufacturers; and
- sustained mild weather that reduces heating or cooling needs.

Each Registrant's operating results may fluctuate on a seasonal and quarterly basis and may be adversely affected by weather.

In most parts of the U.S. and other markets in which each Registrant operates, demand for electricity peaks during the summer months when irrigation and cooling needs are higher. Market prices for electricity also generally peak at that time. In other areas, including the western portion of PacifiCorp's service territory, demand for electricity peaks during the winter when heating needs are higher. In addition, demand for natural gas and other fuels generally peaks during the winter. This is especially true in MidAmerican Energy's and Sierra Pacific's retail natural gas businesses. Further, extreme weather conditions, such as heat waves, winter storms or floods could cause these seasonal fluctuations to be more pronounced. Periods of low rainfall or snowpack may negatively impact electricity generation at PacifiCorp's hydroelectric generating facilities, which may result in greater purchases of electricity from the wholesale market or from other sources at market prices. Additionally, PacifiCorp and MidAmerican Energy have added substantial wind-powered generating capacity, and BHE's unregulated subsidiaries are adding solar-powered and wind-powered generating capacity, each of which is also a climate-dependent resource.

As a result, the overall financial results of each Registrant may fluctuate substantially on a seasonal and quarterly basis. Each Registrant has historically provided less service, and consequently earned less income, when weather conditions are mild. Unusually mild weather in the future may adversely affect each Registrant's financial results through lower revenue or margins. Conversely, unusually extreme weather conditions could increase each Registrant's costs to provide services and could adversely affect its financial results. The extent of fluctuation in each Registrant's financial results may change depending on a number of factors related to its regulatory environment and contractual agreements, including its ability to recover energy costs, the existence of revenue sharing provisions as it relates to MidAmerican Energy, Nevada Power and Sierra Pacific, and terms of its wholesale sale contracts.

Each Registrant is subject to market risk associated with the wholesale energy markets, which could adversely affect its financial results.

In general, each Registrant's primary market risk is adverse fluctuations in the market price of wholesale electricity and fuel, including natural gas, coal and fuel oil, which is compounded by volumetric changes affecting the availability of or demand for electricity and fuel. The market price of wholesale electricity may be influenced by several factors, such as the adequacy or type of generating capacity, scheduled and unscheduled outages of generating facilities, prices and availability of fuel sources for generation, disruptions or constraints to transmission and distribution facilities, weather conditions, demand for electricity, economic growth and changes in technology. Volumetric changes are caused by fluctuations in generation or changes in customer needs that can be due to the weather, electricity and fuel prices, the economy, regulations and governmental policies or customer behavior. For example, the Utilities purchase electricity and fuel in the open market as part of their normal operating businesses. If market prices rise, especially in a time when larger than expected volumes must be purchased at market prices, the Utilities may incur significantly greater expenses than anticipated. Likewise, if electricity market prices decline in a period when the Utilities are a net seller of electricity in the wholesale market, the Utilities could earn less revenue. Although the Utilities have ECAMs, the risks associated with changes in market prices may not be fully mitigated due to customer sharing bands as it relates to PacifiCorp and other factors, including potential interjurisdictional allocation constraints and extended recovery periods that negatively impact cash flows.

Certain of BHE's subsidiaries are subject to the risk that customers will not renew their contracts or that BHE's subsidiaries will be unable to obtain new customers for expanded capacity, each of which could adversely affect its financial results.

If BHE's subsidiaries are unable to renew, remarket, or find replacements for their customer agreements on favorable terms, BHE's subsidiaries' sales volumes and operating revenue would be exposed to reduction and increased volatility. For example, without the benefit of long-term transportation agreements, BHE cannot assure that the Pipeline Companies will be able to transport natural gas at efficient capacity levels. Substantially all of the Pipeline Companies' revenue is generated under transportation, storage and LNG contracts that periodically must be renegotiated and extended or replaced, and the Pipeline Companies are dependent upon relatively few customers for a substantial portion of their revenue. Similarly, without long-term power purchase agreements, BHE cannot assure that its unregulated power generators will be able to operate profitably. Failure to maintain existing long-term agreements or secure new long-term agreements, or being required to discount rates significantly upon renewal or replacement, could adversely affect BHE's consolidated financial results. The replacement of any existing long-term agreements depends on market conditions and other factors that may be beyond BHE's subsidiaries' control.

Each Registrant is subject to counterparty risk, which could adversely affect its financial results.

Each Registrant is subject to counterparty credit risk related to contractual payment obligations with wholesale suppliers and customers. Adverse economic conditions or other events affecting counterparties with whom each Registrant conducts business could impair the ability of these counterparties to meet their payment obligations. Each Registrant depends on these counterparties to remit payments on a timely basis. Each Registrant monitors the creditworthiness of its wholesale suppliers and customers in an attempt to reduce the impact of any potential counterparty default. If strategies used to minimize these risk exposures are ineffective or if a Registrant's wholesale suppliers' or customers' financial condition deteriorates or they otherwise become unable to pay, it could have a significant adverse impact on the Registrant's liquidity and its financial results.

Each Registrant is subject to counterparty performance risk related to performance of contractual obligations by wholesale suppliers, customers and contractors. Each Registrant relies on wholesale suppliers to deliver commodities, primarily natural gas, coal and electricity, in accordance with short- and long-term contracts. Failure or delay by suppliers to provide these commodities pursuant to existing contracts could disrupt the delivery of electricity and require the Utilities to incur additional expenses to meet customer needs. In addition, when these contracts terminate, the Utilities may be unable to purchase the commodities on terms equivalent to the terms of current contracts.

Each Registrant relies on wholesale customers to take delivery of the energy they have committed to purchase. Failure of customers to take delivery may require the relevant Registrant to find other customers to take the energy at lower prices than the original customers committed to pay. If each Registrant's wholesale customers are unable to fulfill their obligations, there may be a significant adverse impact on its financial results.

The Northern Powergrid Distribution Companies' customers are concentrated in a small number of electricity supply businesses. AltaLink's primary source of operating revenue is the AESO. Generally, a single customer purchases the energy from BHE's independent power projects in the U.S. pursuant to long-term power purchase agreements. Any material payment or other performance failure by the counterparties in these arrangements could have a significant adverse impact on BHE's consolidated financial results.

Inflation and changes in commodity prices and transportation fuel costs may adversely affect each Registrant's financial results.

Inflation and increases in commodity prices and transportation fuel costs may affect each Registrant by increasing both operating and capital costs. As a result of existing rate agreements, contractual arrangements or competitive price pressures, each Registrant may not be able to pass the inflated costs on to its customers. If a Registrant is unable to manage cost increases or pass them on to its customers, its financial results could be adversely affected.

Physical or cyber attacks, both threatened and actual, could impact each Registrant's operations and could adversely affect its financial results.

Each Registrant relies on technology in virtually all aspects of its business. Like any business, the Registrants' technology systems are a target for computer viruses, malicious codes, unauthorized access, phishing efforts, denial-of-service attacks and other cyber attacks and each Registrant expects to be subject to attempted attacks in the future and will continue to adapt defensive capabilities as such attacks become more sophisticated and frequent. A significant disruption or failure of its technology systems by cyber or physical attack could result in service interruptions, safety failures, security events, regulatory

compliance failures, an inability to protect information and assets against unauthorized users, and other operational difficulties. Attacks perpetrated against each Registrant's systems could result in loss of assets and critical information and expose it to remediation costs and reputational damage.

Although the Registrants have taken steps intended to mitigate these risks, a significant disruption or cyber intrusion at one or more of each Registrant's operations could adversely affect the impacted Registrant's financial results. Cyber attacks could further adversely affect each Registrant's ability to operate facilities, information technology and business systems, or compromise sensitive customer and employee information. In addition, physical or cyber attacks against key suppliers or service providers could have a similar effect on each Registrant. Additionally, if each Registrant is unable to acquire, develop, implement, adopt or protect rights around new technology, it may suffer a competitive disadvantage.

Much of BHE's growth has been achieved through acquisitions, and any such acquisition may not be successful.

Much of BHE's growth has been achieved through acquisitions. Future acquisitions may range from buying individual assets to the purchase of entire businesses. BHE will continue to investigate and pursue opportunities for future acquisitions that it believes, but cannot assure, may increase value and expand or complement existing businesses. BHE may participate in bidding or other negotiations at any time for such acquisition opportunities which may or may not be successful. An acquisition could cause an interruption of, or a loss of momentum in, the activities of one or more of BHE's subsidiaries. In addition, the final orders of regulatory authorities approving acquisitions may be subject to appeal by third parties. The diversion of BHE management's attention and any delays or difficulties encountered in connection with the approval and integration of the acquired operations could adversely affect BHE's combined businesses and financial results and could impair its ability to realize the anticipated benefits of the acquisition. BHE cannot assure that future acquisitions, if any, or any integration efforts will be successful, or that BHE's ability to repay its obligations will not be adversely affected by any future acquisitions.

Certain Registrants are subject to the unique risks associated with nuclear generation.

The ownership and operation of nuclear generating facilities, such as MidAmerican Energy's 25% interest in Quad Cities Station, involves certain risks. These risks include, among other items, mechanical or structural problems, inadequacy or lapses in maintenance protocols, the impairment of reactor operation and safety systems due to human error, the costs of storage, handling and disposal of nuclear materials, compliance with and changes in regulation of nuclear generating facilities, limitations on the amounts and types of insurance coverage commercially available, economic risks impacting the current and expected value of the facilities, and uncertainties with respect to the technological and financial aspects of decommissioning nuclear facilities at the end of their useful lives. Additionally, Constellation Energy, the 75% owner and operator of the facility, may respond to the occurrence of any of these or other operational or economic risks in a manner that negatively impacts MidAmerican Energy, including closure of Quad Cities Station prior to the expiration of its operating license. The prolonged unavailability, or early closure, of Quad Cities Station due to operational or economic factors could have a materially adverse effect on the relevant Registrant's financial results, particularly when the cost to produce power at the generating facility is significantly less than market wholesale prices. The following are among the more significant of these risks:

- *Operational Risk* - Operations at any nuclear generating facility could degrade to the point where the generating facility would have to be shut down. If such degradations were to occur, the process of identifying and correcting the causes of the operational downgrade to return the generating facility to operation could require significant time and expenses, resulting in both lost revenue and increased fuel and purchased electricity costs to meet supply commitments. Rather than incurring substantial costs to restart the generating facility, the generating facility could be shut down. Furthermore, a shut-down or failure at any other nuclear generating facility could cause regulators to require a shut-down or reduced availability at Quad Cities Station.

  In addition, issues relating to the disposal of nuclear waste material, including the availability, unavailability and expenses of a permanent repository for spent nuclear fuel could adversely impact operations as well as the cost and ability to decommission nuclear generating facilities, including Quad Cities Station, in the future.

- *Regulatory Risk* - The NRC may modify, suspend or revoke licenses and impose civil penalties for failure to comply with applicable Atomic Energy Act regulations or the terms of the licenses of nuclear facilities. Unless extended, the NRC operating licenses for Quad Cities Station will expire in 2032. Changes in regulations by the NRC could require a substantial increase in capital expenditures or result in increased operating or decommissioning costs.

- *Nuclear Accident and Catastrophic Risks* - Accidents and other unforeseen catastrophic events have occurred at nuclear facilities other than Quad Cities Station, both in the U.S. and elsewhere, such as at the Fukushima Daiichi nuclear generating facility in Japan as a result of the earthquake and tsunami in March 2011. The consequences of an accident or catastrophic event can be severe and include loss of life and property damage. Any resulting liability from a nuclear accident or catastrophic event could exceed the relevant Registrant's resources, including insurance coverage.
- *Economic Risks* - Market power prices, results of capacity auctions, potential legislative and regulatory actions that impact the compensation received from state or federal policies, reliability or fuel security, and the financial impact of potential rules from the EPA requiring reduction of carbon and other emissions and the efforts of states to implement those final rules may affect the current and expected economic value of the nuclear generating facility resulting in an early nuclear generating facility retirement.

Potential terrorist activities and the impact of military or other actions, including sanctions, export controls and similar measures, could adversely affect each Registrant's financial results.

The ongoing threat of terrorism and the impact of military or other actions by nations or politically, ethnically or religiously motivated organizations regionally or globally may create increased political, economic, social and financial market instability, which could subject each Registrant's operations to increased risks. Additionally, the U.S. government has issued warnings that energy assets, specifically pipeline, nuclear generation, transmission and other electric utility infrastructure, are potential targets for terrorist attacks. Further, the potential or actual outbreak of war or other hostilities and the resulting economic sanctions on aggressor nations, as well as the existing and potential further responses from such aggressors or other countries to such sanctions and military actions, could adversely affect global and regional economies and financial markets. For instance, a ban on imports of oil, liquefied natural gas and coal to the U.S. could contribute to increases in prices for such commodities in the U.S. and elsewhere which could adversely affect each Registrant's business. Further, each Registrant's business must be conducted in compliance with applicable economic and trade sanctions laws and regulations, including those administered and enforced by the U.S. Department of Treasury's Office of Foreign Assets Control, the U.S. Department of State, the U.S. Department of Commerce, the United Nations Security Council and other relevant governmental authorities in the U.S., Canada, the United Kingdom and European Union, which include sanctions that could potentially restrict or prohibit each Registrant's relationships with certain suppliers and customers. Political, economic, social or financial market instability or damage to or interference with the operating assets of the Registrants, customers or suppliers, or continued increases in the price of natural gas and other petroleum commodities may result in business interruptions, lost revenue, higher costs, disruption in fuel supplies, lower energy consumption and unstable markets, particularly with respect to electricity and natural gas, and increased security, repair or other costs, any of which may materially adversely affect each Registrant in ways that cannot be predicted at this time. Any of these risks could materially affect BHE's consolidated financial results. Furthermore, instability in the financial markets as a result of terrorism or war could also materially adversely affect each Registrant's ability to raise capital.

Each Registrant's business could be adversely affected by epidemics, pandemics or other outbreaks.

Each Registrant's business could be adversely affected by epidemics, pandemics or other outbreaks generally and more specifically in the markets in which we operate, including, without limitation, if each Registrant's utility customers experience decreases in demand for their products and services or otherwise reduce their consumption of electricity or natural gas that the respective Registrant supplies, or if such Registrant experiences material payment defaults by its customers. In addition, each Registrant's results and financial condition may be adversely affected by federal, state or local and foreign legislation related to such epidemics, pandemics or other outbreaks (or other similar laws, regulations, policies, orders or other governmental or regulatory actions) that would impose a moratorium on terminating electric or natural gas utility services, including related assessment of late fees, due to non-payment or other circumstances. Additionally, HomeServices' real estate businesses could experience a decline (which could be significant) in real estate transactions if potential customers elect to defer purchases in reaction to any epidemic, pandemic or other outbreak or due to general economic uncertainty such as high unemployment levels, in some or all of the real estate markets in which HomeServices operates. The government and regulators could impose other requirements on each Registrant's business that could have an adverse impact on such Registrant's financial results.

Further, epidemics, pandemics or other outbreaks could disrupt supply chains (including supply chains for energy generation, steel or transmission wire) relating to the markets each Registrant serves, which could adversely impact such Registrant's ability to generate or supply power. In addition, such disruptions to the supply chain could delay certain construction and other capital expenditure projects, including construction and repowering of the Registrants' renewable generation projects. Such disruptions could adversely affect the impacted Registrant's future financial results.

Such declines in demand, any inability to generate or supply power or delays in capital projects could also significantly reduce cash flows at BHE's subsidiaries, thereby reducing the availability of distributions to BHE, which could adversely affect its financial results.

Cyclical fluctuations and competition in the residential real estate brokerage and mortgage businesses could adversely affect HomeServices.

The residential real estate brokerage and mortgage industries tend to experience cycles of greater and lesser activity and profitability and are typically affected by changes in economic conditions, which are beyond HomeServices' control. Any of the following, among others, are examples of items that could have a material adverse effect on HomeServices' businesses by causing a general decline in the number of home sales, sale prices or the number of home financings which, in turn, would adversely affect its financial results:

- rising interest rates or unemployment rates, including a sustained high unemployment rate in the U.S.;
- periods of economic slowdown or recession in the markets served or the adverse effects on market actions as a result of epidemics, pandemics or other outbreaks;
- decreasing home affordability;
- lack of available mortgage credit for potential homebuyers, such as the reduced availability of credit, which may continue into future periods;
- inadequate home inventory levels;
- sources of new competition; and
- changes in applicable tax law.

BHE holds investments in foreign countries that are exposed to risks related to fluctuations in foreign currency exchange rates and increased economic, regulatory and political risks.

BHE's business operations and investments outside the U.S. increase its risk related to fluctuations in foreign currency exchange rates, primarily the British pound and the Canadian dollar. BHE's principal reporting currency is the U.S. dollar, and the value of the assets and liabilities, earnings, cash flows and potential distributions from its foreign operations changes with the fluctuations of the currency in which they transact. BHE may selectively reduce some foreign currency exchange rate risk by, among other things, requiring contracted amounts be settled in, or indexed to, U.S. dollars or a currency freely convertible into U.S. dollars, or hedging through foreign currency derivatives. These efforts, however, may not be effective and could negatively affect BHE's consolidated financial results.

In addition to any disruption in the global financial markets, the economic, regulatory and political conditions in some of the countries where BHE has operations or is pursuing investment opportunities may present increased risks related to, among others, inflation, foreign currency exchange rate fluctuations, currency repatriation restrictions, nationalization, renegotiation, privatization, availability of financing on suitable terms, customer creditworthiness, construction delays, business interruption, political instability, civil unrest, guerilla activity, terrorism, pandemics, expropriation, trade sanctions, contract nullification and changes in law, regulations or tax policy. BHE may not choose to or be capable of either fully insuring against or effectively hedging these risks.

Item 1B. Unresolved Staff Comments

Not applicable.

Item 1C. Cybersecurity

CYBER RISK MANAGEMENT AND STRATEGY

BHE and its Subsidiary Registrants recognize that maintaining processes for identifying, assessing and managing cybersecurity threats is important in dealing with their significant business risks. As such, BHE has implemented a framework for cybersecurity and cyber-related information management across its businesses. BHE's Chief Security Office ("CSO") drives collective focus and central coordination of BHE's cyber and physical security programs. The CSO identifies the strategic framework that promotes standardization of business security policies and practices and provides direction in managing security risks. Although the CSO provides oversight, the businesses retain accountability for executing company security objectives, policies and practices within their areas of responsibility.

BHE manages cybersecurity threats through its proactive risk management program and cybersecurity awareness program. BHE's businesses are certified against the ISO 27001 standard. The standard is authored by the International Organization for Standardization ("ISO") of Geneva, Switzerland. To achieve the certification, each business must sustain an information security management system that includes a risk-based framework to identify and manage information security risks through a continuous improvement cycle. The risks and controls identified in the system must be approved by top management and confirmed through annual internal and external ISO audits prior to certification. BHE administers security policies and standards supporting these initiatives, ensuring alignment with the NIST Cybersecurity 2.0 and ISO 27001.

In addition, BHE's compliance requirements include the North American Electric Reliability Corporation Critical Infrastructure Protection Standards, the Transportation Security Administration Pipeline Security Directives and the United Kingdom Center for the Protection of National Infrastructure Standards as applicable to each of the companies. These requirements are audited and assessed as mandated by applicable government agencies.

Each Registrant relies on technology in virtually all aspects of its business. Like any business, the Registrants' technology systems are a target for cyber attacks. Each Registrant expects to be subject to attempted attacks in the future and will continue to adapt defensive capabilities as such attacks become more sophisticated and frequent. A significant disruption or failure of its technology systems by cyber or physical attack could result in service interruptions, safety failures, security events, regulatory compliance failures, an inability to protect information and assets against unauthorized users, and other operational difficulties. Attacks perpetrated against each Registrant's systems could result in loss of assets and critical information and expose it to remediation costs and reputational damage.

In certain circumstances, BHE relies on third-party service providers for a variety of products and services to run its information systems. This dependence exposes BHE, along with others who use these service providers, to the impact of a cyber attack on these providers. Cyber attacks at a third-party service provider could have a significant financial, operational, or reputational impact. BHE continuously monitors the risks associated with its service providers.

GOVERNANCE

BHE's Board of Directors is responsible for the oversight of BHE's cybersecurity risk management program.

BHE's CSO is responsible for cyber and physical security across BHE and its Subsidiary Registrants. The CSO is responsible for identifying, assessing and managing cyber risk for BHE and its Subsidiary Registrants. BHE's Board of Directors has evaluated the expertise of the CSO and determined that it possesses the knowledge and expertise necessary to oversee BHE's cybersecurity risk management processes.

The CSO provides, at least annually, updates to the Board of Directors on:

- Strategic cyber and physical security initiatives
- Current threats and the risk landscape impacting the organization
- Security compliance with regulatory requirements
- Compliance with ISO 27001 framework
- Number and impact of incidents reported through the BHE cybersecurity incident reporting process

BHE's Cybersecurity Reporting Framework enables BHE to use a repeatable and timely process to identify, assess and manage any security incidents for materiality reporting. Each BHE business is required to report significant cybersecurity events to BHE. The Board of Directors reviews summaries of incidents and together with the CSO determines whether a cyber incident report should be filed with the SEC.

Item 2. Properties

Each Registrant's energy properties consist of the physical assets necessary to support its electricity and natural gas businesses. Properties of the relevant Registrant's electricity businesses include electric generation, transmission and distribution facilities, as well as coal mining assets that support certain of PacifiCorp's electric generating facilities. Properties of the relevant Registrant's natural gas businesses include natural gas distribution facilities, interstate pipelines, storage facilities, LNG facilities, compressor stations and meter stations. The transmission and distribution assets are primarily within each Registrant's service territories. In addition to these physical assets, the Registrants have rights-of-way, mineral rights and water rights that enable each Registrant to utilize its facilities. It is the opinion of each Registrant's management that the principal depreciable properties owned by it are in good operating condition and are well maintained. Pursuant to separate financing agreements, substantially all of PacifiCorp's electric utility properties, MidAmerican Energy's electric utility properties in the state of Iowa, Nevada Power's and Sierra Pacific's properties in the state of Nevada, AltaLink's transmission properties and substantially all of the assets of the subsidiaries of BHE Renewables that are direct or indirect owners of generation projects are pledged or encumbered to support or otherwise provide the security for the related subsidiary debt. For additional information regarding each Registrant's energy properties, refer to Item 1 of this Form 10-K and Notes 4, 5 and 22 of the Notes to Consolidated Financial Statements of Berkshire Hathaway Energy in Item 8 of this Form 10-K, Notes 3 and 4 of the Notes to Consolidated Financial Statements of PacifiCorp in Item 8 of this Form 10-K, Notes 3 and 4 of the Notes to Financial Statements of MidAmerican Energy in Item 8 of this Form 10-K, Notes 3 and 4 of the Notes to Consolidated Financial Statements of Nevada Power in Item 8 of this Form 10-K, Notes 3 and 4 of the Notes to Consolidated Financial Statements of Sierra Pacific in Item 8 of this Form 10-K, Notes 4 and 5 of the Notes to Consolidated Financial Statements of Eastern Energy Gas in Item 8 of this Form 10-K and Notes 3 and 4 of the Notes to Consolidated Financial Statements of EGTS in Item 8 of this Form 10-K.

The following table summarizes Berkshire Hathaway Energy's operating electric generating facilities as of December 31, 2025:

Energy Source	Entity	Location by Significance	Facility Net Capacity (MWs)	Net Owned Capacity (MWs)
Wind	PacifiCorp, MidAmerican Energy, BHE Canada, BHE Montana and BHE Renewables	Iowa, Wyoming, Texas, Montana, Nebraska, Washington, California, Illinois, Canada, Oregon and Kansas	13,642	13,642
Natural gas	PacifiCorp, MidAmerican Energy, NV Energy, BHE Canada and BHE Renewables	Nevada, Utah, Iowa, Wyoming, Illinois, Washington, Oregon, Texas, New York, Arizona and Canada	13,193	12,430
Coal	PacifiCorp, MidAmerican Energy and NV Energy	Iowa, Utah, Wyoming, Colorado and Montana	11,272	6,856
Solar	MidAmerican Energy, NV Energy, Northern Powergrid and BHE Renewables	California, Australia, Nevada, Texas, Arizona, Iowa and Minnesota	2,270	2,122
Hydroelectric	PacifiCorp, MidAmerican Energy and BHE Renewables	Washington, Oregon, Idaho, Utah, Hawaii, Montana, Illinois, California and Wyoming	984	984
Nuclear	MidAmerican Energy	Illinois	1,822	455
Geothermal	PacifiCorp and BHE Renewables	California and Utah	377	377
		Total	43,560	36,866

Additionally, as of December 31, 2025, the Company has electric generating facilities that are under construction in Iowa, Nevada, Montana, West Virginia and California having total Facility Net Capacity and Net Owned Capacity of 1,949 MWs.

As of December 31, 2025, the Company also has battery energy storage systems in Nevada, Montana, California, West Virginia and Oregon having total Facility Net Capacity and Net Owned Capacity in operation of 320 MW and under construction of 543 MW.

The right to construct and operate each Registrant's electric transmission and distribution facilities and interstate natural gas pipelines across certain property was obtained in most circumstances through negotiations and, where necessary, through prescription, eminent domain or similar rights. PacifiCorp, MidAmerican Energy, Nevada Power, Sierra Pacific, BHE GT&S, Northern Natural Gas and Kern River in the U.S.; Northern Powergrid (Northeast) plc and Northern Powergrid (Yorkshire) plc in Great Britain; and AltaLink in Alberta, Canada continue to have the power of eminent domain or similar rights in each of the jurisdictions in which they operate their respective facilities, but the U.S. and Canadian utilities do not have the power of eminent domain with respect to governmental, Native American or Canadian First Nations' tribal lands. Although the main Kern River pipeline crosses the Moapa Indian Reservation, all facilities in the Moapa Indian Reservation are located within a utility corridor that is reserved to the U.S. Department of Interior, Bureau of Land Management.

With respect to real property, each of the electric transmission and distribution facilities and interstate natural gas pipelines fall into two basic categories: (1) parcels that are owned in fee, such as certain of the electric generating facilities, electric substations, natural gas compressor stations, natural gas meter stations and office sites; and (2) parcels where the interest derives from leases, easements (including prescriptive easements), rights-of-way, permits or licenses from landowners or governmental authorities permitting the use of such land for the construction, operation and maintenance of the electric transmission and distribution facilities and interstate natural gas pipelines. Each Registrant believes it has satisfactory title or interest to all of the real property making up their respective facilities in all material respects.

Item 3. Legal Proceedings

BERKSHIRE HATHAWAY ENERGY AND PACIFICORP

In September 2020, a severe weather event with high winds, low humidity and warm temperatures contributed to several major wildfires, including the 2020 Wildfires, which resulted in real and personal property and natural resource damage, personal injuries and loss of life and widespread power outages in Oregon and Northern California. The wildfires spread across certain parts of PacifiCorp's service territory and surrounding areas across multiple counties in Oregon and California, including Siskiyou County, California; Jackson County, Oregon; Douglas County, Oregon; Marion County, Oregon; Lincoln County, Oregon; and Klamath County, Oregon, burning over 500,000 acres in aggregate. Third-party reports for these wildfires indicate over 2,000 structures destroyed, including residences; several structures damaged; multiple individuals injured; and several fatalities.

In July 2022, the 2022 McKinney Fire began in the Oak Knoll Ranger District of the Klamath National Forest in Siskiyou County, California located in PacifiCorp's service territory, burning over 60,000 acres. Third-party reports indicate that the 2022 McKinney Fire resulted in 11 structures damaged; 185 structures destroyed, including residences; 12 injuries; and four fatalities.

As described below, a significant number of complaints and demands alleging similar claims have been filed in Oregon and California related to the Wildfires. Amounts sought in outstanding complaints and demands filed in Oregon and in certain demands made in California totaled approximately $50 billion, excluding any doubling or trebling of damages or punitive damages included in the complaints, and of which approximately $48 billion represents the economic and noneconomic damages sought in the *James* mass complaints described below, as amended. Oregon law provides for doubling of economic and property damages in the event the defendant is found to have acted with gross negligence, recklessness, willfulness or malice. Oregon law provides for trebling of damages associated with timber, shrubs and produce in the event the defendant is determined to have willfully and intentionally trespassed. Generally, the complaints filed in California do not specify damages sought and are excluded from this amount. For class actions, amounts specified by the plaintiffs in the complaints include amounts based on estimates of the potential class size, which ultimately may be significantly greater than estimated. Additionally, damages are not limited to the amounts specified in the initially filed complaints as plaintiffs are frequently allowed to amend their complaints to add additional damages and amounts awarded in a court proceeding may be significantly greater than the damages specified. However, as described below, plaintiffs included in the *James* mass complaints are required to amend their complaints to align the economic damages to the facts specific to their complaints rather than the common per plaintiff damages specified in the originally filed mass complaints. Based on the damages awarded in the jury verdicts to date as presented in Note 14 of the Notes to Consolidated Financial Statements of PacifiCorp in Part II, Item 8 of this Form 10-K, it is likely that amended damages and those ultimately awarded by jury verdicts in additional damages phase trials associated with the plaintiffs included in the mass complaints will be significantly lower than the amounts sought in the mass complaints.

The following map illustrates the general vicinity of the Wildfires.

Investigations

In April 2023, the U.S. Department of Agriculture Forest Service ("USFS") issued its report of investigation into a wildland fire that began in the Opal Creek wilderness outside of the Santiam Canyon that was first reported on August 16, 2020 ("Beachie Creek Fire"), approximately three weeks prior to the September 2020 wind event described above. In March 2025, PacifiCorp received the Oregon Department of Forestry's final investigation report on the Santiam Canyon fires ("ODF's Report"), which concluded that embers from the pre-existing Beachie Creek Fire caused 12 fires within the Santiam Canyon. The ODF's Report also found that PacifiCorp's power lines did not contribute to the overall spread of fire into the Santiam Canyon even though its power lines ignited seven spot fires within the Santiam Canyon that were each suppressed.

The Beachie Creek fire that spread into the Santiam Canyon burned approximately 193,000 acres; the South Obenchain fire burned approximately 33,000 acres; the Echo Mountain Complex fire burned approximately 3,000 acres; and the 242 fire burned approximately 14,000 acres. The *James* cases described below are associated with the Beachie Creek (Santiam Canyon), South Obenchain, Echo Mountain Complex and 242 fires, which are four distinct fires located hundreds of miles apart.

For more information regarding certain investigative reports from the USFS and the Oregon Department of Forestry ("ODF") and certain legal proceedings affecting Berkshire Hathaway Energy, refer to Note 16 of the Notes to Consolidated Financial Statements of Berkshire Hathaway Energy in Part II, Item 8 of this Form 10-K, and PacifiCorp, refer to Note 14 of the Notes to Consolidated Financial Statements of PacifiCorp in Part II, Item 8 of this Form 10-K.

Wildfire Settlements

PacifiCorp has settled various claims associated with the Wildfires as described below and has settled all wrongful death claims and federal government demands and complaints associated with the Wildfires. For the Archie Creek fire, Slater fire and 2022 McKinney Fire, settlements have been reached with substantially all plaintiffs. For the Santiam Canyon, Echo Mountain Complex, South Obenchain and 242 fires, while PacifiCorp settled claims with individual plaintiffs who were granted substitution of counsel in the *James* case, with the Oregon wineries and with the federal government as described below, claims remain outstanding for a substantial number of class members in the *James* case and individual plaintiffs in the *Dietrich* case.

2020 Wildfires

As of the date of this filing, PacifiCorp has made settlement payments associated with individual plaintiffs, wrongful death claims, insurance subrogation claims, commercial timber claims and certain government claims associated with the 2020 Wildfires totaling $1,467 million. The $1,467 million in settlements were comprised of $605 million associated with the *James* related fires for plaintiffs who opted out of the *James* class, plaintiffs granted substitution counsel in the *James* case, Oregon wineries, insurance subrogation claims and for plaintiffs in certain of the consolidated cases; $605 million associated with the Archie Creek fire; $254 million associated with the Slater fire; and $3 million associated with other fires. Amounts associated with the February 2026 settlement with the federal government described below will be paid in March 2026. For more information, refer to description of the 2020 Wildfires complaints and specific wildfires below.

2022 McKinney Fire

As of the date of this filing, PacifiCorp has made settlement payments associated with individual plaintiffs, wrongful death claims, insurance subrogation claims, commercial timber claims, private timber claims and certain government claims associated with the 2022 McKinney Fire totaling $227 million. Amounts associated with the February 2026 settlement with the federal government described below will be paid in March 2026. For more information, refer to description of the 2022 McKinney Fire complaints below.

2020 Oregon Wildfires, Excluding the Northern California and Southern Oregon Slater Fire ("Slater Fire")

As described below, a significant number of complaints on behalf of plaintiffs associated with the 2020 Wildfires have been filed in Oregon in addition to those described below for the Slater Fire. The plaintiffs generally allege: (i) negligence due in part to alleged failure to comply with certain Oregon statutes and administrative rules, including those issued by the OPUC; (ii) gross negligence alleged in the form of willful, wanton and reckless disregard of known risks to the public; (iii) trespass; (iv) nuisance; (v) inverse condemnation; (vi) pre- and post-judgment interest; and (vii) reasonable attorney fees, investigation costs and expert witness fees. The complaints generally assert claims for: (i) noneconomic damages, including mental suffering, emotional distress, inconvenience and interference with normal and usual activities; (ii) damages for real and personal property and other economic losses; (iii) double the amount of property and economic damages; (iv) treble damages for specific costs associated with loss of forestry, trees and shrubbery; and (v) double the amount of damages for the costs of litigation and reforestation. Certain complaints include wrongful death claims as described below. The plaintiffs generally demand a trial by jury and reserve their right to further amend their complaints to allege claims for punitive damages.

The James Case

On September 30, 2020, a class action complaint against PacifiCorp was filed, captioned *Jeanyne James et al. v. PacifiCorp*, ("*James*") in Oregon Circuit Court in Multnomah County, Oregon ("*Multnomah County Circuit Court Oregon*"). The complaint was filed by Oregon residents and businesses who sought to represent a class of all Oregon citizens and entities whose real or personal property was harmed beginning on September 7, 2020, by wildfires in Oregon allegedly caused by PacifiCorp. In November 2021, the plaintiffs filed an amended complaint to limit the class to include Oregon citizens allegedly impacted by the Santiam Canyon, Echo Mountain Complex, South Obenchain and 242 fires, as well as to add claims for noneconomic damages. The amended complaint alleged that PacifiCorp's assets contributed to the Oregon wildfires occurring on or after September 7, 2020, and that PacifiCorp acted with gross negligence, among other things. The amended complaint seeks damages similar to those described above, including not less than $600 million of economic damages and in excess of $1 billion of noneconomic damages for the plaintiffs and the class. Since filing of the original class action complaint, numerous James class members have been named and damages specified in various complaints as described below. Additionally, numerous cases were consolidated into the original *James* complaint as described below under "*James* Consolidated Cases."

In April, May, July and September 2024; January, May and September 2025; and January 2026, nine separate mass complaints against PacifiCorp naming 1,000, 100, 265, 78, 93, 55, 99, 34 and 36 individual class members, respectively, were filed in Multnomah County Circuit Court Oregon captioned *Shane A Henson et al. v. PacifiCorp*, *Karen Andersen et al. v. PacifiCorp, Vanessa Alexander et al. v. PacifiCorp, Emily Broderick et al. v. PacifiCorp, Sergio Garcia Montes et al. v. PacifiCorp*, *Butte Falls Family Ranch, LLC et al. v. PacifiCorp*, *Amanda Bateman et al. v. PacifiCorp*, *Philip Estes et al. v. PacifiCorp* and *Stephen Becker et al. v. PacifiCorp*, respectively, each referencing the original *James* case as the lead case. The *James* mass complaints make damages-only allegations seeking for each individual class member $5 million of economic damages, $25 million of noneconomic damages and punitive damages equal to 0.25 times the amount of economic and noneconomic damages, as well as doubling of economic damages. The class members demand a trial by jury. Refer to "*James* Court Activity" section below for information regarding additional damages phase trials and the requirement for plaintiffs to amend their complaints to specify damages based on facts associated with their claims. Complaints for some of the plaintiffs in the mass complaints have been dismissed.

On December 31, 2024, a complaint against PacifiCorp was filed, captioned *Frank Timber Resources, Inc. et al. v. PacifiCorp*, referencing the original *James* case as the lead case, ("*Frank Timber*") in Multnomah County Circuit Court Oregon by four plaintiffs. Similar to the mass complaints described above, the complaint makes damages-only allegations seeking approximately $12 million of economic damages, doubling of economic damages and punitive damages equal to 0.25 times the amount of economic damages. In November 2025, settlement was reached with the *Frank Timber* plaintiffs. As a result of the settlement, the trial previously scheduled for early January 2026 was cancelled and the complaint was dismissed.

On December 31, 2024, a complaint against PacifiCorp was filed, captioned *Theodore and Deana Freres et al. v. PacifiCorp*, referencing the original *James* case as the lead case, ("*Theodore and Deana Freres*") in Multnomah County Circuit Court Oregon by four plaintiffs. Similar to the mass complaints described above, the complaint makes damages-only allegations seeking approximately $1 million of economic damages, doubling of economic damages and punitive damages equal to 0.25 times the amount of economic damages. In November 2025, settlement was reached with the *Theodore and Deana Freres* plaintiffs. As a result of the settlement, the trial previously scheduled for early January 2026 was cancelled and the complaint was dismissed.

From October 2024 through March 2025, various plaintiffs' counsel filed motions with the Multnomah County Circuit Court Oregon for substitution of lead counsel in the *James* case for approximately 1,500 individual plaintiffs, including a minor number of plaintiffs included in the *James* mass complaints described above and a small portion who filed complaints in Multnomah County Circuit Court Oregon seeking the same damages as those in the *James* mass complaints. Substitution motions covering substantially all of the approximately 1,500 plaintiffs were granted. In November 2025, PacifiCorp settled with approximately 1,400 of the individual plaintiffs granted substitution counsel for $150 million, substantially all of which was paid in December 2025.

As described above under "Investigations," in March 2025, PacifiCorp received the ODF's Report, which concluded that while PacifiCorp's power lines ignited various spot fires within the Santiam Canyon, every such ignition was suppressed and did not contribute to the overall spread of the Beachie Creek Fire into the Santiam Canyon. Approximately 60% of the named plaintiffs in the *James* mass complaints are associated with the Santiam Canyon fires. Refer to "*James* Court Activity" below for information regarding PacifiCorp's filings of motions to stay further *James* damages phase trials in consideration of the ODF's Report described above under "Investigations."

From October 2025 through February 2026, PacifiCorp reached settlement with several individual plaintiffs in the *James* case. As a result of dismissals for the mass complaints and settlements, *James* complaints for approximately 1,700 individual plaintiffs remain outstanding, substantially all of which are represented by lead counsel.

James Trial Activity

In June 2023, a jury verdict was issued in the first *James* trial finding PacifiCorp's conduct grossly negligent, reckless and willful as to each of the 17 named plaintiffs and the entire class. The jury awarded economic and noneconomic damages. After the jury verdict, the Multnomah County Circuit Court Oregon doubled the economic damages, in accordance with Oregon law, and added punitive damages by applying a 0.25 multiplier to the awarded economic and noneconomic damages. PacifiCorp filed a motion with the Multnomah County Circuit Court Oregon requesting the court offset the damage awards by deducting insurance proceeds received by any of the plaintiffs. In January 2024, PacifiCorp filed a notice of appeal associated with the June 2023 verdict, including whether the case can proceed as a class action.

Subsequent to the June 2023 *James* verdict, numerous damages phase trials were held with separate jury verdicts issued and damages awarded for each on a basis consistent with the initial trial and relying on the liability determination in the June 2023 *James* verdict. PacifiCorp amended its January 2024 appeal of the June 2023 *James* verdict to include the jury verdicts for the first two damages phase trials. PacifiCorp has filed notices of appeal for the subsequent jury verdicts in the damages phase trials once limited judgments are entered and any post-trial motions filed. Refer to "*James* Court Activity" below regarding the filing of PacifiCorp's appellate briefs. The appeals process and further actions could take several years.

The *James* jury verdicts to date have awarded total net damages of $1,005 million to 145 plaintiffs, including $114 million of doubled economic damages, $725 million of noneconomic damages, $196 million of punitive damages and partially offset by estimated insurance offsets of $30 million. Refer to additional details by trial in Note 14 of Notes to the Consolidated Financial Statements of PacifiCorp in Part II, Item 8 of this Form 10-K.

Through February 2026, jury verdict awards averaged approximately $7 million per plaintiff, including insurance offset. Additional damages phase trials are scheduled to occur through 2028 as described below.

James Court Activity

In April 2025, PacifiCorp filed its appellate brief with the Oregon Court of Appeals in connection with its appeal of the June 2023 *James* verdict and the January and March 2024 *James* damages phase trial verdicts. In the appellate brief, PacifiCorp addresses numerous procedural and legal issues, including that the class certification is improper due to the plaintiffs being impacted by distinct fires with independent ignition points that were hundreds of miles apart; awarding of non-economic damages is not allowed under Oregon law; plaintiffs failed to prove that PacifiCorp caused harm to every class member; and jury instructions applied incorrect legal standards in assessing class-wide evidence and individual claims. Additionally, PacifiCorp incorporated the ODF's Report into its appellate brief. Various parties who are not party to the *James* case filed supportive amicus briefs with the court. Plaintiffs filed their combined answering and cross-appeal brief on August 21, 2025, after plaintiffs requested three delays from the Oregon Court of Appeals. PacifiCorp has filed additional appellate briefs and will continue to file individual appellate briefs in connection with appeals of each of the verdicts for additional *James* damages phase trials.

In November 2025, the Oregon Court of Appeals issued an order for expedited oral argument in response to PacifiCorp's October 2025 request to facilitate a more prompt decision from the court. As a result of the order, oral argument for the appeal was held on February 4, 2026.

Subsequent to the first two damages phase trials, nine damages phase trials were scheduled to be held in 2025 in accordance with the Multnomah County Circuit Court Oregon's October 2024 case management order, adjudicating the damages of approximately 10 plaintiffs per trial. In March 2025, PacifiCorp filed a motion to stay the additional damages phase trials scheduled under the October 2024 case management order in consideration of the ODF's Report, but the motion was denied in April 2025. Plaintiffs selected for the nine damages phase trials scheduled in 2025 were required to file amended complaints alleging the specific facts that supported their claims for economic and noneconomic damages. Damages sought in the amended complaints were significantly lower than the amounts sought in the original mass complaints. Jury verdicts were issued in 2025 for each of the nine damages phase trials, resulting in amounts awarded that are also significantly less than the amounts sought in the original mass complaints as described above under "*James* Trial Activity." Also in accordance with the October 2024 case management order, the parties engaged in a global mediation on May 5, 2025, July 28, 2025, and December 10, 2025, with the objective of resolving the claims of the remaining absent class members. Although PacifiCorp has been unable to resolve claims as a class through mediation efforts, it has reached settlement with a minor number of individual plaintiffs in the *James* case as described above.

In July 2025, the Multnomah County Circuit Court Oregon issued CMO No. 11 in response to the May 2025 hearing that was held to evaluate the scheduling of additional damages phase trials. As ordered, CMO No. 11 proposes to schedule dozens of trials in 2026 and over 100 more in 2027 and 2028. Currently, approximately 1,500 plaintiffs are scheduled for trial under CMO No. 11, including substantially all of those included in the mass complaints described above and reflecting the impacts of settlements and dismissals. CMO No. 11 requires plaintiffs included in the mass complaints to amend their complaints alleging the specific facts that support their claims for economic damages within 180 days before the start of their respective trials. Additionally, CMO No. 11 requires mediation every other month.

In August 2025, PacifiCorp filed a motion with the Oregon Court of Appeals to stay the *James* damages phase trials addressed in CMO No. 11. In September 2025, the Appellate Commissioner of the Oregon Court of Appeals denied PacifiCorp's motion to stay, to which PacifiCorp filed a request for reconsideration of the stay denial with the Chief Judge of the Oregon Court of Appeals. In October 2025, the Oregon Court of Appeals issued an order denying PacifiCorp's request for reconsideration. In November 2025, PacifiCorp petitioned the Oregon Supreme Court to review the Oregon Court of Appeals' decisions. In December 2025, plaintiffs' counsel filed their opposition to the petition, and a decision is expected in 2026.

Refer to "Potential Effects of *James* CMO No. 11" in Note 14 of the Notes to Consolidated Financial Statements of PacifiCorp in Part II, Item 8 of this Form 10-K for additional information.

James Consolidated Cases

The following cases were consolidated into the original *James* case:

The amended *Salter* complaint was filed August 20, 2021, in Multnomah County Circuit Court Oregon by approximately 97 individuals seeking damages similar to those described above, including economic damages not to exceed $150 million and noneconomic damages not to exceed $500 million. A portion of these plaintiffs are included in the *James* mass complaints and either already have verdicts or have trials scheduled under CMO No. 11. The *Salter* case is currently stayed due to plaintiffs' motion to consolidate the case into *James*.

The amended *Allen* complaint was filed September 2, 2021, in Multnomah County Circuit Court Oregon by approximately five individuals seeking damages similar to those described above, including $8 million in economic and $24 million in noneconomic damages related to the Beachie Creek Fire. All five of these plaintiffs are included in the *James* mass complaints and either already have verdicts or have trials scheduled under CMO No. 11. The *Allen* case is currently stayed due to plaintiffs' motion to consolidate the case into *James*.

The amended *Dietrich* complaint was filed September 6, 2022, in Multnomah County Circuit Court Oregon by six Oregon residents individually and on behalf of a proposed class defined to include residents of, business owners in, real or personal property owners in and any other individuals physically present in specified Oregon counties as of September 7, 2020 who experienced any harm, damage or loss as a result of the Santiam Canyon, Echo Mountain Complex, 242 or South Obenchain fires. The amended complaint seeks $400 million in economic damages and $500 million in noneconomic damages on behalf of the proposed class. The *Dietrich* case is currently stayed due to plaintiffs' motion to consolidate the case into *James*.

The *Bell* complaint was filed September 7, 2022, in Multnomah County Circuit Court Oregon by 59 plaintiffs seeking $35 million in damages, including economic and noneconomic damages. A portion of these plaintiffs have trials scheduled under CMO No. 11. The *Bell* case is currently stayed due to plaintiffs' motion to consolidate the case into *James*.

Ashley Andersen et al. v. PacifiCorp and Judith O'Keefe v. PacifiCorp and Consolidated Cases

As a result of settlements reached in 2024 for the *Andersen et al. v. PacifiCorp* consolidated cases and the *Judith O'Keefe v. PacifiCorp* consolidated cases, the complaints have been resolved but for one remaining plaintiff in *Andersen* in the consolidated *Weathers* complaint described below.

The *Weathers* complaint was filed in Multnomah County Circuit Court Oregon by approximately 46 plaintiffs and consolidated into the *Andersen* case with allegations and damages similar to those described above for the *Andersen* case, seeking economic damages of approximately $83 million and noneconomic damages of approximately $83 million. As described above, settlement was reached for all but one plaintiff in *Weathers*.

The *Bogle* complaint was filed September 1, 2022, in Multnomah County Circuit Court Oregon by approximately 39 plaintiffs seeking economic damages of approximately $83 million and noneconomic damages of approximately $83 million and consolidated into the *O'Keefe* case. As described above, settlement was reached for all plaintiffs in *Bogle*.

Other Cases

Several other complaints were filed against PacifiCorp associated with the 2020 Wildfires for which several settlements were reached as described above. However, certain complaints remain outstanding as described below.

On September 1, 2022, a complaint against PacifiCorp associated with the Archie Creek Fire was filed, captioned *Leonard Mitchell Lee et al. v. PacifiCorp*, ("*Lee*") in Multnomah County Circuit Court Oregon by approximately five plaintiffs, seeking approximately $25 million in economic and noneconomic damages and makes allegations similar to those described above. In 2024, PacifiCorp settled with three of the *Lee* plaintiffs and the complaints were dismissed. In 2025, the court dismissed the complaints for the remaining two plaintiffs.

A group of subrogation insurers that filed complaints against PacifiCorp associated with the Archie Creek Fire agreed to a mediator's proposal under which PacifiCorp will pay 51.75% of the total claims paid and to be paid by the carriers related to the Archie Creek Fire. Across 2022, 2023 and early 2024, PacifiCorp paid approximately $28 million to the subrogation insurers, and all but the following subrogation complaints were fully dismissed.

The *Lexington* complaint was filed against PacifiCorp by two insurers in Douglas County Circuit Court Oregon seeking $14 million in damages for negligence and, as amended on February 3, 2022, makes allegations similar to those described above. The *Lexington* case was partially dismissed following settlement, but general judgment of dismissal has not yet been entered because certain plaintiffs remain active. This complaint is expected to be fully dismissed as a result of the Rock Creek Fish Hatchery settlement described below under "United States and State of Oregon – Loss and Damages to Federal and State Lands – Oregon Fires."

The *Ace American Insurance Co.* complaint was filed against PacifiCorp by 15 insurers in Douglas County Circuit Court Oregon on August 25, 2022, seeking approximately $24 million in damages for negligence. The *Ace American Insurance Co.* case was partially dismissed following settlement, but general judgment of dismissal has not yet been entered because certain plaintiffs remain active. This complaint is expected to be fully dismissed as a result of the Rock Creek Fish Hatchery settlement described below under "United States and State of Oregon – Loss and Damages to Federal and State Lands – Oregon Fires."

Winery Cases

In 2023 and 2024, multiple Oregon vineyards filed lawsuits against PacifiCorp alleging economic damages of approximately $198 million and unspecified punitive damages associated with the 2020 Wildfires. In November 2025, PacifiCorp settled and paid all claims made by these Oregon vineyards. As a result, the associated trials were cancelled and complaints dismissed.

United States and State of Oregon – Loss and Damages to Federal and State Lands – Oregon Fires

In 2023, PacifiCorp received correspondence from the U.S. Department of Justice ("USDOJ"), representing the U.S. Department of the Interior, Bureau of Land Management, Bureau of Indian Affairs and USFS, regarding the potential recovery of certain costs and damages alleged to have occurred to federal lands from the Archie Creek and Susan Creek fires. The USDOJ provided a damages estimate of approximately $625 million for mediation purposes only, which included costs and damages relating to damaged timber and improvements; reforestation; coordination with hydropower license, suppression costs and other assessment costs; and cleanup and rehabilitation costs. The amounts alleged for natural resource damage from these fires do not include intangible environmental and natural resource damages that the U.S. could potentially seek to recover if this matter was fully litigated, nor do they include multipliers which the agencies are allegedly entitled to collect under pertinent federal regulations, under which, for example, minimum damages for trespass to timber managed by the U.S. Department of Interior are twice the fair market value of the resource at the time of the trespass, or three times if the violation was willful. While PacifiCorp participated in mediation with the USDOJ and continues to seek resolution of the dispute, the USDOJ filed a formal complaint against PacifiCorp as described below.

In 2023, PacifiCorp also received correspondence from the Oregon Department of Justice ("ODOJ"), representing the State of Oregon, regarding the potential recovery of losses and damages to state lands from the Archie Creek and Susan Creek fires. The ODOJ provided a damage estimate of approximately $109 million for mediation purposes only, which included losses and damages relating to the sheltering of, and assistance to, affected Oregonians; fire control and extinguishment costs; timber damage across 39 acres of Oregon forestland; losses and damages at the Rock Creek Fish Hatchery; road and highway damages; and other costs. In November 2025, PacifiCorp reached settlement for the Rock Creek Fish Hatchery component of this matter.

In 2023, the ODF sent demand notices for fire suppression costs totaling $2 million for three separate ignition points associated with the 2020 Wildfires. On May 30, 2024, PacifiCorp reached settlement with the ODF for suppression costs associated with one of these ignition points for less than $1 million.

In December 2024, in conjunction with the USDOJ correspondence for the Archie Creek fire described above, a complaint against PacifiCorp was filed, captioned the *United States of America* v. *PacifiCorp*, in U.S. District Court, District of Oregon, Portland Division, seeking various unquantified damages and a jury trial. The civil cover sheet accompanying the complaint demands damages estimated to exceed $900 million, which is greater than the damages included in the original correspondence from the USDOJ due to the addition of estimates for intangible environmental and natural resource damages. PacifiCorp responded to the complaint on February 18, 2025.

On February 19, 2025, PacifiCorp received a demand from the ODF for $2 million in fire suppression costs incurred by the ODF associated with the Oregon portion of the Slater Fire. On May 5, 2025, PacifiCorp received a demand from the ODOJ for $5 million of suppression costs incurred by the Oregon State Fire Marshal associated with the Oregon portion of the Slater Fire.

On April 4, 2025, PacifiCorp received a demand from the ODF for $11 million in fire suppression costs associated with the South Obenchain fire.

On April 21, 2025, PacifiCorp received a demand from the ODF for $4 million in fire suppression costs associated with the Echo Mountain and Kimberling Mountain fires.

On May 5, 2025, PacifiCorp received a demand from the Oregon State Fire Marshal for $5 million in fire suppression costs associated with the Slater Fire.

On February 20, 2026, the United States Attorney for the District of Oregon and the United States Attorney for the Eastern District of California approved a settlement agreement for $575 million between PacifiCorp and the United States of America resolving all known federal government complaints and demands associated with the Wildfires, including those associated with the 242, Archie Creek, Echo Mountain Complex, McKinney, Slater and South Obenchain fires. In accordance with the settlement agreement, PacifiCorp will pay the $575 million within 10 calendar days of the February 20, 2026, effective date.

PacifiCorp is actively cooperating with the ODOJ on resolving the alleged claims.

2020 Slater Fire California and Oregon Complaints and Demands

A significant number of complaints on behalf of plaintiffs associated with the Slater Fire were filed in Oregon and California. The complaints generally allege: (i) inverse condemnation; (ii) negligence; (iii) trespass; (iv) nuisance; and (v) violation of certain sections of the California Public Utilities Code and the California Health & Safety Code and request a jury trial and seek various damages. The damages sought generally include: (i) economic damages; (ii) noneconomic damages; (iii) doubling of economic damages; (iv) punitive damages; (v) pre- and post-judgment interest; and (vi) attorneys' fees and other costs. Substantially all of the complaints have been resolved.

In May 2025, PacifiCorp settled claims with one plaintiff in the *Hillman* complaint filed January 29, 2021, and with one plaintiff in the *Nixon* complaint filed August 31, 2022, against PacifiCorp in California Superior Court, Sacramento County, California ("Sacramento County Superior Court California") and previously part of the resolved consolidated *Hitchcock et al. v. PacifiCorp* cases. All settled cases are expected to be dismissed.

United States – Loss and Damages to Federal Lands – Slater Fire

PacifiCorp received a notice of indebtedness from the USFS indicating that PacifiCorp owes $356 million for fire suppression costs, natural resource damages and burned area emergency response costs incurred by the USFS associated with the Slater Fire in California. The notice further indicates that the alleged amounts owed may not include all environmental damages to which the USFS may be entitled and which the U.S. may seek to recover if further action is taken to resolve the debt. Additional charges for interest, penalties and administrative costs may also be sought associated with amounts considered overdue. In January 2024, PacifiCorp received correspondence from the USDOJ indicating its intent to litigate the matter because PacifiCorp has not paid the $356 million demand. As described above under "United States and State of Oregon – Loss and Damages to Federal and State Lands – Oregon Fires," PacifiCorp settled this demand in February 2026.

2022 McKinney Fire

Numerous complaints associated with the 2022 McKinney Fire were filed in Sacramento County Superior Court California on behalf of approximately 1,200 plaintiffs as described below. Certain complaints include wrongful death claims associated with the four fatalities. The complaints generally allege: (i) inverse condemnation; (ii) negligence; (iii) trespass; (iv) nuisance; and (v) violation of certain sections of the California Public Utilities Code and the California Health & Safety Code and seek various damages. The damages sought generally include: (i) economic damages; (ii) noneconomic damages; (iii) doubling or trebling of timber damages; (iv) punitive damages; (v) prejudgment interest; and (vi) attorneys' fees and other costs. The complaints do not specify the amount of damages sought.

On August 16, 2022, a complaint against PacifiCorp was filed, captioned *Bridges et al. v. PacifiCorp*, ("*Bridges*") in Sacramento County Superior Court California by approximately five plaintiffs. Additional complaints associated with the 2022 McKinney Fire were filed and subsequently consolidated into the *Bridges* case, covering approximately 1,200 plaintiffs, including wrongful death claims. To date, settlements have been reached with substantially all the plaintiffs associated with the 2022 McKinney Fire, including all wrongful death claims, and PacifiCorp believes that there are approximately 50 plaintiffs remaining to settle. While only a portion of the associated complaints have been dismissed as a result of the settlements, the remaining settled complaints are also expected to be dismissed. No trials are scheduled for the remaining 2022 McKinney Fire plaintiffs.

On April 12, 2024, a complaint against PacifiCorp was filed, captioned *Susanne White v. PacifiCorp,* ("*White*") in U.S. District Court for the Eastern District of California by one plaintiff. In November 2025, the *White* case was dismissed.

On July 25, 2025, a complaint against PacifiCorp was filed, captioned *California Department of Transportation v. PacifiCorp*, ("*Caltrans*") in Siskiyou Superior Court California alleging negligence and seeking damages of less than $1 million.

Refer to "United States and State of Oregon – Loss and Damages to Federal and State Lands – Oregon Fires" for information regarding the February 2026 settlement with the federal government.

BERKSHIRE HATHAWAY ENERGY

HomeServices, a subsidiary of BHE, is currently defending against several antitrust cases, all in federal district courts. In each case, plaintiffs claim HomeServices and certain of its subsidiaries (in one instance, HomeServices and BHE) conspired with co-defendants to artificially inflate real estate commissions by following and enforcing multiple listing service ("MLS") rules that require listing agents to offer a commission split to cooperating agents in order for the property to appear on the MLS ("Cooperative Compensation Rule"). None of the complaints specify damages sought. However, two cases allege Texas state law deceptive trade practices claims, for which plaintiffs have asserted damages totaling approximately $9 billion by separate written notice as required by Texas law. The cases are captioned as follows.

In April 2019, the Burnett (formerly Sitzer) et al. v. HomeServices of America, Inc. et al. complaint was filed in the U.S. District Court for the Western District of Missouri (the "Burnett case"). This lawsuit, which was certified as a class in April 2022, was originally brought on behalf of named plaintiffs Joshua Sitzer and Amy Winger against the National Association of Realtors ("NAR"), Anywhere Real Estate, HomeServices of America, Inc., RE/MAX, LLC, and Keller Williams Realty, Inc. HSF Affiliates, LLC and BHH Affiliates, LLC, each a subsidiary of HomeServices, were subsequently added as defendants. Rhonda Burnett became a lead class plaintiff in June 2021. The jury trial commenced on October 16, 2023, and the jury returned a verdict for the plaintiffs on October 31, 2023, finding that the named defendants participated in a conspiracy to follow and enforce the Cooperative Compensation Rule, which conspiracy had the purpose or effect of raising, inflating, or stabilizing broker commission rates paid by home sellers. The jury further found that the class plaintiffs had proved damages in the amount of $1.8 billion. Joint and several liability applies for the co- defendants. Federal law authorizes trebling of damages and the award of pre-judgment interest and attorney fees. Prior to the trial, Anywhere Real Estate and RE/MAX, LLC reached settlement agreements with the plaintiffs and settlements were reached by Keller Williams, NAR and HomeServices subsequent to the trial. All settlements received court approval, had final judgments entered by the court and were appealed to the U.S. Court of Appeals for the Eighth Circuit. All appeals were fully briefed by December 19, 2025, and oral arguments took place on January 14, 2026. A ruling from the court on the appeals is pending. The final HomeServices settlement agreement with the plaintiffs reached on April 25, 2024, settles all claims asserted against HomeServices, HSF Affiliates LLC and BHH Affiliates, LLC in the Burnett case and effectuates a nationwide class settlement. The final settlement agreement includes scheduled payments over four years aggregating $250 million. If the settlement is not affirmed by the U.S. Court of Appeals for the Eighth Circuit, HomeServices intends to vigorously appeal on multiple grounds the jury's findings and damage award in the Burnett case, including whether the case can proceed as a class action. The appeals process and further actions could take several years.

In March 2019, the *Christopher Moehrl v. National Association of Realtors, et al. and Sawbill Strategic, Inc. v. HomeServices of America, Inc. et al.* (together "Moehrl") complaint was filed in the U.S. District Court for the Northern District of Illinois. This certified class action lawsuit was brought on behalf of named plaintiff Christopher Moehrl against the NAR, Anywhere Real Estate, HomeServices of America, Inc., HSF Affiliates, LLC, BHH Affiliates, LLC, Long & Foster Companies, Inc. (also a HomeServices subsidiary), RE/MAX, LLC and Keller Williams Realty, Inc. In February 2025, the court ordered the case stayed as to the HomeServices' defendants pending a decision on the appeal of the HomeServices' nationwide settlement approved in November 2024.

In December 2020, the *Nosalek (formerly Bauman) v. HomeServices of America, Inc. et al.* complaint was filed in the U.S. District Court for the District of Massachusetts. This putative class action lawsuit was originally filed on behalf of named plaintiffs Gary Bauman, Mary Jane Bauman, and Jennifer Nosalek against the MLS Property Information Network, Inc. (MassPIN), Anywhere Real Estate, HomeServices of America, Inc., BHH Affiliates, LLC, HSF Affiliates, LLC, RE/MAX, LLC, Keller Williams Realty, Inc. and additional named defendants. In October 2021, the Baumans voluntarily dismissed themselves from the case, removing them as class representatives. A motion by HomeServices' defendants for summary judgment remains pending based on resolution of the motion for multidistrict litigation. In June 2024, the court ordered the case stayed as to the HomeServices' defendants pending a decision on the appeal of the HomeServices' nationwide settlement approved in November 2024.

In November 2023, the *QJ v. HomeServices of America, Inc. et al.* complaint was filed in the U.S. District Court for the Eastern District of Texas. This putative class action lawsuit was brought on behalf of named plaintiff QJ Team, LLC against the Texas Association of Realtors, Inc., HomeServices of America, Inc., ABA Management, L.L.C. (a HomeServices subsidiary), Ebby Halliday Real Estate, LLC (a HomeServices subsidiary), Keller Williams Realty, Inc. and additional named defendants. In June 2024, the court ordered the case stayed as to the HomeServices' defendants pending a decision on the appeal of the HomeServices' nationwide settlement approved in November 2024.

In December 2023, the *Martin v. HomeServices of America, Inc. et al.* complaint was filed in the U.S. District Court for the Eastern District of Texas. This putative class action lawsuit was brought on behalf of named plaintiff Julie Martin against the Texas Association of Realtors, Inc., HomeServices of America, Inc., ABA Management, L.L.C., Ebby Halliday Real Estate, LLC, Keller Williams Realty, Inc. and additional named defendants. In June 2024, the court ordered the case stayed as to the HomeServices' defendants pending a decision on the appeal of the HomeServices' nationwide settlement approved in November 2024.

On March 21, 2024, the court granted plaintiffs' motion to consolidate the *QJ* case and the *Martin* case.

In December 2023, the *Umpa v. HomeServices of America, Inc. et al.* complaint was filed in the U.S. District Court for the Western District of Missouri. This putative class action lawsuit was brought on behalf of named plaintiff Daniel Umpa against the NAR, HomeServices of America, Inc., BHH Affiliates, LLC, HSF Affiliates, LLC, Long & Foster Companies, Inc., Keller Williams Realty, Inc. and additional named defendants. In April 2024, the court ordered the case stayed as to the HomeServices' defendants pending a decision on the appeal of the HomeServices' nationwide settlement approved in November 2024.

In January 2024, the *Masiello v. Roy H. Long Realty, Inc. d/b/a Long Realty et al.* complaint was filed in the U.S. District Court for the District of Arizona. This putative class action lawsuit was brought on behalf of named plaintiff Joseph Masiello against the Arizona Association of Realtors, Roy H. Long Realty, Inc. d/b/a Long Realty (a HomeServices of America, Inc. subsidiary) and additional named defendants. In July 2024, the court ordered the case stayed as to defendant Long Realty, Inc. pending a decision on the appeal of the HomeServices' nationwide settlement approved in November 2024.

In January 2024, the *Fierro v. BHH Affiliates, LLC, et al.* complaint was filed in the U.S. District Court for the Central District of California. This putative class action lawsuit was brought on behalf of named plaintiffs Gael Fierro and Patrick Thurber against the NAR, Berkshire Hathaway Inc., BHH Affiliates, LLC and additional named defendants. In April 2024, the court ordered the case stayed as to defendant BHH Affiliates, LLC pending a decision on the appeal of the HomeServices' nationwide settlement approved in November 2024.

In January 2024, the *Whaley v. Berkshire Hathaway HomeServices Nevada Properties et al.* amended complaint was filed in the U.S. District Court for the District of Nevada. This putative class action lawsuit was brought on behalf of named plaintiff Nathaniel Whaley against the NAR, Berkshire Hathaway HomeServices Nevada Properties (a HomeServices of America, Inc. subsidiary) and additional named defendants. In May 2024, the court ordered the case stayed as to defendants Berkshire Hathaway HomeServices Nevada Properties and BHH Affiliates, LLC pending a decision on the appeal of the HomeServices' nationwide settlement approved in November 2024.

In February 2024, the *Boykin v. BHH Affiliates, LLC, et al.* compliant was filed in the U.S. District Court for the District of Nevada. This putative class action lawsuit was brought on behalf of named plaintiff Angela Boykin against the NAR, BHH Affiliates, LLC and additional named defendants. In May 2024, the court ordered the case stayed as to defendants Berkshire Hathaway HomeServices Nevada Properties and BHH Affiliates, LLC pending a decision on the appeal of the HomeServices' nationwide settlement approved in November 2024.

On March 20, 2024, the court consolidated the *Boykin* case with the *Whaley* case.

In March 2024, the *Wang v. HomeServices of America, Inc. et al*. complaint was filed in the U.S. District Court for the Southern District of New York. This *pro se* action was filed against the NAR, the Real Estate Board of New York, Inc., and HomeServices of America, Inc., et al. In February 2025, the court ordered the case stayed as to the HomeServices' defendants pending a decision on the appeal of the HomeServices' nationwide settlement approved in November 2024.

In March 2024, the first amended complaint in the *Gibson v. National Association of Realtors, et al.* complaint was filed in the U.S. District Court for the Western District of Missouri. The putative class action lawsuit was brought on behalf of named plaintiffs Don Gibson, Lauren Criss and John Meiners against the NAR, BHE and additional named defendants. In April 2024, the court ordered the case stayed as to the HomeServices' defendants pending a decision on the appeal of the HomeServices' nationwide settlement approved in November 2024.

On April 23, 2024, the court consolidated the *Gibson* case with the *Umpa* case.

In April 2024, the *Burton v. HomeServices of America, Inc., et al.* complaint was filed in the U.S. District Court for the District of South Carolina. This putative class action was brought on behalf of named plaintiffs Shauntell Burton, Benny D. Cheatham, Robert Douglass, Douglas Fender, and Dena Fender against HomeServices of America, Inc., HSF Affiliates, LLC, et al. This is the second complaint filed by these plaintiffs; the first complaint was filed against the National Association of Realtors, Keller Williams Realty, Inc. et al. ("Burton I") and is still pending. In June 2024, the court ordered the case stayed as to the HomeServices' defendants pending a decision on the appeal of the HomeServices' nationwide settlement approved in November 2024.

Item 4. Mine Safety Disclosures

Information regarding Berkshire Hathaway Energy's and PacifiCorp's mine safety violations and other legal matters disclosed in accordance with Section 1503(a) of the Dodd-Frank Reform Act is included in Exhibit 95 to this Form 10-K.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

BERKSHIRE HATHAWAY ENERGY

BHE's common stock is held by Berkshire Hathaway, and has not been registered with the SEC pursuant to the Securities Act of 1933, as amended, listed on a stock exchange or otherwise publicly held or traded. BHE has not declared or paid any cash dividends to its common shareholders since Berkshire Hathaway acquired an equity interest in BHE in March 2000 and does not presently anticipate that it will declare any dividends on its common stock in the foreseeable future.

PACIFICORP

All common stock of PacifiCorp is held by its parent company, PPW Holdings LLC, which is a direct, wholly owned subsidiary of BHE. PacifiCorp declared and paid dividends to PPW Holdings LLC of $— million in 2025, $— million in 2024 and $300 million in 2023.

MIDAMERICAN FUNDING AND MIDAMERICAN ENERGY

MidAmerican Funding is an Iowa limited liability company whose membership interest is held solely by BHE. All common stock of MidAmerican Energy is held by its parent company, MHC, which is a direct, wholly owned subsidiary of MidAmerican Funding. MidAmerican Funding declared and paid cash distributions to BHE of $474 million in 2025, $425 million in 2024 and $1,025 million in 2023. MidAmerican Energy declared and paid cash dividends to MHC totaling $500 million in 2025, $425 million in 2024 and $1,025 million in 2023.

NEVADA POWER

All common stock of Nevada Power is held by its parent company, NV Energy, which is an indirect, wholly owned subsidiary of BHE. Nevada Power declared and paid dividends to NV Energy of $185 million in 2025, $75 million in 2024 and $50 million in 2023.

SIERRA PACIFIC

All common stock of Sierra Pacific is held by its parent company, NV Energy, which is an indirect, wholly owned subsidiary of BHE. Sierra Pacific declared and paid dividends to NV Energy of $100 million in 2025, $200 million in 2024 and $100 million in 2023.

EASTERN ENERGY GAS

Eastern Energy Gas is a Virginia limited liability corporation whose membership interest is held solely by its parent company, BHE GT&S, which is an indirect, wholly owned subsidiary of BHE. Eastern Energy Gas declared and paid dividends to BHE GT&S of $1,319 million in 2025, $361 million in 2024 and $332 million in 2023.

EGTS

All common stock of EGTS is held by its parent company, Eastern Energy Gas, which is an indirect, wholly owned subsidiary of BHE. EGTS declared and paid dividends to Eastern Energy Gas of $56 million in 2025, $297 million in 2024 and $158 million in 2023.

Item 6. [Reserved]

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

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Berkshire Hathaway Energy Company and its subsidiaries
Consolidated Financial Section

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following is management's discussion and analysis of certain significant factors that have affected the consolidated financial condition and results of operations of the Company during the periods included herein. Explanations include management's best estimate of the impact of weather, customer growth, usage trends and other factors. This discussion should be read in conjunction with the Company's historical Consolidated Financial Statements and Notes to Consolidated Financial Statements in Item 8 of this Form 10-K. The Company's actual results in the future could differ significantly from the historical results.

The reportable segment financial information includes all necessary adjustments and eliminations needed to conform to the Company's significant accounting policies. The differences between the reportable segment amounts and the consolidated amounts, described as BHE and Other, relate principally to other corporate entities, corporate functions and intersegment eliminations.

Results of Operations

Overview

Operating revenue and earnings on common shares for the Company's reportable segments for the years ended December 31 are summarized as follows (in millions):

	2025	2024	Change		2024	2023	Change	
Operating revenue:								
PacifiCorp	$ 7,493	$ 6,600	$ 893	14 %	$ 6,600	$ 5,936	$ 664	11 %
MidAmerican Funding	3,907	3,251	656	20	3,251	3,393	(142)	(4)
NV Energy	3,451	4,140	(689)	(17)	4,140	4,523	(383)	(8)
Northern Powergrid	1,373	1,627	(254)	(16)	1,627	1,303	324	25
BHE Pipeline Group	3,943	3,810	133	3	3,810	3,774	36	1
BHE Transmission	744	801	(57)	(7)	801	799	2	—
BHE Renewables	1,113	1,475	(362)	(25)	1,475	1,710	(235)	(14)
HomeServices	4,327	4,354	(27)	(1)	4,354	4,322	32	1
BHE and Other	(153)	(138)	(15)	11	(138)	(158)	20	(13)
Total operating revenue	$26,198	$25,920	$ 278	1 %	$25,920	$25,602	$ 318	1 %
Earnings on common shares:								
PacifiCorp	$ 642	$ 526	$ 116	22 %	$ 526	$ (468)	$ 994	* %
MidAmerican Funding	1,048	991	57	6	991	980	11	1
NV Energy	407	444	(37)	(8)	444	394	50	13
Northern Powergrid	343	547	(204)	(37)	547	165	382	232
BHE Pipeline Group	1,151	1,232	(81)	(7)	1,232	1,079	153	14
BHE Transmission	247	263	(16)	(6)	263	246	17	7
BHE Renewables[(1)]	585	447	138	31	447	518	(71)	(14)
HomeServices	24	(107)	131	*	(107)	13	(120)	*
BHE and Other	(381)	(43)	(338)	*	(43)	59	(102)	*
Total earnings on common shares	$ 4,066	$ 4,300	$ (234)	(5)%	$ 4,300	$ 2,986	$ 1,314	44 %

(1) Includes the tax attributes of disregarded entities that are not required to pay income taxes and the earnings of which are taxable directly to BHE.

* Not meaningful.

Earnings on common shares decreased $234 million for 2025 compared to 2024. Included in these results was a pre-tax gain in 2025 of $110 million ($87 million after-tax) compared to a pre-tax gain in 2024 of $444 million ($351 million after-tax) related to the Company's investment in BYD Company Limited ("BYD"). Excluding the impact of this item, adjusted earnings on common shares in 2025 was $3,979 million, an increase of $30 million, or 1%, compared to adjusted earnings on common shares in 2024 of $3,949 million.

The decrease in earnings on common shares for 2025 compared to 2024 was primarily due to:

- The Utilities' earnings increased $136 million primarily due to higher electric utility margin and lower wildfire loss accruals of $246 million. These items were offset by higher operations and maintenance expense, increased depreciation and amortization expense, lower interest and dividend income, higher interest expense, lower allowances for equity and borrowed funds used during construction and unfavorable income tax benefits, largely due to the effects of ratemaking. Electric retail customer volumes increased 2.2% for 2025 compared to 2024, primarily due to higher customer usage and an increase in the average number of customers, partially offset by the unfavorable impact of weather;
- Northern Powergrid's earnings decreased $204 million, primarily due to lower distribution revenue and higher interest expense. Units distributed increased 1.1% for 2025 compared to 2024 mainly due to higher customer usage;
- BHE Pipeline Group's earnings decreased $81 million, primarily due to higher interest expense at BHE GT&S, higher operations and maintenance expense and lower margins on gas sales at Northern Natural Gas, higher depreciation and amortization expense at BHE GT&S and Northern Natural Gas and lower equity earnings at BHE GT&S, partially offset by higher transportation and storage revenues at Northern Natural Gas and BHE GT&S and higher variable revenue at Cove Point;
- BHE Renewables' earnings increased $138 million, primarily due to higher earnings from the wind tax equity investment portfolio, higher natural gas and geothermal earnings and higher solar earnings, partially offset by lower earnings from owned wind projects;
- HomeServices' earnings increased $131 million, primarily due to an after-tax charge of approximately $140 million recognized in the first quarter of 2024 associated with a settlement reached in the ongoing real estate industry litigation matters; and
- BHE and Other's earnings decreased $338 million, primarily due to an unfavorable comparative change of $264 million and lower net interest and dividend income of $91 million, each related to the Company's investment in BYD, and unfavorable consolidated income tax adjustments, partially offset by lower interest expense.

Earnings on common shares increased $1,314 million for 2024 compared to 2023. Included in these results was a pre-tax gain in 2024 of $444 million ($351 million after-tax) compared to a pre-tax gain in 2023 of $639 million ($505 million after-tax) related to the Company's investment in BYD. Excluding the impact of this item, adjusted earnings on common shares in 2024 was $3,949 million, an increase of $1,468 million, or 59%, compared to adjusted earnings on common shares in 2023 of $2,481 million.

The increase in earnings on common shares for 2024 compared to 2023 was primarily due to:

- The Utilities' earnings increased $1,055 million largely due to a decrease in wildfire loss accruals, net of expected insurance recoveries, of $1,331 million, higher electric utility margin, higher PTCs and increased allowances for equity and borrowed funds used during construction. These items were offset by increased interest expense and increased operations and maintenance expense. Electric retail customer volumes increased 3.6% for 2024 compared to 2023, primarily due to higher customer usage and an increase in the average number of customers, partially offset by the unfavorable impact of weather;
- Northern Powergrid's earnings increased $382 million, primarily due to higher distribution revenue, the write-off of gas exploration costs in 2023 and lower income tax expense from charges recognized in 2023 related to the Energy Profits Levy income tax and a group relief tax claim recognized in 2024, partially offset by higher distribution-related costs and unfavorable operating performance at the upstream gas exploration and production business. Units distributed increased 0.4% mainly due to the favorable impact of weather;
- BHE Pipeline Group's earnings increased $153 million, primarily due to the acquisition of an additional 50% limited partner interest in Cove Point on September 1, 2023;
- BHE Renewables' earnings decreased $71 million, primarily due to lower earnings from the wind tax equity investment portfolio, gains on the extinguishment of debt recognized in 2023 and lower geothermal and natural gas earnings, partially offset by higher earnings from the retail energy service business;

- HomeServices' earnings decreased $120 million, primarily due to a charge of approximately $140 million recognized in the first quarter of 2024 associated with a settlement reached in the ongoing real estate industry litigation matters, partially offset by higher mortgage earnings and favorable operating expenses; and
- BHE and Other's earnings decreased $102 million, primarily due to an unfavorable comparative change of $154 million related to the Company's investment in BYD, partially offset by lower dividends due to the final redemption of BHE's 4.00% Perpetual Preferred Stock issued to certain subsidiaries of Berkshire Hathaway in December 2023.

Reportable Segment Results

PacifiCorp

Operating revenue increased $893 million for 2025 compared to 2024, primarily due to higher retail revenue of $793 million and higher wholesale and other revenue of $100 million. Retail revenue increased primarily due to price impacts of $710 million from higher average rates, largely from tariff changes and favorable adjustments of $87 million due to the buy-down of certain plant balances and regulatory assets pursuant to the Utah general rate case order (fully offset in depreciation and amortization expense), and $83 million from higher retail volumes. Retail customer volumes increased 1.3% primarily due to an increase in the average number of customers and higher customer usage, partially offset by the unfavorable impact of weather. Wholesale and other revenue increased primarily due to higher wholesale volumes, partially offset by lower average wholesale prices.

Earnings increased $116 million for 2025 compared to 2024, primarily due to higher utility margin of $455 million, lower wildfire loss accruals of $246 million and a favorable income tax benefit from higher PTCs of $41 million offset by the effects of ratemaking of $34 million. These items were partially offset by higher operations and maintenance expense of $161 million, increased depreciation and amortization expense of $137 million, decreased allowances for equity and borrowed funds used during construction of $112 million, lower interest and dividend income of $78 million and higher interest expense of $37 million. Utility margin increased primarily due to higher retail rates and volumes, lower purchased electricity costs and higher wholesale volumes, partially offset by unfavorable deferred net power costs, higher thermal generation costs and lower wholesale average prices. Operations and maintenance expense increased mainly due to higher insurance premiums, increased amortization of demand-side management costs, higher general and plant maintenance costs, increased salary and benefit expenses and higher legal fees, partially offset by lower vegetation management and other wildfire prevention costs and higher accruals of federal grant reimbursements. Depreciation and amortization expense increased largely due to additional assets placed in-service and the buy-down of certain plant balances and regulatory assets pursuant to the Utah general rate case order. Interest expense increased primarily due to a debt issuance in March 2025.

Operating revenue increased $664 million for 2024 compared to 2023, primarily due to higher retail revenue of $716 million, partially offset by lower wholesale and other revenue of $52 million. Retail revenue increased primarily due to price impacts of $554 million from higher average rates, largely from tariff changes, and $162 million from higher retail volumes. Retail customer volumes increased 3.1%, primarily due to higher customer usage and an increase in the average number of customers, partially offset by the unfavorable impact of weather. Wholesale and other revenue decreased primarily due to lower wholesale volumes and lower average wholesale prices, partially offset by higher wheeling revenue.

Earnings increased $994 million for 2024 compared to 2023, primarily due to lower wildfire loss accruals, net of expected insurance recoveries, of $1,331 million, higher utility margin of $158 million, increased allowances for equity and borrowed funds used during construction of $109 million and higher interest and dividend income of $93 million. These items were partially offset by higher interest expense of $210 million, increased operations and maintenance expense of $152 million and higher depreciation and amortization expense of $26 million. Utility margin increased primarily due to higher retail rates and volumes and lower thermal generation costs, partially offset by unfavorable deferred net power costs, higher purchased electricity costs and lower wholesale volumes and average prices. Interest expense increased due to debt issuances in May 2023 and January 2024. Operations and maintenance expense increased due to higher vegetation management and other wildfire prevention costs, increased insurance premiums, higher amortization of demand-side management costs, increased legal fees and higher salary and benefit expenses. Depreciation and amortization expense increased largely due to additional assets placed in-service.

MidAmerican Funding

Operating revenue increased $656 million for 2025 compared to 2024, primarily due to higher electric operating revenue of $540 million and higher natural gas operating revenue of $120 million. Electric operating revenue increased due to higher retail revenue of $313 million and higher wholesale and other revenue of $227 million. Electric retail revenue increased primarily due to higher recoveries through adjustment clauses of $175 million (fully offset in cost of sales, operations and maintenance expense and income tax benefit) and higher retail volumes of $150 million, partially offset by price impacts of $12 million from changes in sales mix. Electric retail customer volumes increased 9.6%, primarily due to customer growth, higher customer usage and the favorable impact of weather. Electric wholesale and other revenue increased mainly due to higher average wholesale prices of $217 million and higher wholesale volumes of $17 million. Natural gas operating revenue increased primarily due to higher energy-related rates of $113 million (fully offset in cost of sales) from a higher average per-unit cost of natural gas sold and the favorable impact of weather of $10 million.

Earnings increased $57 million for 2025 compared to 2024, primarily due to higher electric utility margin of $257 million and increased allowances for equity and borrowed funds used during construction of $20 million. These items were partially offset by an unfavorable income tax benefit, largely from lower PTCs of $47 million and the effects of ratemaking of $22 million, higher operations and maintenance expense of $54 million and increased depreciation and amortization expense of $30 million. Electric utility margin increased primarily due to higher retail and wholesale revenues, partially offset by higher purchased electricity and thermal generation fuel costs. Operations and maintenance expense increased primarily due to increased general and plant maintenance costs, partially offset by lower administrative and other costs. Depreciation and amortization expense increased primarily due to additional assets placed in-service.

Operating revenue decreased $142 million for 2024 compared to 2023, primarily due to lower electric operating revenue of $89 million and lower natural gas operating revenue of $55 million. Electric operating revenue decreased due to lower wholesale and other revenue of $65 million and lower retail revenue of $24 million. Electric wholesale and other revenue decreased mainly due to lower average wholesale prices of $41 million and lower wholesale volumes of $25 million. Electric retail revenue decreased primarily due to lower recoveries through adjustment clauses of $39 million (fully offset in operations and maintenance expense and income tax benefit), partially offset by higher retail volumes of $12 million. Electric retail customer volumes increased 1.2%, primarily due to higher customer usage, partially offset by the unfavorable impact of weather. Natural gas operating revenue decreased primarily due to lower energy-related rates of $84 million (fully offset in cost of sales) from a lower average per-unit cost of natural gas sold and the unfavorable impact of weather of $8 million, partially offset by higher base rates of $33 million.

Earnings increased $11 million for 2024 compared to 2023, primarily due to a favorable income tax benefit, primarily from higher PTCs of $129 million offset by the effects of ratemaking of $24 million, higher natural gas utility margin of $29 million, increased interest and dividend income of $16 million and higher allowances for equity and borrowed funds used during construction of $12 million. These items were partially offset by higher depreciation and amortization expense of $93 million, increased interest expense of $72 million, higher operations and maintenance expense of $28 million and lower electric utility margin of $18 million. Natural gas utility margin increased primarily due to higher base rates from tariff changes, partially offset by the unfavorable impact of weather. Depreciation and amortization expense increased primarily due to additional assets placed in-service and the impacts of certain regulatory mechanisms. Interest expense increased due to debt issuances in September 2023 and January 2024. Operations and maintenance expense increased primarily due to higher general and plant maintenance costs. Electric utility margin decreased primarily due to lower wholesale and retail revenues, partially offset by lower thermal generation and purchased electricity costs.

NV Energy

Operating revenue decreased $689 million for 2025 compared to 2024, primarily due to lower electric operating revenue of $633 million and lower natural gas operating revenue of $58 million, largely due to lower energy-related rates (fully offset in costs of sales) from a lower average per-unit cost of natural gas sold. Electric operating revenue decreased primarily due to lower fully bundled energy rates (fully offset in cost of sales) of $571 million, lower revenue related to an accrual in connection with a potential customer refund arising from an ongoing regulatory proceeding of $60 million and lower customer volumes of $43 million, partially offset by higher base rates of $34 million at Sierra Pacific. Electric retail customer volumes decreased 2.2%, primarily due to the unfavorable impact of weather.

Earnings decreased $37 million for 2025 compared to 2024, primarily due to lower electric utility margin of $61 million, higher interest expense of $31 million, increased operations and maintenance expense of $24 million and lower interest and dividend income of $11 million. These items were partially offset by higher allowances for borrowed and equity funds used during construction of $58 million and a favorable income tax expense, largely from the effects of ratemaking of $9 million and higher PTCs of $4 million. Electric utility margin decreased primarily due to lower revenue related to an accrual in connection with a potential customer refund arising from an ongoing regulatory proceeding and lower retail volumes, partially offset by higher base rates at Sierra Pacific. Interest expense increased mainly due to higher outstanding long-term debt balances. Operations and maintenance expense increased primarily due to higher insurance premiums and increased general and plant maintenance costs, partially offset by lower administrative costs.

Operating revenue decreased $383 million for 2024 compared to 2023, primarily due to lower electric operating revenue of $329 million and lower natural gas operating revenue of $55 million, largely due to lower energy-related rates (fully offset in costs of sales) from a lower average per-unit cost of natural gas sold. Electric operating revenue decreased primarily due to lower fully bundled energy rates (fully offset in cost of sales) of $463 million, partially offset by higher customer volumes of $70 million and higher base rates of $57 million at Nevada Power and Sierra Pacific. Electric retail customer volumes increased 6.5%, primarily due to the favorable impact of weather, an increase in the average number of customers and higher customer usage.

Earnings increased $50 million for 2024 compared to 2023, primarily due to higher electric utility margin of $134 million, lower depreciation and amortization of $61 million and higher allowances for equity and borrowed funds used during construction of $13 million. These items were partially offset by lower interest and dividend income of $59 million, higher operations and maintenance expense of $49 million, increased interest expense of $32 million and an unfavorable income tax expense primarily due to the effects of ratemaking of $24 million offset by higher PTCs of $8 million. Electric utility margin increased primarily due to higher retail volumes and higher base rates at Nevada Power and Sierra Pacific. Depreciation and amortization decreased largely from lower regulatory amortizations. Operations and maintenance expense increased primarily due to higher insurance premiums, increased general and plant maintenance costs and higher salary and benefit expenses. Interest expense increased mainly due to higher outstanding long-term debt balances.

Northern Powergrid

Operating revenue decreased $254 million for 2025 compared to 2024, primarily due to lower distribution revenue of $232 million, lower revenue at a solar project of $42 million from lower pricing and generation and decreased non-regulated meter rental revenue of $12 million, partially offset by $36 million from the weaker U.S. dollar. Distribution revenue decreased primarily due to lower tariff rates of $227 million driven by the impacts of inflation and lower recoveries of Supplier of Last Resort payments of $12 million (largely offset in cost of sales), partially offset by an increase in units distributed of 1.1% mainly due to higher customer usage.

Earnings decreased $204 million for 2025 compared to 2024, primarily due to lower distribution revenue, higher interest expense of $20 million and higher income tax expense from a charge related to the March 2025 enactment of a change in the Energy Profits Levy income tax of $14 million, partially offset by lower income tax expense from higher utilization of tax losses from the upstream gas exploration and production business of $7 million. Interest expense increased primarily due to debt issuances in March and November 2025.

Operating revenue increased $324 million for 2024 compared to 2023, primarily due to higher distribution revenue of $288 million and $45 million from the weaker U.S. dollar, partially offset by lower revenue at the upstream gas exploration and production business of $21 million due to lower gas production volumes and prices. Distribution revenue increased due to higher tariff rates of $347 million driven by the impacts of inflation and an increase in units distributed of 0.4% mainly due to the favorable impact of weather, partially offset by lower recoveries of Supplier of Last Resort payments of $63 million (largely offset in cost of sales).

Earnings increased $382 million for 2024 compared to 2023, primarily due to higher distribution revenue, the write-off of upstream gas exploration and production costs in 2023 of $92 million and lower income tax expense from charges recognized in 2023 related to the Energy Profits Levy income tax and a group relief tax claim recognized in 2024, partially offset by higher distribution-related costs of $38 million and unfavorable operating performance at the upstream gas exploration and production business of $12 million.

BHE Pipeline Group

Operating revenue increased $133 million for 2025 compared to 2024, primarily due to higher operating revenue of $110 million at BHE GT&S, higher non-regulated revenues of $33 million from additional compressor units placed in-service and higher operating revenue of $3 million at Northern Natural Gas, partially offset by lower operating revenue of $13 million at Kern River, largely due to a decline in variable transportation revenues from lower rates and volumes. The increase in operating revenue at BHE GT&S was primarily due to favorable variable revenue at Cove Point of $55 million, increased non-regulated revenues of $37 million (largely offset in cost of sales) primarily from higher volumes offset by lower rates and higher regulated gas transmission and storage services revenue of $37 million, largely from additional capacity contracts. The increase in operating revenue at Northern Natural Gas was primarily due to higher transportation and storage revenues of $37 million due to higher volumes and rates, partially offset by lower gas sales of $34 million from system balancing activities.

Earnings decreased $81 million for 2025 compared to 2024, primarily due to lower earnings of $47 million at Northern Natural Gas, lower earnings of $32 million at BHE GT&S and lower earnings of $13 million at Kern River, largely due to a decline in variable transportation revenues, partially offset by higher non-regulated earnings of $14 million from additional compressor units placed in-service. The decrease at Northern Natural Gas was primarily due to higher operations and maintenance expense of $28 million, largely from increased costs for operations projects and higher salary and benefit expenses, lower margin on gas sales of $26 million from system balancing activities, decreased interest and dividend income of $22 million and higher depreciation and amortization expense of $11 million from additional assets placed in-service, partially offset by higher transportation and storage revenues. The decrease at BHE GT&S was primarily due to higher interest expense of $105 million, primarily from debt issuances in January 2025 and debt refinancings in the fourth quarter of 2024 at higher interest rates, lower equity earnings of $26 million primarily at Iroquois and higher depreciation and amortization expense of $18 million largely from additional assets placed in-service, partially offset by favorable variable revenue at Cove Point, higher regulated gas transmission and storage services revenue and increased interest and dividend income of $21 million.

Operating revenue increased $36 million for 2024 compared to 2023, primarily due to higher operating revenue of $74 million at Northern Natural Gas and higher non-regulated revenues of $38 million from additional compressor units placed in-service, partially offset by lower operating revenue of $55 million at BHE GT&S and lower operating revenue of $20 million at Kern River, largely due to a decline in variable transportation revenues from lower rates and volumes. The increase in operating revenue at Northern Natural Gas was primarily due to higher transportation revenue of $50 million due to higher volumes and rates and higher gas sales of $23 million from system balancing activities. The decrease in operating revenue at BHE GT&S was primarily due to lower revenues at Cove Point of $34 million largely from unfavorable variable revenue and storage-related service revenues, a decrease in variable revenue related to natural gas storage park and loan activity of $18 million at EGTS and lower gas sales of $15 million at EGTS from operational and system balancing activities, partially offset by an increase in regulated gas transmission and storage services revenue of $17 million at EGTS largely due to additional capacity contracts.

Earnings increased $153 million for 2024 compared to 2023, primarily due to higher earnings of $136 million at BHE GT&S and higher earnings of $23 million at Northern Natural Gas. The increase at BHE GT&S was primarily due to higher earnings at Cove Point of $147 million, largely due to the acquisition of an additional 50% limited partner interest in Cove Point on September 1, 2023, decreased cost of gas of $30 million from the unfavorable revaluation of volumes retained at EGTS in 2023 due to lower natural gas prices and lower operations and maintenance expense of $23 million largely from lower outside services, partially offset by higher depreciation and amortization expense of $16 million, mainly due to additional assets placed in-service, and unfavorable income tax adjustments of $14 million. The increase at Northern Natural Gas was primarily due to higher transportation revenue and higher margin on gas sales of $40 million from system balancing activities, partially offset by increased operations and maintenance expense of $46 million, largely from higher costs for operations projects and increased salary and benefit expenses, and higher depreciation and amortization expense of $14 million from additional assets placed in-service.

BHE Transmission

Operating revenue decreased $57 million for 2025 compared to 2024, primarily due to $35 million of lower revenue from non-regulated wind-powered generating facilities from lower generation and pricing, $14 million from the stronger U.S. dollar and the 2024 recovery of costs from the 2023 spring wildfire and storm events of $13 million (fully offset in operations and maintenance expense).

Earnings decreased $16 million for 2025 compared to 2024, primarily due to lower equity earnings at ETT, lower revenue from non-regulated wind-powered generating facilities, the impact of the AUC's approved return on equity rate decrease at AltaLink and $4 million from the stronger U.S. dollar.

Operating revenue increased $2 million for 2024 compared to 2023, primarily due to the recovery of higher costs totaling $17 million and the impact of the AUC's approved return on equity rate increase of $17 million at AltaLink, partially offset by lower revenue from non-regulated generating facilities of $21 million and $11 million from the stronger U.S. dollar.

Earnings increased $17 million for 2024 compared to 2023, primarily due to the impact of the AUC's approved return on equity rate increase at AltaLink and higher equity earnings at ETT, partially offset by lower revenue from non-regulated generating facilities and $3 million from the stronger U.S. dollar.

BHE Renewables

Operating revenue decreased $362 million for 2025 compared to 2024, primarily due to lower electric and natural gas retail energy services revenue of $489 million from the sale of customer contracts in December 2024 and lower wind revenue of $7 million, partially offset by higher natural gas and geothermal revenue of $116 million from higher pricing and generation and higher solar revenue of $24 million from higher generation and pricing. Wind revenue decreased largely from lower generation, partially offset by favorable changes in the valuations of certain derivative contracts.

Earnings increased $138 million for 2025 compared to 2024, primarily due to higher wind earnings of $55 million, higher natural gas and geothermal earnings of $55 million, from higher pricing and generation offset by higher costs associated with a joint venture formed in May 2024, and higher solar earnings of $30 million from higher generation and pricing and lower maintenance costs. Wind earnings increased due to higher earnings from the wind tax equity investment portfolio of $83 million, primarily due to the addition of eight tax equity investments from a common control merger completed in December 2024, partially offset by lower earnings from owned wind projects of $28 million mainly due to lower PTCs.

Operating revenue decreased $235 million for 2024 compared to 2023, primarily due to lower electric and natural gas retail energy services revenue of $172 million, lower geothermal and natural gas revenue of $80 million due to lower generation and pricing and lower wind revenue of $10 million, partially offset by higher solar revenue of $25 million from higher generation. Retail energy services revenue decreased mainly due to lower electric and natural gas volumes. Wind revenue decreased largely from unfavorable changes in the valuations of certain derivative contracts and lower pricing, partially offset by higher generation.

Earnings decreased $71 million for 2024 compared to 2023, primarily due to lower wind earnings of $73 million, lower geothermal and natural gas earnings of $37 million from lower revenue offset by maintenance outages in 2023 and lower solar earnings of $3 million from higher maintenance costs offset by higher revenue, partially offset by higher earnings of $46 million from the retail energy services business largely due to favorable changes in the unrealized positions on derivative contracts. Wind earnings decreased due to lower earnings from the wind tax equity investment portfolio of $49 million and lower earnings at owned wind projects of $24 million, primarily due to gains on the extinguishment of debt recognized in 2023 and lower revenue.

HomeServices

Operating revenue decreased $27 million for 2025 compared to 2024, primarily due to lower brokerage and settlement services revenue of $50 million, partially offset by higher mortgage revenue of $20 million. The decrease in brokerage and settlement services revenue resulted from a 5% decrease in closed brokerage units driven by the continued slowdown of overall market activity due to increased interest rates and low inventory. The increase in mortgage revenue was due to a 12% increase in funded volume driven primarily by a 9% increase in average loan size.

Earnings increased $131 million for 2025 compared to 2024, primarily due to an after-tax charge of approximately $140 million recognized in the first quarter of 2024 associated with a settlement reached in the ongoing real estate industry litigation matters and favorable operating expenses, partially offset by the write-off of internally developed software costs.

Operating revenue increased $32 million for 2024 compared to 2023, primarily due to higher mortgage revenue of $35 million. The increase in mortgage revenue was due to a 4% increase in funded volume, primarily due to higher refinance activity and a 7% increase in average loan size.

Earnings decreased $120 million for 2024 compared to 2023, primarily due to an after-tax charge of approximately $140 million recognized in the first quarter of 2024 associated with a settlement reached in the ongoing real estate industry litigation matters, partially offset by higher mortgage earnings of $31 million, mainly due to higher revenue, and favorable operating expenses.

BHE and Other

Earnings decreased $338 million for 2025 compared to 2024, primarily due to the $264 million unfavorable comparative change and lower net interest and dividend income of $91 million each related to the Company's investment in BYD and unfavorable consolidated income tax adjustments totaling $43 million, partially offset by lower interest expense of $69 million largely due to lower outstanding long-term debt balances.

Earnings decreased $102 million for 2024 compared to 2023, primarily due to the $154 million unfavorable comparative change and lower net interest and dividend income of $18 million each related to the Company's investment in BYD, partially offset by $34 million of lower dividends due to the final redemption of BHE's 4.00% Perpetual Preferred Stock issued to certain subsidiaries of Berkshire Hathaway in December 2023 and favorable consolidated income tax adjustments totaling $28 million.

Liquidity and Capital Resources

Each of BHE's direct and indirect subsidiaries is organized as a legal entity separate and apart from BHE and its other subsidiaries. It should not be assumed that the assets of any subsidiary will be available to satisfy BHE's obligations or the obligations of its other subsidiaries. However, unrestricted cash or other assets that are available for distribution may, subject to applicable law, regulatory commitments and the terms of financing and ring-fencing arrangements for such parties, be advanced, loaned, paid as dividends or otherwise distributed or contributed to BHE or affiliates thereof. The Company's long-term debt may include provisions that allow BHE or its subsidiaries to redeem such debt in whole or in part at any time. These provisions generally include make-whole premiums. Refer to Note 18 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for further discussion regarding the limitation of distributions from BHE's subsidiaries.

As of December 31, 2025, the Company's total net liquidity was as follows (in millions):

	BHE	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	BHE Canada	HomeServices	BHE Pipeline Group and Other	Total
Cash and cash equivalents	$ 145	$ 80	$ 672	$ 40	$ 37	$ 126	$ 345	$ 250	$ 1,695
Credit facilities[1]	3,500	2,900	1,509	1,000	410	674	1,525	—	11,518
Less:									
Short-term debt	—	(1,000)	—	(50)	(220)	(72)	(655)	—	(1,997)
Tax-exempt bond support and letters of credit	—	—	(258)	—	—	(4)	—	—	(262)
Net credit facilities	3,500	1,900	1,251	950	190	598	870	—	9,259
Total net liquidity	$3,645	$ 1,980	$ 1,923	$ 990	$ 227	$ 724	$ 1,215	$ 250	$10,954
Credit facilities:									
Maturity dates	2028	2026, 2028	2026, 2028	2028	2026, 2028	2028, 2029, 2030	2026, 2030		

(1) Includes $140 million drawn on capital expenditure and other uncommitted credit facilities at Northern Powergrid.

Refer to Note 9 of the Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for further discussion regarding the Company's credit facilities, letters of credit, equity commitments and other related items.

On July 4, 2025, the One Big Beautiful Bill Act (the "OBBBA") was enacted, introducing substantial revisions to federal energy-related tax policy. Among its provisions, the OBBBA accelerates the phase-out of clean electricity production and investment tax credits and establishes new sourcing requirements applicable to facilities commencing construction after December 31, 2025. On July 7, 2025, a federal executive order (the "Executive Order") was issued directing the Secretary of the Treasury to promulgate new or revised guidance consistent with applicable law to ensure that policies concerning the "beginning of construction" requirements are not circumvented for wind and solar-powered generating facilities. In response, the U.S. Secretary of the Treasury issued partial guidance on September 2, 2025, through Notice 2025-42. While the guidance largely reaffirmed existing standards, it notably eliminated the five percent safe harbor method for establishing the beginning of construction for projects commencing construction on or after September 2, 2025. The OBBBA and Notice 2025-42 did not have a material impact on the Company's 2025 consolidated financial results.

The Company's future financial performance and capital expenditures related to renewable energy, storage and technology neutral projects may be affected by the combined effects of the OBBBA, the Executive Order, and broader macroeconomic and geopolitical conditions, including changes in international trade policies and tariff regimes. The pace of change in these areas accelerated during 2025, and uncertainty persists regarding the scope and duration of these external factors. However, the Company currently does not believe these items and any resulting changes to future capital project allocations will significantly impact its business in the near term.

Operating Activities

Net cash flows from operating activities for the years ended December 31, 2025 and 2024 were $8,359 million and $8,442 million, respectively. The decrease was primarily due to the timing of payments related to fuel and energy costs, lower income tax receipts and higher cash paid for interest, partially offset by favorable operating results and changes in working capital, including receipt of $98 million of insurance reimbursements related to wildfire liabilities and a decrease in wildfire liability settlement payments.

Net cash flows from operating activities for the years ended December 31, 2024 and 2023 were $8.4 billion and $7.1 billion, respectively. The increase was primarily due to favorable operating results, changes in working capital, including receipt of $401 million of insurance reimbursements related to wildfire liabilities, a decrease in wildfire liability settlement payments and higher income tax receipts, partially offset by higher cash paid for interest.

The timing of the Company's income tax cash flows from period to period can be significantly affected by the estimated federal income tax payment methods selected and assumptions made for each payment date.

Investing Activities

Net cash flows from investing activities for the years ended December 31, 2025 and 2024 were $(10.1) billion and $(6.0) billion, respectively. The change was primarily due to lower proceeds from sales, net of purchases, of marketable securities of $1.7 billion, higher capital expenditures of $1.6 billion and lower proceeds from sales and maturities, net of purchases, of U.S. Treasury Bills totaling $726 million. Refer to "Future Uses of Cash" for further discussion of capital expenditures.

Net cash flows from investing activities for the years ended December 31, 2024 and 2023 were $(6.0) billion and $(5.9) billion, respectively. The change was primarily due to lower proceeds from sales and maturities, net of purchases, of U.S. Treasury Bills totaling $349 million, partially offset by lower capital expenditures of $135 million and higher proceeds from sales, net of purchases, of marketable securities of $55 million. Refer to "Future Uses of Cash" for further discussion of capital expenditures.

Financing Activities

Net cash flows from financing activities for the year ended December 31, 2025 were $2.0 billion. Sources of cash totaled $5.4 billion and consisted of proceeds from subsidiary debt issuances of $4.3 billion and net proceeds from short-term debt totaling $864 million. Uses of cash totaled $3.4 billion and consisted of repayment of BHE senior debt of $1.7 billion, repayments of subsidiary debt totaling $1.1 billion, preferred stock redemptions totaling $481 million and distributions to noncontrolling interests of $178 million.

Net cash flows from financing activities for the year ended December 31, 2024 were $(2.6) billion. Sources of cash totaled $6.4 billion and consisted of proceeds from subsidiary debt issuances. Uses of cash totaled $9.0 billion and consisted of net repayments of short-term debt totaling $3.0 billion, repayments of subsidiary debt totaling $2.8 billion, repurchases of common stock of $2.3 billion, repayments of notes payable of $600 million and distributions to noncontrolling interests of $163 million.

Net cash flows from financing activities for the year ended December 31, 2023 were $(1.3) billion. Sources of cash totaled $7.1 billion and consisted of proceeds from subsidiary debt issuances of $4.1 billion and net proceeds from short-term debt totaling $3.0 billion. Uses of cash totaled $8.4 billion and consisted mainly of $3.3 billion for the purchase of Cove Point noncontrolling interest, repayments of subsidiary debt totaling $2.8 billion, repayment of BHE senior debt of $900 million, preferred stock redemptions totaling $850 million and distributions to noncontrolling interests of $395 million.

Recent Financing Transactions

In February 2026, PacifiCorp issued $400 million of 4.25% First Mortgage Bonds due March 2029.

In February 2026, PacifiCorp issued $1.1 billion of its 7.125% Fixed-to-Fixed Reset Rate Junior Subordinated Notes due August 2056. PacifiCorp will pay interest on the junior subordinated notes at a rate of 7.125% through August 2031, subject to a reset every five years, not to reset below 7.125%.

Debt Repurchases

The Company may from time to time seek to acquire its outstanding debt securities through cash purchases in the open market, privately negotiated transactions or otherwise. Any debt securities repurchased by the Company may be reissued or resold by the Company from time to time and will depend on prevailing market conditions, the Company's liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

Preferred Stock Redemptions

For the years ended December 31, 2025 and 2023, BHE redeemed at par 481,000 and 849,982 shares of its 4.00% Perpetual Preferred Stock from certain subsidiaries of Berkshire Hathaway Inc. for $481 million and $850 million.

Common Stock Transactions

For the year ended December 31, 2024, BHE repurchased 4,424,494 shares of its voting common stock held by certain family members and related or affiliated entities of the late Mr. Walter Scott, Jr., a former member of BHE's Board of Directors for (i) cash in an aggregate amount of $2.4 billion and (ii) a Promissory Note, due and payable on September 30, 2025, having an aggregate principal amount of $600 million, which was fully repaid plus accrued interest in October 2024.

There were no common stock repurchases for the years ended December 31, 2025 and 2023.

Future Uses of Cash

The Company has available a variety of sources of liquidity and capital resources, both internal and external, including net cash flows from operating activities, public and private debt offerings, the issuance of commercial paper, the use of unsecured revolving credit facilities, the issuance of equity and other sources. These sources are expected to provide funds required for current operations, capital expenditures, acquisitions, investments, debt retirements and other capital requirements. The availability and terms under which BHE and each subsidiary has access to external financing depends on a variety of factors, including regulatory approvals, its credit ratings, investors' judgment of risk and conditions in the overall capital markets, including the condition of the utility industry and project finance markets, among other items.

Capital Expenditures

The Company has significant future capital requirements. Capital expenditure needs are reviewed regularly by management and may change significantly as a result of these reviews, which may consider, among other factors, impacts to customers' rates; changes in environmental and other rules and regulations; outcomes of regulatory proceedings; changes in income tax laws; general business conditions; load projections; system reliability standards; the cost and efficiency of construction labor, equipment and materials; commodity prices; and the cost and availability of capital. Expenditures for certain assets may ultimately include acquisitions of existing assets.

The Company's historical and forecast capital expenditures, each of which exclude amounts for non-cash equity AFUDC and other non-cash items, by reportable segment for the years ended December 31 are as follows (in millions):

	Historical			Forecast		
	2023	2024	2025	2026	2027	2028
PacifiCorp	$ 3,226	$ 3,102	$ 2,995	$ 2,884	$ 2,533	$ 2,455
MidAmerican Funding	1,833	1,704	1,780	2,570	3,546	2,803
NV Energy	1,797	1,777	2,857	2,823	2,812	1,928
Northern Powergrid	557	657	712	887	1,147	772
BHE Pipeline Group	1,294	1,050	1,378	1,345	1,389	1,523
BHE Transmission	206	253	313	337	311	208
BHE Renewables	177	455	459	510	309	284
HomeServices	41	8	12	34	35	36
BHE and Other[1]	17	7	83	6	32	1
Total	$ 9,148	$ 9,013	$ 10,589	$ 11,396	$ 12,114	$ 10,010

(1) BHE and Other includes intersegment eliminations.

	Historical			Forecast		
	2023	2024	2025	2026	2027	2028
Electric transmission	$ 1,802	$ 1,679	$ 1,997	$ 2,891	$ 3,271	$ 2,084
Electric distribution	2,047	2,235	2,444	2,630	2,542	2,342
Natural gas transmission and storage	997	854	1,102	1,116	1,179	1,431
Solar generation	271	324	961	849	926	1,063
Wind generation	1,538	937	891	1,041	904	87
Wildfire prevention	352	622	847	644	593	645
Electric battery storage	367	180	360	192	5	—
Other	1,774	2,182	1,987	2,033	2,694	2,358
Total	$ 9,148	$ 9,013	$ 10,589	$ 11,396	$ 12,114	$ 10,010

The Company's historical and forecast capital expenditures consisted mainly of the following:

- Electric transmission includes both growth and operating expenditures. Growth expenditures include spending for the following:
  - PacifiCorp's transmission investment primarily reflects costs associated with major transmission projects. Expenditures for certain projects placed in-service during 2024 totaled $72 million for 2025, $382 million for 2024 and $738 million for 2023. Expenditures for major transmission projects that are expected to be placed in-service through 2032 totaled Planned spending for major transmission projects that are expected to be placed in-service through 2032 totals $431 million in 2026, $260 million in 2027 and $132 million in 2028.
  - Nevada Utilities' Greenlink Nevada transmission expansion program totaling $718 million for 2025, $265 million for 2024 and $130 million for 2023. Planned spending for the expansion program expected to be placed in-service in 2027 and 2028 totals $1.1 billion in 2026, $1.4 billion in 2027 and $619 million in 2028.
  - Operating expenditures include spending for system reinforcement, upgrades and replacements of facilities to maintain system reliability and investments in routine expenditures for transmission needed to serve existing and expected demand.
- Electric distribution includes both growth and operating expenditures. Growth expenditures include spending for new customer connections and enhancements to existing customer connections. Operating expenditures include spending for ongoing distribution systems infrastructure needed at the Utilities and Northern Powergrid, storm damage restoration and repairs and investments in routine expenditures for distribution needed to serve existing and expected demand.

- Natural gas transmission and storage includes both growth and operating expenditures. Growth expenditures include, among other items, spending for customer driven expansion projects. Operating expenditures include spending for pipeline integrity projects, automation and controls upgrades, corrosion control, unit exchanges, compressor modifications, projects related to Pipeline and Hazardous Materials Safety Administration natural gas storage rules and natural gas transmission, storage, LNG terminalling infrastructure needs to serve existing and expected demand and asset modernization programs.
- Solar generation and electric battery storage includes growth expenditures, including spending for the following:
    - Construction and operation of solar-powered generating facilities at MidAmerican Energy with total spend of $40 million in 2025, $3 million in 2024 and $13 million in 2023. Planned spending for the construction and operation of solar-powered generating facilities totals $162 million in 2026, $582 million in 2027 and $873 million in 2028.
    - Construction of solar-powered generating facilities and co-located battery storage at the Nevada Utilities including expenditures for 150-MW solar photovoltaic facility with an additional 100-MWs of co-located battery storage that was developed in Clark County, Nevada which commenced commercial operation in May 2024 and a 400-MW solar photovoltaic facility with an additional 400 MWs of co-located battery storage that is being developed in Churchill County, Nevada with an ownership share approved by the PUCN of 10% for Nevada Power and 90% for Sierra Pacific with total spend of $925 million in 2025, $240 million in 2024 and $541 million in 2023. Planned spending totals $342 million in 2026 and $66 million in 2027.
    - Construction of solar-powered generating facilities and co-located battery storage at BHE Renewables including expenditures for a 48-MW solar photovoltaic facility with an additional 46 MWs of co-located battery storage that will be developed in Kern County, California, with commercial operation expected in 2026 and a 106-MW solar photovoltaic facility with an additional 20 MWs of co-located battery storage located in Jackson County, West Virginia, with commercial operations expected to be complete in 2027 with total spend of $116 million in 2025, and $212 million in 2024 and $60 million in 2023. Planned spending totals $125 million in 2026 and $51 million in 2027.
- Wind generation includes both growth and operating expenditures. Growth expenditures include spending for the following:
    - Construction of wind-powered generating facilities at MidAmerican Energy totaling $233 million for 2025, $127 million for 2024 and $608 million for 2023. MidAmerican Energy placed in-service 214 MWs and 200 MWs of new wind-powered generation in 2025 and 2023, respectively. Planned spending for the construction of additional wind-powered generating facilities totals $239 million in 2026.
    - Repowering of wind-powered generating facilities at MidAmerican Energy totaling $346 million for 2025, $307 million for 2024 and $47 million for 2023. Planned spending for repowering totals $700 million in 2026 and $815 million in 2027. MidAmerican Energy expects its repowered facilities to meet IRS guidelines for the re-establishment of PTCs under the prevailing wage and apprenticeship guidelines for 10 years from the date the facilities are placed in-service.
    - Construction of new wind-powered generating facilities and construction at existing wind-powered generating facility sites acquired from third parties at PacifiCorp totaling $195 million for 2025, $396 million for 2024 and $735 million for 2023. PacifiCorp placed in-service 529 MWs at the Rock Creek I and Rock Creek II wind-powered generating facilities in 2025, 50 MWs at the Rock River I and 61 MWs at the Rock Creek I wind-powered generating facilities in 2024 and 42 MWs at the Foote Creek III and Foote Creek IV wind-powered generating facilities in 2023.
    - Repowering of wind-powered generating facilities at BHE Renewables totaling $5 million for 2024 and $39 million in 2023. BHE Renewables repowered facilities were placed in-service in the first quarter of 2024 and the fourth quarter of 2023 and meet IRS guidelines for the re-establishment of PTCs for 10 years.
- Wildfire prevention includes growth and operating expenditures, including spending for the following:
    - Expenditures at PacifiCorp totaling $789 million in 2025, $539 million in 2024 and $325 million in 2023. Planned spending totals $499 million in 2026, $468 million in 2027 and $520 million in 2028 and is comprised of reducing wildfire risk in the fire high consequence areas by conversion of overhead systems to underground, replacing overhead bare wire conductor with covered conductors, replacing traditional fuses with non-expulsion fuses and deployment of advanced protection devices for faster fault detection. The efforts will also include an expansion of the weather station network and predictive tools for situational awareness across the entire service territory.

- Expenditures at the Nevada Utilities related to projects included in a comprehensive natural disaster protection plan filed and approved by the PUCN. These projects include, but are not limited to, rebuilding distribution lines with covered conductor, converting overhead distribution lines to underground and copper wire and pole replacement projects totaling $50 million in 2025, $59 million in 2024 and $38 million in 2023. Planned spending totals $129 million in 2026, $109 million in 2027 and $111 million in 2028.

- Other capital expenditures includes both growth and operating expenditures, including spending for routine expenditures for generation and other infrastructure needed to serve existing and expected demand, natural gas distribution, technology, and environmental spending relating to emissions control equipment and the management of CCR.

Off-Balance Sheet Arrangements

The Company has certain investments that are accounted for under the equity method in accordance with GAAP. Accordingly, an amount is recorded on the Company's Consolidated Balance Sheets as an equity investment and is increased or decreased for the Company's pro-rata share of earnings or losses, respectively, less any dividends from such investments. Certain equity investments are presented on the Consolidated Balance Sheets net of investment tax credits.

As of December 31, 2025, the Company's investments that are accounted for under the equity method had short- and long-term debt of $2.9 billion, unused revolving credit facilities of $210 million and letters of credit outstanding of $27 million. As of December 31, 2025, the Company's pro-rata share of such short- and long-term debt was $1.4 billion, unused revolving credit facilities was $105 million and outstanding letters of credit was $13 million. The entire amount of the Company's pro-rata share of the outstanding short- and long-term debt and unused revolving credit facilities is non-recourse to the Company. The entire amount of the Company's pro-rata share of the outstanding letters of credit is recourse to the Company. Although the Company is generally not required to support debt service obligations of its equity investees, default with respect to this non-recourse short- and long-term debt could result in a loss of invested equity.

Material Cash Requirements

The Company has cash requirements that may affect its consolidated financial condition that arise primarily from long- and short-term debt (refer to Note 9, 10 and 11), operating and financing leases (refer to Note 6), firm commitments (refer to Note 16), letters of credit (refer to Note 9), construction and other development costs (refer to Liquidity and Capital Resources included within this Item 7), uncertain tax positions (refer to Note 12) and AROs (refer to Note 14). Refer, where applicable, to the respective referenced note in Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

The Company has cash requirements relating to interest payments of $48.6 billion on long-term debt, including $2.7 billion due in 2026.

Regulatory Matters

The Company is subject to comprehensive regulation. Refer to the discussion contained in Item 1 of this Form 10-K for further information regarding the Company's general regulatory framework and current regulatory matters.

Environmental Laws and Regulations

The Company is subject to federal, state, local and foreign laws and regulations regarding air quality, climate change, emissions performance standards, water quality, coal ash disposal and other environmental matters that have the potential to impact its current and future operations. In addition to imposing continuing compliance obligations, these laws and regulations provide regulators with the authority to levy substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. These laws and regulations are administered by various federal, state, local and international agencies. The Company believes it is in material compliance with all applicable laws and regulations, although many are subject to interpretation that may ultimately be resolved by the courts. Environmental laws and regulations continue to evolve, and the Company is unable to predict the impact of the changing laws and regulations on its operations and consolidated financial results.

Refer to "Environmental Laws and Regulations" in Item 1 of this Form 10-K for further discussion regarding environmental laws and regulations.

Collateral and Contingent Features

Debt of BHE and debt and preferred securities of certain of its subsidiaries are rated by credit rating agencies. Assigned credit ratings are based on each rating agency's assessment of the rated company's ability to, in general, meet the obligations of its issued debt or preferred securities. The credit ratings are not a recommendation to buy, sell or hold securities, and there is no assurance that a particular credit rating will continue for any given period of time.

BHE and its subsidiaries have no credit rating downgrade triggers that would accelerate the maturity dates of outstanding debt, and a change in ratings is not an event of default under the applicable debt instruments. The Company's unsecured revolving credit facilities do not require the maintenance of a minimum credit rating level in order to draw upon their availability. However, commitment fees and interest rates under the credit facilities are tied to credit ratings and increase or decrease when the ratings change. A ratings downgrade could also increase the future cost of commercial paper, short- and long-term debt issuances or new credit facilities.

In accordance with industry practice, certain wholesale agreements, including derivative contracts, contain credit support provisions that in part base certain collateral requirements on credit ratings for senior unsecured debt as reported by one or more of the recognized credit rating agencies. These agreements may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance," or in some cases terminate the contract, in the event of a material adverse change in creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2025, the applicable entities' credit ratings from the recognized credit rating agencies were investment grade. If all credit-risk-related contingent features or adequate assurance provisions for these agreements had been triggered as of December 31, 2025, the Company would have been required to post $378 million of additional collateral. The Company's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation, or other factors.

Inflation

Historically, overall inflation and changing prices in the economies where BHE's subsidiaries operate have not had a significant impact on the Company's consolidated financial results. In the U.S. and Canada, the Regulated Businesses operate under cost-of-service based rate-setting structures administered by various state and provincial commissions and the FERC. Under these rate-setting structures, the Regulated Businesses are allowed to include prudent costs in their rates, including the impact of inflation. The price control formula used by the Northern Powergrid Distribution Companies incorporates the rate of inflation in determining rates charged to customers. BHE's subsidiaries attempt to minimize the potential impact of inflation on their operations through the use of fuel, energy and other cost adjustment clauses and bill riders, by employing prudent risk management and hedging strategies and by considering, among other areas, its impact on purchases of energy, operating expenses, materials and equipment costs, contract negotiations, future capital spending programs and long-term debt issuances. There can be no assurance that such actions will be successful.

New Accounting Pronouncements

For a discussion of new accounting pronouncements affecting the Company, refer to Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Critical Accounting Estimates

Certain accounting measurements require management to make estimates and judgments concerning transactions that will be settled several years in the future. Amounts recognized on the Consolidated Financial Statements based on such estimates involve numerous assumptions subject to varying and potentially significant degrees of judgment and uncertainty and will likely change in the future as additional information becomes available. The following critical accounting estimates are impacted significantly by the Company's methods, judgments and assumptions used in the preparation of the Consolidated Financial Statements and should be read in conjunction with the Company's Summary of Significant Accounting Policies included in Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Accounting for the Effects of Certain Types of Regulation

The Regulated Businesses prepare their financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, the Regulated Businesses defer the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur.

The Company continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future regulated rates by considering factors such as a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation, other regulatory actions or the impact of competition that could limit the Regulated Businesses' ability to recover their costs. The Company believes its application of the guidance for regulated operations is appropriate and its existing regulatory assets and liabilities are probable of inclusion in future regulated rates. The evaluation reflects the current political and regulatory climate at the federal, state and provincial levels. If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the related regulatory assets and liabilities will be recognized in net income, returned to customers or re-established as AOCI. Total regulatory assets were $4.8 billion and total regulatory liabilities were $7.0 billion as of December 31, 2025. Refer to Note 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding the Regulated Businesses' regulatory assets and liabilities.

Impairment of Goodwill and Long-Lived Assets

The Company's Consolidated Balance Sheet as of December 31, 2025, includes goodwill of acquired businesses of $11.5 billion. The Company evaluates goodwill for impairment at least annually and completed its annual review as of October 31, 2025. Additionally, no indicators of impairment were identified as of December 31, 2025. Significant judgment is required in estimating the fair value of the reporting unit and performing goodwill impairment tests. The Company uses a variety of methods to estimate a reporting unit's fair value, principally discounted projected future net cash flows. Key assumptions used include, but are not limited to, the use of estimated future cash flows; multiples of earnings or rate base; and an appropriate discount rate. Estimated future cash flows are impacted by, among other factors, growth rates, changes in regulations and rates, ability to renew contracts and estimates of future commodity prices. In estimating future cash flows, the Company incorporates current market information, as well as historical factors.

The Company evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or when the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Consolidated Statements of Operations. As a majority of all property, plant and equipment is used in regulated businesses, the impacts of regulation are considered when evaluating the carrying value of regulated assets.

The estimate of cash flows arising from the future use of an asset, for the purposes of impairment analysis, requires the exercise of judgment. Circumstances that could significantly alter the calculation of fair value or the recoverable amount of an asset may include significant changes in the regulatory environment, the business climate, management's plans, legal factors, market price of the asset, the use of the asset, the physical condition of the asset, future market prices, load growth, competition and many other factors over the life of the asset. Any resulting impairment loss is highly dependent on the underlying assumptions and could significantly affect the Company's results of operations.

Pension and Other Postretirement Benefits

Certain of the Company's subsidiaries sponsor defined benefit pension and other postretirement benefit plans that cover the majority of employees. The Company recognizes the funded status of the defined benefit pension and other postretirement benefit plans on the Consolidated Balance Sheets. Funded status is the fair value of plan assets minus the benefit obligation as of the measurement date. As of December 31, 2025, the Company recognized a net asset totaling $471 million for the funded status of the defined benefit pension and other postretirement benefit plans. As of December 31, 2025, amounts not yet recognized as a component of net periodic benefit cost that were included in net regulatory assets totaled $122 million and in AOCI totaled $646 million.

The expense and benefit obligations relating to these defined benefit pension and other postretirement benefit plans are based on actuarial valuations. Inherent in these valuations are key assumptions, including, but not limited to, discount rates, expected long-term rate of return on plan assets and healthcare cost trend rates. These key assumptions are reviewed annually and modified as appropriate. The Company believes that the key assumptions utilized in recording obligations under the plans are reasonable based on prior plan experience and current market and economic conditions. Refer to Note 13 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for disclosures about the defined benefit pension and other postretirement benefit plans, including the key assumptions used to calculate the funded status and net periodic benefit cost for these plans as of and for the year ended December 31, 2025.

The Company chooses a discount rate based upon high quality debt security investment yields in effect as of the measurement date that corresponds to the expected benefit period. The pension and other postretirement benefit liabilities increase as the discount rate is reduced.

In establishing its assumption as to the expected long-term rate of return on plan assets, the Company utilizes the expected asset allocation and return assumptions for each asset class based on historical performance and forward-looking views of the financial markets. Pension and other postretirement benefits expense increases as the expected long-term rate of return on plan assets decreases. The Company regularly reviews its actual asset allocations and rebalances its investments to its targeted allocations when considered appropriate.

The Company chooses a healthcare cost trend rate that reflects the near and long-term expectations of increases in medical costs and corresponds to the expected benefit payment periods. The healthcare cost trend rate is assumed to gradually decline to 5.00% by 2035, at which point the rate of increase is assumed to remain constant.

The key assumptions used may differ materially from period to period due to changing market and economic conditions. These differences may result in a significant impact to pension and other postretirement benefits expense and funded status. If changes were to occur for the following key assumptions, the approximate effect on the Consolidated Financial Statements would be as follows (dollars in millions):

	Domestic Plans					
	Pension Plans		Other Postretirement Benefit Plans		United Kingdom Pension Plan	
	+0.5%	-0.5%	+0.5%	-0.5%	+0.5%	-0.5%
Effect on December 31, 2025						
Benefit Obligations:						
Discount rate	$ (69)	$ 76	$ (19)	$ 20	$ (66)	$ 61
Effect on 2025 Periodic Cost:						
Discount rate	$ 3	$ —	$ —	$ —	$ (3)	$ 3
Expected rate of return on plan assets	(10)	10	(3)	3	(7)	7

A variety of factors affect the funded status of the plans, including discount rates, asset returns, mortality assumptions, plan changes and the Company's funding policy for each plan.

Income Taxes

In determining the Company's income taxes, management is required to interpret complex income tax laws and regulations, which includes consideration of regulatory implications imposed by the Company's various regulatory commissions. The Company's income tax returns are subject to continuous examinations by federal, state, local and foreign income tax authorities that may give rise to different interpretations of these complex laws and regulations. Due to the nature of the examination process, it generally takes years before these examinations are completed and these matters are resolved. The Company recognizes the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the Consolidated Financial Statements from such a position are measured based on the largest benefit that is more-likely-than-not to be realized upon ultimate settlement. Although the ultimate resolution of the Company's federal, state, local and foreign income tax examinations is uncertain, the Company believes it has made adequate provisions for these income tax positions. The aggregate amount of any additional income tax liabilities that may result from these examinations is not expected to have a material impact on the Company's consolidated financial results. Refer to Note 12 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding the Company's income taxes.

It is probable the Company's regulated businesses will pass income tax benefit and expense related to the federal tax rate change from 35% to 21%, certain property-related basis differences and other various differences on to their customers. As of December 31, 2025, these amounts were recognized as a net regulatory liability of $1.7 billion and will be included in regulated rates when the temporary differences reverse.

The Company has not established deferred income taxes on its undistributed foreign earnings from Northern Powergrid that have been determined by management to be reinvested indefinitely; however, the Company periodically evaluates its capital requirements. If circumstances change in the future and a portion of the Company's undistributed foreign earnings were repatriated, the dividends may be subject to taxation in the U.S. but the tax is not expected to be material.

Loss Contingencies

As a result of certain conditions, situations or circumstances involving uncertainty as to possible loss, including (i) several wildfires that have occurred in the Company's service territory and surrounding areas in the western U.S. and Canada and (ii) antitrust cases at HomeServices, the Company is required to evaluate its exposure to potential loss contingencies arising from claims associated with these items. In determining this exposure, the Company is required to assess whether the likelihood of loss for each of these items is remote, reasonably possible or probable, which involves complex judgments based on several variables including available information regarding the outcome of the appeals process, cause and origin investigations, settlement medication activities, other litigation matters and upcoming legal proceedings. If deemed reasonably possible, the Company is required to estimate the potential loss or range of potential loss and disclose any material amounts. If deemed probable, the Company is required to accrue a loss if reasonably estimable based on the bottom end of the range if no amount within the range of estimated loss is any better than another amount. Many assumptions and variables are involved in determining the estimates relative to wildfires, including identifying the various categories of potential loss such as fire suppression costs, real and personal property damages, natural resource damages and noneconomic damages such as personal injury damages and loss of life damages. Within the categories of potential loss, further assumptions are made regarding items such as the types of structures damaged, estimated replacement values associated with those structures, value of personal property, the types of natural resource damage such as timber, the value of that timber, the nature of noneconomic damages such as those arising from personal injuries, other damages the Company may be responsible for if found negligent such as punitive damages, and the amount of any penalties or fines that may be imposed by governmental entities. Estimates associated with the Wildfires are subject to change as additional relevant information becomes available. Refer to Note 16 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding the Company's loss contingencies associated with wildfires and the antitrust cases at HomeServices.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The Company's Consolidated Balance Sheets include assets and liabilities with fair values that are subject to market risks. The Company's significant market risks are primarily associated with commodity prices, interest rates, foreign currency exchange rates and the extension of credit to counterparties with which the Company transacts. The following discussion addresses the significant market risks associated with the Company's business activities. Each of the Company's businesses has established guidelines for credit risk management.

Commodity Price Risk

The Company is principally exposed to electricity, natural gas, coal and fuel oil commodity price risk primarily through BHE's ownership of the Utilities as they have an obligation to serve retail customer load in their regulated service territories. The Utilities' load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity, wholesale electricity that is purchased and sold and natural gas supply for retail customers. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, generating facility availability, customer usage, storage and transmission and transportation constraints. The Company does not engage in a material amount of proprietary trading activities. To manage a portion of its commodity price risk, the Company uses commodity derivative contracts, which may include forwards, futures, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. The Company does not hedge all of its commodity price risk, thereby exposing the unhedged portion to changes in market prices. The Company's exposure to commodity price risk is generally limited by its ability to include commodity costs in regulated rates, which is subject to regulatory lag that occurs between the time the costs are incurred and when the costs are included in regulated rates, as well as the impact of any customer sharing resulting from cost adjustment mechanisms.

The table that follows summarizes the Company's price risk on commodity contracts accounted for as derivatives, excluding collateral netting of $75 million and $9 million, respectively, as of December 31, 2025 and 2024, and shows the effects of a hypothetical 10% increase and 10% decrease in forward market prices with the contracted or expected volumes. The selected hypothetical change does not reflect what could be considered the best or worst case scenarios (dollars in millions).

	Fair Value - Net Asset (Liability)	Estimated Fair Value after Hypothetical Change in Price	
		10% increase	10% decrease
As of December 31, 2025:			
Not designated as hedging contracts	$ (190)	$ (153)	$ (227)
Designated as hedging contracts	1	(1)	3
Total commodity derivative contracts	$ (189)	$ (154)	$ (224)
As of December 31, 2024:			
Not designated as hedging contracts	$ (168)	$ (118)	$ (218)
Designated as hedging contracts	21	23	19
Total commodity derivative contracts	$ (147)	$ (95)	$ (199)

The settled cost of certain of the Company's commodity derivative contracts not designated as hedging contracts is included in regulated rates and, therefore, net unrealized gains and losses associated with interim price movements on commodity derivative contracts do not expose the Company to earnings volatility. Consolidated financial results would be negatively impacted if the costs of wholesale electricity, wholesale natural gas or fuel are higher than what is included in regulated rates, including the impacts of adjustment mechanisms. As of December 31, 2025 and 2024, a net regulatory asset of $206 million and $181 million, respectively, was recorded related to the net derivative liability of $190 million and $168 million, respectively. For the Company's commodity derivative contracts designated as hedging contracts, net unrealized gains and losses associated with interim price movements on commodity derivative contracts, to the extent the hedge is considered effective, generally do not expose the Company to earnings volatility.

Interest Rate Risk

The Company is exposed to interest rate risk on its outstanding variable-rate short- and long-term debt, future debt issuances and mortgage commitments. The Company manages its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. As a result of the fixed interest rates, the Company's fixed-rate long-term debt does not expose the Company to the risk of loss due to changes in market interest rates. Additionally, because fixed-rate long-term debt is not carried at fair value on the Consolidated Balance Sheets, changes in fair value would impact earnings and cash flows only if the Company were to reacquire all or a portion of these instruments prior to their maturity. The nature and amount of the Company's short- and long-term debt can be expected to vary from period to period as a result of future business requirements, market conditions and other factors. Refer to Notes 9, 10, 11, and 15 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional discussion of the Company's short and long-term debt.

As of December 31, 2025 and 2024, the Company had short- and long-term variable-rate obligations totaling $2.3 billion and $1.5 billion, respectively, that expose the Company to the risk of increased interest expense in the event of increases in short-term interest rates. If variable interest rates were to increase by 10% from December 31 levels, it would not have a material effect on the Company's consolidated annual interest expense. The carrying value of the variable-rate obligations approximates fair value as of December 31, 2025 and 2024.

The Company may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, forward sale commitments or mortgage interest rate lock commitments, to mitigate the Company's exposure to interest rate risk. Changes in fair value of agreements designated as cash flow hedges are reported in AOCI to the extent the hedge is effective until the forecasted transaction occurs. Changes in fair value of agreements not designated as hedging contracts are recognized in earnings. As of December 31, 2025 and 2024, the Company had variable-to-fixed interest rate swaps with notional amounts of $289 million and $370 million, respectively, £106 million and £137 million, respectively, and A$— million and A$154 million, respectively, to protect the Company against an increase in interest rates. Additionally, as of December 31, 2025 and 2024, the Company had mortgage commitments, net, with notional amounts of $1.4 billion and $1.2 billion, respectively, to protect the Company against an increase in interest rates. The fair value of the Company's interest rate derivative contracts was a net derivative asset of $42 million and $79 million as of December 31, 2025 and 2024, respectively. A hypothetical 10 basis point increase and a 10 basis point decrease in interest rates would not have a material impact on the Company.

The Company holds foreign currency swaps with the purpose of hedging the foreign currency exchange rate associated with Euro denominated debt. As of December 31, 2025 and 2024, the Company had €250 million in aggregate notional amounts of these foreign currency swaps outstanding. A hypothetical 10% decrease in market interest rates would not have resulted in a material decrease in fair value of the Company's foreign currency swaps.

Foreign Currency Exchange Rate Risk

BHE's business operations and investments outside of the U.S. increase its risk related to fluctuations in foreign currency exchange rates primarily in relation to the British pound and the Canadian dollar. BHE's reporting currency is the U.S. dollar, and the value of the assets and liabilities, earnings, cash flows and potential distributions from BHE's foreign operations changes with the fluctuations of the currency in which they transact.

Northern Powergrid's functional currency is the British pound. As of December 31, 2025, a 10% devaluation in the British pound to the U.S. dollar would result in the Company's Consolidated Balance Sheet being negatively impacted by a $532 million cumulative translation adjustment in AOCI. A 10% devaluation in the average currency exchange rate would have resulted in lower reported earnings for Northern Powergrid of $34 million in 2025.

BHE Canada's functional currency is the Canadian dollar. As of December 31, 2025, a 10% devaluation in the Canadian dollar to the U.S. dollar would result in the Company's Consolidated Balance Sheet being negatively impacted by a $372 million cumulative translation adjustment in AOCI. A 10% devaluation in the average currency exchange rate would have resulted in lower reported earnings for BHE Canada of $19 million in 2025.

Credit Risk

Domestic Regulated Operations

The Utilities are exposed to counterparty credit risk associated with wholesale energy supply and marketing activities with other utilities, energy marketing companies, financial institutions and other market participants. Credit risk may be concentrated to the extent the Utilities' counterparties have similar economic, industry or other characteristics and due to direct or indirect relationships among the counterparties. Before entering into a transaction, the Utilities analyze the financial condition of each significant wholesale counterparty, establish limits on the amount of unsecured credit to be extended to each counterparty and evaluate the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate wholesale counterparty credit risk, the Utilities enter into netting and collateral arrangements that may include margining and cross-product netting agreements and obtain third-party guarantees, letters of credit and cash deposits. If required, the Utilities exercise rights under these arrangements, including calling on the counterparty's credit support arrangement.

As of December 31, 2025, PacifiCorp's aggregate credit exposure with wholesale energy supply and marketing counterparties included counterparties having non-investment grade, internally rated credit ratings. Substantially all of these non-investment grade, internally rated counterparties are associated with long-duration solar and wind power purchase agreements, some of which are from facilities that have not yet achieved commercial operation and for which PacifiCorp has no obligation should the facilities not achieve commercial operation.

Substantially all of MidAmerican Energy's electric wholesale sales revenue results from participation in RTOs, including the MISO and the PJM. MidAmerican Energy's share of historical losses from defaults by other RTO market participants has not been material. Additionally, as of December 31, 2025, MidAmerican Energy's aggregate direct credit exposure from electric wholesale marketing counterparties was not material.

As of December 31, 2025, NV Energy's aggregate credit exposure from energy related transactions, based on settlement and mark-to-market exposures, net of collateral, was not material.

BHE GT&S primary customers include electric and natural gas distribution utilities, natural gas producers and LNG export, import and storage customers. Northern Natural Gas' primary customers include utilities in the upper Midwest. Kern River's primary customers are electric and natural gas distribution utilities, major oil and natural gas companies or affiliates of such companies, electric generating companies, energy marketing and trading companies and financial institutions. As a general policy, collateral is not required for receivables from creditworthy customers. Customers' financial condition and creditworthiness, as defined by the tariff, are regularly evaluated and historical losses have been minimal. In order to provide protection against credit risk, and as permitted by the separate terms of each of BHE GT&S, Northern Natural Gas' and Kern River's tariffs, the companies have required customers that lack creditworthiness to provide cash deposits, letters of credit or other security until they meet the creditworthiness requirements of the respective tariff.

Northern Powergrid

The Northern Powergrid Distribution Companies charge fees for the use of their distribution systems to supply companies. The supply companies purchase electricity from generators and traders, sell the electricity to end-use customers and use the Northern Powergrid Distribution Companies' distribution networks pursuant to the multilateral "Distribution Connection and Use of System Agreement." The Northern Powergrid Distribution Companies' customers are concentrated in a small number of electricity supply businesses. During 2025, E.ON and certain of its affiliates, British Gas Trading Limited and Octopus Energy Group Limited represented 16%, 15% and 12%, respectively, of the total combined distribution revenue of the Northern Powergrid Distribution Companies. The industry operates in accordance with a framework which sets credit limits for each supply business based on its credit rating or payment history and requires them to provide credit cover if their value at risk (measured as being equivalent to 45 days usage) exceeds the credit limit. Acceptable credit typically is provided in the form of a parent company guarantee, letter of credit or an escrow account. Ofgem has indicated that, provided the Northern Powergrid Distribution Companies have implemented credit control, billing and collection in line with best practice guidelines and can demonstrate compliance with the guidelines or are able to satisfactorily explain departure from the guidelines, any bad debt losses arising from supplier default will be recovered through an increase in future allowed income. Losses incurred to date have not been material.

BHE Canada

AltaLink's primary source of operating revenue is the AESO, an entity rated AA- by Standard and Poor's. Because of the dependence on a single customer, any material failure of the customer to fulfill its obligations would significantly impair AltaLink's ability to meet its existing and future obligations. Total operating revenue for AltaLink was $666 million for the year ended December 31, 2025.

BHE Renewables

BHE Renewables owns independent power projects that generally have separate project financing agreements. Operating revenue for these projects is derived primarily from long-term power purchase agreements with single customers, primarily utilities, which expire between 2026 and 2043. Because of the dependence generally from a single customer at each project, any material failure of the customer to fulfill its obligations would significantly impair that project's ability to meet its existing and future obligations. Total operating revenue for BHE Renewables' independent power projects was $1.1 billion for the year ended December 31, 2025.

Item 8. Financial Statements and Supplementary Data

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and the shareholders of
Berkshire Hathaway Energy Company
Des Moines, Iowa

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Berkshire Hathaway Energy Company and subsidiaries (the "Company") as of December 31, 2025 and 2024, the related consolidated statements of operations, comprehensive income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2025, the related notes and the schedule listed in the Index at Item 15(a)(2) (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, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025, in conformity with accounting principles generally accepted in the United States of America.

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 Public Company Accounting Oversight Board (United States) (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 audits to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current-period audit of the financial statements that were communicated or required to be communicated to the Board of Directors and that (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Regulatory Matters — Effects of Rate Regulation on the Financial Statements — Refer to Note 7 to the financial statements

Critical Audit Matter Description

The Company is subject to rate regulation by the Federal Energy Regulatory Commission as well as certain other regulatory commissions (collectively, the "Commissions"), which have jurisdiction with respect to the rates of electric and natural gas companies in the respective service territories where the Company operates. Management has determined its regulated operations meet the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. Accounting for the economic effects of rate regulation has a pervasive effect on the financial statements.

Regulated rates are subject to regulatory rate-setting processes. Rates are determined, approved, and established based on a cost-of-service basis, which is designed to allow the Company an opportunity to recover its prudently incurred costs of providing services and to earn a reasonable return on its invested capital. Regulatory decisions can have an effect on the recovery of costs, the rate of return earned on investment, and the timing and amount of assets to be recovered by rates. While the Company has indicated it expects to recover costs from customers through regulated rates, there is a risk that changes to the Commissions' approach to setting rates or other regulatory actions could limit the Company's ability to recover its costs.

We identified the effects of rate regulation on the financial statements as a critical audit matter due to the significant judgments made by management to support its assertions about certain affected account balances and disclosures and the high degree of subjectivity involved in assessing the impact of 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 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 decisions by the Commissions included the following, among others:

- We evaluated the Company's disclosures related to the effects of rate regulation, by testing certain recorded balances and evaluating regulatory developments.
- We read relevant regulatory orders issued by the Commissions, regulatory statutes, filings made by the Company and other external information. We evaluated relevant external information and compared it to certain recorded regulatory asset and liability balances for completeness.
- For certain regulatory matters, we inspected the Company's filings with the Commissions and the filings with the Commissions by intervenors to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedents of the Commissions' treatment of similar costs under similar circumstances.

Wildfires — Contingencies — Refer to Note 16 to the financial statements

Critical Audit Matter Description

As a result of several wildfires that have occurred in the Company's service territory and surrounding areas in Oregon and California, the Company is required to evaluate its exposure to potential loss contingencies arising from claims associated with the 2020 Wildfires and the 2022 McKinney Fire (the "Wildfires"). In determining this exposure, the Company is required to determine whether the likelihood of loss for each of the Wildfires is remote, reasonably possible or probable, which involves complex judgments based on several variables including available information regarding the cause and origin of the Wildfires, investigations, discovery associated with lawsuits and negotiations with claimants.

A provision for a loss contingency is recorded when it is probable that a liability has been incurred and the amount of loss can be reasonably estimated. If deemed reasonably possible, the Company is required to estimate and disclose the potential loss or range of potential loss.

Management has recorded estimated liabilities, which represent its best estimate of probable losses associated with the Wildfires.

We identified wildfire-related contingencies and the related disclosures as a critical audit matter because of the significant judgments made by management to determine the probability of loss and estimate the probable losses. Auditing the reasonableness of management's judgments, estimates and disclosures related to wildfire-related loss contingencies required the application of a high degree of judgment and extensive effort.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to management's judgments regarding the probability of loss, estimated losses and related disclosures for wildfire-related contingencies included the following, among others:

- We evaluated management's judgments related to whether a loss was remote, reasonably possible, or probable for the Wildfires by inquiring of management and the Company's external and internal legal counsel regarding the likelihood of loss and amounts of probable and reasonably possible losses. We also evaluated the potential impact of information gained through the Company and third parties' investigations into the cause of the fires, information from claimants, the advice of legal counsel, and reading external information for any evidence that might contradict management's assertions.
- We evaluated the estimation methodology for determining the amount of probable and reasonably possible losses through inquiries with management and external and internal legal counsel and we tested the significant assumptions, including certain settlements, used in the estimates of probable and reasonably possible losses.
- We read legal letters from the Company's external and internal legal counsel regarding known information and evaluated whether the information therein was consistent with the information obtained in our procedures.
- We evaluated whether the Company's disclosures were appropriate and consistent with the information obtained in our procedures.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
February 27, 2026

We have served as the Company's auditor since 1991.

BERKSHIRE HATHAWAY ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2025	**2024**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,695	$ 1,392
Investments and restricted cash and cash equivalents	254	216
Trade receivables, net	2,678	2,551
Inventories	2,105	1,962
Mortgage loans held for sale	698	528
Regulatory assets	892	1,136
Other current assets	1,315	1,314
Total current assets	9,637	9,099
Property, plant and equipment, net	112,368	103,769
Goodwill	11,521	11,413
Regulatory assets	3,929	4,213
Investments and restricted cash and cash equivalents and investments	7,608	8,635
Other assets	3,264	3,011
Total assets	$ 148,327	$ 140,140

The accompanying notes are an integral part of these consolidated financial statements.

BERKSHIRE HATHAWAY ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (continued)
(Amounts in millions, except share amounts)

	As of December 31,	
	2025	**2024**
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 3,389	$ 2,928
Accrued interest	797	728
Accrued property, income and other taxes	745	1,043
Accrued employee expenses	345	364
Short-term debt	1,997	1,123
Current portion of long-term debt	1,455	2,646
Wildfires liabilities (Note 16)	734	247
Other current liabilities	1,930	1,862
Total current liabilities	11,392	10,941
BHE senior debt	11,461	11,457
Subsidiary debt	42,759	41,154
Subsidiary junior subordinated debt	1,584	—
Regulatory liabilities	6,772	6,754
Deferred income taxes	12,999	12,628
Wildfires liabilities (Note 16)	427	1,289
Other long-term liabilities	5,624	4,628
Total liabilities	93,018	88,851
Commitments and contingencies (Note 16)		
Equity:		
BHE shareholders' equity:		
Preferred stock - 100,000,000 shares authorized, $0.01 par value, — and 481,000 shares issued and outstanding	—	481
Common stock - 100 shares authorized, no par value, 1 share issued and outstanding	—	—
Additional paid-in capital	5,558	5,558
Retained earnings	50,351	46,311
Accumulated other comprehensive loss, net	(1,844)	(2,341)
Total BHE shareholders' equity	54,065	50,009
Noncontrolling interests	1,244	1,280
Total equity	55,309	51,289
Total liabilities and equity	$ 148,327	$ 140,140

The accompanying notes are an integral part of these consolidated financial statements.

BERKSHIRE HATHAWAY ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2025	**2024**	**2023**
Operating revenue:			
Energy	$ 21,871	$ 21,566	$ 21,280
Real estate	4,327	4,354	4,322
Total operating revenue	26,198	25,920	25,602
Operating expenses:			
Energy:			
Cost of sales	6,346	6,616	7,057
Operations and maintenance	5,345	5,125	4,779
Wildfire losses, net of recoveries (Note 16)	100	346	1,677
Depreciation and amortization	4,363	4,138	4,170
Property and other taxes	897	840	823
Real estate	4,302	4,509	4,316
Total operating expenses	21,353	21,574	22,822
Operating income	4,845	4,346	2,780
Other income (expense):			
Interest expense	(2,821)	(2,716)	(2,415)
Capitalized interest	179	188	132
Allowance for equity funds	327	352	267
Interest and dividend income	245	443	412
Gains on marketable securities, net	136	474	669
Other, net	63	86	116
Total other income (expense)	(1,871)	(1,173)	(819)
Income before income tax expense (benefit) and equity income (loss)	2,974	3,173	1,961
Income tax expense (benefit)	(1,762)	(1,582)	(1,699)
Equity income (loss)	(522)	(318)	(288)
Net income	4,214	4,437	3,372
Net income attributable to noncontrolling interests	145	137	352
Net income attributable to BHE shareholders	4,069	4,300	3,020
Preferred dividends	3	—	34
Earnings on common shares	$ 4,066	$ 4,300	$ 2,986

The accompanying notes are an integral part of these consolidated financial statements.

BERKSHIRE HATHAWAY ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Amounts in millions)

	Years Ended December 31,		
	2025	**2024**	**2023**
Net income	$ 4,214	$ 4,437	$ 3,372
Other comprehensive income (loss), net of tax:			
Unrecognized amounts on retirement benefits, net of tax of $(19), $(1) and $(13)	(61)	5	(36)
Foreign currency translation adjustment	590	(449)	346
Unrealized (losses) gains on cash flow hedges, net of tax of $(9), $2 and $(13)	(32)	7	(64)
Total other comprehensive income (loss), net of tax	497	(437)	246
Comprehensive income	4,711	4,000	3,618
Comprehensive income attributable to noncontrolling interests	145	137	352
Comprehensive income attributable to BHE shareholders	$ 4,566	$ 3,863	$ 3,266

The accompanying notes are an integral part of these consolidated financial statements.

BERKSHIRE HATHAWAY ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(Amounts in millions)

	BHE Shareholders' Equity						
	Preferred Stock	Common Stock	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive (Loss), Net	Noncontrolling Interests	Total Equity
Balance, December 31, 2022	$ 850	$ —	$ 6,298	$ 41,833	$ (2,149)	$ 3,807	$ 50,639
Net income	—	—	—	3,020	—	352	3,372
Other comprehensive income	—	—	—	—	246	—	246
Long-term income tax receivable adjustments	—	—	—	(54)	—	—	(54)
Preferred stock redemptions	(850)	—	—	—	—	—	(850)
Preferred stock dividend	—	—	—	(34)	—	—	(34)
Distributions	—	—	—	—	—	(394)	(394)
Contributions	—	—	—	—	—	4	4
Purchase of Cove Point noncontrolling interest	—	—	(725)	—	(1)	(2,454)	(3,180)
Other equity transactions	—	—	—	—	—	(9)	(9)
Balance, December 31, 2023	—	—	5,573	44,765	(1,904)	1,306	49,740
Net income	—	—	—	4,300	—	137	4,437
Other comprehensive loss	—	—	—	—	(437)	—	(437)
Long-term income tax receivable adjustments	—	—	—	(33)	—	—	(33)
Common stock repurchases	—	—	(155)	(2,721)	—	—	(2,876)
Distributions	—	—	—	—	—	(162)	(162)
BHE B Merger	481	—	140	—	—	—	621
Other equity transactions	—	—	—	—	—	(1)	(1)
Balance, December 31, 2024	481	—	5,558	46,311	(2,341)	1,280	51,289
Net income	—	—	—	4,069	—	145	4,214
Other comprehensive income	—	—	—	—	497	—	497
Long-term income tax receivable adjustments	—	—	—	(23)	—	—	(23)
Preferred stock redemptions	(481)	—	—	—	—	—	(481)
Preferred stock dividend	—	—	—	(3)	—	—	(3)
Distributions	—	—	—	—	—	(177)	(177)
Other equity transactions	—	—	—	(3)	—	(4)	(7)
Balance, December 31, 2025	$ —	$ —	$ 5,558	$ 50,351	$ (1,844)	$ 1,244	$ 55,309

The accompanying notes are an integral part of these consolidated financial statements.

BERKSHIRE HATHAWAY ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Amounts in millions)

	Years Ended December 31,		
	2025	**2024**	**2023**
Cash flows from operating activities:			
Net income	$ 4,214	$ 4,437	$ 3,372
Adjustments to reconcile net income to net cash flows from operating activities:			
Gains on marketable securities, net	(136)	(474)	(669)
Depreciation and amortization	4,403	4,184	4,220
Allowance for equity funds	(327)	(352)	(267)
Equity (income) loss, net of distributions	624	452	415
Net power cost deferrals	(322)	(41)	(629)
Amortization of net power cost deferrals	925	584	354
Other changes in regulatory assets and liabilities	(172)	(198)	(260)
Deferred income taxes and investment tax credits, net	36	(267)	(257)
Other, net	143	50	(46)
Changes in other operating assets and liabilities, net of effects from acquisitions:			
Trade receivables and other assets	(242)	(542)	(134)
Derivative collateral, net	(51)	18	(226)
Pension and other postretirement benefit plans	(16)	(19)	(10)
Accrued property, income and other taxes, net	(531)	144	(58)
Accounts payable and other liabilities	88	252	280
Wildfires insurance receivable	98	401	(253)
Wildfires liability	(375)	(187)	1,300
Net cash flows from operating activities	8,359	8,442	7,132
Cash flows from investing activities:			
Capital expenditures	(10,589)	(9,013)	(9,148)
Purchases of marketable securities	(478)	(354)	(314)
Proceeds from sales of marketable securities	1,050	2,615	2,520
Purchases of U.S. Treasury Bills	(81)	(2,013)	(4,282)
Proceeds from sales of U.S. Treasury Bills	—	1,975	1,809
Proceeds from maturities of U.S. Treasury Bills	40	723	3,507
Equity method investments	(43)	(12)	(12)
Other, net	32	44	21
Net cash flows from investing activities	(10,069)	(6,035)	(5,899)
Cash flows from financing activities:			
Preferred stock redemptions	(481)	—	(850)
Preferred dividends	(3)	—	(38)
Common stock repurchases	—	(2,276)	—
Repayment of note payable	—	(600)	—
Repayments of BHE senior debt	(1,650)	—	(900)
Repayments of BHE junior subordinated debt	—	(91)	—
Proceeds from subsidiary debt	4,251	6,358	4,084
Repayments of subsidiary debt	(1,061)	(2,794)	(2,821)
Net proceeds from (repayments of) short-term debt	864	(3,017)	3,024
Purchase of Cove Point noncontrolling interest	—	—	(3,300)
Distributions to noncontrolling interests	(178)	(163)	(395)
Other, net	244	(37)	(54)
Net cash flows from financing activities	1,986	(2,620)	(1,250)
Effect of exchange rate changes	16	(12)	11
Net change in cash and cash equivalents and restricted cash and cash equivalents	292	(225)	(6)
Cash and cash equivalents and restricted cash and cash equivalents at beginning of period	1,586	1,811	1,817
Cash and cash equivalents and restricted cash and cash equivalents at end of period	$ 1,878	$ 1,586	$ 1,811

The accompanying notes are an integral part of these consolidated financial statements.

(1) Organization and Operations

Berkshire Hathaway Energy Company ("BHE"), a wholly owned subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway"), is a holding company headquartered in Iowa that has investments in a highly diversified portfolio of locally managed and operated businesses principally engaged in the energy industry (collectively with its subsidiaries, the "Company").

The Company's operations are organized as eight business segments: PacifiCorp and its subsidiaries ("PacifiCorp"), MidAmerican Funding, LLC and its subsidiaries ("MidAmerican Funding") (which primarily consists of MidAmerican Energy Company ("MidAmerican Energy")), NV Energy, Inc. and its subsidiaries ("NV Energy") (which primarily consists of Nevada Power Company and its subsidiaries ("Nevada Power") and Sierra Pacific Power Company and its subsidiaries ("Sierra Pacific")), Northern Powergrid Holdings Company and its subsidiaries ("Northern Powergrid") (which primarily consists of Northern Powergrid (Northeast) plc and Northern Powergrid (Yorkshire) plc), BHE Pipeline Group, LLC and its subsidiaries (which primarily consists of BHE GT&S, LLC and its subsidiaries ("BHE GT&S"), Northern Natural Gas Company ("Northern Natural Gas") and Kern River Gas Transmission Company ("Kern River")), BHE Transmission (which consists of BHE Canada Holdings Corporation and its subsidiaries ("BHE Canada") (which primarily consists of AltaLink, L.P. ("AltaLink")) and BHE U.S. Transmission, LLC and its subsidiaries), BHE Renewables, LLC and its subsidiaries ("BHE Renewables") and HomeServices of America, Inc. and its subsidiaries ("HomeServices"). The Company, through these locally managed and operated businesses, has investments in four utility companies in the U.S. serving customers in 11 states, two electricity distribution companies in Great Britain, five interstate natural gas pipeline companies and interests in a liquefied natural gas ("LNG") export, import and storage facility in the U.S., an electric transmission business in Canada, interests in electric transmission businesses in the U.S., a renewable energy business primarily investing in wind, solar, geothermal and hydroelectric projects, one of the largest residential real estate brokerage firms and a residential real estate brokerage business in the U.S.

(2) Summary of Significant Accounting Policies

Basis of Consolidation and Presentation

The Consolidated Financial Statements include the accounts of BHE and its subsidiaries in which it holds a controlling financial interest as of the financial statement date. The Consolidated Statements of Operations include the revenue and expenses of any acquired entities from the date of acquisition. The Company consolidates variable interest entities ("VIE") in which it possesses both (i) the power to direct the activities that most significantly impact the entity's economic performance and (ii) the obligation to absorb losses or receive benefits from the entity that could potentially be significant to the VIE. Intercompany accounts and transactions have been eliminated.

Use of Estimates in Preparation of Financial Statements

The preparation of the Consolidated Financial Statements in conformity with accounting principles generally accepted in the United States of America ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the period. These estimates include, but are not limited to, the effects of regulation; impairment of goodwill; recovery of long-lived assets; certain assumptions made in accounting for pension and other postretirement benefits; asset retirement obligations ("AROs"); income taxes; unbilled revenue; valuation of certain financial assets and liabilities, including derivative contracts; and accounting for loss contingencies and applicable insurance recoveries, including those related to the Oregon and Northern California 2020 wildfires (the "2020 Wildfires") and a wildfire that began in the Oak Knoll Ranger District of the Klamath National Forest in Siskiyou County, California in July 2022 (the "2022 McKinney Fire"), referred to together as "the Wildfires" as discussed in Note 16. Actual results may differ from the estimates used in preparing the Consolidated Financial Statements.

Accounting for the Effects of Certain Types of Regulation

PacifiCorp, MidAmerican Energy, Nevada Power, Sierra Pacific, BHE GT&S, Northern Natural Gas, Kern River and AltaLink (the "Regulated Businesses") prepare their financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, the Regulated Businesses defer the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur. If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the related regulatory assets and liabilities will be recognized in net income, returned to customers or re-established as accumulated other comprehensive income (loss) ("AOCI").

Fair Value Measurements

As defined under GAAP, fair value is the price that would be received to sell an asset or paid to transfer a liability between market participants in the principal market or in the most advantageous market when no principal market exists. Adjustments to transaction prices or quoted market prices may be required in illiquid or disorderly markets in order to estimate fair value. Alternative valuation techniques may be appropriate under the circumstances to determine the value that would be received to sell an asset or paid to transfer a liability in an orderly transaction. Market participants are assumed to be independent, knowledgeable, able and willing to transact an exchange and not under duress. Nonperformance or credit risk is considered when determining fair value. Considerable judgment may be required in interpreting market data used to develop the estimates of fair value. Accordingly, estimates of fair value presented herein are not necessarily indicative of the amounts that could be realized in a current or future market exchange.

Cash and Cash Equivalents and Restricted Cash and Cash Equivalents

Cash equivalents consist of funds invested in money market mutual funds, U.S. Treasury Bills and other investments with a maturity of three months or less when purchased. Cash and cash equivalents exclude amounts where availability is restricted by legal requirements, loan agreements or other contractual provisions. Restricted cash and cash equivalents consist substantially of funds restricted for debt service obligations for certain of the Company's nonregulated renewable energy projects. A reconciliation of cash and cash equivalents and restricted cash and cash equivalents as of December 31, 2025 and 2024, as presented on the Consolidated Statements of Cash Flows is outlined below and disaggregated by the line items in which they appear on the Consolidated Balance Sheets (in millions):

	As of December 31,	
	2025	2024
Cash and cash equivalents	$ 1,695	$ 1,392
Investments and restricted cash and cash equivalents	168	177
Investments and restricted cash and cash equivalents and investments	15	17
Total cash and cash equivalents and restricted cash and cash equivalents	$ 1,878	$ 1,586

Investments

Fixed Maturity Securities

The Company's management determines the appropriate classification of investments in fixed maturity securities at the acquisition date and reevaluates the classification at each balance sheet date. Investments and restricted cash and cash equivalents and investments that management does not intend to use or is restricted from using in current operations are presented as noncurrent on the Consolidated Balance Sheets.

Available-for-sale investments are carried at fair value with realized gains and losses, as determined on a specific identification basis, recognized in earnings and unrealized gains and losses recognized in AOCI, net of tax. Realized and unrealized gains and losses on fixed maturity securities in a trust related to the decommissioning of the Quad Cities Generating Station Units 1 and 2 ("Quad Cities Station") are recorded as a net regulatory liability because the Company expects to refund to customers any decommissioning funds in excess of costs for these activities through regulated rates. Trading investments are carried at fair value with changes in fair value recognized in earnings. Held-to-maturity investments are carried at amortized cost, reflecting the ability and intent to hold the securities to maturity. The difference between the original cost and maturity value of a fixed maturity security is amortized to earnings using the interest method.

Investment gains and losses arise when investments are sold (as determined on a specific identification basis) or are other-than-temporarily impaired with respect to securities classified as available-for-sale. If the fair value of a fixed maturity investment declines to below amortized cost and the decline is deemed other than temporary, the amortized cost of the investment is reduced to fair value, with a corresponding charge to earnings. Any resulting impairment loss is recognized in earnings if the Company intends to sell, or expects to be required to sell, the debt security before its amortized cost is recovered. If the Company does not expect to ultimately recover the amortized cost basis even if it does not intend to sell the security, the credit loss component is recognized in earnings and any difference between fair value and the amortized cost basis, net of the credit loss, is reflected in other comprehensive income (loss) ("OCI"). For regulated fixed maturity investments, any impairment charge is offset by the establishment of a regulatory asset to the extent recovery in regulated rates is probable.

Equity Securities

Investments in equity securities are carried at fair value with changes in fair value recognized in earnings as a component of gains (losses) on marketable securities, net. All changes in fair value of equity securities in a trust related to the decommissioning of the Quad Cities Station are recorded as a net regulatory liability because the Company expects to refund to customers any decommissioning funds in excess of costs for these activities through regulated rates.

Equity Method Investments

The Company utilizes the equity method of accounting with respect to investments when it possesses the ability to exercise significant influence, but not control, over the operating and financial policies of the investee. The ability to exercise significant influence is presumed when the investor possesses more than 20% of the voting interests of the investee. This presumption may be overcome based on specific facts and circumstances that demonstrate that the ability to exercise significant influence is restricted. In applying the equity method, the Company records the investment at cost and subsequently increases or decreases the carrying value of the investment by the Company's share of the net earnings or losses and OCI of the investee. The Company records dividends or other equity distributions as reductions in the carrying value of the investment. Certain equity investments are presented on the Consolidated Balance Sheets net of related investment tax credits.

Allowance for Credit Losses

Trade receivables are primarily short-term in nature with stated collection terms of less than one year from the date of origination and are stated at the outstanding principal amount, net of an estimated allowance for credit losses. The allowance for credit losses is based on the Company's assessment of the collectability of amounts owed to the Company by its customers. This assessment requires judgment regarding the ability of customers to pay or the outcome of any pending disputes. In measuring the allowance for credit losses for trade receivables, the Company primarily utilizes credit loss history. However, the Company may adjust the allowance for credit losses to reflect current conditions and reasonable and supportable forecasts that deviate from historical experience. The changes in the balance of the allowance for credit losses, which is included in trade receivables, net on the Consolidated Balance Sheets, is summarized as follows for the years ended December 31 (in millions):

	2025	2024	2023
Beginning balance	$ 79	$ 102	$ 106
Charged to operating costs and expenses, net	51	61	68
Write-offs, net	(66)	(84)	(72)
Ending balance	$ 64	$ 79	$ 102

Derivatives

The Company employs a number of different derivative contracts, which may include forwards, futures, options, swaps and other agreements, to manage its commodity price, interest rate and foreign currency exchange rate risks. Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. Derivative balances reflect offsetting permitted under master netting agreements with counterparties and cash collateral paid or received under such agreements. Cash collateral received from or paid to counterparties to secure derivative contract assets or liabilities in excess of amounts offset is included in other current assets on the Consolidated Balance Sheets.

Commodity derivatives used in normal business operations that are settled by physical delivery, among other criteria, are eligible for and may be designated as normal purchases or normal sales. Normal purchases or normal sales contracts are not marked-to-market and settled amounts are recognized as operating revenue or cost of sales on the Consolidated Statements of Operations.

For the Company's derivatives not designated as hedging contracts, the settled amount is generally included in regulated rates. Accordingly, the net unrealized gains and losses associated with interim price movements on contracts that are accounted for as derivatives and probable of inclusion in regulated rates are recorded as regulatory assets and liabilities. For the Company's derivatives not designated as hedging contracts and for which changes in fair value are not recorded as regulatory assets and liabilities, unrealized gains and losses are recognized on the Consolidated Statements of Operations as operating revenue for sales contracts; cost of sales and operating expense for purchase contracts and electricity, natural gas and fuel swap contracts; and other, net for interest rate swap derivatives.

For the Company's derivatives designated as hedging contracts, the Company formally assesses, at inception and thereafter, whether the hedging contract is highly effective in offsetting changes in the hedged item. The Company formally documents hedging activity by transaction type and risk management strategy. For derivative instruments that are accounted for as cash flow hedges or fair value hedges, the cash flows from the derivatives and from the related hedged items are classified in operating cash flows.

Changes in the estimated fair value of a derivative contract designated and qualified as a cash flow hedge, to the extent effective, are included on the Consolidated Statements of Changes in Equity as AOCI, net of tax, until the contract settles and the hedged item is recognized in earnings. The Company discontinues hedge accounting prospectively when it has determined that a derivative contract no longer qualifies as an effective hedge, or when it is no longer probable that the hedged forecasted transaction will occur. When hedge accounting is discontinued because the derivative contract no longer qualifies as an effective hedge, future changes in the estimated fair value of the derivative contract are charged to earnings. Gains and losses related to discontinued hedges that were previously recorded in AOCI will remain in AOCI until the contract settles and the hedged item is recognized in earnings, unless it becomes probable that the hedged forecasted transaction will not occur at which time associated deferred amounts in AOCI are immediately recognized in earnings.

Inventories

Inventories consist mainly of fuel, which includes coal stocks, stored gas and fuel oil, totaling $399 million and $422 million as of December 31, 2025 and 2024, respectively, and materials and supplies totaling $1,706 million and $1,540 million as of December 31, 2025 and 2024, respectively. The cost of materials and supplies, coal stocks and fuel oil is determined primarily using the average cost method. The cost of stored gas is determined using either the last-in-first-out ("LIFO") method or the lower of average cost or market. With respect to inventories carried at LIFO cost, the replacement cost would be $26 million and $18 million higher as of December 31, 2025 and 2024, respectively.

Property, Plant and Equipment, Net

General

Additions to property, plant and equipment are recorded at cost. The Company capitalizes all construction-related materials, direct labor and contract services, as well as indirect construction costs. Indirect construction costs include capitalized interest, including debt allowance for funds used during construction ("AFUDC"), and equity AFUDC, as applicable to the Regulated Businesses. The cost of additions and betterments are capitalized, while costs incurred that do not improve or extend the useful lives of the related assets are generally expensed. Additionally, MidAmerican Energy has regulatory arrangements in Iowa in which the carrying cost of certain utility plant has been reduced for amounts associated with electric returns on equity exceeding specified thresholds.

Depreciation and amortization are generally computed by applying the composite or straight-line method based on either estimated useful lives or mandated recovery periods as prescribed by the Company's various regulatory authorities. Depreciation studies are completed by the Regulated Businesses to determine the appropriate group lives, net salvage and group depreciation rates. These studies are reviewed and rates are ultimately approved by the applicable regulatory commission. Net salvage includes the estimated future residual values of the assets and any estimated removal costs recovered through approved depreciation rates. Estimated removal costs are recorded as either a cost of removal regulatory liability or an ARO liability on the Consolidated Balance Sheets, depending on whether the obligation meets the requirements of an ARO. As actual removal costs are incurred, the associated liability is reduced.

Generally when the Company retires or sells a component of regulated property, plant and equipment, it charges the original cost, net of any proceeds from the disposition, to accumulated depreciation. Any gain or loss on disposals of all other assets is recorded through earnings.

Debt and equity AFUDC, which represent the estimated costs of debt and equity funds necessary to finance the construction of regulated facilities, is capitalized by the Regulated Businesses as a component of property, plant and equipment, with offsetting credits to the Consolidated Statements of Operations. AFUDC is computed based on guidelines set forth by the Federal Energy Regulatory Commission ("FERC") and the Alberta Utilities Commission. After construction is completed, the Company is permitted to earn a return on these costs as a component of the related assets, as well as recover these costs through depreciation expense over the useful lives of the related assets.

Asset Retirement Obligations

The Company recognizes AROs when it has a legal obligation to perform decommissioning, reclamation or removal activities upon retirement of an asset. The Company's AROs are primarily related to the decommissioning of the Quad Cities Station and obligations associated with its other generating facilities and offshore natural gas pipelines. The fair value of an ARO liability is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made, and is added to the carrying amount of the associated asset, which is then depreciated over the remaining useful life of the asset. Subsequent to the initial recognition, the ARO liability is adjusted for any revisions to the original estimate of undiscounted cash flows (with corresponding adjustments to property, plant and equipment, net) and for accretion of the ARO liability due to the passage of time. For the Regulated Businesses, the difference between the ARO liability, the corresponding ARO asset included in property, plant and equipment, net and amounts recovered in rates to satisfy such liabilities is recorded as a regulatory asset or liability.

Impairment

The Company evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or when the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Consolidated Statements of Operations. As a majority of all property, plant and equipment is used in regulated businesses, the impacts of regulation are considered when evaluating the carrying value of regulated assets.

Leases

The Company has non-cancelable operating leases primarily for office space, office equipment, generating facilities, land and rail cars and finance leases consisting primarily of transmission assets, generating facilities and vehicles. These leases generally require the Company to pay for insurance, taxes and maintenance applicable to the leased property. Given the capital-intensive nature of the utility industry, it is common for a portion of lease costs to be capitalized when used during construction or maintenance of assets, in which the associated costs will be capitalized with the corresponding asset and depreciated over the remaining life of that asset. Certain leases contain renewal options for varying periods and escalation clauses for adjusting rent to reflect changes in price indices. The Company does not include options in its lease calculations unless there is a triggering event indicating the Company is reasonably certain to exercise the option. The Company's accounting policy is to not recognize right-of-use assets and lease obligations for leases with contract terms of one year or less and not separate lease components from non-lease components and instead account for each separate lease component and the non-lease components associated with a lease as a single lease component. Leases are evaluated for impairment in line with Accounting Standards Codification ("ASC") 360, "Property, Plant and Equipment" when a triggering event has occurred that might affect the value and use of the assets being leased.

The Company's leases of generating facilities generally are for the long-term purchase of electric energy, also known as power purchase agreements ("PPA"). PPAs are generally signed before or during the early stages of project construction and can yield a lease that has not yet commenced. These agreements are primarily for renewable energy and the payments are considered variable lease payments as they are based on the amount of output.

The Company's operating and finance right-of-use assets are recorded in other assets and the operating and finance lease liabilities are recorded in current and long-term other liabilities accordingly.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of identifiable net assets acquired in business combinations. The Company evaluates goodwill for impairment at least annually and completed its annual review as of October 31, 2025. When evaluating goodwill for impairment, the Company estimates the fair value of its reporting units. If the carrying amount of a reporting unit, including goodwill, exceeds the estimated fair value, then the excess is charged to earnings as an impairment loss. Significant judgment is required in estimating the fair value of the reporting unit and performing goodwill impairment tests. The determination of fair value incorporates significant unobservable inputs. During 2025, 2024 and 2023, the Company did not record any material goodwill impairments.

The Company records goodwill adjustments for changes to the purchase price allocation prior to the end of the measurement period, which is not to exceed one year from the acquisition date.

Revenue Recognition

Customer Revenue

The Company uses a single five-step model to identify and recognize revenue from contracts with customers ("Customer Revenue") upon transfer of control of promised goods or services in an amount that reflects the consideration to which the Company expects to be entitled in exchange for those goods or services. The Company records sales, franchise and excise taxes collected directly from customers and remitted directly to the taxing authorities on a net basis on the Consolidated Statements of Operations. In the event one of the parties to a contract has performed before the other, the Company would recognize a contract asset or contract liability depending on the relationship between the Company's performance and the customer's payment.

Energy Products and Services

A majority of the Company's energy revenue is derived from tariff-based sales arrangements approved by various regulatory commissions. These tariff-based revenues are mainly comprised of energy, transmission, distribution and natural gas and have performance obligations to deliver energy products and services to customers which are satisfied over time as energy is delivered or services are provided. The Company's energy revenue that is nonregulated primarily relates to the Company's renewable energy business.

Revenue recognized is equal to what the Company has the right to invoice as it generally corresponds directly with the value to the customer of the Company's performance to date and includes billed and unbilled amounts. As of December 31, 2025 and 2024, trade receivables, net on the Consolidated Balance Sheets relate substantially to Customer Revenue, including unbilled revenue of $811 million and $807 million, respectively. Payments for amounts billed are generally due from the customer within 30 days of billing. Rates charged for energy products and services are established by regulators or contractual arrangements that establish the transaction price as well as the allocation of price amongst the separate performance obligations. When preliminary regulated rates are permitted to be billed prior to final approval by the applicable regulator, certain revenue collected may be subject to refund and a liability for estimated refunds is accrued.

Real Estate Services

The Company's HomeServices reportable segment consists of separate brokerage, mortgage and franchise businesses. Rates charged for brokerage, mortgage and franchise real estate services are established through contractual arrangements that establish the transaction price and the allocation of the price amongst the separate performance obligations.

The full-service residential real estate brokerage business has performance obligations to deliver integrated real estate services including brokerage services, title and closing services, property and casualty insurance, home warranties, relocation services, and other home-related services to customers. All performance obligations related to the full-service residential real estate brokerage business are satisfied in less than one year at the point in time when a real estate transaction is closed or when services are provided. Commission revenue from real estate brokerage transactions and related amounts due to agents are recognized when a real estate transaction is closed. Title and escrow closing fee revenue from real estate transactions and related amounts due to the title insurer are recognized at closing. Payments for amounts billed are generally due from the customer at closing.

The franchise business operates a network that has performance obligations to provide the right to use certain brand names and other related service marks as well as to provide orientation programs, training and consultation services, advertising programs and other services to its franchisees. The performance obligations related to the franchise business are satisfied over time or when the services are provided. Franchise royalty fees are sales-based variable consideration and are based on a percentage of commissions earned by franchisees on real estate sales, which are recognized when the sale closes. Meetings and training revenue, referral fees, late fees, service fees and franchise termination fees are earned when services have been completed. Payments for amounts billed are generally due from the franchisee within 30 days of billing.

Other Revenue

Energy Products and Services

Other revenue consists primarily of revenue related to power purchase agreements not considered Customer Revenue as they are recognized in accordance with ASC 815, "Derivatives and Hedging" and ASC 842, "Leases" and certain non-tariff-based revenue approved by the regulator that is not considered Customer Revenue within ASC 606, "Revenue from Contracts with Customers."

Real Estate Service

Mortgage and other revenue consists primarily of revenue related to the mortgage business. Mortgage fee revenue consists of amounts earned related to application and underwriting fees and fees on canceled loans. Fees associated with the origination of mortgage loans are recognized as earned. These amounts are not considered Customer Revenue as they are recognized in accordance with ASC 815, "Derivatives and Hedging," ASC 825, "Financial Instruments" and ASC 860, "Transfers and Servicing."

Unamortized Debt Premiums, Discounts and Debt Issuance Costs

Premiums, discounts and debt issuance costs incurred for the issuance of long-term debt are amortized over the term of the related financing using the effective interest method.

Foreign Currency

The accounts of foreign-based subsidiaries are measured in most instances using the local currency of the subsidiary as the functional currency. Revenue and expenses of these businesses are translated into U.S. dollars at the average exchange rate for the period. Assets and liabilities are translated at the exchange rate as of the end of the reporting period. Gains or losses from translating the financial statements of foreign-based operations are included in equity as a component of AOCI. Gains or losses arising from transactions denominated in a currency other than the functional currency of the entity that is party to the transaction are included in earnings.

Income Taxes

The Company's provision for income taxes has been computed on a stand-alone basis. Berkshire Hathaway includes the Company in its consolidated U.S. federal and Iowa state income tax returns and the majority of the Company's U.S. federal income tax is remitted to or received from Berkshire Hathaway, pursuant to a tax allocation agreement.

Deferred income tax assets and liabilities are based on differences between the financial statement and income tax basis of assets and liabilities using enacted income tax rates expected to be in effect for the year in which the differences are expected to reverse. Changes in deferred income tax assets and liabilities associated with components of OCI are charged or credited directly to OCI. Changes in deferred income tax assets and liabilities associated with certain property-related basis differences and other various differences that the Company's regulated businesses deems probable to be passed on to their customers are charged or credited directly to a regulatory asset or liability and will be included in regulated rates when the temporary differences reverse. Other changes in deferred income tax assets and liabilities are included as a component of income tax expense. Changes in deferred income tax assets and liabilities attributable to changes in enacted income tax rates are charged or credited to income tax expense or a regulatory asset or liability in the period of enactment. Valuation allowances are established when necessary to reduce deferred income tax assets to the amount that is more-likely-than-not to be realized.

Investment tax credits are deferred and amortized over the estimated useful lives of the related properties or as prescribed by various regulatory commissions. The Company has not established deferred income taxes on its undistributed foreign earnings from Northern Powergrid that have been determined by management to be reinvested indefinitely.

The Company recognizes the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the Consolidated Financial Statements from such a position are measured based on the largest benefit that is more-likely-than-not to be realized upon ultimate settlement. The Company's unrecognized tax benefits are primarily included in accrued property, income and other taxes and other long-term liabilities on the Consolidated Balance Sheets. Estimated interest and penalties, if any, related to uncertain tax positions are included as a component of income tax expense (benefit) on the Consolidated Statements of Operations.

New Accounting Pronouncements

In December 2023, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2023-09, Income Taxes Topic 740, "Income Tax—Improvements to Income Tax Disclosures" which requires enhanced disclosures, including specific categories and disaggregation of information in the effective tax rate reconciliation, disaggregated information related to income taxes paid, income or loss from continuing operations before income tax expense or benefit, and income tax expense or benefit from continuing operations. This guidance is effective for annual reporting periods beginning after December 15, 2024. Early adoption is permitted and should be applied on a prospective basis, however retrospective application is permitted. The Company adopted this guidance for the fiscal year beginning January 1, 2025, under the retrospective method. The adoption did not have a material impact on the Company's Consolidated Financial Statements, but did expand the disclosures included within Notes to Consolidated Financial Statements. Refer to Note 12 for expanded rate reconciliation disclosures and disaggregation of income taxes paid.

In November 2024, the FASB issued ASU No. 2024-03, Income Statement—Reporting Comprehensive Income—Expense Disaggregation Disclosures Subtopic 220-40, "Disaggregation of Income Statement Expenses" which addresses requests from investors for more detailed information about certain expenses and requires disclosure of the amounts of purchases of inventory, employee compensation, depreciation and intangible asset amortization included in each relevant expense caption presented on the income statement. This guidance, as clarified in ASU 2025-01, is effective for annual reporting periods beginning after December 15, 2026 and interim reporting periods beginning after December 15, 2027. Early adoption is permitted and should be applied on a prospective basis, however retrospective application is permitted. The Company is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

In December 2025, the FASB issued ASU No. 2025-10, Government Grants Topic 832, "Accounting for Government Grants Received by Business Entities" which establishes accounting for government grants received by an entity, including guidance for a grant related to an asset and a grant related to income. This guidance also requires, consistent with current disclosure requirements, that an entity provide disclosures including the nature of the government grant received, the accounting policies used to account for the grant, and significant terms and conditions of the grant. This guidance is effective for interim and annual reporting periods beginning after December 15, 2028. Early adoption is permitted and can be applied using either a modified prospective approach, a modified retrospective approach or a retrospective approach. The Company is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

(3) Business Acquisitions

On September 1, 2023, BHE and Eastern MLP Holding Company II, LLC ("the Buyer"), an indirect wholly owned subsidiary of BHE, completed the acquisition of DECP Holdings, Inc.'s (the "Seller"), an indirect wholly owned subsidiary of Dominion Energy, Inc., 50% limited partner interests in Cove Point LNG, LP ("Cove Point") ("The Transaction"). Under the terms of the Purchase and Sale Agreement, dated July 9, 2023 (the "Purchase Agreement"), the Buyer paid $3.3 billion in cash, plus the pro rata portion of the quarterly distribution made by Cove Point for the third fiscal quarter of 2023. BHE funded the Transaction with cash on hand, including cash realized from the liquidation of certain investments, which was contributed to BHE GT&S. The Buyer now holds 75% of the limited partner interests, and its affiliate, Cove Point GP Holding Company, LLC, continues to hold 100% of the general partner interest, of Cove Point. Prior to the Transaction, BHE held 100% of the general partner interest and 25% of the limited partner interests in Cove Point. BHE previously determined it has the power to direct the activities that most significantly impact Cove Point's economic performance as well as the obligation to absorb losses and benefits which could be significant to it and accordingly, consolidated Cove Point. Because BHE controls Cove Point both before and after the Transaction, the changes in BHE's interest in Cove Point were accounted for as an equity transaction and no gain or loss was recognized. In connection with the Transaction, BHE recognized $120 million of income taxes in equity primarily attributable to the step up in tax basis of the investment in Cove Point of $144 million, partially offset by establishing additional regulatory liabilities related to excess deferred income taxes of $24 million.

(4) Property, Plant and Equipment, Net

Property, plant and equipment, net consists of the following as of December 31 (in millions):

	Depreciable Life	2025	2024
Regulated assets:			
Utility generation, transmission and distribution systems	5-80 years	$ 109,815	$ 103,015
Interstate natural gas pipeline assets	3-80 years	21,334	20,237
		131,149	123,252
Accumulated depreciation and amortization		(40,365)	(38,940)
Regulated assets, net		90,784	84,312
Nonregulated assets:			
Independent power plants	2-50 years	9,242	8,619
LNG facility	40 years	3,476	3,455
Other assets	2-30 years	2,912	2,766
		15,630	14,840
Accumulated depreciation and amortization		(4,637)	(4,176)
Nonregulated assets, net		10,993	10,664
		101,777	94,976
Construction in progress		10,591	8,793
Property, plant and equipment, net		$ 112,368	$ 103,769

Construction work-in-progress includes $9.5 billion and $8.0 billion as of December 31, 2025 and 2024, respectively, related to the construction of regulated assets.

(5) Jointly Owned Utility Facilities

Under joint facility ownership agreements, the Domestic Regulated Businesses, as tenants in common, have undivided interests in jointly owned generation, transmission, distribution and pipeline common facilities. The Company accounts for its proportionate share of each facility and each joint owner has provided financing for its share of each facility. Operating costs of each facility are assigned to joint owners based on their percentage of ownership or energy production, depending on the nature of the cost. Operating costs and expenses on the Consolidated Statements of Operations include the Company's share of the expenses of these facilities.

The amounts shown in the table below represent the Company's share in each jointly owned facility included in property, plant and equipment, net as of December 31, 2025 (dollars in millions):

	Company Share	Facility In Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
PacifiCorp:				
Jim Bridger Nos. 1-4	67 %	$ 1,537	$ 989	$ 2
Hunter No. 1	94	510	273	11
Hunter No. 2	60	317	172	—
Wyodak	80	495	316	—
Colstrip Nos. 3 and 4	10	267	234	2
Hermiston	50	198	122	7
Craig Nos. 1 and 2	19	373	363	—
Hayden No. 1	25	77	61	—
Hayden No. 2	13	45	36	—
Transmission and distribution facilities	Various	963	312	554
Total PacifiCorp		4,782	2,878	576
MidAmerican Energy:				
Louisa No. 1	88	901	576	7
Quad Cities Nos. 1 and 2[(1)]	25	774	526	46
Walter Scott, Jr. No. 3	79	1,038	701	12
Walter Scott, Jr. No. 4[(2)]	60	218	124	5
George Neal No. 4	41	339	204	11
Ottumwa No. 1[(2)]	52	405	289	7
George Neal No. 3	72	599	349	10
Transmission facilities	Various	282	107	3
Total MidAmerican Energy		4,556	2,876	101
NV Energy:				
Valmy Nos. 1 and 2	50	448	373	21
ON Line Transmission Line	25	162	44	31
Other transmission facilities	Various	62	32	—
Total NV Energy		672	449	52
BHE Pipeline Group:				
Ellisburg Pool	39	35	13	—
Ellisburg Station	50	34	10	3
Harrison	50	62	22	2
Leidy	50	160	55	3
Oakford	50	219	78	—
Common facilities	Various	276	187	—
Total BHE Pipeline Group		786	365	8
Total		$ 10,796	$ 6,568	$ 737

(1) Includes amounts related to nuclear fuel.

(2) Facility in-service and accumulated depreciation and amortization amounts are net of credits applied under Iowa regulatory arrangements totaling $1,067 million and $257 million, respectively.

(6) Leases

The following table summarizes the Company's leases recorded on the Consolidated Balance Sheets as of December 31 (in millions):

	2025	2024
Right-of-use assets:		
Operating leases	$ 417	$ 441
Finance leases	794	399
Total right-of-use assets	$ 1,211	$ 840
Lease liabilities:		
Operating leases	$ 466	$ 492
Finance leases	801	412
Total lease liabilities	$ 1,267	$ 904

The following table summarizes the Company's lease costs for the years ended December 31 (in millions):

	2025	2024	2023
Variable	$ 532	$ 434	$ 439
Operating	123	128	136
Finance:			
Amortization	29	23	21
Interest	33	34	35
Short-term	28	33	46
Total lease costs	$ 745	$ 652	$ 677
Weighted-average remaining lease term (years):			
Operating leases	6.9	7.2	7.4
Finance leases	22.8	25.9	27.5
Weighted-average discount rate:			
Operating leases	5.3 %	5.1 %	4.5 %
Finance leases	7.2 %	8.5 %	8.6 %

The following table summarizes the Company's supplemental cash flow information relating to leases for the years ended December 31 (in millions):

	2025	2024	2023
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows from operating leases	$ (126)	$ (131)	$ (138)
Operating cash flows from finance leases	(31)	(33)	(35)
Financing cash flows from finance leases	(35)	(29)	(27)
Right-of-use assets obtained in exchange for lease liabilities:			
Operating leases	$ 80	$ 61	$ 71
Finance leases	11	15	6

The Company has the following remaining lease commitments as of December 31, 2025 (in millions):

	Operating	Finance	Total
2026	$ 137	$ 101	$ 238
2027	110	97	207
2028	78	94	172
2029	56	75	131
2030	38	75	113
Thereafter	132	1,004	1,136
Total undiscounted lease payments	551	1,446	1,997
Less - amounts representing interest	(85)	(645)	(730)
Lease liabilities	$ 466	$ 801	$ 1,267

(7) Regulatory Matters

Regulatory Assets

Regulatory assets represent costs that are expected to be recovered in future regulated rates. The Company's regulatory assets reflected on the Consolidated Balance Sheets consist of the following as of December 31 (in millions):

	Weighted Average Remaining Life	2025	2024
Deferred net power costs	1 year	$ 820	$ 1,400
Asset retirement obligations	25 years	792	1,031
Deferred income taxes[1]	Various	533	455
Demand side management	9 years	407	281
Employee benefit plans[2]	13 years	363	386
Levelized depreciation	27 years	214	185
Unrealized losses on regulated derivative contracts	1 year	207	182
Wildfire mitigation and vegetation management costs	Various	168	208
Environmental costs	26 years	159	145
Asset disposition costs	Various	151	140
Cost of removal	23 years	151	122
Other	Various	856	814
Total regulatory assets		$ 4,821	$ 5,349
Reflected as:			
Current assets		$ 892	$ 1,136
Noncurrent assets		3,929	4,213
Total regulatory assets		$ 4,821	$ 5,349

(1) Amounts primarily represent income tax benefits related to certain property-related basis differences and other various differences that were previously passed on to customers and will be included in regulated rates when the temporary differences reverse.

(2) Includes amounts not yet recognized as a component of net periodic benefit cost that are expected to be included in regulated rates when recognized.

The Company had regulatory assets not earning a return on investment of $2.0 billion and $2.1 billion as of December 31, 2025 and 2024, respectively.

Regulatory Liabilities

Regulatory liabilities represent income to be recognized or amounts to be returned to customers in future periods. The Company's regulatory liabilities reflected on the Consolidated Balance Sheets consist of the following as of December 31 (in millions):

	Weighted Average Remaining Life	2025	2024
Cost of removal[1]	27 years	$ 3,060	$ 2,918
Deferred income taxes[2]	Various	2,239	2,493
Asset retirement obligations	28 years	529	446
Employee benefit plans[3]	Various	321	292
Levelized depreciation	27 years	215	215
Revenue sharing mechanisms	Various	201	263
Other	Various	448	406
Total regulatory liabilities		$ 7,013	$ 7,033
Reflected as:			
Current liabilities		$ 241	$ 279
Noncurrent liabilities		6,772	6,754
Total regulatory liabilities		$ 7,013	$ 7,033

(1) Amounts represent estimated costs, as accrued through depreciation rates and exclusive of ARO liabilities, of removing regulated property, plant and equipment in accordance with accepted regulatory practices. Amounts are deducted from rate base or otherwise accrue a carrying cost.

(2) Amounts primarily represent income tax liabilities related to the federal tax rate change from 35% to 21% that are probable to be passed on to customers, offset by income tax benefits related to certain property-related basis differences and other various differences that were previously passed on to customers and will be included in regulated rates when the temporary differences reverse.

(3) Includes amounts not yet recognized as a component of net periodic benefit cost that are expected to be returned to customers in future periods when recognized.

(8) Investments and Restricted Cash and Cash Equivalents and Investments

Investments and restricted cash and cash equivalents and investments consists of the following as of December 31 (in millions):

	2025	2024
Investments:		
BYD Company Limited common stock	$ —	$ 415
U.S. Treasury Bills	42	—
Corporate-owned life insurance	572	525
Other	386	394
Total investments	1,000	1,334
Equity method investments:		
BHE Renewables tax equity investments	3,945	4,773
Electric Transmission Texas, LLC	835	761
Iroquois Gas Transmission System, L.P.	584	580
Other	336	339
Total equity method investments	5,700	6,453
Restricted cash and cash equivalents and investments:		
Quad Cities Station nuclear decommissioning trust funds	979	871
Other restricted cash and cash equivalents	183	194
Total restricted cash and cash equivalents and investments	1,162	1,065
Total investments and restricted cash and cash equivalents and investments	$ 7,862	$ 8,852
Reflected as:		
Other current assets	$ 254	$ 217
Noncurrent assets	7,608	8,635
Total investments and restricted cash and cash equivalents and investments	$ 7,862	$ 8,852

Investments

BHE's investment in BYD Company Limited common stock is accounted for as a marketable security with changes in fair value recognized in net income.

BHE holds corporate-owned life insurance on certain current and former key executives and directors. The amount represents the cash surrender value of all of the policies, net of amounts borrowed against the cash surrender value.

Other primarily holds Rabbi trusts which were established to hold investments used to fund the obligations of various nonqualified executive and director compensation plans and to pay the costs of the trusts.

Gains on marketable securities, net recognized during the period consists of the following for the years ended December 31 (in millions):

	2025	2024	2023
Unrealized gains recognized on marketable securities held at the reporting date	$ 17	$ 110	$ 252
Net gains recognized on marketable securities sold during the period	119	364	417
Gains on marketable securities, net	$ 136	$ 474	$ 669

Equity Method Investments

The Company has invested in wind projects sponsored by third parties, commonly referred to as tax equity investments. Under the terms of these tax equity investments, the Company has entered into equity capital contribution agreements with the project sponsors that require contributions. The Company made no contributions in 2025, 2024 and 2023. Once a project achieves commercial operation, the Company enters into a partnership agreement with the project sponsor that directs and allocates the operating profits and tax benefits from the project.

BHE, through separate subsidiaries, owns (i) 50% of Electric Transmission Texas, LLC, which owns and operates electric transmission assets in the Electric Reliability Council of Texas footprint; (ii) 50% of Iroquois, which owns and operates an interstate natural gas transmission system located in the states of New York and Connecticut; (iii) 50% of JAX LNG, LLC, which is an LNG supplier in Florida serving the growing marine and truck LNG markets; and (iv) 66.67% of Bridger Coal Company ("Bridger Coal"), which is a coal mining joint venture that supplies coal to PacifiCorp's Jim Bridger Nos. 3-4 generating facility. Bridger Coal is being accounted for under the equity method of accounting as the power to direct the activities that most significantly impact Bridger Coal's economic performance are shared with the joint venture partner. Coal purchases from Bridger Coal for the years ended December 31, 2025, 2024 and 2023 totaled $104 million, $107 million and $115 million, respectively.

Restricted Investments

MidAmerican Energy has established a trust for the investment of funds for decommissioning the Quad Cities Station. The debt and equity securities in the trust are reported at fair value. Funds are invested in the trust in accordance with applicable federal and state investment guidelines and are restricted for use as reimbursement for costs of decommissioning the Quad Cities Station, which are currently licensed for operation until December 2032.

(9) Short-term Debt and Credit Facilities

The following table summarizes BHE's and its subsidiaries' availability under their credit facilities as of December 31 (in millions):

	BHE	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	BHE Canada	HomeServices	Total[1]
2025:								
Credit facilities[2]	$ 3,500	$ 2,900	$ 1,509	$ 1,000	$ 410	$ 674	$ 1,525	$ 11,518
Less:								
Short-term debt	—	(1,000)	—	(50)	(220)	(72)	(655)	(1,997)
Tax-exempt bond support and letters of credit	—	—	(258)	—	—	(4)	—	(262)
Net credit facilities	$ 3,500	$ 1,900	$ 1,251	$ 950	$ 190	$ 598	$ 870	$ 9,259
2024:								
Credit facilities[2]	$ 3,500	$ 2,900	$ 1,509	$ 1,000	$ 344	$ 643	$ 1,700	$ 11,596
Less:								
Short-term debt	(180)	(240)	—	—	(94)	(106)	(503)	(1,123)
Tax-exempt bond support and letters of credit	—	(52)	(271)	—	—	(2)	—	(325)
Net credit facilities	$ 3,320	$ 2,608	$ 1,238	$ 1,000	$ 250	$ 535	$ 1,197	$ 10,148

(1) The table does not include unused credit facilities and letters of credit for investments that are accounted for under the equity method.

(2) Includes $140 million and $94 million, respectively, drawn on capital expenditure and other uncommitted credit facilities at Northern Powergrid as of December 31, 2025 and 2024.

As of December 31, 2025, the Company was in compliance with the covenants of its credit facilities and letter of credit arrangements.

BHE

BHE has a $3.5 billion unsecured credit facility expiring in June 2028 with an unlimited number of maturity extension options, subject to lender consent. This credit facility, which is for general corporate purposes, supports BHE's commercial paper program and provides for the issuance of letters of credit, has a variable interest rate based on the Secured Overnight Financing Rate ("SOFR") or a base rate, at BHE's option, plus a spread that varies based on BHE's credit ratings for its senior unsecured long-term debt securities.

As of December 31, 2025 and 2024, BHE had $— million and $180 million of commercial paper borrowings outstanding at a weighted average interest rate of —% and 4.70%, respectively. The credit facility requires that BHE's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.70 to 1.0 as of the last day of each quarter.

As of December 31, 2025 and 2024, BHE had $210 million of letter of credit capacity under its $3.5 billion unsecured credit facility, of which no amounts were outstanding. Additionally, as of December 31, 2025 and 2024, BHE had $52 million and $100 million, respectively, of letters of credit outstanding outside of its $3.5 billion unsecured credit facility, which primarily support power purchase agreements and debt service requirements at certain subsidiaries of BHE Renewables, LLC expiring from March 2026 through August 2045 and have provisions that automatically extend the annual expiration dates for an additional year unless the issuing bank elects not to renew a letter of credit prior to the expiration date.

PacifiCorp

PacifiCorp has a $2.0 billion unsecured credit facility expiring in June 2028 with an unlimited number of maturity extension options, subject to lender consent. The credit facility, which supports PacifiCorp's commercial paper program and certain series of its tax-exempt bond obligations and provides for the issuance of a certain level of letters of credit, has a variable interest rate based on SOFR or a base rate, at PacifiCorp's option, plus a spread that varies based on PacifiCorp's credit ratings for its senior unsecured long-term debt securities. In addition, PacifiCorp has a $900 million 364-day unsecured credit facility expiring in June 2026 which, similar to its other existing $2.0 billion credit facility provides for loans at variable interest rates based on the SOFR or a base rate, at PacifiCorp's option, plus a spread that varies based on PacifiCorp's credit ratings for its senior unsecured long-term debt securities.

As of December 31, 2025 and 2024, PacifiCorp had $1.0 billion and $240 million of short-term debt outstanding at a weighted average rate of 5.23% and 4.65%, respectively. The outstanding short-term debt as of December 31, 2025, was subsequently repaid in February 2026.

The credit facilities require that PacifiCorp's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.65 to 1.0 as of the last day of each quarter.

As of December 31, 2025 and 2024, PacifiCorp had $255 million of letter of credit capacity under its $2.0 billion revolving credit facility of which no amounts were outstanding. Additionally, as of December 31, 2025 and 2024, PacifiCorp had $963 million and $488 million, respectively, of letter of credit capacity outside of its $2.0 billion revolving credit facility, of which $14 million and $34 million, respectively, were outstanding and were utilized in support of certain transactions required by third parties.

MidAmerican Funding

As of December 31, 2025, MidAmerican Energy has a $1.5 billion unsecured credit facility expiring in June 2028 with an unlimited number of maturity extension options, subject to lender consent. The credit facility, which supports MidAmerican Energy's commercial paper program and its variable-rate tax-exempt bond obligations and provides for the issuance of letters of credit, has a variable interest rate based on SOFR or a base rate, at MidAmerican Energy's option, plus a spread that varies based on MidAmerican Energy's credit ratings for senior unsecured long-term debt securities. Additionally, MidAmerican Energy has a $5 million unsecured credit facility, which expires June 2026 and has a variable interest rate based on SOFR, plus a spread.

As of December 31, 2025 and 2024, MidAmerican Energy had no commercial paper borrowings outstanding. The $1.5 billion credit facility requires that MidAmerican Energy's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.65 to 1.0 as of the last day of any quarter.

As of December 31, 2025 and 2024, MidAmerican Energy had $135 million of letter of credit capacity under its $1.5 billion unsecured credit facility, of which no amounts were outstanding. Additionally, as of December 31, 2025 and 2024, MidAmerican Energy had $57 million and $53 million, respectively, of letters of credit outstanding outside of its $1.5 billion unsecured credit facility in support of certain transactions required by third parties that generally have provisions that automatically extend the annual expiration dates for an additional year unless the issuing bank elects not to renew a letter of credit prior to the expiration date.

NV Energy

Nevada Power has a $600 million secured credit facility expiring in June 2028 and Sierra Pacific has a $400 million secured credit facility expiring in June 2028 each with an unlimited number of maturity extension options, subject to lender consent. These credit facilities, which are for general corporate purposes and provide for the issuance of letters of credit, have a variable interest rate based on SOFR or a base rate, at each of the Nevada Utilities' option, plus a spread that varies based on each of the Nevada Utilities' credit ratings for its senior secured long-term debt securities.

As of December 31, 2025 and 2024, the Nevada Utilities had $50 million and $— million of short-term debt outstanding at a weighted average rate of 4.71% and —%, respectively.

Amounts due under each credit facility are collateralized by each of the Nevada Utilities' general and refunding mortgage bonds. These credit facilities require that each of the Nevada Utilities' ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.65 to 1.0 as of the last day of each quarter.

As of December 31, 2025 and 2024, Nevada Power had $50 million of letter of credit capacity under its $600 million secured credit facility and Sierra Pacific had $50 million of letter of credit capacity under its $400 million secured credit facility, of which no amounts were outstanding.

Northern Powergrid

Northern Powergrid has a £200 million unsecured credit facility expiring in December 2028. The credit facility has a variable interest rate based on Sterling Overnight Index Average plus a spread that varies based on Northern Powergrid's credit ratings. The credit facility requires that the ratio of consolidated senior total net debt, including current maturities, to regulated asset value not exceed 0.8 to 1.0 at Northern Powergrid and 0.65 to 1.0 at each of Northern Powergrid (Northeast) plc and Northern Powergrid (Yorkshire) plc as of June 30 and December 31. Northern Powergrid's interest coverage ratio shall not be less than 2.5 to 1.0.

As of December 31, 2025 and 2024, Northern Powergrid had $71 million and $— of short-term debt outstanding at a weighted average rate of 3.92% and —%, respectively.

As of December 31, 2025 and 2024, Northern Powergrid had $28 million and $15 million, respectively, of letters of credit outstanding outside of its £200 million unsecured credit facility, primarily in support of certain transactions required by third parties.

BHE Canada

BHE Canada has a C$50 million unsecured revolving term credit facility expiring in December 2029 with a recurring one-year extension option subject to lender consent. The credit facility, which may be used for general corporate purposes and letters of credit, has a variable interest rate based on the Canadian bank prime lending rate, or a spread above the Canadian Overnight Repo Rate Average ("CORRA"), at BHE Canada's option, based on BHE Canada's senior unsecured credit rating. The credit facility requires the ratio of consolidated total debt to consolidated total capitalization not exceed 0.75 to 1.0 measured as of the last day of each quarter. In addition, BHE Canada is required to maintain a ratio of unconsolidated earnings before interest, taxes, depreciation and amortization to interest expense of not less than 2.25 to 1.00 measured as of the last day of each quarter.

As of December 31, 2025 and 2024, BHE Canada had no borrowings outstanding under the credit facility.

As of December 31, 2025 and 2024, BHE Canada had C$50 million of letter of credit capacity under its C$50 million unsecured revolving term credit facility, of which $2 million and $1 million, respectively were outstanding.

AltaLink

AltaLink has a C$500 million secured revolving term credit facility expiring in December 2030 with a recurring one-year extension option subject to lender consent. The credit facility, which supports AltaLink's commercial paper program and may also be used for general corporate purposes, has a variable interest rate based on the Canadian bank prime lending rate or a spread above CORRA, at AltaLink's option, based on AltaLink's senior secured credit rating.

As of December 31, 2025 and 2024, AltaLink had $72 million and $106 million outstanding under the facility at a weighted average rate of 2.30% and 3.32%, respectively. The credit facility requires the ratio of consolidated indebtedness to total capitalization not exceed 0.75 to 1.0 measured as of the last day of each quarter.

AltaLink also has a C$75 million secured revolving term credit facility expiring in December 2030 with a recurring one-year extension option subject to lender consent. The credit facility, which may be used for general corporate purposes and letters of credit, has a variable interest rate based on the Canadian bank prime lending rate, or a spread above CORRA, at AltaLink's option, based on AltaLink's senior secured credit rating.

As of December 31, 2025 and 2024, AltaLink had no borrowings outstanding under the facility. The credit facility requires the ratio of consolidated indebtedness to total capitalization not exceed 0.75 to 1.0 measured as of the last day of each quarter.

As of December 31, 2025 and 2024, AltaLink had C$75 million of letter of credit capacity under its C$75 million secured revolving term credit facility, of which $2 million and $1 million, respectively were outstanding.

AltaLink Investments, L.P. has a C$300 million unsecured revolving term credit facility expiring in December 2028 with a recurring one-year extension option subject to lender consent. The credit facility, which may be used for general corporate purposes and letters of credit, has a variable interest rate based on the Canadian bank prime lending rate, or a spread above the Bankers' Acceptance rate, at AltaLink Investments, L.P.'s option, based on AltaLink Investments, L.P.'s senior unsecured credit rating.

As of December 31, 2025 and 2024, AltaLink Investments, L.P. had no amounts outstanding under the facility. The credit facility requires the ratio of consolidated total debt to capitalization not exceed 0.8 to 1.0 and earnings before interest, taxes, depreciation and amortization to interest expense for the four fiscal quarters ended not be less than 2.25 to 1.0 measured as of the last day of each quarter.

As of December 31, 2025 and 2024, AltaLink Investments, L.P. had C$10 million of letter of credit capacity under its C$300 million unsecured revolving term credit facility, of which no amounts were outstanding.

HomeServices

HomeServices has a $350 million secured credit facility expiring in June 2030. The credit facility, which is for general corporate purposes and provides for the issuance of letters of credit, has a variable interest rate based on SOFR or a base rate, at HomeServices' option, plus a spread that varies based on HomeServices' total net leverage ratio as of the last day of each quarter. As of December 31, 2025, HomeServices had no amounts outstanding under its credit facility.

As of December 31, 2024, HomeServices had a $200 million secured credit facility. The credit facility, which was for general corporate purposes and provided for the issuance of letters of credit, had a variable interest rate based on SOFR or a base rate, at HomeServices' option, plus a spread that varied based on HomeServices' total net leverage ratio as of the last day of each quarter. As of December 31, 2024, HomeServices had no amounts outstanding under the facility.

Through its subsidiaries, HomeServices maintains mortgage lines of credit totaling $1.2 billion and $1.5 billion, respectively, as of December 31, 2025 and 2024, used for mortgage banking activities that expire beginning in March 2026 through August 2026. The mortgage lines of credit have variable rates based on SOFR, plus a spread. Collateral for these credit facilities is comprised of residential property being financed and is equal to the loans funded with the facilities. As of December 31, 2025 and 2024, HomeServices had $655 million and $503 million, respectively, outstanding under these mortgage lines of credit at a weighted average interest rate of 5.10% and 5.88%, respectively.

BHE Renewables Letters of Credit

As of December 31, 2025 and 2024, certain renewable projects collectively have letters of credit outstanding of $278 million and $287 million, respectively, primarily in support of the power purchase agreements and large generator interconnection agreements associated with the projects.

(10) BHE Debt

Senior Debt

BHE senior debt represents unsecured senior obligations of BHE that are redeemable in whole or in part at any time generally with make whole premiums. BHE senior debt consists of the following, including fair value adjustments and unamortized premiums, discounts and debt issuance costs, as of December 31 (in millions):

	Par Value	2025	2024
3.50% Senior Notes, due 2025	$ —	$ —	$ 400
4.05% Senior Notes, due 2025	—	—	1,250
3.25% Senior Notes, due 2028	600	598	597
8.48% Senior Notes, due 2028	256	256	257
3.70% Senior Notes, due 2030	1,100	1,098	1,097
1.65% Senior Notes, due 2031	500	498	498
6.125% Senior Bonds, due 2036	1,670	1,663	1,663
5.95% Senior Bonds, due 2037	550	548	548
6.50% Senior Bonds, due 2037	225	223	223
5.15% Senior Notes, due 2043	750	741	741
4.50% Senior Notes, due 2045	750	739	739
3.80% Senior Notes, due 2048	750	739	738
4.45% Senior Notes, due 2049	1,000	992	991
4.25% Senior Notes, due 2050	900	890	889
2.85% Senior Notes, due 2051	1,500	1,489	1,489
4.60% Senior Notes, due 2053	1,000	987	987
Total BHE Senior Debt	$ 11,551	$ 11,461	$ 13,107
Reflected as:			
Current liabilities		$ —	$ 1,650
Noncurrent liabilities		11,461	11,457
Total BHE Senior Debt		$ 11,461	$ 13,107

Junior Subordinated Debentures

In September 2024, BHE acquired, cancelled and extinguished the junior subordinated debentures held by a minority shareholder. Interest expense to the minority shareholder was $4 million and $5 million for the years ended December 31, 2024 and 2023.

(11) Subsidiary Debt

BHE's direct and indirect subsidiaries are organized as legal entities separate and apart from BHE and its other subsidiaries. Pursuant to separate financing agreements, substantially all of PacifiCorp's electric utility properties; the equity interest of MidAmerican Funding's subsidiary; MidAmerican Energy's electric utility properties in the state of Iowa; substantially all of Nevada Power's and Sierra Pacific's properties in the state of Nevada; AltaLink's transmission properties; and substantially all of the assets of the subsidiaries of BHE Renewables that are direct or indirect owners of wind and solar generation projects are pledged or encumbered to support or otherwise provide the security for their related subsidiary debt. It should not be assumed that the assets of any subsidiary will be available to satisfy BHE's obligations or the obligations of its other subsidiaries. However, unrestricted cash or other assets which are available for distribution may, subject to applicable law, regulatory commitments and the terms of financing and ring-fencing arrangements for such parties, be advanced, loaned, paid as dividends or otherwise distributed or contributed to BHE or affiliates thereof. The long-term debt of BHE's subsidiaries may include provisions that allow BHE's subsidiaries to redeem such debt in whole or in part at any time. These provisions generally include make-whole premiums.

Distributions at these separate legal entities are limited by various covenants including, among others, leverage ratios, interest coverage ratios and debt service coverage ratios. As of December 31, 2025, all subsidiaries were in compliance with their long-term debt covenants.

Senior Debt

Subsidiary debt consists of the following, including fair value adjustments and unamortized premiums, discounts and debt issuance costs, as of December 31 (in millions):

	Par Value	2025	2024
PacifiCorp	$ 13,400	$ 13,293	$ 13,588
MidAmerican Funding	9,561	9,438	9,053
NV Energy	4,971	4,933	4,932
Northern Powergrid	4,241	4,192	3,337
BHE Pipeline Group	6,593	6,783	5,582
BHE Transmission	3,499	3,481	3,267
BHE Renewables	2,110	2,094	2,331
HomeServices	—	—	60
Total subsidiary senior debt	$ 44,375	$ 44,214	$ 42,150
Reflected as:			
Current liabilities		$ 1,455	$ 996
Noncurrent liabilities		42,759	41,154
Total subsidiary senior debt		$ 44,214	$ 42,150

Junior Subordinated Debt

Subsidiary junior subordinated debt consists of the following, including unamortized premiums, discounts and debt issuance costs, as of December 31 (in millions):

	Par Value	2025	2024
PacifiCorp	$ 850	$ 841	$ —
NV Energy	750	743	—
Total subsidiary junior subordinated debt - noncurrent	$ 1,600	$ 1,584	$ —

PacifiCorp

Senior Debt

PacifiCorp's senior debt consists of the following, including unamortized premiums, discounts and debt issuance costs as of December 31 (dollars in millions):

	Par Value	2025	2024
First mortgage bonds:			
3.35%, due 2025	$ —	$ —	$ 250
6.71%, due 2026	100	100	100
5.10%, due 2029	500	498	498
3.50%, due 2029	400	399	399
2.70%, due 2030	400	399	398
5.30%, due 2031	700	696	696
7.70%, due 2031	300	299	299
5.45%, due 2034	1,100	1,093	1,093
5.90%, due 2034	200	199	199
5.25%, due 2035	300	299	299
6.10%, due 2036	350	349	348
5.75%, due 2037	600	600	600
6.25%, due 2037	600	598	598
6.35%, due 2038	300	298	298
6.00%, due 2039	650	645	644
4.10%, due 2042	300	298	298
4.125%, due 2049	600	595	594
4.15%, due 2050	600	594	594
3.30%, due 2051	600	592	591
2.90%, due 2052	1,000	986	985
5.35%, due 2053	1,100	1,088	1,088
5.50%, due 2054	1,200	1,189	1,189
5.80%, due 2055	1,500	1,479	1,478
Variable-rate series, tax-exempt bond obligations (2024-3.20% to 4.45%):			
Secured[(1)], due 2025	—	—	27
Unsecured, due 2025	—	—	25
Total PacifiCorp senior debt	$ 13,400	$ 13,293	$ 13,588

(1) Secured by pledged first mortgage bonds registered to and held by the tax-exempt bond trustee generally with the same interest rates, maturity dates and redemption provisions as the tax-exempt bond obligations.

PacifiCorp currently has regulatory authority from the Oregon Public Utility Commission and the Idaho Public Utilities Commission to issue an additional $2.7 billion of long-term debt. PacifiCorp must make a notice filing with the Washington Utilities and Transportation Commission prior to any future issuance. PacifiCorp currently has an effective shelf registration statement filed with the U.S. Securities and Exchange Commission to issue an indeterminate amount of first mortgage bonds and unsecured debt securities through July 2027.

The issuance of PacifiCorp's first mortgage bonds is limited by available property, earnings tests and other provisions of PacifiCorp's mortgage. Approximately $42.4 billion of PacifiCorp's eligible property (based on original cost) was subject to the lien of the mortgage as of December 31, 2025.

In February 2026, PacifiCorp issued $400 million of 4.25% First Mortgage Bonds due March 2029.

Junior Subordinated Debt

PacifiCorp's junior subordinated debt consists of the following, including unamortized premiums, discounts and debt issuance costs as of December 31 (dollars in millions):

	Par Value	2025	2024
7.375%, due 2055[(1)]	$ 850	$ 841	$ —
Total PacifiCorp junior subordinated debt	$ 850	$ 841	$ —

(1) PacifiCorp will pay interest on the junior subordinated notes at a rate of 7.375% through September 2030, subject to a reset every five years, not to reset below 7.375%.

In February 2026, PacifiCorp issued $1.1 billion of its 7.125% Fixed-to-Fixed Reset Rate Junior Subordinated Notes due August 2056. PacifiCorp will pay interest on the junior subordinated notes at a rate of 7.125% through August 2031, subject to a reset every five years, not to reset below 7.125%.

MidAmerican Funding

MidAmerican Funding's long-term debt consists of the following, including fair value adjustments and unamortized premiums, discounts and debt issuance costs, as of December 31 (dollars in millions):

	Par Value	2025	2024
MidAmerican Funding:			
6.927% Senior Bonds, due 2029	$ 239	$ 240	$ 240
Fair value adjustment	—	(9)	(11)
MidAmerican Funding, net of fair value adjustments	239	231	229
MidAmerican Energy:			
First mortgage bonds:			
3.10%, due 2027	375	375	374
3.65%, due 2029	850	854	857
5.35%, due 2034	350	348	347
4.80%, due 2043	350	347	347
4.40%, due 2044	400	396	396
4.25%, due 2046	450	446	446
3.95%, due 2047	475	471	471
3.65%, due 2048	700	691	690
4.25%, due 2049	900	878	876
3.15%, due 2050	600	593	593
2.70%, due 2052	500	493	493
5.85%, due 2054	1,000	990	990
5.30%, due 2055	600	592	592
5.50%, due 2056	400	393	—
Notes:			
6.75% Series, due 2031	400	398	398
5.75% Series, due 2035	300	299	299
5.80% Series, due 2036	350	349	348
Transmission upgrade obligation, 3.20% to 7.81%, due 2036 to 2043	64	37	37
Tax-exempt bond obligations -			
Variable-rate tax-exempt bond obligation series: (weighted average interest rate - 2025-2.49%, 2024-3.36%), due 2025-2047	258	257	270
Total MidAmerican Energy	9,322	9,207	8,824
Total MidAmerican Funding	$ 9,561	$ 9,438	$ 9,053

Pursuant to MidAmerican Energy's mortgage dated September 9, 2013, MidAmerican Energy's first mortgage bonds, currently and from time to time outstanding, are secured by a first mortgage lien on substantially all of its electric generating, transmission and distribution property within the state of Iowa, subject to certain exceptions and permitted encumbrances. Approximately $26 billion of MidAmerican Energy's eligible property, based on original cost, was subject to the lien of the mortgage as of December 31, 2025. Additionally, MidAmerican Energy's senior notes outstanding are equally and ratably secured with the first mortgage bonds as required by the indentures under which the senior notes were issued.

MidAmerican Energy's variable-rate tax-exempt bond obligations bear interest at rates that are periodically established through remarketing of the bonds in the short-term tax-exempt market. MidAmerican Energy, at its option, may change the mode of interest calculation for these bonds by selecting from among several floating or fixed rate alternatives. The interest rates shown in the table above are the weighted average interest rates as of December 31, 2025 and 2024. MidAmerican Energy maintains revolving credit facility agreements to provide liquidity for holders of these issues. Additionally, MidAmerican Energy's obligations associated with the $30 million and $150 million variable rate, tax-exempt bond obligations due 2046 and 2047, respectively, are secured by an equal amount of first mortgage bonds pursuant to MidAmerican Energy's mortgage dated September 9, 2013, as supplemented and amended.

NV Energy

Senior Debt

NV Energy's senior debt consists of the following, including fair value adjustments and unamortized premiums, discounts and debt issuance costs, as of December 31 (dollars in millions):

	Par Value	2025	2024
Nevada Power:			
General and refunding mortgage securities:			
3.70% Series CC, due 2029	$ 500	$ 498	$ 498
2.40% Series DD, due 2030	425	423	423
6.65% Series N, due 2036	367	362	361
6.75% Series R, due 2037	349	347	347
5.375% Series X, due 2040	250	248	248
5.45% Series Y, due 2041	250	241	240
3.125% Series EE, due 2050	300	298	298
5.90% Series GG, due 2053	400	395	394
6.00% Series 2023A, due 2054	500	495	495
Tax-exempt refunding revenue bond obligations:			
Fixed-rate series:			
4.125% Pollution Control Bonds Series 2017A, due 2032[1]	40	39	39
3.75% Pollution Control Bonds Series 2017, due 2036[1]	40	39	39
3.75% Pollution Control Bonds Series 2017B, due 2039[1]	13	13	13
Total Nevada Power	3,434	3,398	3,395
Fair value adjustments	—	8	9
Total Nevada Power, net of fair value adjustments	3,434	3,406	3,404
Sierra Pacific:			
General and refunding mortgage securities:			
2.60% Series U, due 2026	400	400	399
6.75% Series P, due 2037	252	253	254
4.71% Series W, due 2052	250	248	248
5.90% Series 2023A, due 2054	400	394	394
Tax-exempt refunding revenue bond obligations:			
Fixed-rate series:			
3.55% Pollution Control Series 2016A, due 2029	20	20	20
3.55% Pollution Control Series 2016B, due 2029[2]	30	29	29
3.625% Gas and Water Series 2016B, due 2036[3]	60	59	59
4.125% Water Facilities Series 2016C, due 2036[3]	30	29	30
4.125% Water Facilities Series 2016F, due 2036[3]	75	74	74
3.625% Water Facilities Series 2016G, due 2036[3]	20	20	20
Total Sierra Pacific	1,537	1,526	1,527
Fair value adjustments	—	1	1
Total Sierra Pacific, net of fair value adjustment	1,537	1,527	1,528
Total NV Energy senior debt	$ 4,971	$ 4,933	$ 4,932

(1) Subject to mandatory purchase by Nevada Power in March 2026 at which date the interest rate may be adjusted.

(2) Subject to mandatory sinking fund redemption by Sierra Pacific in the principal amount of $10 million in April 2026.

(3) Subject to mandatory purchase by Sierra Pacific in October 2029 at which date the interest rate may be adjusted.

The issuance of General and Refunding Mortgage Securities by the Nevada Utilities are subject to Public Utilities Commission of Nevada ("PUCN") approval and are limited by available property and other provisions of the mortgage indentures for each of Nevada Power and Sierra Pacific. As of December 31, 2025, approximately $11.8 billion of Nevada Power's and $5.6 billion of Sierra Pacific's (based on original cost) property was subject to the liens of the mortgages.

Junior Subordinated Debt

NV Energy's junior subordinated debt consists of the following, including unamortized premiums, discounts and debt issuance costs as of December 31 (dollars in millions):

	Par Value	2025	2024
Nevada Power:			
6.250%, Series 2025A, due 2055[1]	$ 300	$ 297	$ —
Sierra Pacific:			
6.200%, Series 2025A, due 2055[2]	450	446	—
Total NV Energy junior subordinated debt	$ 750	$ 743	$ —

(1) Nevada Power will pay interest on the junior subordinated notes at a rate of 6.25% through May 2030, subject to a reset every five years.

(2) Sierra Pacific will pay interest on the junior subordinated notes at a rate of 6.20% through December 2030, subject to a reset every five years.

Northern Powergrid

Northern Powergrid and its subsidiaries' long-term debt consists of the following, including fair value adjustments and unamortized premiums, discounts and debt issuance costs, as of December 31 (dollars in millions):

	Par Value[1]	2025	2024
2.50% Bonds, due 2025	$ —	$ —	$ 187
2.073% European Investment Bank loan, due 2025	—	—	63
2.564% European Investment Bank loans, due 2027	337	337	313
7.25% Bonds, due 2028	250	251	234
4.375% Bonds, due 2032	202	200	186
5.625% Bonds, due 2033	337	333	309
5.125% Bonds, due 2035	270	267	248
5.125% Bonds, due 2035	202	201	186
5.375% Bonds, due 2037	337	334	—
2.75% Bonds, due 2049	202	199	185
6.125% Bonds, due 2050	337	327	—
3.25% Bonds, due 2052	472	467	433
5.875% Bonds, due 2055	404	399	—
2.25% Bonds, due 2059	404	397	368
1.875% Bonds, due 2062	404	397	369
Variable-rate loan, due 2025	—	—	137
Variable-rate loan, due 2026[2]	83	83	119
Total Northern Powergrid	$ 4,241	$ 4,192	$ 3,337

(1) The par values for these debt instruments are denominated in sterling.

(2) Amortizes semiannually and the Company has entered into an interest rate swap that fixes the interest rate on 80% of the outstanding debt. The variable interest rate as of December 31, 2025 was 5.73% (including 1.75% margin) and the fixed interest rate was 2.65% (including 1.75% margin), resulting in a blended rate of 3.30%.

BHE Pipeline Group

BHE Pipeline Group's long-term debt consists of the following, including fair value adjustments and unamortized premiums, discounts and debt issuance costs, as of December 31 (dollars in millions):

	Par Value	2025	2024
Eastern Energy Gas:			
3.317% Senior Notes, due 2026 (€250)[1]	$ 293	$ 293	$ 259
3.00% Senior Notes, due 2029	174	173	173
3.80% Senior Notes, due 2031	150	150	150
5.80% Senior Notes, due 2035	700	694	—
4.80% Senior Notes, due 2043	54	53	53
4.60% Senior Notes, due 2044	56	56	56
3.90% Senior Notes, due 2049	27	26	26
5.65% Senior Notes, due 2054	900	892	892
6.20% Senior Notes, due 2055	500	494	—
EGTS:			
3.00% Senior Notes, due 2029	426	423	423
5.02% Senior Notes, due 2034	150	149	149
4.80% Senior Notes, due 2043	346	342	342
4.60% Senior Notes, due 2044	444	438	437
3.90% Senior Notes, due 2049	273	271	271
Total Eastern Energy Gas	4,493	4,454	3,231
Fair value adjustments	—	245	268
Total Eastern Energy Gas, net of fair value adjustments	4,493	4,699	3,499
Northern Natural Gas:			
5.80% Senior Bonds, due 2037	150	149	149
4.10% Senior Bonds, due 2042	250	248	248
4.30% Senior Bonds, due 2049	650	651	651
3.40% Senior Bonds, due 2051	550	540	540
5.625% Senior Bonds, due 2054	500	496	495
Total Northern Natural Gas	2,100	2,084	2,083
Total BHE Pipeline Group	$ 6,593	$ 6,783	$ 5,582

(1) The senior notes are denominated in Euros with an outstanding principal balance of €250 million and a fixed interest rate of 1.45%. Eastern Energy Gas has entered into cross currency swaps that fix USD payments for 100% of the notes. The fixed USD outstanding principal when combined with the swaps is $280 million, with fixed interest rates at both December 31, 2025 and 2024 that averaged 3.317%.

BHE Transmission

BHE Transmission's long-term debt consists of the following, including fair value adjustments and unamortized premiums, discounts and debt issuance costs, as of December 31 (dollars in millions):

	Par Value[1]	2025	2024
AltaLink, L.P.:			
2.747% Series 2016-1 Notes, due 2026	$ 255	$ 255	$ 243
1.509% Series 2020-1 Notes, due 2030	164	164	156
4.692% Series 2022-1 Notes, due 2032	200	199	190
5.249% Series 2006-1 Notes, due 2036	109	109	104
5.381% Series 2010-1 Notes, due 2040	91	91	87
4.872% Series 2010-2 Notes, due 2040	109	109	104
4.462% Series 2011-1 Notes, due 2041	201	200	190
3.99% Series 2012-1 Notes, due 2042	383	378	360
4.922% Series 2013-3 Notes, due 2043	255	254	242
4.054% Series 2014-3 Notes, due 2044	215	214	204
4.09% Series 2015-1 Notes, due 2045	255	254	242
3.717% Series 2016-2 Notes, due 2046	328	326	311
4.446% Series 2013-1 Notes, due 2053	182	181	173
4.742% Series 2024-1 Notes, due 2054	237	235	225
5.463% Series 2023-1 Notes, due 2055	364	362	346
2.17% Canada Infrastructure Bank loans, due 2056	56	56	—
4.274% Series 2014-2 Notes, due 2064	95	94	90
Total AltaLink, L.P.	3,499	3,481	3,267
Total BHE Transmission	$ 3,499	$ 3,481	$ 3,267

(1) The par values for these debt instruments are denominated in Canadian dollars.

BHE Renewables

BHE Renewables' long-term debt consists of the following, including unamortized premiums, discounts and debt issuance costs, as of December 31 (dollars in millions):

	Par Value	2025	2024
Fixed-rate[1]:			
Bishop Hill Holdings Senior Notes, 5.125%, due 2032	$ 43	$ 43	$ 47
Solar Star Funding Senior Notes, 3.95%, due 2035	197	196	213
Solar Star Funding Senior Notes, 5.375%, due 2035	648	644	693
Grande Prairie Wind Senior Notes, 3.86%, due 2037	163	162	200
Topaz Solar Farms Senior Notes, 5.75%, due 2039	476	472	504
Topaz Solar Farms Senior Notes, 4.875%, due 2039	132	131	140
Alamo 6 Senior Notes, 4.17%, due 2042	161	160	169
Variable-rate[1]:			
TX Jumbo Road Term Loan, due 2025[2]	—	—	48
Marshall Wind Term Loan, due 2026[2]	34	34	41
Pinyon Pines I and II Term Loans, due 2034[2]	256	252	276
Total BHE Renewables	$ 2,110	$ 2,094	$ 2,331

(1) Amortizes quarterly or semiannually.

(2) The term loans have variable interest rates based on SOFR plus a margin that varies during the terms of the agreements. The Company has entered into interest rate swaps that fix the interest rate on 100% of the TX Jumbo Road, Marshall Wind and Pinyon Pines outstanding debt. The fixed interest rates as of December 31, 2025 ranged from. 3.31% to 3.36%. The fixed interest rates as of December 31, 2024 ranged from 3.31% to 3.73%.

HomeServices

HomeServices' long-term debt consists of the following, including unamortized premiums, discounts and debt issuance costs, as of December 31 (dollars in millions):

	Par Value	2025	2024
Variable-rate:			
Variable-rate term loan (2024 - 7.41%), due 2026[1]	$ —	$ —	$ 60

(1) Term loan amortizes quarterly and variable-rate resets monthly. The term loan was fully repaid in June 2025.

Annual Repayments of Long-Term Debt

The annual repayments of BHE and subsidiary debt for the years beginning January 1, 2026 and thereafter, excluding fair value adjustments and unamortized premiums, discounts and debt issuance costs, are as follows (in millions):

	2026	2027	2028	2029	2030	2031 and Thereafter	Total
BHE senior notes	$ —	$ —	$ 856	$ —	$ 1,100	$ 9,595	$ 11,551
PacifiCorp	100	—	—	900	400	12,850	14,250
MidAmerican Funding	4	379	4	1,094	4	8,076	9,561
NV Energy	503	—	—	540	425	4,253	5,721
Northern Powergrid	83	337	250	—	—	3,571	4,241
BHE Pipeline Group	293	—	—	600	—	5,700	6,593
BHE Transmission	255	—	—	—	164	3,080	3,499
BHE Renewables	217	168	174	182	190	1,179	2,110
Totals	$ 1,455	$ 884	$ 1,284	$ 3,316	$ 2,283	$ 48,304	$ 57,526

(12) Income Taxes

The Company's provision for income taxes has been computed on a stand-alone basis. Berkshire Hathaway includes the Company in its consolidated U.S. federal and Iowa state income tax returns and the majority of the Company's U.S. federal income tax is remitted to or received from Berkshire Hathaway, pursuant to a tax allocation agreement. The Company had a current income tax receivable from Berkshire Hathaway of $282 million and a current income tax payable to Berkshire Hathaway of $138 million for federal income tax as of December 31, 2025 and 2024, respectively.

The following table summarizes the Company's income before income tax expense (benefit) and equity income (loss) by jurisdiction for the years ended December 31 (in millions):

	2025	2024	2023
Income before income tax expense (benefit) and equity income (loss) by jurisdiction:			
U.S.	$ 2,377	$ 2,302	$ 1,483
Foreign	597	871	478
Total income before income tax (benefit) expense and equity loss by jurisdiction:	$ 2,974	$ 3,173	$ 1,961

Income tax expense (benefit) consists of the following for the years ended December 31 (in millions):

	2025	2024	2023
Current:			
Federal	$ (1,833)	$ (1,333)	$ (1,650)
State	(87)	(16)	118
Foreign	122	34	90
	(1,798)	(1,315)	(1,442)
Deferred:			
Federal	(16)	(371)	(114)
State	120	(29)	(275)
Foreign	(61)	94	33
	43	(306)	(356)
Investment tax credits, net	(7)	39	99
Total	$ (1,762)	$ (1,582)	$ (1,699)

The following table presents income taxes paid (received), net of refunds, for the years ended December 31 (in millions):

	2025	2024	2023
Jurisdiction:			
Federal	$ (1,426)	$ (1,573)	$ (1,469)
State	23	16	13
Foreign	104	56	86
Total[(1)]	$ (1,299)	$ (1,501)	$ (1,370)

(1) Includes $1,429 million, $1,580 million and $1,479 million of income taxes received from Berkshire Hathaway in 2025, 2024 and 2023, respectively.

Income taxes paid (received), net of refunds exceeded five percent of total income taxes paid (received) in the following jurisdictions (in millions):

	2025	2024	2023
Foreign:			
United Kingdom	$ 104	$ *	$ 86

* Jurisdiction below the threshold for the period presented

A reconciliation of the federal statutory income tax rate to the effective income tax rate applicable to income before income tax expense (benefit) is as follows for the years ended December 31 (amounts in millions):

	2025		2024		2023	
	Amount	Percent	Amount	Percent	Amount	Percent
U.S. federal statutory income tax rate	$ 624	21.0 %	$ 666	21.0 %	$ 412	21.0 %
State and local income taxes, net of federal income tax[1]	26	0.9	(36)	(1.1)	(124)	(6.3)
Foreign tax effects:						
United Kingdom						
Effects of changes in tax laws or rates enacted in the current period	—	—	—	—	45	2.7
Other	(25)	(0.8)	(14)	(0.4)	16	0.4
Canada						
Foreign regulated flow-thru	(42)	(1.4)	(44)	(1.4)	(41)	(2.1)
Other	2	0.1	3	0.1	3	0.2
Effect of cross-border tax laws	(5)	(0.2)	(8)	(0.3)	7	0.4
Energy-related tax credits	(2,061)	(69.3)	(1,875)	(59.1)	(1,660)	(84.7)
Nontaxable or nondeductible items:						
Equity earnings	(110)	(3.7)	(67)	(2.1)	(61)	(3.1)
Non-controlling interest	(29)	(1.0)	(28)	(0.9)	(73)	(3.7)
Other, net	(5)	(0.3)	(5)	(0.2)	(5)	(0.3)
Changes in unrecognized tax benefits	3	0.1	3	0.1	—	—
Other adjustments:						
Effects of ratemaking	(140)	(4.7)	(182)	(5.7)	(217)	(11.1)
Other	—	—	5	0.1	(1)	(0.1)
Effective income tax rate	$ (1,762)	(59.3)%	$ (1,582)	(49.9)%	$ (1,699)	(86.7)%

(1) State taxes in Oregon in 2025, Illinois in 2024, and Iowa in 2023 made up the majority (greater than 50%) of the tax effect in this category.

Energy-related tax credits relate primarily to production tax credits ("PTC") from wind- and solar-powered generating facilities owned by MidAmerican Energy, PacifiCorp, NV Energy and BHE Renewables. Federal renewable electricity PTCs are earned as energy from qualifying wind- and solar-powered generating facilities is produced and sold and are based on a per-kilowatt hour rate pursuant to the applicable federal income tax law. Wind- and solar-powered generating facilities are eligible for the credits for 10 years from the date the qualifying generating facilities are placed in-service.

The net deferred income tax liability consists of the following as of December 31 (in millions):

	2025	2024
Deferred income tax assets:		
Regulatory liabilities	$ 1,336	$ 1,290
Federal, state and foreign carryforwards	634	686
Asset retirement obligations	384	347
Loss contingency	336	434
Other	593	649
Total deferred income tax assets	3,283	3,406
Valuation allowance	(85)	(78)
Total deferred income tax assets, net	3,198	3,328
Deferred income tax liabilities:		
Property-related items	(13,577)	(12,949)
Investments	(1,257)	(1,505)
Regulatory assets	(982)	(1,124)
Other	(381)	(378)
Total deferred income tax liabilities	(16,197)	(15,956)
Net deferred income tax liability	$ (12,999)	$ (12,628)

The following table provides, without regard to valuation allowances, the Company's net operating loss and tax credit carryforwards and expiration dates as of December 31, 2025 (in millions):

	Federal	State	Foreign	Total
Net operating loss carryforwards	$ 50	$ 13,222	$ 118	$ 13,390
Deferred income taxes on net operating loss carryforwards	$ 11	$ 559	$ 27	$ 597
Expiration dates	2026 - indefinite	2026 - indefinite	2028 - 2045	
Tax credits	$ 14	$ 23	$ —	$ 37
Expiration dates	2026 - 2034	2026 - indefinite		

The U.S. Internal Revenue Service has closed or effectively settled its examination of the Company's income tax returns through December 31, 2013. The statute of limitations for the Company's income tax returns have expired for certain states through December 31, 2011 and December 31, 2013, and for other states through December 31, 2021, except for the impact of any federal audit adjustments.

A reconciliation of the beginning and ending balances of the Company's net unrecognized tax benefits is as follows for the years ended December 31 (in millions):

	2025	2024
Beginning balance	$ 76	$ 73
Additions based on tax positions related to the current year	8	6
Additions for tax positions of prior years	2	4
Reductions based on tax positions related to the current year	(5)	(7)
Reductions for tax positions of prior years	(1)	—
Settlements	(25)	(2)
Interest and penalties	3	2
Ending balance	$ 58	$ 76

As of December 31, 2025 and 2024, the Company had unrecognized tax benefits totaling $81 million and $95 million, respectively, that if recognized, would have an impact on the effective tax rate. The remaining unrecognized tax benefits relate to tax positions for which ultimate deductibility is highly certain but for which there is uncertainty as to the timing of such deductibility. Recognition of these tax benefits, other than applicable interest and penalties, would not affect the Company's effective income tax rate.

(13) Employee Benefit Plans

Defined Benefit Plans

Domestic Operations

PacifiCorp, MidAmerican Energy and NV Energy sponsor defined benefit pension plans that cover a majority of all employees of BHE and its domestic energy subsidiaries. These pension plans include noncontributory defined benefit pension plans, supplemental executive retirement plans ("SERP") and restoration plans. PacifiCorp, MidAmerican Energy and NV Energy also provide certain postretirement healthcare and life insurance benefits through various plans to eligible retirees.

Net Periodic Benefit Cost (Credit)

For purposes of calculating the expected return on plan assets, a market-related value is used. The market-related value of plan assets is generally calculated by spreading the difference between expected and actual investment returns over a five-year period beginning after the first year in which they occur.

Net periodic benefit cost (credit) for the plans included the following components for the years ended December 31 (in millions):

	Pension			Other Postretirement		
	2025	2024	2023	2025	2024	2023
Service cost	$ 13	$ 14	$ 15	$ 5	$ 7	$ 8
Interest cost	106	105	110	28	29	30
Expected return on plan assets	(121)	(126)	(123)	(37)	(36)	(33)
Curtailment	—	(1)	—	—	—	—
Settlement	—	—	(3)	—	—	—
Net amortization	6	9	14	(6)	(1)	(2)
Net periodic benefit cost (credit)	$ 4	$ 1	$ 13	$ (10)	$ (1)	$ 3

Funded Status

The following table is a reconciliation of the fair value of plan assets for the years ended December 31 (in millions):

	Pension		Other Postretirement	
	2025	2024	2025	2024
Plan assets at fair value, beginning of year	$ 2,010	$ 2,069	$ 691	$ 665
Employer contributions	13	13	2	7
Participant contributions	—	—	6	6
Actual return on plan assets	198	105	60	63
Benefits paid	(188)	(177)	(48)	(50)
Plan assets at fair value, end of year	$ 2,033	$ 2,010	$ 711	$ 691

The following table is a reconciliation of the benefit obligations for the years ended December 31 (in millions):

	Pension		Other Postretirement	
	2025	2024	2025	2024
Benefit obligation, beginning of year	$ 1,932	$ 2,050	$ 512	$ 565
Service cost	13	14	5	7
Interest cost	106	105	28	29
Participant contributions	—	—	6	6
Actuarial loss (gain)	31	(57)	14	(45)
Amendment	—	(3)	2	—
Benefits paid	(188)	(177)	(48)	(50)
Benefit obligation, end of year	$ 1,894	$ 1,932	$ 519	$ 512
Accumulated benefit obligation, end of year	$ 1,864	$ 1,900		

The funded status of the plans and the amounts recognized on the Consolidated Balance Sheets as of December 31 are as follows (in millions):

	Pension		Other Postretirement	
	2025	2024	2025	2024
Plan assets at fair value, end of year	$ 2,033	$ 2,010	$ 711	$ 691
Benefit obligation, end of year	1,894	1,932	519	512
Funded status	$ 139	$ 78	$ 192	$ 179
Amounts recognized on the Consolidated Balance Sheets:				
Other assets	$ 264	$ 209	$ 196	$ 183
Other current liabilities	(12)	(13)	—	—
Other long-term liabilities	(113)	(118)	(4)	(4)
Amounts recognized	$ 139	$ 78	$ 192	$ 179

The SERPs and restoration plan have no plan assets; however, the Company has Rabbi trusts that hold corporate-owned life insurance and other investments to provide funding for the future cash requirements of the SERPs and restoration plan. The cash surrender value of all of the policies included in the Rabbi trusts, net of amounts borrowed against the cash surrender value, plus the fair market value of other Rabbi trust investments, was $409 million and $371 million as of December 31, 2025 and 2024, respectively. These assets are not included in the plan assets in the above table, but are reflected in noncurrent investments and restricted cash and investments on the Consolidated Balance Sheets. The projected and accumulated benefit obligations for the SERP were $126 million and $131 million at December 31, 2025 and 2024, respectively.

Unrecognized Amounts

The portion of the funded status of the plans not yet recognized in net periodic benefit cost as of December 31 is as follows (in millions):

	Pension		Other Postretirement	
	2025	2024	2025	2024
Net loss (gain)	$ 231	$ 283	$ (160)	$ (158)
Prior service (credit) cost	(4)	(5)	19	18
Regulatory deferrals	18	19	—	—
Total	$ 245	$ 297	$ (141)	$ (140)

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost for the years ended December 31, 2025 and 2024 is as follows (in millions):

	Regulatory Assets (Liabilities)	Accumulated Other Comprehensive Income	Total
Pension			
Balance, December 31, 2023	$ 345	$ (1)	$ 344
Net gain arising during the year	(30)	(5)	(35)
Net prior service credit arising during the year	(3)	—	(3)
Net amortization	(9)	—	(9)
Total	(42)	(5)	(47)
Balance, December 31, 2024	303	(6)	297
Net gain arising during the year	(45)	(1)	(46)
Net amortization	(6)	—	(6)
Total	(51)	(1)	(52)
Balance, December 31, 2025	$ 252	$ (7)	$ 245

	Regulatory Assets (Liabilities)	Accumulated Other Comprehensive Income	Total
Other Postretirement			
Balance, December 31, 2023	$ (63)	$ (5)	$ (68)
Net gain arising during the year	(68)	(5)	(73)
Net amortization	1	—	1
Total	(67)	(5)	(72)
Balance, December 31, 2024	(130)	(10)	(140)
Net gain arising during the year	(9)	(1)	(10)
Net prior service cost arising during the year	3	—	3
Net amortization	6	—	6
Total	—	(1)	(1)
Balance, December 31, 2025	$ (130)	$ (11)	$ (141)

Plan Assumptions

Weighted-average assumptions used to determine benefit obligations and net periodic benefit cost were as follows:

	Pension			Other Postretirement		
	2025	2024	2023	2025	2024	2023
Benefit obligations as of December 31:						
Discount rate	5.56 %	5.77 %	5.36 %	5.50 %	5.73 %	5.35 %
Rate of compensation increase	3.00 %	3.00 %	3.00 %	N/A	N/A	N/A
Interest crediting rates for cash balance plan						
2023	N/A	N/A	4.19 %	N/A	N/A	N/A
2024	N/A	4.65 %	4.58 %	N/A	N/A	N/A
2025	4.37 %	4.41 %	4.58 %	N/A	N/A	N/A
2026	4.38 %	4.41 %	3.73 %	N/A	N/A	N/A
2027	4.38 %	3.99 %	3.73 %	N/A	N/A	N/A
2028 and beyond	4.18 %	3.99 %	3.73 %	N/A	N/A	N/A
Net periodic benefit cost for the years ended December 31:						
Discount rate	5.77 %	5.36 %	5.65 %	5.73 %	5.35 %	5.58 %
Expected return on plan assets	6.14 %	6.19 %	6.10 %	5.70 %	5.71 %	5.84 %
Rate of compensation increase	3.00 %	3.00 %	3.00 %	N/A	N/A	N/A
Interest crediting rate for cash balance plan	4.37 %	4.65 %	4.19 %	N/A	N/A	N/A

In establishing its assumption as to the expected return on plan assets, the Company utilizes the asset allocation and return assumptions for each asset class based on historical performance and forward-looking views of the financial markets.

	2025	2024
Assumed healthcare cost trend rates as of December 31:		
Healthcare cost trend rate assumed for next year	7.00 %	7.00 %
Rate that the cost trend rate gradually declines to	5.00 %	5.00 %
Year that the rate reaches the rate it is assumed to remain at	2035	2033

Contributions and Benefit Payments

Employer contributions to the pension and other postretirement benefit plans are expected to be $13 million and $4 million, respectively, during 2026. Funding to the established pension trusts is based upon the actuarially determined costs of the plans and the requirements of the IRC, the Employee Retirement Income Security Act of 1974 and the Pension Protection Act of 2006, as amended. The Company considers contributing additional amounts from time to time in order to achieve certain funding levels specified under the Pension Protection Act of 2006, as amended. The Company evaluates a variety of factors, including funded status, income tax laws and regulatory requirements, in determining contributions to its other postretirement benefit plans.

The expected benefit payments to participants in the Company's pension and other postretirement benefit plans for 2026 through 2030 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments	
	Pension	Other Postretirement
2026	$ 188	$ 51
2027	181	51
2028	174	51
2029	170	50
2030	165	49
2031-2035	740	212

Plan Assets

Investment Policy and Asset Allocations

The Company's investment policy for its pension and other postretirement benefit plans is to balance risk and return through a diversified portfolio of debt securities, equity securities and other alternative investments. Maturities for debt securities are managed to targets consistent with prudent risk tolerances. The plans retain outside investment consultants to advise on plan investments within the parameters outlined by the Berkshire Hathaway Energy Company Investment Committee. The investment portfolio is managed in line with the investment policy with sufficient liquidity to meet near-term benefit payments.

The target allocations (percentage of plan assets) for the Company's pension and other postretirement benefit plan assets are as follows as of December 31, 2025:

	Pension	Other Postretirement
	%	%
PacifiCorp:		
Debt securities[1]	50-80	76-95
Equity securities[1]	10-50	0-19
Limited partnership interests	0-10	0-5
MidAmerican Energy:		
Debt securities[1]	40-60	20-40
Equity securities[1]	30-60	60-80
Other	0-15	0-5
NV Energy:		
Debt securities[1]	65-80	66-87
Equity securities[1]	20-35	13-34

(1) For purposes of target allocation percentages and consistent with the plans' investment policy, investment funds are allocated based on the underlying investments in debt and equity securities.

Fair Value Measurements

The following table presents the fair value of plan assets, by major category, for the Company's defined benefit pension plans (in millions):

	Input Levels for Fair Value Measurements[1]		
	Level 1	Level 2	Total
As of December 31, 2025:			
Cash equivalents	$ 10	$ 3	$ 13
Debt securities:			
U.S. government obligations	132	—	132
Corporate obligations	—	624	624
Municipal obligations	—	31	31
Agency, asset and mortgage-backed obligations	—	103	103
Equity securities:			
U.S. companies	63	—	63
International companies	1	—	1
Total assets in the fair value hierarchy	$ 206	$ 761	967
Investment funds[2] measured at net asset value			1,045
Limited partnership interests[3] measured at net asset value			21
Total assets measured at fair value			$ 2,033
As of December 31, 2024:			
Cash equivalents	$ —	$ 15	$ 15
Debt securities:			
U.S. government obligations	156	—	156
Corporate obligations	—	639	639
Municipal obligations	—	33	33
Agency, asset and mortgage-backed obligations	—	103	103
Equity securities:			
U.S. companies	180	—	180
International companies	1	—	1
Total assets in the fair value hierarchy	$ 337	$ 790	1,127
Investment funds[2] measured at net asset value			861
Limited partnership interests[3] measured at net asset value			22
Total assets measured at fair value			$ 2,010

(1) Refer to Note 15 for additional discussion regarding the three levels of the fair value hierarchy.

(2) Investment funds are comprised of mutual funds and collective trust funds. These funds consist of equity and debt securities of approximately 57% and 43%, respectively, for 2025 and 53% and 47%, respectively, for 2024. Additionally, these funds are invested in U.S. and international securities of approximately 92% and 8%, respectively, for 2025 and 94% and 6%, respectively, for 2024.

(3) Limited partnership interests include several funds that invest primarily in real estate, buyout, growth equity and venture capital.

The following table presents the fair value of plan assets, by major category, for the Company's defined benefit other postretirement plans (in millions):

	Input Levels for Fair Value Measurements[1]		
	Level 1	Level 2	Total
As of December 31, 2025:			
Cash equivalents	$ 39	$ 2	$ 41
Debt securities:			
U.S. government obligations	13	—	13
Corporate obligations	—	38	38
Municipal obligations	—	82	82
Agency, asset and mortgage-backed obligations	—	60	60
Equity securities:			
U.S. companies	—	—	—
Investment funds[2]	388	—	388
Total assets in the fair value hierarchy	$ 440	$ 182	622
Investment funds[2] measured at net asset value			89
Total assets measured at fair value			$ 711
As of December 31, 2024:			
Cash equivalents	$ 9	$ 13	$ 22
Debt securities:			
U.S. government obligations	18	—	18
Corporate obligations	—	37	37
Municipal obligations	—	43	43
Agency, asset and mortgage-backed obligations	—	55	55
Equity securities:			
U.S. companies	7	—	7
Investment funds[2]	375	—	375
Total assets in the fair value hierarchy	$ 409	$ 148	557
Investment funds[2] measured at net asset value			134
Total assets measured at fair value			$ 691

(1) Refer to Note 15 for additional discussion regarding the three levels of the fair value hierarchy.

(2) Investment funds are comprised of mutual funds and collective trust funds. These funds consist of equity and debt securities of approximately 54% and 46%, respectively, for 2025 and 59% and 41%, respectively, for 2024. Additionally, these funds are invested in U.S. and international securities of approximately 97% and 3%, respectively, for 2025 and 88% and 12%, respectively, for 2024.

For level 1 investments, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value. For level 2 investments, the fair value is determined using pricing models based on observable market inputs. Shares of mutual funds not registered under the Securities Act of 1933, private equity limited partnership interests, common and commingled trust funds and investment entities are reported at fair value based on the net asset value per unit, which is used for expedience purposes. A fund's net asset value is based on the fair value of the underlying assets held by the fund less its liabilities.

Foreign Operations

Certain wholly owned subsidiaries of Northern Powergrid participate in the Northern Powergrid group of the United Kingdom industry-wide Electricity Supply Pension Scheme (the "UK Plan"), which provides pension and other related defined benefits, based on final pensionable pay, to the employees of Northern Powergrid. The UK Plan is closed to employees hired after July 23, 1997. Employees hired after that date are covered by a defined contribution plan sponsored by a wholly owned subsidiary of Northern Powergrid.

Net Periodic Benefit Cost (Credit)

For purposes of calculating the expected return on pension plan assets, a market-related value is used. The market-related value of plan assets is calculated by including the difference between expected and actual investment returns after the first year in which they occur.

Net periodic benefit cost (credit) for the UK Plan included the following components for the years ended December 31 (in millions):

	2025	2024	2023
Service cost	$ 5	$ 6	$ 6
Interest cost	59	54	57
Expected return on plan assets	(83)	(80)	(80)
Net amortization	32	29	26
Net periodic benefit cost (credit)	$ 13	$ 9	$ 9

Funded Status

The following table is a reconciliation of the fair value of plan assets for the years ended December 31 (in millions):

	2025	2024
Plan assets at fair value, beginning of year	$ 1,242	$ 1,402
Employer contributions	11	12
Participant contributions	1	1
Actual return on plan assets	49	(71)
Benefits paid	(81)	(80)
Foreign currency exchange rate changes	95	(22)
Plan assets at fair value, end of year	$ 1,317	$ 1,242

The following table is a reconciliation of the benefit obligation for the years ended December 31 (in millions):

	2025	2024
Benefit obligation, beginning of year	$ 1,074	$ 1,219
Service cost	5	6
Interest cost	59	54
Participant contributions	1	1
Actuarial (gain) loss	37	(107)
Benefits paid	(81)	(80)
Foreign currency exchange rate changes	82	(19)
Benefit obligation, end of year	$ 1,177	$ 1,074
Accumulated benefit obligation, end of year	$ 1,069	$ 970

The funded status of the UK Plan and the amounts recognized on the Consolidated Balance Sheets as of December 31 are as follows (in millions):

	2025	2024
Plan assets at fair value, end of year	$ 1,317	$ 1,242
Benefit obligation, end of year	1,177	1,074
Funded status	$ 140	$ 168
Amounts recognized on the Consolidated Balance Sheets:		
Other assets	$ 140	$ 168

Unrecognized Amounts

The portion of the funded status of the UK Plan not yet recognized in net periodic benefit cost as of December 31 is as follows (in millions):

	2025	2024
Net loss	$ 625	$ 541
Prior service cost	39	40
Total	$ 664	$ 581

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost, which are included in accumulated other comprehensive loss on the Consolidated Balance Sheets, for the years ended December 31 is as follows (in millions):

	2025	2024
Balance, beginning of year	$ 581	$ 576
Net loss arising during the year	70	44
Net amortization	(32)	(29)
Foreign currency exchange rate changes	45	(10)
Total	83	5
Balance, end of year	$ 664	$ 581

Plan Assumptions

Assumptions used to determine benefit obligations and net periodic benefit cost were as follows:

	2025	2024	2023
Benefit obligations as of December 31:			
Discount rate	5.55 %	5.50 %	4.55 %
Rate of compensation increase	2.95 %	3.30 %	3.00 %
Rate of future price inflation	2.70 %	3.05 %	2.75 %
Net periodic benefit cost for the years ended December 31:			
Discount rate	5.50 %	4.55 %	4.80 %
Expected return on plan assets	6.80 %	5.95 %	6.00 %
Rate of compensation increase	3.30 %	3.00 %	3.20 %
Rate of future price inflation	3.05 %	2.75 %	2.95 %

Contributions and Benefit Payments

Employer contributions to the UK Plan are expected to be £5 million during 2026. The expected benefit payments to participants in the UK Plan for 2026 through 2030 and for the five years thereafter, excluding lump sum settlement elections and using the foreign currency exchange rate as of December 31, 2025, are summarized below (in millions):

2026	$ 86
2027	88
2028	90
2029	92
2030	94
2031-2035	506

Plan Assets

Investment Policy and Asset Allocations

The investment policy for the UK Plan is to balance risk and return through a diversified portfolio of debt securities, equity securities, real estate and other asset classes. Maturities for debt securities are managed to targets consistent with prudent risk tolerances. The UK Plan retains outside investment advisors to manage plan investments within the parameters set by the trustees of the UK Plan in consultation with Northern Powergrid. The investment portfolio is managed in line with the investment policy with sufficient liquidity to meet near-term benefit payments. The return on assets assumption is based on a weighted-average of the expected historical performance for the types of assets in which the UK Plan invests.

The target allocations (percentage of plan assets) for the UK Plan assets are as follows as of December 31, 2025:

	%
Debt securities[(1)]	60-70
Equity securities[(1)]	10-20
Real estate funds and other	15-25

(1) For purposes of target allocation percentages and consistent with the plans' investment policy, investment funds have been allocated based on the underlying investments in debt and equity securities.

Fair Value Measurements

The following table presents the fair value of the UK Plan assets, by major category (in millions):

	Input Levels for Fair Value Measurements[1]			
	Level 1	Level 2	Level 3	Total
As of December 31, 2025:				
Cash equivalents	$ 3	$ 37	$ —	$ 40
Debt securities:				
United Kingdom government obligations	447	—	—	447
Equity securities:				
Investment funds[2]	—	609	—	609
Real estate funds	—	—	148	148
Total	$ 450	$ 646	$ 148	1,244
Investment funds[2] measured at net asset value				73
Total assets measured at fair value				$ 1,317
As of December 31, 2024:				
Cash equivalents	$ 1	$ 22	$ —	$ 23
Debt securities:				
United Kingdom government obligations	428	—	—	428
Equity securities:				
Investment funds[2]	—	570	—	570
Real estate funds	—	—	134	134
Total	$ 429	$ 592	$ 134	1,155
Investment funds[2] measured at net asset value				87
Total assets measured at fair value				$ 1,242

(1) Refer to Note 15 for additional discussion regarding the three levels of the fair value hierarchy.

(2) Investment funds are comprised of mutual funds and collective trust funds. These funds consist of equity and debt securities of approximately 7% and 93%, respectively, for 2025 and 10% and 90%, respectively, for 2024.

The fair value of the UK Plan's assets are determined similar to the plan assets of the domestic plans as previously discussed.

The following table reconciles the beginning and ending balances of the UK Plan assets measured at fair value using significant Level 3 inputs for the years ended December 31 (in millions):

	Real Estate Funds		
	2025	2024	2023
Beginning balance	$ 134	$ 136	$ 214
Actual return on plan assets still held at period end	4	—	(87)
Foreign currency exchange rate changes	10	(2)	9
Ending balance	$ 148	$ 134	$ 136

Defined Contribution Plans

The Company sponsors various defined contribution plans covering substantially all employees. The Company's contributions vary depending on the plan, but matching contributions are based on each participant's level of contribution, and certain participants receive contributions based on eligible pre-tax annual compensation. Contributions cannot exceed the maximum allowable for tax purposes. The Company's contributions to these plans were $202 million, $196 million and $177 million for the years ended December 31, 2025, 2024 and 2023, respectively.

(14) Asset Retirement Obligations

The Company estimates its ARO liabilities based upon detailed engineering calculations of the amount and timing of the future cash spending for a third party to perform the required work. Spending estimates are escalated for inflation and then discounted at a credit-adjusted, risk-free rate. Changes in estimates could occur for a number of reasons, including changes in laws and regulations, plan revisions, inflation and changes in the amount and timing of the expected work.

The Company does not recognize liabilities for AROs for which the fair value cannot be reasonably estimated. Due to the indeterminate removal date, the fair value of the associated liabilities on certain generation, transmission, distribution and other assets cannot currently be estimated, and no amounts are recognized on the Consolidated Financial Statements other than those included in the cost of removal regulatory liability established via approved depreciation rates in accordance with accepted regulatory practices. These accruals totaled $3.1 billion and $2.9 billion as of December 31, 2025 and 2024, respectively.

The following table presents the Company's ARO liabilities by asset type as of December 31 (in millions):

	2025	2024
Fossil-fueled generating facilities	$ 567	$ 477
Wind-powered generating facilities	503	471
Quad Cities Station	455	428
Other	185	174
Total asset retirement obligations	$ 1,710	$ 1,550
Quad Cities Station nuclear decommissioning trust funds	$ 979	$ 871

The following table reconciles the beginning and ending balances of the Company's ARO liabilities for the years ended December 31 (in millions):

	2025	2024
Beginning balance	$ 1,550	$ 1,428
Change in estimated costs	113	63
Acquisitions	3	—
Additions	16	39
Retirements	(38)	(38)
Accretion	66	58
Ending balance	$ 1,710	$ 1,550
Reflected as:		
Other current liabilities	$ 73	$ 63
Other long-term liabilities	1,637	1,487
Total ARO liability	$ 1,710	$ 1,550

The Nuclear Regulatory Commission regulates the decommissioning of the Quad Cities Station, which includes the planning and funding for the decommissioning. In accordance with these regulations, MidAmerican Energy submits a biennial report to the Nuclear Regulatory Commission providing reasonable assurance that funds will be available to pay for its share of the Quad Cities Station decommissioning.

Certain of the Company's decommissioning and reclamation obligations relate to jointly owned facilities and mine sites, and as such, each subsidiary is committed to pay a proportionate share of the decommissioning or reclamation costs. In the event of a default by any of the other joint participants, the respective subsidiary may be obligated to absorb, directly or by paying additional sums to the entity, a proportionate share of the defaulting party's liability. The Company's estimated share of the decommissioning and reclamation obligations are primarily recorded as ARO liabilities.

In May 2024, the United States Environmental Protection Agency published its final rule on legacy coal combustion residuals ("CCR") surface impoundments and CCR management units ("CCRMUs") in the Federal Register. CCRMUs include CCR surface impoundments and landfills closed before October 19, 2015 and inactive CCR landfills. The final rule contains three main components: (1) a definition for legacy CCR surface impoundments, which are inactive surface impoundments at inactive generating facilities that must adhere to the same regulations as inactive CCR impoundments at active generating facilities, barring location restrictions and liner design criteria, with customized compliance deadlines; (2) groundwater monitoring, corrective action, closure, and post closure care requirements for CCRMUs, which may be located at active generating facilities and inactive generating facilities with a legacy CCR surface impoundment; and (3) the owners and operators of inactive generating facilities must identify the presence of legacy CCR surface impoundments and comply with all rule requirements for surface impoundments; and the owners and operators of active generating facilities and inactive generating facilities with a legacy CCR surface impoundment must prepare Facility Evaluation Reports ("FERs") that identify and describe the CCRMUs and determine whether closure is required. In February 2026, the EPA extended certain compliance deadlines with CCRMUs. Accordingly, and in a manner consistent with existing CCR rules, owners and operators must publish FERs on their CCR websites in two parts, within 12 months (Part 1) and 24 months (Part 2) of the final rule's effective date in February 2026. The Company is currently evaluating the final rule and does not anticipate identifying any legacy surface impoundments, but does anticipate identifying CCRMUs subject to the rule. Due to the number of site investigations warranted by this rule and the nature of engineering and other studies required at each site, the Company is unable to reasonably estimate the potential impact, which may be material, to its asset retirement obligations.

(15) Fair Value Measurements

The carrying value of the Company's cash, certain cash equivalents, receivables, payables, accrued liabilities and short-term borrowings approximates fair value because of the short-term maturity of these instruments. The Company has various financial assets and liabilities that are measured at fair value on the Consolidated Financial Statements using inputs from the three levels of the fair value hierarchy. A financial asset or liability classification within the hierarchy is determined based on the lowest level input that is significant to the fair value measurement. The three levels are as follows:

- Level 1 - Inputs are unadjusted quoted prices in active markets for identical assets or liabilities that the Company has the ability to access at the measurement date.
- Level 2 - Inputs include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means (market corroborated inputs).
- Level 3 - Unobservable inputs reflect the Company's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. The Company develops these inputs based on the best information available, including its own data.

The following table presents the Company's financial assets and liabilities recognized on the Consolidated Balance Sheets and measured at fair value on a recurring basis (in millions):

	Input Levels for Fair Value Measurements				
	Level 1	Level 2	Level 3	Other[1]	Total
As of December 31, 2025:					
Assets:					
Commodity derivatives	$ —	$ 47	$ 2	$ (8)	$ 41
Foreign currency exchange rate derivatives	—	11	—	—	11
Interest rate derivatives	12	25	8	—	45
Mortgage loans held for sale	—	698	—	—	698
Money market mutual funds	1,469	—	—	—	1,469
Debt securities:					
U.S. government obligations	326	—	—	—	326
Corporate obligations	—	133	—	—	133
Municipal obligations	—	2	—	—	2
Equity securities:					
U.S. companies	549	—	—	—	549
International companies	9	—	—	—	9
Investment funds	283	—	—	—	283
	$ 2,648	$ 916	$ 10	$ (8)	$ 3,566
Liabilities:					
Commodity derivatives	$ (13)	$ (169)	$ (56)	$ 83	$ (155)
Interest rate derivatives	—	(3)	—	1	(2)
	$ (13)	$ (172)	$ (56)	$ 84	$ (157)

	Input Levels for Fair Value Measurements				
	Level 1	Level 2	Level 3	Other[1]	Total
As of December 31, 2024:					
Assets:					
Commodity derivatives	$ —	$ 81	$ 2	$ (22)	$ 61
Interest rate derivatives	33	42	7	—	82
Mortgage loans held for sale	—	528	—	—	528
Money market mutual funds	927	—	—	—	927
Debt securities:					
U.S. government obligations	271	—	—	—	271
Corporate obligations	—	109	—	—	109
Municipal obligations	—	2	—	—	2
Equity securities:					
U.S. companies	479	—	—	—	479
International companies	424	—	—	—	424
Investment funds	313	—	—	—	313
	$ 2,447	$ 762	$ 9	$ (22)	$ 3,196
Liabilities:					
Commodity derivatives	$ (15)	$ (141)	$ (74)	$ 31	$ (199)
Foreign currency exchange rate derivatives	—	(23)	—	—	(23)
Interest rate derivatives	—	(1)	(2)	—	(3)
	$ (15)	$ (165)	$ (76)	$ 31	$ (225)

(1) Represents netting under master netting arrangements and a net cash collateral receivable of $76 million and $9 million as of December 31, 2025 and 2024, respectively.

Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. When available, the fair value of derivative contracts is estimated using unadjusted quoted prices for identical contracts in the market in which the Company transacts. When quoted prices for identical contracts are not available, the Company uses forward price curves. Forward price curves represent the Company's estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates. The Company bases its forward price curves upon market price quotations, when available, or internally developed and commercial models, with internal and external fundamental data inputs. Market price quotations are obtained from independent brokers, exchanges, direct communication with market participants and actual transactions executed by the Company. Market price quotations are generally readily obtainable for the applicable term of the Company's outstanding derivative contracts; therefore, the Company's forward price curves reflect observable market quotes. Market price quotations for certain electricity and natural gas trading hubs are not as readily obtainable due to the length of the contract. Given that limited market data exists for these contracts, as well as for those contracts that are not actively traded, the Company uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs that are based on unobservable inputs. The estimated fair value of these derivative contracts is a function of underlying forward commodity prices, interest rates, currency rates, related volatility, counterparty creditworthiness and duration of contracts.

The Company's mortgage loans held for sale are valued based on independent quoted market prices, where available, or the prices of other mortgage whole loans with similar characteristics. As necessary, these prices are adjusted for typical securitization activities, including servicing value, portfolio composition, market conditions and liquidity.

The Company's investments in money market mutual funds and debt and equity securities are stated at fair value. When available, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value. In the absence of a quoted market price or net asset value of an identical security, the fair value is determined using pricing models or net asset values based on observable market inputs and quoted market prices of securities with similar characteristics.

The following table reconciles the beginning and ending balances of the Company's financial assets and liabilities measured at fair value on a recurring basis using significant Level 3 inputs for the years ended December 31 (in millions). Transfers out of Level 3 occur primarily due to increased price observability.

	Commodity Derivatives			Interest Rate Derivatives		
	2025	2024	2023	2025	2024	2023
Beginning balance	$ (72)	$ (91)	$ (59)	$ 5	$ 7	$ 6
Changes included in earnings[(1)]	—	(4)	9	3	(2)	1
Changes in fair value recognized in OCI	—	—	(3)	—	—	—
Changes in fair value recognized in net regulatory assets	(98)	(135)	(256)	—	—	—
Purchases	—	—	2	—	—	—
Settlements	116	158	216	—	—	—
Ending balance	$ (54)	$ (72)	$ (91)	$ 8	$ 5	$ 7

(1) Changes included in earnings for interest rate derivatives are reported net of amounts related to the satisfaction of the associated loan commitment.

The Company's long-term debt is carried at cost, including fair value adjustments and unamortized premiums, discounts and debt issuance costs as applicable, on the Consolidated Financial Statements. The fair value of the Company's long-term debt is a Level 2 fair value measurement and has been estimated based upon quoted market prices, where available, or at the present value of future cash flows discounted at rates consistent with comparable maturities with similar credit risks. The carrying value of the Company's variable-rate long-term debt approximates fair value because of the frequent repricing of these instruments at market rates. The following table presents the carrying value and estimated fair value of the Company's long-term debt as of December 31 (in millions):

	2025		2024	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 57,259	$ 52,665	$ 55,257	$ 50,179

(16) Commitments and Contingencies

Commitments

The Company has the following firm commitments that are not reflected on the Consolidated Balance Sheet. Minimum payments as of December 31, 2025 are as follows (in millions):

	2026	2027	2028	2029	2030	2031 and Thereafter	Total
Contract type:							
Fuel, capacity and transmission contract commitments	$ 1,782	$ 1,553	$ 1,490	$ 1,402	$ 1,087	$ 8,121	$ 15,435
Construction commitments	2,724	1,624	501	40	2	25	4,916
Easements	93	93	97	94	96	2,970	3,443
Maintenance, service and other contracts	491	428	335	245	147	952	2,598
	$ 5,090	$ 3,698	$ 2,423	$ 1,781	$ 1,332	$ 12,068	$ 26,392

Fuel, Capacity and Transmission Contract Commitments

The Utilities have fuel supply and related transportation and lime contracts for their coal- and natural gas-fueled generating facilities. The Utilities expect to supplement these contracts with additional contracts and spot market purchases to fulfill their future fossil fuel needs. The Utilities acquire a portion of their electricity through long-term purchases and exchange agreements. The Utilities have several power purchase agreements with renewable generating facilities that are not included in the table above as the payments are based on the amount of energy generated and there are no minimum payments. The Utilities also have contracts for the right to transmit electricity over other entities' transmission lines to facilitate delivery to their customers.

MidAmerican Energy has long-term rail transportation contracts with BNSF Railway Company ("BNSF"), an affiliate company, and Union Pacific Railroad Company for the transportation of coal to all of the MidAmerican Energy-operated coal-fueled generating facilities. For the years ended December 31, 2025, 2024 and 2023, $98 million, $80 million and $109 million, respectively, were incurred for coal transportation services, the majority of which was related to the BNSF and Union Pacific Railway Company agreements.

Construction Commitments

The Company's firm construction commitments reflected in the table above include the following major construction projects:

- PacifiCorp's costs associated with certain generating plant, transmission, distribution and operations projects.
- MidAmerican Energy's firm construction commitments primarily consisting of contracts for the repowering of wind-powered generating facilities and construction of new natural gas-powered and solar-powered generating facilities.
- Nevada Utilities' firm construction commitments consisting of costs associated with a 400-MW solar photovoltaic facility with an additional 400-MWs of co-located battery storage that is being developed in Churchill County, Nevada, with ownership share approved by the PUCN of 10% Nevada Power and 90% Sierra Pacific, the Greenlink Nevada transmission expansion program that is being developed in western and northern Nevada, the repower project at the Valmy generating station to convert existing coal-fired combustion to natural gas-fire combustion, a hydrogen-capable natural gas simple cycle combustion turbine peakers project at the Valmy generating station and certain other generation plant projects.
- AltaLink's investments in directly assigned transmission projects from the Alberta Electric System Operator.

Easements

The Company has non-cancelable easements for land on which certain of its assets, primarily wind- and solar-powered generating facilities, are located.

Maintenance, Service and Other Contracts

The Company has entered into service agreements related to its nonregulated wind-powered and solar-powered projects with third parties to operate and maintain the projects under fixed-fee operating and maintenance agreements. Additionally, the Company has various non-cancelable maintenance, service and other contracts primarily related to turbine and equipment maintenance and various other service agreements.

Hydroelectric Commitments

Certain of PacifiCorp's hydroelectric licenses and settlement agreements contain requirements for PacifiCorp to make certain capital and operating expenditures related to its hydroelectric facilities, which are estimated to be approximately $278 million over the next 10 years.

Environmental Laws and Regulations

The Company is subject to federal, state, local and foreign laws and regulations regarding air quality, climate change, emissions performance standards, water quality, coal ash disposal and other environmental matters that have the potential to impact its current and future operations. The Company believes it is in material compliance with all applicable laws and regulations.

Legal Matters

The Company is party to a variety of legal actions, including litigation, arising out of the normal course of business, some of which assert claims for damages in substantial amounts and are described below. For certain legal actions, parties at times may seek to impose fines, penalties and other costs.

Pursuant to ASC 450, "Contingencies," a provision for a loss contingency is recorded when it is probable a liability is likely to occur and the amount of loss can be reasonably estimated. The Company evaluates the related range of reasonably estimated losses and records a loss based on its best estimate within that range or the lower end of the range if there is no better estimate.

Wildfires

A significant number of complaints and demands alleging similar claims related to the Wildfires have been filed in Oregon and California, including a class action complaint in Oregon associated with 2020 Wildfires for which certain jury verdicts were issued as described below. The plaintiffs seek damages for economic losses, noneconomic losses, including mental suffering, emotional distress, personal injury and loss of life, punitive damages, other damages and attorneys' fees. Several insurance carriers also filed subrogation complaints in Oregon and California with allegations similar to those made in the aforementioned complaints. Additionally, PacifiCorp received correspondence from the U.S. and Oregon Departments of Justice regarding the potential recovery of certain costs and damages alleged to have occurred on federal and state lands in connection with certain of the 2020 Wildfires. In December 2024, the United States of America filed a complaint against PacifiCorp in conjunction with the correspondence from the U.S. Department of Justice. The civil cover sheet accompanying the complaint demands damages estimated to exceed $900 million. On February 20, 2026, the United States Attorney for the District of Oregon and the United States Attorney for the Eastern District of California approved a settlement agreement for $575 million between PacifiCorp and the United States of America resolving all known federal government complaints and demands associated with the Wildfires, including those associated with the 242, Archie Creek, Echo Mountain Complex, McKinney, Slater and South Obenchain fires. In accordance with the settlement agreement, PacifiCorp will pay the $575 million within 10 calendar days of the February 20, 2026, effective date. PacifiCorp is actively cooperating with the Oregon Department of Justice on resolving the alleged claims.

Amounts sought in outstanding complaints and demands filed in Oregon and in certain demands made in California totaled approximately $50 billion, excluding any doubling or trebling of damages or punitive damages included in the complaints, and of which approximately $48 billion represents the economic and noneconomic damages sought in the *James* mass complaints described below, as amended. Oregon law provides for doubling of economic and property damages in the event the defendant is found to have acted with gross negligence, recklessness, willfulness or malice. Oregon law provides for trebling of damages associated with timber, shrubs and produce in the event the defendant is determined to have willfully and intentionally trespassed. Generally, the complaints filed in California do not specify damages sought and are excluded from this amount. For class actions, amounts specified by the plaintiffs in the complaints include amounts based on estimates of the potential class size, which ultimately may be significantly greater than estimated. Additionally, damages are not limited to the amounts specified in the initially filed complaints as plaintiffs are frequently allowed to amend their complaints to add additional damages and amounts awarded in a court proceeding may be significantly greater than the damages specified. However, plaintiffs included in the *James* mass complaints are required to amend their complaints to align the economic damages to the facts specific to their complaints rather than the common per plaintiff damages specified in the originally filed mass complaints. Refer to "*James* Trial Activity" below for information regarding damages awarded to date in the *James* case.

In California, under inverse condemnation, courts have held that investor-owned utilities can be liable for real and personal property damages from wildfires without the utility being found negligent and regardless of fault. California law also permits inverse condemnation plaintiffs to recover reasonable attorney fees and costs. In both Oregon and California, PacifiCorp has equipment in areas accessed through special use permits, easements or similar agreements that may contain provisions requiring it to pay for damages caused by its equipment regardless of fault. Even if inverse condemnation or other provisions do not apply, PacifiCorp could be found liable for all damage.

Based on available information to date, losses have been and will likely continue to be incurred associated with the Wildfires. Final determinations of liability will only be made following the completion of comprehensive investigations, which may be or have been performed by various entities, including the U.S. Department of Agriculture Forest Service ("USFS"), the California Public Utilities Commission, the Oregon Department of Forestry ("ODF") and the Oregon Department of Justice, as well as litigation or similar processes, the outcome of which, if adverse, could, in the aggregate, have a material adverse effect on PacifiCorp's financial condition.

2020 Wildfires

In September 2020, a severe weather event with high winds, low humidity and warm temperatures contributed to several major wildfires, which resulted in real and personal property and natural resource damage, personal injuries and loss of life and widespread power outages in Oregon and Northern California. The wildfires spread across certain parts of PacifiCorp's service territory and surrounding areas across multiple counties in Oregon and California, including Siskiyou County, California; Jackson County, Oregon; Douglas County, Oregon; Marion County, Oregon; Lincoln County, Oregon; and Klamath County, Oregon, burning over 500,000 acres in aggregate and include the Santiam Canyon, Beachie Creek, South Obenchain, Echo Mountain Complex, 242, Archie Creek, Slater and other fires. The Slater fire occurred in both Oregon and California. Third-party reports for these wildfires indicate over 2,000 structures destroyed, including residences; several structures damaged; multiple individuals injured; and several fatalities.

In May 2022, the USFS issued its report of investigation into the Archie Creek fire concluding that the probable cause of the fire was power lines owned and operated by PacifiCorp. The USFS report for the Archie Creek fire also states that evidence indicates failure of power line infrastructure. The USFS report of investigation into the Slater fire for the investigation period October 5, 2020, to December 8, 2020, concluded that the fire was caused by a downed power line owned and operated by PacifiCorp. The USFS report for the Slater fire also states that evidence indicates a tree fell onto the power line and that wind blew over the 137-foot tree with internal rot that showed no outward signs of distress and would not have been classified or identified as a hazard tree.

Settlements have been reached with substantially all individual plaintiffs, timber companies and insurance subrogation plaintiffs in both the Archie Creek and Slater fires. Additionally, PacifiCorp has settled all wrongful death claims and all federal government demands and complaints associated with the 2020 Wildfires.

In April 2023, the USFS issued its report of investigation into a wildland fire that began in the Opal Creek wilderness outside of the Santiam Canyon that was first reported on August 16, 2020 ("Beachie Creek Fire"), approximately three weeks prior to the September 2020 wind event described above. In March 2025, PacifiCorp received the ODF's final investigation report on the Santiam Canyon fires ("ODF's Report"), which concluded that embers from the pre-existing Beachie Creek Fire caused 12 fires within the Santiam Canyon. The ODF's Report also found that PacifiCorp's power lines did not contribute to the overall spread of fire into the Santiam Canyon even though its power lines ignited seven spot fires within the Santiam Canyon that were each suppressed.

The Beachie Creek fire that spread into the Santiam Canyon burned approximately 193,000 acres; the South Obenchain fire burned approximately 33,000 acres; the Echo Mountain Complex fire burned approximately 3,000 acres; and the 242 fire burned approximately 14,000 acres. The *James* cases described below are associated with the Beachie Creek (Santiam Canyon), South Obenchain, Echo Mountain Complex and 242 fires, which are four distinct fires located hundreds of miles apart.

The James Case

On September 30, 2020, a class action complaint against PacifiCorp was filed, captioned *Jeanyne James et al. v. PacifiCorp*, ("*James*") in Oregon Circuit Court in Multnomah County, Oregon ("*Multnomah County Circuit Court Oregon*"). The complaint was filed by Oregon residents and businesses who sought to represent a class of all Oregon citizens and entities whose real or personal property was harmed beginning on September 7, 2020, by wildfires in Oregon allegedly caused by PacifiCorp. In November 2021, the plaintiffs filed an amended complaint to limit the class to include Oregon citizens allegedly impacted by the Santiam Canyon, Echo Mountain Complex, South Obenchain and 242 fires, as well as to add claims for noneconomic damages. The amended complaint alleged that PacifiCorp's assets contributed to the Oregon wildfires occurring on or after September 7, 2020, and that PacifiCorp acted with gross negligence, among other things. The amended complaint seeks damages similar to those described above, including not less than $600 million of economic damages and in excess of $1 billion of noneconomic damages for the plaintiffs and the class. Since filing of the original class action complaint, numerous James class members have been named and damages specified in various complaints as described below. Additionally, numerous cases were consolidated into the original *James* complaint.

As of December 2025, various mass complaints against PacifiCorp naming 1,760 class members have been filed referencing the *James* case as the lead case with complaints for some of the plaintiffs subsequently dismissed. These *James* mass complaints make damages-only allegations with substantially all plaintiffs individually seeking $5 million of economic damages, $25 million of noneconomic damages and punitive damages equal to 0.25 times the amount of economic and noneconomic damages, as well as doubling of economic damages. As described below under "*James* Court Activity," plaintiffs included in the mass complaints are required to amend their complaints to align the economic damages to the facts specific to their complaints.

An additional approximately 1,500 plaintiffs were granted the ability not to be represented by *James* lead counsel, a small portion of which filed complaints seeking damages similar to those in the mass complaints. In November 2025, PacifiCorp settled with approximately 1,400 of these plaintiffs for $150 million.

As a result of dismissals for the mass complaints and the November 2025 settlement, James complaints for approximately 1,700 individual plaintiffs remain outstanding, substantially all of which are represented by lead counsel. PacifiCorp believes the magnitude of damages sought by the class members in the *James* mass complaints to be of remote likelihood of being awarded based on the amounts awarded in the jury verdicts described below under "*James* Trial Activity" that are being appealed.

James Trial Activity

In June 2023, a jury verdict was issued in the first *James* trial finding PacifiCorp's conduct grossly negligent, reckless and willful as to each of the 17 named plaintiffs and the entire class. The jury awarded economic and noneconomic damages. After the jury verdict, the Multnomah County Circuit Court Oregon doubled the economic damages, in accordance with Oregon law, and added punitive damages by applying a 0.25 multiplier to the awarded economic and noneconomic damages. PacifiCorp filed a motion with the Multnomah County Circuit Court Oregon requesting the court offset the damage awards by deducting insurance proceeds received by any of the plaintiffs. In January 2024, PacifiCorp filed a notice of appeal associated with the June 2023 verdict, including whether the case can proceed as a class action.

Subsequent to the June 2023 *James* verdict, numerous damages phase trials were held with separate jury verdicts issued and damages awarded for each on a basis consistent with the initial trial and relying on the liability determination in the June 2023 *James* verdict. PacifiCorp amended its January 2024 appeal of the June 2023 *James* verdict to include the jury verdicts for the first two damages phase trials. PacifiCorp has filed notices of appeal for the subsequent jury verdicts in the damages phase trials once limited judgments are entered and any post-trial motions filed. Refer to "*James* Court Activity" below regarding the filing of PacifiCorp's appellate briefs. The appeals process and further actions could take several years.

The *James* jury verdicts awarded various damages as follows (in millions):

James Trial Start Date	Number of Plaintiffs	Verdict / Limited Judgment Date	Damages[1]			Insurance Offset[2]	Net Damages	Appeal Notice Filed
			Doubled Economic	Non-economic	Punitive			
Jury verdicts, limited judgments entered[3]								
Initial *James* trial	17	June 2023 / January 2024	$ 9	$ 67	$ 18	$ 2	$ 92	Yes
January 8, 2024	9	January 2024 / April 2024	12	56	16	4	80	Yes
February 26, 2024	10	March 2024 / June 2024	12	23	7	4	38	Yes
February 3, 2025	8	February 2025 / April 2025	8	32	9	4	45	Yes
March 24, 2025	7	March 2025 / June 2025	5	34	9	1	47	Yes
April 21, 2025	9	April 2025 / August 2025	5	11	3	1	18	Yes
May 12, 2025	10	May 2025 / July 2025	11	30	9	2	48	Yes
June 2, 2025	10	June 2025 / August 2025	8	28	8	1	43	Yes
July 7, 2025	11	July 2025 / September 2025	10	36	10	3	53	Yes
September 8, 2025	10	September 2025 / November 2025	11	63	17	3	88	Yes
October 6, 2025	8	October 2025 / December 2025	5	26	7	1	37	Yes
Jury verdicts, limited judgments not yet entered								
December 1, 2025	10	December 2025	10	39	11	3	57	
February 2, 2026	2	February 2026	1	2	1	—	4	
February 9, 2026	8	February 2026	5	36	10	1	50	
February 17, 2026	16	February 2026	2	242	61	—	305	
	145		$ 114	$ 725	$ 196	$ 30	$ 1,005	

(1) For jury verdicts where the limited judgment has not yet been entered, the doubling of economic damages and the application of punitive damages are estimates.

(2) For jury verdicts where limited judgment has been entered, the court offset the awards by the amount of insurance proceeds received by any of the plaintiffs. For jury verdicts where the limited judgment has not yet been entered, the insurance offset is an estimate.

(3) For each limited judgment entered in the court, PacifiCorp has posted or expects to post a supersedeas bond, which stays any effort to seek payment of the judgments pending final resolution of any appeals. Under Oregon Revised Statutes 82.010, interest at a rate of 9% per annum will accrue on the judgments commencing at the date the judgments were entered until the entire money award is paid, amended or reversed by an appellate court. The supersedeas bond posted for the June 2023 *James* verdict covers three years of post-judgment interest while amounts posted for the subsequent verdicts cover two years of post-judgment interest.

Through February 2026, jury verdict awards averaged approximately $7 million per plaintiff, including insurance offset. Additional damages phase trials are scheduled to occur through 2028 as described below.

James Court Activity

In April 2025, PacifiCorp filed its appellate brief with the Oregon Court of Appeals in connection with its appeal of the June 2023 *James* verdict and the January and March 2024 *James* damages phase trial verdicts. In the appellate brief, PacifiCorp addresses numerous procedural and legal issues, including that the class certification is improper due to the plaintiffs being impacted by distinct fires with independent ignition points that were hundreds of miles apart; awarding of non-economic damages is not allowed under Oregon law; plaintiffs failed to prove that PacifiCorp caused harm to every class member; and jury instructions applied incorrect legal standards in assessing class-wide evidence and individual claims. Additionally, PacifiCorp incorporated the ODF's Report into its appellate brief. Various parties who are not party to the *James* case filed supportive amicus briefs with the court. Plaintiffs filed their combined answering and cross-appeal brief on August 21, 2025, after plaintiffs requested three delays from the Oregon Court of Appeals. PacifiCorp has filed additional appellate briefs and will continue to file individual appellate briefs in connection with appeals of each of the verdicts for additional *James* damages phase trials.

In November 2025, the Oregon Court of Appeals issued an order for expedited oral argument in response to PacifiCorp's October 2025 request to facilitate a more prompt decision from the court. As a result of the order, oral argument for the appeal was held on February 4, 2026.

Subsequent to the first two damages phase trials, nine damages phase trials were scheduled to be held in 2025 in accordance with the Multnomah County Circuit Court Oregon's October 2024 case management order, adjudicating the damages of approximately 10 plaintiffs per trial. In March 2025, PacifiCorp filed a motion to stay the additional damages phase trials scheduled under the October 2024 case management order in consideration of the ODF's Report, but the motion was denied in April 2025. Refer to "*James* Trial Activity" above for information regarding the damages phase trials held in 2025.

In July 2025, the Multnomah County Circuit Court Oregon issued Case Management Order No. 11 ("CMO No. 11") in response to the May 2025 hearing that was held to evaluate the scheduling of additional damages phase trials. As ordered, CMO No. 11 proposes to schedule dozens of trials in 2026 and over 100 more in 2027 and 2028. Currently, approximately 1,500 plaintiffs are scheduled for trial under CMO No. 11, including substantially all of those included in the mass complaints described above and reflecting the impacts of settlements and dismissals. CMO No. 11 requires plaintiffs included in the mass complaints to amend their complaints alleging the specific facts that support their claims for economic damages within 180 days before the start of their respective trials. Additionally, CMO No. 11 requires mediation every other month.

In August 2025, PacifiCorp filed a motion with the Oregon Court of Appeals to stay the *James* damages phase trials addressed in CMO No. 11. In September 2025, the Appellate Commissioner of the Oregon Court of Appeals denied PacifiCorp's motion to stay, to which PacifiCorp filed a request for reconsideration of the stay denial with the Chief Judge of the Oregon Court of Appeals. In October 2025, the Oregon Court of Appeals issued an order denying PacifiCorp's request for reconsideration. In November 2025, PacifiCorp petitioned the Oregon Supreme Court to review the Oregon Court of Appeals' decisions. In December 2025, plaintiffs' counsel filed their opposition to the petition, and a decision is expected in 2026.

Potential Effects of *James* CMO No. 11

To stay payment of damages awarded by the limited judgments while on appeal, PacifiCorp is required to bond the judgments. As of the date of this filing, PacifiCorp has posted bonds totaling $606 million associated with the limited judgments entered to date for 109 plaintiffs. These bonding requirements will continue to apply to future judgments associated with the CMO No. 11 trials. As noted above, CMO No. 11 proposes to schedule dozens of trials in 2026 and over 100 more in 2027 and 2028, with trials currently scheduled for approximately 1,500 plaintiffs. Each trial is subject to and dependent on judicial resources and availability, which will be determined six weeks before each trial. The CMO No. 11 proposed schedule is likely to put significant strain on the Multnomah County Circuit Court system, and PacifiCorp believes this may challenge the court's ability to fulfill the schedule in CMO No. 11.

PacifiCorp's liquidity has been materially impacted and its credit ratings have been downgraded as a result of the litigation risk and estimated losses recorded to date associated with the Wildfires. Due to the volume of *James* damages phase trials scheduled under CMO No. 11 combined with the requirement to bond judgments for each verdict to stay payment of damages during the appeals process, PacifiCorp may be unable to obtain the necessary funding to meet its liquidity needs.

While bonding of judgments awarded in *James* verdicts to date have been supported by surety bonds, they can also be supported by posting letters of credit or cash. If the trial schedule and caseload progress as proposed in CMO No. 11 and the future limited judgments follow current trends, damages awarded in additional *James* jury verdicts could exceed PacifiCorp's available surety bond and letter of credit capacity, requiring cash bonding thereafter. PacifiCorp expects additional debt financings, including potential borrowings under its $2.0 billion credit facility to the extent available, or other sources of funding will be needed to provide liquidity to post cash for judgments. These bonding requirements could weaken PacifiCorp's credit metrics. Any further credit rating downgrade may result in the loss of surety bond and letter of credit capacity, trigger cash collateral calls for surety bonds posted and trigger cash collateral calls or other forms of security for wholesale energy agreements that contain credit risk-related contingent features or rights to demand adequate assurance in the event of a material adverse change in PacifiCorp's creditworthiness. Additionally, a downgrade of PacifiCorp's senior secured debt below investment grade would require new regulatory applications and approvals due to certain authorizations or exemptions currently in place with certain regulatory commissions for the issuance of securities. PacifiCorp may also be subject to borrowing limitations under its long-term debt covenants.

In the event of a downgrade below investment grade, PacifiCorp may be unable to secure sufficient debt financings or alternative funding sources to support ongoing operations, including the ability to absorb wholesale power volatility, pay suppliers and meet debt obligations, and such liquidity issues may impact transmission and generation development, purchasing power in the market, building and upgrading substations, connecting new customers, addressing outages and maintaining system resilience. Investors in PacifiCorp's first mortgage bonds may be unable to hold existing bonds or to invest in new bonds, and perceived risks associated with the Wildfires may limit PacifiCorp's ability to attract investors. At a minimum, the cost of any short- or long-term financing is expected to be higher as a result of the wildfire litigation risks and decline in PacifiCorp's credit ratings.

Litigation is inherently difficult to predict, and its potential financial impacts are therefore based on assumptions that will change. Furthermore, there may be judicial decisions and other events or circumstances that could improve or worsen the challenges PacifiCorp faces. PacifiCorp believes it will have sufficient liquidity to cover its operations and obligations beyond a year.

2022 McKinney Fire

According to the California Department of Forestry and Fire Protection, a wildfire began on July 29, 2022, in the Oak Knoll Ranger District of the Klamath National Forest in Siskiyou County, California located in PacifiCorp's service territory, burning over 60,000 acres. Third-party reports indicate that the 2022 McKinney Fire resulted in 11 structures damaged; 185 structures destroyed, including residences; 12 injuries; and four fatalities. The USFS issued a Wildland Fire Origin and Cause Supplemental Incident Report. The report concluded that a tree coming in contact with a power line is the probable cause of the 2022 McKinney Fire. Settlements have been reached with substantially all individual plaintiffs, timber companies and insurance subrogation plaintiffs in the 2022 McKinney Fire. Additionally, PacifiCorp has settled all wrongful death claims associated with the 2022 McKinney Fire and has settled with the federal government as described above.

Estimated Losses for and Settlements Associated with the Wildfires

Based on the facts and circumstances available to PacifiCorp as of the date of this filing, including (i) cause and origin investigations; (ii) ongoing settlement and mediation activities; (iii) other litigation matters and upcoming legal proceedings; and (iv) the status of the *James* case, PacifiCorp recorded cumulative estimated probable losses associated with the Wildfires of $2,853 million through December 31, 2025. PacifiCorp's cumulative accrual includes estimates of probable losses for fire suppression costs, real and personal property damages, natural resource damages and noneconomic damages such as personal injury damages and loss of life damages that it is reasonably able to estimate at this time and which is subject to change as additional relevant information becomes available.

Through December 31, 2025, PacifiCorp paid $1,692 million in settlements associated with the Wildfires, $53 million of which occurred in 2022. As a result of the settlements, various trials have been cancelled. In January and February 2026, PacifiCorp made additional settlement payments related to the Wildfires totaling $2 million.

The following table presents changes in PacifiCorp's liability for estimated losses associated with the Wildfires for the years ended December 31 (in millions):

	2025	2024	2023
Beginning balance	$ 1,536	$ 1,723	$ 424
Accrued losses	100	346	1,930
Payments	(475)	(533)	(631)
Ending balance	$ 1,161	$ 1,536	$ 1,723

As of December 31, 2025, and 2024, $734 million and $247 million of PacifiCorp's liability for estimated losses associated with the Wildfires was included in Other current liabilities on the Consolidated Balance Sheets. The amounts reflected as current as of December 31, 2025, reflect amounts reasonably expected to be paid out within the next year based on settlements reached as well as ongoing settlement and mediation efforts. The remainder of PacifiCorp's liability for estimated losses associated with the Wildfires as of December 31, 2025, and 2024 was included in Other long-term liabilities on the Consolidated Balance Sheets.

The following table presents changes in PacifiCorp's receivable for expected insurance recoveries associated with the Wildfires for the years ended December 31 (in millions):

	2025	2024	2023
Beginning balance	$ 98	$ 499	$ 246
Accruals	—	—	253
Payments received	(98)	(401)	—
Ending balance	$ —	$ 98	$ 499

As of December 31, 2025, PacifiCorp had received all expected insurance recoveries. As of December 31, 2024, PacifiCorp's receivable for expected insurance recoveries was included in Other current assets on the Consolidated Balance Sheets. No additional insurance recoveries beyond those received to date are expected to be available.

During the years ended December 31, 2025, 2024 and 2023, PacifiCorp recognized probable losses net of expected insurance recoveries associated with the Wildfires of $100 million, $346 million and $1,677 million, respectively.

It is reasonably possible PacifiCorp will incur material additional losses beyond the amounts accrued for the Wildfires that could have a material adverse effect on PacifiCorp's financial condition. PacifiCorp is currently unable to reasonably estimate a specific range of possible additional losses that could be incurred due to the number of properties and parties involved, including claimants in the class to the *James* case, the variation in the types of properties and damages and the ultimate outcome of legal actions, including mediation, settlement negotiations, jury verdicts and the appeals process.

HomeServices Antitrust Cases

HomeServices is currently defending against several antitrust cases, all in federal district courts. In each case, plaintiffs claim HomeServices and certain of its subsidiaries (in one instance, HomeServices and BHE) conspired with co-defendants to artificially inflate real estate commissions by following and enforcing multiple listing service ("MLS") rules that require listing agents to offer a commission split to cooperating agents in order for the property to appear on the MLS ("Cooperative Compensation Rule"). None of the complaints specify damages sought. However, two cases allege Texas state law deceptive trade practices claims, for which plaintiffs have asserted damages totaling approximately $9 billion by separate written notice as required by Texas law.

In April 2019, the Burnett (formerly Sitzer) et al. v. HomeServices of America, Inc. et al. complaint was filed in the U.S. District Court for the Western District of Missouri (the "Burnett case"). This lawsuit, which was certified as a class in April 2022, was originally brought on behalf of named plaintiffs Joshua Sitzer and Amy Winger against the National Association of Realtors ("NAR"), Anywhere Real Estate, HomeServices of America, Inc., RE/MAX, LLC, and Keller Williams Realty, Inc. HSF Affiliates LLC and BHH Affiliates, LLC, each a subsidiary of HomeServices, were subsequently added as defendants. Rhonda Burnett became a lead class plaintiff in June 2021. The jury trial commenced on October 16, 2023, and the jury returned a verdict for the plaintiffs on October 31, 2023, finding that the named defendants participated in a conspiracy to follow and enforce the Cooperative Compensation Rule, which conspiracy had the purpose or effect of raising, inflating, or stabilizing broker commission rates paid by home sellers. The jury further found that the class plaintiffs had proved damages in the amount of $1.8 billion. Joint and several liability applies for the co-defendants. Federal law authorizes trebling of damages and the award of pre-judgment interest and attorney fees. Prior to the trial, Anywhere Real Estate and RE/MAX, LLC reached settlement agreements with the plaintiffs and settlements were reached by Keller Williams, NAR and HomeServices subsequent to the trial. All settlements received court approval, had final judgments entered by the court and were appealed to the U.S. Court of Appeals for the Eighth Circuit. All appeals were fully briefed by December 19, 2025, and oral arguments took place on January 14, 2026. A ruling from the court on the appeals is pending.

The final HomeServices settlement agreement with the plaintiffs reached on April 25, 2024, settles all claims asserted against HomeServices, HSF Affiliates LLC and BHH Affiliates, LLC in the Burnett case and effectuates a nationwide class settlement. The final settlement agreement includes scheduled payments over four years aggregating $250 million, with payments of $10 million in September 2024 and $57 million in February 2025. HomeServices recognized an after-tax charge of approximately $140 million in the first quarter of 2024, and the liability outstanding as of December 31, 2025 and 2024, was $158 million and $194 million, respectively. If the settlement is not affirmed by the U.S. Court of Appeals for the Eighth Circuit, HomeServices intends to vigorously appeal on multiple grounds the jury's findings and damage award in the Burnett case, including whether the case can proceed as a class action. The appeals process and further actions could take several years.

Guarantees

The Company has entered into guarantees as part of the normal course of business and the sale or transfer of certain assets. These guarantees are not expected to have a material impact on the Company's consolidated financial results.

(17) Revenue from Contracts with Customers

Energy Products and Services

The following table summarizes the Company's energy products and services Customer Revenue by regulated energy and nonregulated energy, with further disaggregation of regulated energy by line of business, including a reconciliation to the Company's reportable segment information included in Note 22, for the years ended December 31 (in millions):

	2025								
	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	BHE Pipeline Group	BHE Transmission	BHE Renewables	BHE and Other[1]	Total
Customer Revenue:									
Regulated:									
Retail Electric	$ 6,958	$ 2,593	$ 3,189	$ —	$ —	$ —	$ —	$ (3)	$ 12,737
Retail Gas	—	707	124	—	—	—	—	(1)	830
Wholesale	87	480	56	—	2	—	—	(1)	624
Transmission and distribution	188	53	72	1,166	—	650	—	—	2,129
Interstate pipeline	—	—	—	—	2,770	—	—	(145)	2,625
Other	134	—	2	—	—	—	—	—	136
Total Regulated	7,367	3,833	3,443	1,166	2,772	650	—	(150)	19,081
Nonregulated	—	5	6	84	1,165	89	927	(4)	2,272
Total Customer Revenue	7,367	3,838	3,449	1,250	3,937	739	927	(154)	21,353
Other revenue	126	69	2	123	6	5	186	1	518
Total	$ 7,493	$ 3,907	$ 3,451	$ 1,373	$ 3,943	$ 744	$ 1,113	$ (153)	$ 21,871

	2024								
	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	BHE Pipeline Group	BHE Transmission	BHE Renewables	BHE and Other[1]	Total
Customer Revenue:									
Regulated:									
Retail Electric	$ 6,162	$ 2,287	$ 3,813	$ —	$ —	$ —	$ —	$ (3)	$ 12,259
Retail Gas	—	604	181	—	—	—	—	—	785
Wholesale	80	221	54	—	7	—	—	(1)	361
Transmission and distribution	176	53	80	1,368	—	674	—	—	2,351
Interstate pipeline	—	—	—	—	2,703	—	—	(130)	2,573
Other	121	—	1	—	4	—	—	—	126
Total Regulated	6,539	3,165	4,129	1,368	2,714	674	—	(134)	18,455
Nonregulated	—	9	6	134	1,042	124	1,273	(4)	2,584
Total Customer Revenue	6,539	3,174	4,135	1,502	3,756	798	1,273	(138)	21,039
Other revenue	61	77	5	125	54	3	202	—	527
Total	$ 6,600	$ 3,251	$ 4,140	$ 1,627	$ 3,810	$ 801	$ 1,475	$ (138)	$ 21,566

	2023								
	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	BHE Pipeline Group	BHE Transmission	BHE Renewables	BHE and Other[1]	Total
Customer Revenue:									
Regulated:									
Retail Electric	$ 5,462	$ 2,309	$ 4,121	$ —	$ —	$ —	$ —	$ (1)	$ 11,891
Retail Gas	—	638	235	—	—	—	—	—	873
Wholesale	165	303	64	—	22	—	—	(1)	553
Transmission and distribution	151	54	77	1,041	—	660	—	—	1,983
Interstate pipeline	—	—	—	—	2,700	—	—	(155)	2,545
Other	129	—	2	—	5	—	—	—	136
Total Regulated	5,907	3,304	4,499	1,041	2,727	660	—	(157)	17,981
Nonregulated	—	7	4	142	984	142	1,436	(1)	2,714
Total Customer Revenue	5,907	3,311	4,503	1,183	3,711	802	1,436	(158)	20,695
Other revenue	29	82	20	120	63	(3)	274	—	585
Total	$ 5,936	$ 3,393	$ 4,523	$ 1,303	$ 3,774	$ 799	$ 1,710	$ (158)	$ 21,280

(1) The BHE and Other reportable segment represents amounts related principally to other corporate entities, corporate functions and intersegment eliminations.

Real Estate Services

The following table summarizes the Company's real estate services Customer Revenue by line of business for the years ended December 31 (in millions):

	HomeServices		
	2025	2024	2023
Customer Revenue:			
Brokerage	$ 3,961	$ 4,006	$ 4,000
Franchise	52	53	55
Total Customer Revenue	4,013	4,059	4,055
Mortgage and other revenue	314	295	267
Total	$ 4,327	$ 4,354	$ 4,322

Remaining Performance Obligations

The following table summarizes the Company's revenue it expects to recognize in future periods related to significant unsatisfied remaining performance obligations for fixed contracts with expected durations in excess of one year as of December 31, 2025, by reportable segment (in millions):

	Performance obligations expected to be satisfied		
	Less than 12 months	More than 12 months	Total
BHE Pipeline Group	$ 3,261	$ 18,107	$ 21,368

(18) BHE Shareholders' Equity

Preferred Stock

As of December 31, 2024, BHE had 481,000 shares outstanding of its Perpetual Preferred Stock (the "4% Perpetual Preferred Stock"), which were issued to a subsidiary of Berkshire Hathaway. The 4% Perpetual Preferred Stock had a liquidation preference of $1,000 per share and paid a 4.00% dividend per share on the liquidation preference. Dividends accrued and accumulated daily, were cumulative, compounded semi-annually and, if declared, were payable in cash semi-annually in arrears on May 15 and November 15 of each year. If dividends were not declared and paid, any accumulating dividends would continue to accumulate and compound. BHE would not make any dividends on shares of any other class or series of its capital stock (other than for dividends on shares of common stock payable in shares of common stock, unless the holders of the then outstanding 4% Perpetual Preferred Stock should first receive, or simultaneously have received, a dividend in an amount at least equivalent to the amount accumulated and not previously paid. BHE would not declare or pay any dividends on shares of the 4% Perpetual Preferred Stock if such declaration or payment would constitute an event of default on BHE's senior indebtedness (as defined)). BHE may, at its option, redeem the 4% Perpetual Preferred Stock in whole or in part at any time at a price per share equal to the liquidation preference. In February 2025, BHE redeemed the 481,000 outstanding shares of 4% Perpetual Preferred Stock for $481 million.

Common Stock

In September 2024, BHE repurchased 4,424,494 shares of its voting common stock held by certain family members and related or affiliated entities of the late Mr. Walter Scott, Jr., a former member of BHE's Board of Directors (each, a "Minority Shareholder") and acquired, cancelled and extinguished the Junior Subordinated Debenture due 2057, having an aggregate principal amount of $100 million, issued by BHE to a certain Minority Shareholder on June 19, 2017 (the "Debenture") (collectively, the "Transactions"). Consideration for the Transactions consisted of (i) cash in an aggregate amount of $2.4 billion and (ii) a Promissory Note, due and payable on September 30, 2025, having an aggregate principal amount of $600 million, which was fully repaid plus accrued interest in October 2024.

BHE B Merger

In December 2024, BHE entered into an agreement and plan of merger ("Merger Agreement") with BHE B, a wholly owned subsidiary of Berkshire Hathaway. BHE B (the "Disappearing Company") merged with and into BHE with BHE surviving (the "Merger"). The Merger was accounted for at book value as BHE and BHE B are entities under common control. BHE B owned eight investments in wind-powered generating facilities sponsored by third parties, commonly referred to as tax equity investments, and had net assets as of December 31, 2024, of approximately $1 billion.

Pursuant to the terms and conditions in the Merger Agreement, at the effective time of the Merger, which took place at 10:59 p.m., Central Time, on December 31, 2024, (a) the separate existence of the Disappearing Company ceased and each share of Common Stock, $0.0001 par value, of the Disappearing Company was cancelled and (b) all shares of the issued and outstanding Preferred Stock, $0.01 par value, of the Disappearing Company, which were held by the BHE B Sole Preferred Stockholder, were converted into and became exchangeable in the aggregate for (i) 481,000 shares of the 4% Perpetual Preferred Stock, (ii) an amount in cash of $57 million and (ii) the transfer of a U.S. Treasury Bill of $364 million.

Restricted Net Assets

BHE has maximum debt-to-total capitalization percentage restrictions imposed by its senior unsecured credit facilities expiring in June 2028 which, in certain circumstances, limit BHE's ability to make cash dividends or distributions. As a result of this restriction, BHE has restricted net assets of $24.5 billion as of December 31, 2025.

Certain of BHE's subsidiaries have restrictions on their ability to dividend, loan or advance funds to BHE due to specific legal or regulatory restrictions, including, but not limited to, maximum debt-to-total capitalization percentages and commitments made to state commissions. As a result of these restrictions, BHE's subsidiaries had restricted net assets of $27.1 billion as of December 31, 2025.

(19) Components of Accumulated Other Comprehensive Loss, Net

The following table shows the change in accumulated other comprehensive loss attributable to BHE shareholders by each component of other comprehensive income (loss), net of applicable income taxes, for the year ended December 31 (in millions):

	Unrecognized Amounts on Retirement Benefits	Foreign Currency Translation Adjustment	Unrealized Gains (Losses) on Cash Flow Hedges	Noncontrolling Interests	AOCI Attributable To BHE Shareholders, Net
Balance, December 31, 2022	$ (390)	$ (1,896)	$ 135	$ 2	$ (2,149)
Other comprehensive (loss) income	(36)	346	(64)	—	246
Purchase of noncontrolling interest	—	—	—	(1)	(1)
Balance, December 31, 2023	(426)	(1,550)	71	1	(1,904)
Other comprehensive income (loss)	5	(449)	7	—	(437)
Balance, December 31, 2024	(421)	(1,999)	78	1	(2,341)
Other comprehensive (loss) income	(61)	590	(32)	—	497
Balance, December 31, 2025	$ (482)	$ (1,409)	$ 46	$ 1	$ (1,844)

Reclassifications from AOCI to net income for the years ended December 31, 2025, 2024 and 2023 were insignificant. Additionally, refer to the "Foreign Operations" discussion in Note 13 for information about unrecognized amounts on retirement benefits reclassifications from AOCI that do not impact net income in their entirety.

(20) Variable Interest Entities and Noncontrolling Interests

The primary beneficiary of a VIE is required to consolidate the VIE and to disclose certain information about its significant variable interests in the VIE. The primary beneficiary of a VIE is the entity that has both (i) the power to direct the activities that most significantly impact the entity's economic performance and (ii) the obligation to absorb losses or receive benefits from the entity that could potentially be significant to the VIE.

As of December 31, 2025, BHE holds 75% of the limited partner interest and holds 100% of the general partner interest of Cove Point. BHE concluded that Cove Point is a VIE due to the limited partner lacking the characteristics of a controlling financial interest. BHE is the primary beneficiary of Cove Point as it has the power to direct the activities that most significantly impact its economic performance as well as the obligation to absorb losses and benefits which could be significant to it.

Included in noncontrolling interests on the Consolidated Balance Sheets are (i) Brookfield Super-Core Infrastructure Partner's 25% interest in Cove Point and (ii) preferred securities of subsidiaries of $56 million and $58 million, respectively, as of December 31, 2025 and 2024, consisting primarily of $56 million of 8.061% cumulative preferred securities of Northern Electric plc, a subsidiary of Northern Powergrid, which are redeemable in the event of the revocation of Northern Electric plc's electricity distribution license by the Secretary of State.

(21) Supplemental Cash Flow Disclosures

The summary of supplemental cash flow disclosures as of and for the years ended December 31 is as follows (in millions):

	2025	2024	2023
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	$ 2,471	$ 2,304	$ 2,109
Supplemental disclosure of non-cash investing and financing transactions:			
Accruals related to property, plant and equipment additions	$ 1,520	$ 1,337	$ 1,494
Issuance of note payable in exchange for common stock	$ —	$ 600	$ —
BHE B Merger:			
Tax equity investments, net of deferred taxes	$ —	$ 985	$ —
U.S. Treasury Bill exchanged for BHE B preferred stock	—	(364)	—
Issuance of 4% Perpetual Preferred Stock	—	(481)	—
BHE B common equity	—	(140)	—
Total	$ —	$ —	$ —

(22) Segment Information

The Company's chief operating decision maker ("CODM") is its President and Chief Executive Officer. Earnings on common shares for each reportable segment are considered by the CODM in allocating resources and capital. The CODM generally considers actual results versus historical results, budgets or forecasts, as well as unique risks and opportunities, when making decisions about the allocation of resources and capital to each reportable segment. The Company's reportable segments with foreign operations include Northern Powergrid, whose business is principally in the United Kingdom, and BHE Transmission, whose business includes operations in Canada. Intersegment eliminations and adjustments, including the allocation of goodwill, have been made. Information related to the Company's reportable segments is shown below for the year ended December 31 (in millions):

	2025									
	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	BHE Pipeline Group	BHE Transmission	BHE Renewables [2]	HomeServices	BHE and Other[1]	Total
Operating revenue	$ 7,493	$ 3,907	$ 3,451	$ 1,373	$ 3,943	$ 744	$ 1,113	$ 4,327	$ (153)	$ 26,198
Cost of sales	3,190	1,193	1,655	131	218	20	90	3,130	(151)	9,476
Operations and maintenance	1,883	933	583	242	1,119	146	449	1,124	90	6,569
Depreciation and amortization	1,289	1,031	560	360	617	213	293	40	—	4,403
Interest expense	793	423	321	158	285	149	129	5	558	2,821
Interest and dividend income	114	33	25	10	62	2	13	16	(30)	245
Income tax expense (benefit)	(197)	(721)	39	60	338	15	(1,146)	9	(159)	(1,762)
Equity income (loss)	—	—	2	1	59	82	(674)	8	—	(522)
Other segment items	(7)	(33)	87	(90)	(336)	(38)	(52)	(19)	140	(348)
Earnings on common shares	$ 642	$ 1,048	$ 407	$ 343	$ 1,151	$ 247	$ 585	$ 24	$ (381)	$ 4,066
Capital expenditures	$ 2,995	$ 1,780	$ 2,857	$ 712	$ 1,378	$ 313	$ 459	$ 12	$ 83	$ 10,589
Property, plant and equipment, net	$ 31,113	$ 24,065	$16,478	$ 9,197	$18,174	$ 6,216	$ 6,939	$ 79	$ 107	$112,368
Total assets	$ 38,323	$ 29,712	$21,118	$ 10,819	$22,977	$ 9,762	$ 11,644	$ 3,449	$ 523	$148,327

	2024									
	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	BHE Pipeline Group	BHE Transmission	BHE Renewables [2]	HomeServices	BHE and Other[1]	Total
Operating revenue	$ 6,600	$ 3,251	$ 4,140	$ 1,627	$ 3,810	$ 801	$ 1,475	$ 4,354	$ (138)	$ 25,920
Cost of sales	2,752	797	2,290	148	198	23	544	3,145	(136)	9,761
Operations and maintenance	1,968	879	560	240	1,094	163	483	1,309	84	6,780
Depreciation and amortization	1,152	1,001	554	346	580	233	270	46	2	4,184
Interest expense	756	434	291	138	178	151	135	9	624	2,716
Interest and dividend income	193	40	36	8	63	3	16	24	60	443
Income tax expense (benefit)	(240)	(843)	67	128	365	18	(925)	(28)	(124)	(1,582)
Equity income (loss)	—	—	3	1	83	89	(503)	9	—	(318)
Other segment items	121	(32)	27	(89)	(309)	(42)	(34)	(13)	485	114
Earnings on common shares	$ 526	$ 991	$ 444	$ 547	$ 1,232	$ 263	$ 447	$ (107)	$ (43)	$ 4,300
Capital expenditures	$ 3,102	$ 1,704	$ 1,777	$ 657	$ 1,050	$ 253	$ 455	$ 8	$ 7	$ 9,013
Property, plant and equipment, net	$ 29,120	$ 22,766	$13,840	$ 8,165	$17,373	$ 5,812	$ 6,377	$ 151	$ 165	$103,769
Total assets	$ 36,134	$ 28,203	$18,708	$ 9,803	$22,114	$ 9,098	$ 11,963	$ 3,382	$ 735	$140,140

	2023									
	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	BHE Pipeline Group	BHE Transmission	BHE Renewables [2]	HomeServices	BHE and Other[1]	Total
Operating revenue	$ 5,936	$ 3,393	$ 4,523	$ 1,303	$ 3,774	$ 799	$ 1,710	$ 4,322	$ (158)	$ 25,602
Cost of sales	2,246	952	2,807	179	256	25	748	3,120	(156)	10,177
Operations and maintenance	3,148	851	511	199	1,052	139	472	1,138	84	7,594
Depreciation and amortization	1,126	908	615	455	542	256	266	50	2	4,220
Interest expense	546	362	259	119	150	150	160	13	656	2,415
Interest and dividend income	100	23	95	2	56	3	13	16	104	412
Income tax expense (benefit)	(553)	(695)	41	122	300	19	(876)	5	(62)	(1,699)
Equity income (loss)	—	—	3	(1)	75	75	(448)	8	—	(288)
Other segment items	9	(58)	6	(65)	(526)	(42)	13	(7)	637	(33)
Earnings on common shares	$ (468)	$ 980	$ 394	$ 165	$ 1,079	$ 246	$ 518	$ 13	$ 59	$ 2,986
Capital expenditures	$ 3,226	$ 1,833	$ 1,797	$ 557	$ 1,294	$ 206	$ 177	$ 41	$ 17	$ 9,148
Property, plant and equipment, net	$ 27,051	$ 21,971	$12,480	$ 8,007	$16,904	$ 6,273	$ 6,169	$ 187	$ 206	$ 99,248
Total assets	$ 33,757	$ 27,331	$17,788	$ 9,596	$21,723	$ 9,624	$ 11,045	$ 3,407	$ 3,569	$137,840

(1) The differences between the reportable segment amounts and the consolidated amounts, described as BHE and Other, relate to other corporate entities, corporate functions and intersegment eliminations.

(2) Income tax (benefit) expense includes the tax attributes of disregarded entities that are not required to pay income taxes and the earnings of which are taxable directly to BHE.

The following table summarizes the other segment items category by the Company's reportable segments:

	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	BHE Pipeline Group	BHE Transmission	BHE Renewables	HomeServices
Property and other taxes	x	x	x	x	x	x	x	x
Capitalized interest	x	x	x	x	x	x	x	
Allowance for equity funds	x	x	x		x	x		
Gains (losses) on marketable securities, net	x	x	x		x	x	x	x
Other income (expense), net	x	x	x	x	x	x	x	x
Net income attributable to noncontrolling interests	x			x	x	x	x	x

The following table summarizes the Company's revenue and property, plant and equipment, net by geographic region for the years ended December 31 (in millions):

	2025	2024	2023
Operating revenue by country:			
U.S.	$ 24,129	$ 23,574	$ 23,593
United Kingdom	1,354	1,577	1,277
Canada	696	719	706
Australia	15	44	20
Other	4	6	6
Total operating revenue by country	$ 26,198	$ 25,920	$ 25,602
Property, plant and equipment, net by country:			
U.S.	$ 97,218	$ 89,958	$ 85,128
United Kingdom	8,919	7,890	7,710
Canada	6,007	5,705	6,178
Australia	224	216	232
Total property, plant and equipment, net by country	$ 112,368	$ 103,769	$ 99,248

The following table shows the changes in the carrying amount of goodwill by reportable segment for the years ended December 31, 2025 and 2024 (in millions):

	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	BHE Pipeline Group	BHE Transmission	BHE Renewables	HomeServices	Total
December 31, 2023	$ 1,129	$ 2,102	$ 2,369	$ 950	$ 1,814	$ 1,492	$ 95	$ 1,596	$ 11,547
Foreign currency translation	—	—	—	(10)	—	(119)	—	—	(129)
Other	—	—	—	—	—	—	—	(5)	(5)
December 31, 2024	1,129	2,102	2,369	940	1,814	1,373	95	1,591	11,413
Foreign currency translation	—	—	—	50	—	66	—	—	116
Other	—	—	—	—	—	—	—	(8)	(8)
December 31, 2025	$ 1,129	$ 2,102	$ 2,369	$ 990	$ 1,814	$ 1,439	$ 95	$ 1,583	$ 11,521

(23) Subsequent Events

On February 15, 2026, PacifiCorp and Portland General Electric Company and an affiliate of Portland General Electric Company (together, the "PGE Entities") entered into an Asset Purchase and Service Area Transfer Agreement (the "Sale Agreement") to sell to the PGE Entities certain PacifiCorp assets and liabilities associated with PacifiCorp's Washington operations for a sales price of $1.9 billion in cash plus additional cash consideration for the value of specified assets delivered at closing, subject to customary purchase price adjustments (the "Transaction").

The Transaction assets and liabilities are associated with PacifiCorp's retail service area in Washington and include certain related distribution assets and infrastructure, as well as PacifiCorp's Chehalis combined cycle natural gas-fueled generating facility located in Chehalis, Washington, Goodnoe Hills wind-powered generating facility located in Goldendale, Washington, and Marengo wind-powered generating facility located in Dayton, Washington.

The Transaction has been approved by PacifiCorp's board of directors but is subject to customary closing conditions including (i) the expiration or termination of the waiting period and other required approvals under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, and (ii) the receipt of all necessary approvals, waivers and rulings from the FERC and each of PacifiCorp's six state public utility commissions. The Transaction is expected to close in the first half of 2027.

The Sale Agreement contains certain termination rights, including if the Transaction is not consummated by August 15, 2027, (subject to a six month extension to the extent certain regulatory approvals have not been received as of such date), and provides that upon termination of the Sale Agreement under certain specified circumstances, the terminating party would be required to pay the other party a termination fee of $35 million.

As a result of the Transaction, PacifiCorp expects that the associated assets and liabilities will be presented as assets held for sale in its first quarter 2026 Form 10-Q. As the Transaction is not expected to have major impact on PacifiCorp's operations or financial results particularly due to the scale of PacifiCorp's Washington operations and retail service territory relative to its overall operations and retail service territory, PacifiCorp does not expect to present the effects of the Transaction as a discontinued operation.

PacifiCorp believes the carrying value of the assets and liabilities are less than fair value and therefore does not expect to record a loss as a result of the Transaction. PacifiCorp expects to continue to depreciate the property, plant and equipment included in the Transaction as it will continue to operate and serve PacifiCorp's customers through closing of the Transaction and the costs to operate such property, plant and equipment will continue to be recovered in PacifiCorp's retail rates. Certain regulatory asset, regulatory liability, asset retirement obligation and deferred income tax balances will also be impacted by the Transaction.

PacifiCorp and its subsidiaries
Consolidated Financial Section

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following is management's discussion and analysis of certain significant factors that have affected the consolidated financial condition and results of operations of PacifiCorp during the periods included herein. Explanations include management's best estimate of the impact of weather, customer growth, usage trends and other factors. This discussion should be read in conjunction with PacifiCorp's historical Consolidated Financial Statements and Notes to Consolidated Financial Statements in Item 8 of this Form 10-K. PacifiCorp's actual results in the future could differ significantly from the historical results.

Results of Operations

Overview

Net income for the year ended December 31, 2025, was $640 million, an increase of $101 million, compared to 2024 net income of $539 million primarily due to higher utility margin and lower estimated losses associated with the Wildfires of $246 million, partially offset by higher operations and maintenance expense, higher depreciation expense, higher net interest expense, lower allowances for equity and borrowed funds used during construction, lower income tax benefit and higher property and other taxes. Utility margin increased primarily due to higher average retail customer prices and volumes, lower purchased electricity costs and higher wholesale sales, partially offset by lower net power cost deferrals and higher thermal generation costs. Retail customer volumes increased 1.3% primarily due to an increase in the average number of customers and an increase in customer usage, partially offset by unfavorable impacts of weather. Energy generated increased 4,587 gigawatt-hours, or 10%, primarily due to higher coal-fueled and wind-powered generation, partially offset by lower natural gas-fueled and hydroelectric-powered generation. Wholesale electricity sales volumes increased 2,074 gigawatt-hours, or 91% and purchased electricity volumes decreased 1,768 gigawatt-hours, or 9%.

Net income for the year ended December 31, 2024, was $539 million, an increase of $1,007 million, compared to 2023 net loss of $468 million, primarily due to lower estimated losses of $1,331 million associated with the Wildfires, net of expected insurance recoveries, higher utility margin and higher allowances for equity and borrowed funds used during construction. These items were partially offset by lower income tax benefit, increased operations and maintenance expense, higher net interest expense, and higher depreciation and amortization expense. Utility margin increased primarily due to higher retail prices and volumes, lower coal-fueled generation volumes, lower purchased electricity prices, lower natural gas-fueled generation prices, and higher net wheeling revenue, partially offset by lower net power cost deferrals, driven by higher amortization of prior deferrals and lower current year deferrals, higher purchased electricity volumes, higher coal-fueled generation prices, higher natural-gas generation volumes and lower wholesale revenue from lower volumes and prices. Retail customer volumes increased 3.1% primarily due to an increase in commercial, industrial and irrigation customer usage and an increase in the average number of customers, partially offset by a decrease in the residential customer usage and unfavorable impacts of weather. Energy generated decreased 807 gigawatt-hours, or 2%, primarily due to lower coal-fueled and hydroelectric-powered generation, partially offset by higher natural gas-fueled and wind-powered generation. Wholesale electricity sales volumes decreased 631 gigawatt-hours, or 22%, and purchased electricity volumes increased 2,192 gigawatt-hours, or 12%.

Non-GAAP Financial Measure

Management utilizes various key financial measures that are prepared in accordance with GAAP, as well as non-GAAP financial measures such as utility margin, to help evaluate results of operations. Utility margin is calculated as operating revenue less cost of fuel and energy, which are captions presented on the Consolidated Statements of Operations.

PacifiCorp's cost of fuel and energy is generally recovered from its retail customers through regulatory recovery mechanisms and, as a result, changes in PacifiCorp's expenses included in regulatory recovery mechanisms result in comparable changes to revenue. As such, management believes utility margin more appropriately and concisely explains results of operations rather than a discussion of revenue and cost of fuel and energy separately. Management believes the presentation of utility margin provides meaningful and valuable insight into the information management considers important to understanding the business and a measure of comparability to others in the industry.

Utility margin is not a measure calculated in accordance with GAAP and should be viewed as a supplement to, and not a substitute for, operating income, which is the most directly comparable financial measure prepared in accordance with GAAP. The following table provides a reconciliation of utility margin to operating income for the years ended December 31 (in millions):

	2025	2024	Change		2024	2023	Change	
Utility margin:								
Operating revenue	$ 7,493	$ 6,600	$ 893	14 %	$ 6,600	$ 5,936	$ 664	11 %
Cost of fuel and energy	3,190	2,752	438	16	2,752	2,246	506	23
Utility margin	4,303	3,848	455	12	3,848	3,690	158	4
Operations and maintenance	1,783	1,603	180	11	1,603	1,469	134	9
Wildfires losses, net of recoveries	100	346	(246)	(71)	346	1,677	(1,331)	(79)
Depreciation and amortization	1,289	1,152	137	12	1,152	1,126	26	2
Property and other taxes	239	218	21	10	218	215	3	1
Operating income (loss)	$ 892	$ 529	$ 363	69 %	$ 529	$ (797)	$ 1,326	(166)%

Utility Margin

A comparison of key operating results related to utility margin is as follows for the years ended December 31:

	2025	2024	Change		2024	2023	Change	
Utility margin (in millions):								
Operating revenue	$ 7,493	$ 6,600	$ 893	14 %	$ 6,600	$ 5,936	$ 664	11 %
Cost of fuel and energy	3,190	2,752	438	16	2,752	2,246	506	23
Utility margin	$ 4,303	$ 3,848	$ 455	12 %	$ 3,848	$ 3,690	$ 158	4 %
Sales (GWhs):								
Residential	18,270	18,253	17	— %	18,253	18,159	94	1 %
Commercial[1]	22,673	21,585	1,088	5	21,585	20,491	1,094	5
Industrial[1]	16,703	17,101	(398)	(2)	17,101	16,705	396	2
Other[1]	1,566	1,536	30	2	1,536	1,341	195	15
Total retail	59,212	58,475	737	1	58,475	56,696	1,779	3
Wholesale	4,354	2,280	2,074	91	2,280	2,911	(631)	(22)
Total sales	63,566	60,755	2,811	5 %	60,755	59,607	1,148	2 %
Average number of retail customers (in thousands)	2,137	2,104	33	2 %	2,104	2,069	35	2 %
Average revenue per MWh:								
Retail	$117.64	$105.56	$ 12.08	11 %	$105.56	$ 96.25	$ 9.31	10 %
Wholesale	$ 45.70	$ 54.30	$ (8.60)	(16)%	$ 54.30	$ 66.04	$(11.74)	(18)%
Heating degree days	9,212	9,526	(314)	(3)%	9,526	10,415	(889)	(9)%
Cooling degree days	2,278	2,339	(61)	(3)%	2,339	2,183	156	7 %
Sources of energy (GWhs)[1]:								
Coal	23,302	18,122	5,180	29 %	18,122	21,950	(3,828)	(17)%
Natural gas	15,379	17,045	(1,666)	(10)	17,045	14,050	2,995	21
Wind[2]	8,011	6,918	1,093	16	6,918	6,500	418	6
Hydroelectric and other[2]	2,846	2,866	(20)	(1)	2,866	3,258	(392)	(12)
Total energy generated	49,538	44,951	4,587	10	44,951	45,758	(807)	(2)
Energy purchased	18,828	20,596	(1,768)	(9)	20,596	18,404	2,192	12
Total	68,366	65,547	2,819	4 %	65,547	64,162	1,385	2 %
Average cost of energy per MWh:								
Energy generated[3]	$ 25.11	$ 24.53	$ 0.58	2 %	$ 24.53	$ 24.65	$ (0.12)	— %
Energy purchased	$ 59.12	$ 75.73	$(16.61)	(22)%	$ 75.73	$ 80.38	$ (4.65)	(6)%

(1) GWh amounts are net of energy used by the related generating facilities.

(2) All or some of the renewable energy attributes associated with generation from these sources may be: (a) used in future years to comply with RPS or other regulatory requirements or (b) sold to third parties in the form of RECs or other environmental commodities.

(3) The average cost per MWh of energy generated includes only the cost of fuel associated with the generating facilities.

Year Ended December 31, 2025 Compared to Year Ended December 31, 2024

Utility margin increased $455 million, or 12%, for 2025 compared to 2024 primarily due to:

- $793 million of higher retail revenue primarily due to higher average prices and higher volumes. Retail customer volumes increased 1.3%, primarily due to higher Utah and Oregon commercial customer usage, mainly due to increase in data centers usage, an increase in the average number of commercial and residential customers across the service territory, mainly in Utah and Oregon, and an increase in irrigation customer usage across the service territory, except in California and Washington, partially offset by a decrease in Wyoming, Utah and Washington industrial customer usage, unfavorable weather related impacts on residential and commercial customers primarily in Utah and a decrease in residential customer usage across the service territory, except in Idaho.
- $447 million of lower purchased electricity costs from lower average market prices and lower volumes;
- $75 million of higher wholesale revenue primarily due to higher volumes, partially offset by lower average prices; and
- $43 million of lower natural gas-fueled generation costs primarily due to lower volumes, partially offset by higher average prices.

The increases above were partially offset by:

- $734 million of lower net power cost deferrals in accordance with established adjustment mechanisms driven by higher amortization of prior deferrals and lower current year deferrals; and
- $184 million of higher coal-fueled generation costs primarily due to higher volumes and prices.

Operations and maintenance increased $180 million, or 11%, for 2025 compared to 2024 primarily due to:

- $89 million of higher insurance expense due to increased liability insurance premiums and lower deferrals compounded by amortization of prior deferrals;
- $55 million of higher demand side management amortization driven by increased spend;
- $49 million of higher general plant and maintenance costs;
- $34 million increase in salary and benefit expenses;
- $29 million of higher legal fees; and
- $15 million of plant disallowance loss of Utah's share of certain assets on the Klamath River hydroelectric system as a result of the 2025 Utah general rate case order.

The increases above were partially offset by:

- $50 million of lower vegetation management and wildfire mitigation costs primarily from lower gross costs and lower amortization of prior deferrals;
- $14 million due to higher accruals of federal grant reimbursements;
- $11 million decrease associated with prior year costs associated with the Lower Klamath Project;
- $10 million decrease associated with prior year plant disallowances due to the 2024 Oregon rate case order partial disallowance of certain wildfire mitigation transmission plant investments; and
- $4 million of lower injuries and damages expenses, excluding the Wildfires.

Wildfires losses, net of recoveries decreased $246 million, or 71%, for 2025 compared to 2024 due to a decrease in loss accruals associated with the Wildfires.

Depreciation and amortization increased $137 million, or 12%, for 2025 compared to 2024 primarily due to higher average in-service plant and accelerated depreciation totaling $87 million to buydown a portion of Utah's share of certain coal-fueled units and depreciation related regulatory assets pursuant to the second quarter 2025 Utah general rate case order, partially offset by a $12 million decrease due to a change in the annual Oregon and Washington allocation adjustment compounded by the prior year increase in the allocation adjustment of $5 million, current year extension of depreciable lives for certain plants as a result of the 2025 Oregon general rate case order of $30 million and lower depreciation expense resulting from the impacts of the second quarter 2025 Utah buydown.

Property and other taxes increased $21 million, or 10%, for 2025 compared to 2024 primarily due to higher property taxes in Utah, Colorado and Washington, higher franchise taxes primarily in Oregon, higher Washington public utility taxes and higher federal excise tax expense.

Interest expense increased $37 million, or 5%, for 2025 compared to 2024 primarily due to the issuance of $850 million of junior subordinated notes in March 2025 and higher levels of commercial paper.

Allowance for borrowed and equity funds decreased $112 million, or 35%, for 2025 compared to 2024 primarily due to lower qualified construction work-in-progress balances and lower rates.

Interest and dividend income decreased $78 million, or 41%, for 2025 compared to 2024 primarily due to lower current year cash equivalents, lower interest rates and lower interest income on regulatory assets.

Income tax benefit decreased $40 million, or 17%, for 2025 compared to 2024. The effective tax rate was (44)% and (78)% for 2025 and 2024, respectively. The $40 million decrease was primarily due to lower loss accruals associated with the Wildfires and lower benefit from the effects of ratemaking, partially offset by higher PTCs from PacifiCorp's wind-powered generating facilities.

Year Ended December 31, 2024 Compared to Year Ended December 31, 2023

Utility margin increased $158 million, or 4%, for 2024 compared to 2023 primarily due to:

- $716 million of higher retail revenue primarily due to higher average prices and higher volumes. Retail customer volumes increased 3.1%, primarily due to a higher Utah, Oregon and Washington commercial customer usage and Utah residential customer usage, higher industrial customer usage in Washington, Wyoming and Idaho, higher irrigation customer usage across the service territory, mainly in Idaho, and increase in the average number of residential and commercial customers. These increases were partially offset by lower residential customer usage across the western service territory, mainly in Oregon and unfavorable weather impacts across the service territory;
- $39 million of lower coal-fueled generation costs due to lower volumes, partially offset by higher prices; and
- $14 million of higher net wheeling revenue.

The increases above were partially offset by:

- $440 million of lower net power cost deferrals in accordance with established adjustment mechanisms driven by higher amortization of prior deferrals and lower current year deferrals;
- $81 million of higher purchased electricity costs from higher volumes, partially offset by lower average market prices;
- $68 million of lower wholesale revenue primarily due to lower volumes and lower average prices; and
- $16 million of higher natural gas-fueled generation costs primarily due to higher volumes, partially offset by lower average prices.

Operations and maintenance increased $134 million, or 9%, for 2024 compared to 2023 primarily due to:

- $38 million of higher vegetation management and other wildfire mitigation costs, primarily due to higher amortization of amounts previously deferred in Oregon and higher costs;
- $32 million of higher liability insurance costs net of current year deferral of $45 million for a portion of Oregon's and Idaho's shares of higher insurance premiums;
- $23 million of higher DSM amortization expense;
- $21 million increase in salary and benefit expenses;
- $15 million increase due to prior year establishment of a regulatory asset associated with the December 2023 California general rate case outcome compounded by amortization in the current year;
- $11 million increase due to costs associated with the Lower Klamath Project;
- $10 million of plant disallowances substantially due to Oregon rate case order partial disallowance of wildfire mitigation transmission plant investments; and
- $4 million of higher legal fees.

The increases above were partially offset by:

- $11 million decrease in general and plant maintenance costs; and
- $9 million decrease in bad debt expense.

Wildfires losses, net of recoveries decreased $1,331 million, or 79%, for 2024 compared to 2023 due to lower accruals for estimated losses associated with the Wildfires, net of expected insurance recoveries in 2024 compared to 2023.

Depreciation and amortization increased $26 million, or 2%, for 2024 compared to 2023 primarily due to higher plant in-service balances in the current year, partially offset by cessation of Washington incremental depreciation of certain coal plants.

Interest expense increased $210 million, or 38%, for 2024 compared to 2023 primarily due to higher average long-term debt balances due to the issuance of $3.8 billion of first mortgage bonds in January 2024.

Allowance for borrowed and equity funds increased $109 million, or 51%, for 2024 compared to 2023 primarily due to higher qualified construction work-in-progress balances, partially offset by lower rates.

Interest and dividend income increased $93 million, or 95%, for 2024 compared to 2023 primarily due to higher investment income of $45 million from higher cash equivalents and higher regulatory asset interest income of $45 million primarily from higher deferred net power cost balances.

Income tax benefit decreased $317 million, or 57%, for 2024 compared to 2023. The effective tax rate was (78)% and 54% for 2024 and 2023, respectively. The $317 million decrease was primarily due to higher prior year loss accruals, net of expected insurance recoveries, associated with the Wildfires and lower current year benefit from the effects of ratemaking, partially offset by higher recognized PTCs from PacifiCorp's wind-powered generating facilities.

Liquidity and Capital Resources

Overview

PacifiCorp's liquidity has been materially impacted and its credit ratings have been downgraded as a result of the litigation risk and estimated losses recorded to date associated with the Wildfires. Due to the volume of *James* damages phase trials scheduled under CMO No. 11 combined with the requirement to bond judgments for each verdict in order to stay payment of damages during the appeals process, PacifiCorp may be unable to obtain the necessary funding to meet its liquidity needs.

While bonding of judgments awarded in *James* verdicts to date have been supported by surety bonds, they can also be supported by posting letters of credit or cash. If the trial schedule and caseload progress as proposed in CMO No. 11 and the future limited judgments follow current trends, PacifiCorp damages awarded in additional *James* jury verdicts could exceed its available surety bond and letter of credit capacity, requiring cash bonding thereafter. PacifiCorp expects additional debt financings, including potential borrowings under its $2.0 billion credit facility to the extent available, or other sources of funding will be needed to provide liquidity to post cash for judgments. These bonding requirements could weaken PacifiCorp's credit metrics. Any further credit rating downgrade may result in the loss of surety bond and letter of credit capacity, trigger cash collateral calls for surety bonds posted and trigger cash collateral calls or other forms of security for wholesale energy agreements that contain credit risk-related contingent features or rights to demand adequate assurance in the event of a material adverse change in PacifiCorp's creditworthiness. Additionally, a downgrade of PacifiCorp's senior secured debt below investment grade would require new regulatory applications and approvals due to certain authorizations or exemptions currently in place with certain regulatory commissions for the issuance of securities. PacifiCorp may also be subject to borrowing limitations under its long-term debt covenants.

In the event of a downgrade below investment grade, PacifiCorp may be unable to secure sufficient debt financings or alternative funding sources to support ongoing operations, including the ability to absorb wholesale power volatility, pay suppliers and meet debt obligations, and such liquidity issues may impact transmission and generation development, purchasing power in the market, building and upgrading substations, connecting new customers, addressing outages and maintaining system resilience. Investors in PacifiCorp's first mortgage bonds may be unable to hold existing bonds or to invest in new bonds, and perceived risks associated with the Wildfires may limit PacifiCorp's ability to attract investors. At a minimum, the cost of any short- or long-term financing is expected to be higher as a result of the wildfire litigation risks and decline in PacifiCorp's credit ratings.

Litigation is inherently difficult to predict, and its potential financial impacts are therefore based on assumptions that will change. Furthermore, there may be judicial decisions and other events or circumstances that could improve or worsen the challenges PacifiCorp faces.

As of December 31, 2025, PacifiCorp's issuer credit ratings for senior unsecured debt from the recognized credit rating agencies were investment grade. Refer to additional information below under "Collateral and Contingent Features."

For more information about the risks that could materially affect PacifiCorp's financial condition, results of operations, liquidity and cash flows, or that could cause future results to differ from historical results, see Item 1A. Risk Factors of this Form 10-K, including those associated with the changes in PacifiCorp's credit ratings and the litigation risk associated with the Wildfires. Additionally, this report contains forward-looking statements that are subject to various risks and uncertainties. These statements reflect management's judgment and opinions that are based on current estimates, expectations, and projections about future events and assumptions regarding these events and management's knowledge of facts as of the date of this report. See "Forward-Looking Statements" above for a list of some of the factors that may cause actual results to differ materially.

Net Liquidity

As of December 31, 2025, PacifiCorp's total net liquidity was as follows (in millions):

Cash and cash equivalents	$	73
Credit facilities		2,900
Less:		
Short-term debt		(1,000)
Net credit facilities		1,900
Total net liquidity	$	1,973
Credit facilities:		
Maturity dates		2026, 2028

Refer to Note 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K and "Credit Facilities and Letters of Credit" below for further discussion regarding PacifiCorp's credit facilities and letters of credit.

Operating Activities

Net cash flows from operating activities for the years ended December 31, 2025 and 2024 were $1.7 billion and $1.2 billion, respectively. The increase was primarily due to higher collections from retail customers and lower wholesale purchases, partially offset by lower insurance reimbursements related to wildfire liabilities and higher cash paid for income taxes and interest.

Net cash flows from operating activities for the years ended December 31, 2024 and 2023 were $1.2 billion and $700 million, respectively. The increase was primarily due to higher collections from retail customers and insurance reimbursements related to wildfire liabilities, partially offset by higher operating expenses, higher wholesale purchases and lower wholesale sales, and higher fuel purchases.

The timing of PacifiCorp's income tax cash flows from period to period can be significantly affected by the estimated federal income tax payment methods selected and assumptions made for each payment date.

Investing Activities

Net cash flows from investing activities for the years ended December 31, 2025 and 2024 were $(3.0) billion and $(3.1) billion, respectively. The decrease in net cash outflows from investing activities is mainly due to a decrease in capital expenditures of $107 million.

Net cash flows from investing activities for the years ended December 31, 2024 and 2023 were $(3.1) billion and $(3.2) billion, respectively. The decrease in net cash outflows from investing activities is mainly due to a decrease in capital expenditures of $124 million.

Financing Activities

Net cash flows from financing activities for the year ended December 31, 2025 and 2024 were $1.3 billion and $1.8 billion, respectively. The decrease was primarily due to lower proceeds from the issuance of long-term debt, partially offset by higher net proceeds from short-term debt and lower repayments of senior debt.

Net cash flows from financing activities for the year ended December 31, 2024 and 2023 were $1.8 billion and $2.0 billion, respectively. The decrease was primarily due to higher net repayments for short-term debt and senior debt, partially offset by higher proceeds from senior debt and lower dividends paid to PPW Holdings LLC.

Future debt issuances are subject to market conditions, may be impacted by the Wildfires, including CMO No. 11, as described above and are further limited by regulatory authorizations or commitments or by covenants and tests contained in other financing agreements, as described below.

Mortgage

PacifiCorp's Mortgage and Deed of Trust creates a lien on most of PacifiCorp's electric utility property, allowing the issuance of bonds based on a percentage of utility property additions, bond credits arising from retirement of previously outstanding bonds or deposits of cash. The amount of bonds that PacifiCorp may issue generally is also subject to a net earnings test. As of December 31, 2025, PacifiCorp estimated it would be able to issue up to $4.4 billion of new first mortgage bonds under the most restrictive issuance test under the Mortgage and Deed of Trust. PacifiCorp also has the ability to release property from the lien of the mortgage on the basis of property additions, bond credits or deposits of cash.

Debt Authorizations, Restrictions and Debt Covenants

Certain of the state regulatory orders that authorized BHE's acquisition of PacifiCorp limit PacifiCorp's capital structure indirectly by requiring the consolidated equity of PPW Holdings LLC to be no less than 44.00% of total consolidated PPW Holdings LLC capitalization, excluding short-term debt and current maturities of long-term debt. As of December 31, 2025, consolidated PPW Holdings LLC equity exceeded the threshold.

PacifiCorp currently has regulatory authority from the OPUC and the IPUC to issue an additional $2.65 billion of long-term debt. PacifiCorp's authorization from the IPUC is through April 2029. PacifiCorp must make a notice filing with the WUTC prior to any future issuance. PacifiCorp currently has an effective shelf registration statement filed with the SEC to issue an indeterminate amount of first mortgage bonds and unsecured debt securities through July 2027.

PacifiCorp currently has regulatory authority from the OPUC, the WUTC, the IPUC and the FERC to issue $3.0 billion of short-term debt.

While PacifiCorp's current revolving credit facilities are unsecured, upon future renewal, PacifiCorp may be required to secure the facilities, which could further limit the amount of first mortgage bonds PacifiCorp can issue.

The credit facilities require that PacifiCorp's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.65 to 1.0 as of the last day of each quarter. As of December 31, 2025, PacifiCorp's debt to total capitalization ratio was 0.58 to 1.0.

As of December 31, 2025, PacifiCorp was in compliance with all financial covenants that affect access to capital.

Short-term Debt

As of December 31, 2025 and 2024, PacifiCorp had $1.0 billion and $240 million of short-term debt outstanding at a weighted average rate of 5.23% and 4.65%, respectively. The outstanding short-term debt as of December 31, 2025, was subsequently repaid in February 2026. For further discussion, refer to Note 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Long-term Debt

In March 2025, PacifiCorp issued $850 million of its 7.375% Fixed-to-Fixed Reset Rate Junior Subordinated Notes due September 2055. PacifiCorp will pay interest on the notes at a rate of 7.375% through September 2030, subject to a reset every five years, not to reset below 7.375%. PacifiCorp initially used a portion of the net proceeds to repay outstanding short-term debt and used the remaining net proceeds to fund capital expenditures and for general corporate purposes.

In February 2026, PacifiCorp issued $1.1 billion of its 7.125% Fixed-to-Fixed Reset Rate Junior Subordinated Notes due August 2056. PacifiCorp will pay interest on the junior subordinated notes at a rate of 7.125% through August 2031, subject to a reset every five years, not to reset below 7.125%. PacifiCorp used a portion of the net proceeds to repay outstanding short-term debt and will use the remaining net proceeds for general corporate purposes.

In February 2026, PacifiCorp issued $400 million of 4.25% First Mortgage Bonds due March 2029. PacifiCorp used a portion of the net proceeds to repay outstanding short-term debt and will use the remaining net proceeds for general corporate purposes.

PacifiCorp made repayments on long-term debt totaling $302 million and $591 million during the years ended December 31, 2025 and 2024, respectively.

Credit Facilities and Letters of Credit

In June 2025, PacifiCorp amended its existing $2.0 billion unsecured credit facility expiring in June 2027. The amendment extended the expiration date to June 2028 and amended certain provisions of the existing credit agreement. Also in June 2025, PacifiCorp amended its existing $900 million 364-day unsecured credit facility expiring in June 2025. The amendment extended the expiration date to June 2026 and amended certain provisions of the existing credit agreement.

As of December 31, 2025 and 2024, PacifiCorp had $255 million of letter of credit capacity under its $2.0 billion revolving credit facility of which no amounts were outstanding. Additionally, as of December 31, 2025 and 2024, PacifiCorp had $963 million and $488 million, respectively, of letter of credit capacity outside of its $2.0 billion revolving credit facility, of which $949 million and $454 million, respectively, was available.

As described above under "Overview" within "Liquidity and Capital Resources," any further credit rating downgrade may result in the loss of letter of credit capacity.

Refer to Note 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding amounts outstanding and the maximum debt-to-total capitalization percentage required under various financing agreements.

Preferred Stock

As of December 31, 2025, PacifiCorp had 350 shares of Serial Preferred Stock authorized at the stated value of $1,000,000 per share, and $16 million shares of Preferred Stock authorized. There are no shares of PacifiCorp Serial Preferred Stock or Preferred Stock issued or outstanding. As of December 31, 2024, PacifiCorp had non-redeemable preferred stock outstanding with an aggregate stated value of $2 million.

On December 17, 2024, PPW Holdings LLC, PacifiCorp's direct parent and sole holder of the common stock of PacifiCorp, commenced a tender offer to purchase for cash any and all of PacifiCorp's outstanding 6.00% and 7.00% Serial Preferred Stock (together the "Serial Preferred Stock"). After giving effect to the tender offer, which expired on January 24, 2025, PPW Holdings LLC held 2,494 shares of the 5,930 issued and outstanding shares of the 6.00% Serial Preferred Stock and 10,269 shares of the 18,046 issued and outstanding shares of the 7.00% Serial Preferred Stock.

On February 6, 2025, PacifiCorp filed a First Articles of Amendment to the Fourth Restated Articles of Incorporation of PacifiCorp authorizing a one-for-ten thousand reverse stock split (the "Reverse Stock Split") of the Serial Preferred Stock. The Reverse Stock Split became effective at 12:01 a.m. Eastern Time on February 10, 2025. As a result of the Reverse Stock Split, every 10,000 shares of each of PacifiCorp's pre-reverse split Serial Preferred Stock were combined and reclassified into one share of Serial Preferred Stock, with a corresponding reduction in the number of authorized shares of Serial Preferred Stock from 3,500 thousand to 350 and change to stated value of $100 to $1,000,000 per share. No fractional shares were issued in connection with the Reverse Stock Split and shareholders who would have otherwise held a fractional share of Serial Preferred Stock received payment in cash. As a result, all issued and outstanding shares of PacifiCorp's preferred stock as of February 10, 2025, were held by PPW Holdings LLC.

On April 23, 2025, PacifiCorp repurchased the sole outstanding share of its 7.00% Serial Preferred Stock from PPW Holdings LLC, for a purchase price of $1,800,000.

Common Shareholder's Equity

In 2025 and 2024, PacifiCorp did not declare or pay dividends to PPW Holdings LLC.

Capitalization

PacifiCorp manages its capital structure with the objective of maintaining liquidity and its investment grade credit ratings, which is expected to facilitate continued access to the debt markets and flexible borrowing arrangements at favorable costs and rates. This objective, subject to periodic review and revision, attempts to balance the interests of all shareholders, customers and creditors and provide a competitive cost of capital and predictable capital market access. Refer to "Overview" within "Liquidity and Capital Resources" above regarding the potential impacts of the Wildfires on PacifiCorp's liquidity and access to capital. To help mitigate PacifiCorp's liquidity pressures, BHE has indicated that it will suspend dividends for the next several years.

Under existing or prospective authoritative accounting guidance, such as guidance pertaining to consolidations and leases, it is possible that new purchase power, energy storage and gas agreements, transmission arrangements or amendments to existing arrangements may be accounted for as lease obligations on PacifiCorp's financial statements. While PacifiCorp has successfully amended covenants in financing arrangements that may be impacted, it may be more difficult for PacifiCorp to comply with its capitalization targets or regulatory commitments concerning minimum levels of common equity as a percentage of capitalization. This may lead PacifiCorp to seek amendments to its financing agreements and from regulators or take other actions.

Future Uses of Cash

PacifiCorp has available a variety of sources of liquidity and capital resources, both internal and external, including net cash flows from operating activities, public and private debt offerings, the issuance of commercial paper, the use of unsecured revolving credit facilities, bank loans, capital contributions and other sources. These sources are expected to provide funds required for current operations, capital expenditures, debt retirements and other capital requirements. The availability and terms under which PacifiCorp has access to external financing depends on a variety of factors, including PacifiCorp's credit ratings, investors' judgment of risk associated with PacifiCorp, conditions in the overall capital markets, including the condition of the utility industry. Refer also to the "Overview" above for potential impacts of the Wildfires and CMO No. 11.

Capital Expenditures

PacifiCorp has significant future capital requirements. Capital expenditure needs are reviewed regularly by management and may change significantly as a result of these reviews, which may consider, among other factors, impacts to customer rates; changes in environmental and other rules and regulations; outcomes of regulatory proceedings, including regulatory filings for Certificates of Public Convenience and Necessity; outcomes of legal actions associated with the Wildfires and the potential impacts of CMO No. 11; changes in income tax laws; general business conditions; new customer requests; load projections; system reliability standards; the cost and efficiency of construction labor, equipment and materials; commodity prices; and the cost and availability of capital.

Historical and forecast capital expenditures, each of which exclude amounts for non-cash equity AFUDC and other non-cash items, for the years ended December 31 are as follows (in millions):

	Historical			Forecast		
	2023	2024	2025	2026	2027	2028
Electric transmission	$ 1,189	$ 840	$ 646	$ 1,133	$ 920	$ 590
Electric distribution	673	761	783	762	387	546
Wildfire prevention	325	539	789	499	468	520
Wind generation	755	425	221	43	29	28
Other	284	537	556	447	729	771
Total	$ 3,226	$ 3,102	$ 2,995	$ 2,884	$ 2,533	$ 2,455

PacifiCorp's historical and forecast capital expenditures include the following:

- Electric transmission includes both growth projects and operating expenditures. Transmission growth primarily reflects costs associated with major transmission projects. Expenditures for certain projects placed in-service during 2024 totaled $72 million for 2025, $382 million for 2024 and $738 million for 2023. Expenditures for major transmission projects that are expected to be placed in-service through 2032 totaled $213 million for 2025, $112 million for 2024 and $55 million for 2023. Planned spending for major transmission projects that are expected to be placed in-service through 2032 totals $431 million in 2026, $260 million in 2027 and $132 million in 2028 and includes the Boardman to Hemingway 300-mile, 500-kV transmission line discussed in Notes 14 and 21 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K. The remaining investments primarily relate to expenditures for transmission operations, generation interconnection requests and other transmission segments.
- Electric distribution includes both growth projects and operating expenditures. Growth expenditures include spending on new customer connections totaled $354 million in 2025, $338 million in 2024 and $264 million in 2023. Planned spending for new customer connections total $397 million in 2026, $29 million in 2027 and $218 million in 2028. The remaining investments primarily relate to expenditures for distribution operations.
- Wildfire prevention includes operating expenditures. Expenditures totaled $789 million in 2025, $539 million in 2024 and $325 million in 2023. Planned spending through 2028 is comprised of reducing wildfire risk in the fire high consequence areas by conversion of overhead systems to underground, replacing overhead bare wire conductor with covered conductors, replacing traditional fuses with non-expulsion fuses and deployment of advanced protection devices for faster fault detection. The efforts will also include an expansion of the weather station network and predictive tools for situational awareness across the entire service territory.
- Wind generation includes both growth projects and operating expenditures. Growth projects include construction of new wind-powered generating facilities and construction at existing wind-powered generating facility sites acquired from third parties totaling $195 million for 2025, $396 million for 2024 and $735 million for 2023. PacifiCorp placed in-service 529 MWs at the Rock Creek I and Rock Creek II wind-powered generating facilities in 2025, 50 MWs at the Rock River I and 61 MWs at the Rock Creek I wind-powered generating facilities in 2024 and 42 MWs at the Foote Creek III and Foote Creek IV wind-powered generating facilities in 2023.
- Other includes both growth projects and operating expenditures. Expenditures for information technology totaled $151 million in 2025, $159 million in 2024 and $179 million for 2023. Planned information technology spending totals $107 million in 2026, $233 million in 2027 and $338 million in 2028. The remaining investments relate to operating projects that consist of routine expenditures for generation and other infrastructure needed to serve existing and expected demand

Certain capital expenditures pertain to projects that are subject to federal grant funding. Forecast amounts included above do not reflect the potential cost reimbursements associated with these federal grants.

Off-Balance Sheet Arrangements

From time to time, PacifiCorp enters into arrangements in the normal course of business to facilitate commercial transactions with third parties that involve guarantees or similar arrangements. PacifiCorp currently has indemnification obligations in connection with the sale or transfer of certain assets. PacifiCorp believes that the likelihood that it would be required to perform or otherwise incur any significant losses associated with any of these obligations is remote. Refer to Notes 11, 14, and 19 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for more information on these obligations and arrangements.

Material Cash Requirements

PacifiCorp has cash requirements that may affect its consolidated financial condition that arise primarily from long-term debt (refer to Note 8); certain commitments and contingencies, including those associated with the Wildfires (refer to Note 14); and cost of removal and AROs (refer to Notes 6 and 11). Refer to the respective referenced note in Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

PacifiCorp has cash requirements relating to interest payments of $13.8 billion on long-term debt, including $738 million due in 2026.

Regulatory Matters

PacifiCorp is subject to comprehensive regulation. Refer to the discussion contained in Item 1 of this Form 10-K for further information regarding PacifiCorp's general regulatory framework and current regulatory matters.

Environmental Laws and Regulations

PacifiCorp is subject to federal, state and local laws and regulations regarding air quality, climate change, emissions performance standards, water quality, coal ash disposal and other environmental matters that have the potential to impact PacifiCorp's current and future operations. In addition to imposing continuing compliance obligations, these laws and regulations provide regulators with the authority to levy substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. These laws and regulations are administered by various federal, state and local agencies. PacifiCorp believes it is in material compliance with all applicable laws and regulations, although many are subject to interpretation that may ultimately be resolved by the courts. Environmental laws and regulations continue to evolve, and PacifiCorp is unable to predict the impact of the changing laws and regulations on its operations and consolidated financial results.

Refer to "Environmental Laws and Regulations" in Item 1 of this Form 10-K for further discussion regarding environmental laws and regulations.

Collateral and Contingent Features

Debt securities of PacifiCorp are rated by credit rating agencies. Assigned credit ratings are based on each rating agency's assessment of PacifiCorp's ability to, in general, meet the obligations of its issued debt securities. The credit ratings are not a recommendation to buy, sell or hold securities, and there is no assurance that a particular credit rating will continue for any given period of time. As of December 31, 2025, PacifiCorp's issuer credit ratings for senior unsecured debt from the recognized credit rating agencies were investment grade.

PacifiCorp has no credit rating downgrade triggers that would accelerate the maturity dates of outstanding debt and a change in ratings is not an event of default under the applicable debt instruments. PacifiCorp's unsecured revolving credit facilities do not require the maintenance of a minimum credit rating level to draw upon their availability. However, commitment fees and interest rates under the credit facilities are tied to credit ratings and increase or decrease when the ratings change. A ratings downgrade could also increase the future cost of commercial paper, short- and long-term debt issuances or new credit facilities. Certain authorizations or exemptions by regulatory commissions for the issuance of securities are valid as long as PacifiCorp maintains investment grade ratings on senior secured debt. A downgrade below that level would necessitate new regulatory applications and approvals.

In accordance with industry practice, certain wholesale energy agreements, including contracts for purchases, sales and transportation of electricity, natural gas and coal, some of which are accounted for as derivatives, contain credit support provisions that in part base certain collateral requirements on credit ratings for senior unsecured debt as reported by one or more of the recognized credit rating agencies. These agreements may provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features"). These agreements and other agreements that do not refer to specified rating-dependent thresholds may provide the right for counterparties to demand "adequate assurance" if there is a material adverse change in PacifiCorp's creditworthiness. These rights can vary by contract and by counterparty. If all credit-risk-related contingent features or adequate assurance provisions for these agreements had been triggered as of December 31, 2025, PacifiCorp would have been required to post $182 million of additional collateral. PacifiCorp's collateral requirements associated with wholesale energy agreements could fluctuate considerably due to market price volatility; changes in credit ratings; changes in legislation or regulation or other factors; and if counterparties demand adequate assurance in the event of a material adverse change in PacifiCorp's creditworthiness. Refer to Note 12 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for a discussion of PacifiCorp's collateral requirements specific to PacifiCorp's derivative contracts.

As described in Note 14 to Consolidated Financial Statements in Item 8 of this Form 10-K, PacifiCorp had posted surety bonds totaling $606 million as of December 31, 2025, to stay payment of damages in the *James* case pending appeals. A limited number of the surety bond agreements include contingent features associated with PacifiCorp's financial condition. If all financial condition-related contingent features associated with the surety bonds had been triggered as of December 31, 2025, PacifiCorp would have been required to post $135 million of cash collateral.

Inflation

PacifiCorp operates under a cost-of-service based rate-setting structure administered by various state commissions and the FERC. Under this rate-setting structure, PacifiCorp is allowed to include prudent costs in its rates, including the impact of inflation. PacifiCorp seeks to minimize the potential impact of inflation on its operations through the use of energy and other cost adjustment clauses and tariff riders, by employing prudent risk management and hedging strategies and entering into contracts with fixed pricing where possible by considering, among other areas, its impact on purchases of energy, operating expenses, materials and equipment costs, contract negotiations, future capital spending programs and long-term debt issuances. There can be no assurance that such actions will be successful.

New Accounting Pronouncements

For a discussion of new accounting pronouncements affecting PacifiCorp, refer to Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Critical Accounting Estimates

Certain accounting measurements require management to make estimates and judgments concerning transactions that will be settled several years in the future. Amounts recognized on the Consolidated Financial Statements based on such estimates involve numerous assumptions subject to varying and potentially significant degrees of judgment and uncertainty and will likely change in the future as additional information becomes available. The following critical accounting estimates are impacted significantly by PacifiCorp's methods, judgments and assumptions used in the preparation of the Consolidated Financial Statements and should be read in conjunction with PacifiCorp's Summary of Significant Accounting Policies included in Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Accounting for the Effects of Certain Types of Regulation

PacifiCorp prepares its financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, PacifiCorp defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in rates occur.

PacifiCorp continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future rates by considering factors such as a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation, other regulatory actions or the impact of competition that could limit PacifiCorp's ability to recover its costs. PacifiCorp believes its application of the guidance for regulated operations is appropriate and its existing regulatory assets and liabilities are probable of inclusion in future rates. The evaluation reflects the current political and regulatory climate at both the federal and state levels. If it becomes no longer probable that the deferred costs or income will be included in future rates, the related regulatory assets and liabilities will be recognized in net income, returned to customers or re-established as AOCI. Total regulatory assets were $2.6 billion and total regulatory liabilities were $2.7 billion as of December 31, 2025. Refer to Note 6 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding PacifiCorp's regulatory assets and liabilities.

Pension and Other Postretirement Benefits

PacifiCorp sponsors defined benefit pension and other postretirement benefit plans as described in Note 10. PacifiCorp recognizes the funded status of these defined benefit pension and other postretirement benefit plans on the Consolidated Balance Sheets. Funded status is the fair value of plan assets minus the benefit obligation as of the measurement date. As of December 31, 2025, PacifiCorp recognized a net asset totaling $132 million for the funded status of its defined benefit pension and other postretirement benefit plans. As of December 31, 2025, amounts not yet recognized as a component of net periodic benefit cost (credit) included in net regulatory assets and accumulated other comprehensive loss totaled $204 million and $13 million, respectively.

The expense and benefit obligations relating to these defined benefit pension and other postretirement benefit plans are based on actuarial valuations. Inherent in these valuations are key assumptions, including, but not limited to, discount rate and expected long-term rate of return on plan assets. These key assumptions are reviewed annually and modified as appropriate. PacifiCorp believes that the key assumptions utilized in recording obligations under the plans are reasonable based on prior plan experience and current market and economic conditions. Refer to Note 10 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for disclosures about PacifiCorp's defined benefit pension and other postretirement benefit plans, including the key assumptions used to calculate the funded status and net periodic benefit cost for these plans as of and for the year ended December 31, 2025.

PacifiCorp chooses a discount rate based upon high quality debt security investment yields in effect as of the measurement date with cash flows aligning to the expected timing and amount of plan liabilities. The pension and other postretirement benefit liabilities increase as the discount rate is reduced.

In establishing its assumption as to the expected long-term rate of return on plan assets, PacifiCorp evaluates the investment allocation between return-seeking investment and fixed income securities based on the funded status of the plan and utilizes the asset allocation and return assumptions for each asset class based on forward-looking views of the financial markets and historical performance. Pension and other postretirement benefits expense increases as the expected long-term rate of return on plan assets decreases. PacifiCorp regularly reviews its actual asset allocations and rebalances its investments to its targeted allocations when considered appropriate.

The key assumptions used may differ materially from period to period due to changing market and economic conditions. These differences may result in a significant impact to pension and other postretirement benefits expense and funded status. If changes were to occur for the following key assumptions, the approximate effect on the Consolidated Financial Statements would be as follows (in millions):

	Pension Plans		Other Postretirement Benefit Plan	
	+0.5%	-0.5%	+0.5%	-0.5%
Effect on December 31, 2025 Benefit Obligations:				
Discount rate	$ (22)	$ 24	$ (7)	$ 7
Effect on 2025 Periodic Cost:				
Discount rate	$ 1	$ (1)	$ —	$ —
Expected rate of return on plan assets	(4)	4	(1)	1

A variety of factors affect the funded status of the plans, including discount rates, asset returns, mortality assumptions, plan changes and PacifiCorp's funding policy for each plan.

Income Taxes

In determining PacifiCorp's income taxes, management is required to interpret complex income tax laws and regulations, which includes consideration of regulatory implications imposed by PacifiCorp's various regulatory commissions. PacifiCorp's income tax returns are subject to continuous examinations by federal, state and local income tax authorities that may give rise to different interpretations of these complex laws and regulations. Due to the nature of the examination process, it generally takes years before these examinations are completed and these matters are resolved. PacifiCorp recognizes the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the Consolidated Financial Statements from such a position are measured based on the largest benefit that is more-likely-than-not to be realized upon ultimate settlement. Although the ultimate resolution of PacifiCorp's federal, state and local income tax examinations is uncertain, PacifiCorp believes it has made adequate provisions for these income tax positions. The aggregate amount of any additional income tax liabilities that may result from these examinations is not expected to have a material impact on PacifiCorp's consolidated financial results. Refer to Note 9 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding PacifiCorp's income taxes.

It is probable that PacifiCorp will pass income tax benefit and expense related to the federal tax rate change from 35% to 21%, certain property-related basis differences and other various differences on to customers in certain state jurisdictions. As of December 31, 2025, these amounts were recognized as a net regulatory liability of $762 million and will primarily be included in regulated rates over the estimated useful lives of the related properties.

Wildfire Loss Contingencies

PacifiCorp is required to evaluate its exposure to potential loss contingencies arising from claims associated with the Wildfires. In determining this exposure, PacifiCorp is required to assess whether the likelihood of loss associated with the Wildfires is remote, reasonably possible or probable, which involves complex judgments based on several variables including available information regarding cause and origin investigations, settlement and mediation activities, other litigation matters and upcoming legal proceedings. If deemed reasonably possible, PacifiCorp is required to estimate the potential loss or range of potential loss and disclose any material amounts. If deemed probable, PacifiCorp is required to accrue a loss if reasonably estimable based on the bottom end of the range if no amount within the range of estimated loss is any better than another amount. Many assumptions and variables are involved in determining these estimates, including identifying the various categories of potential loss such as fire suppression costs, real and personal property damages, natural resource damages and noneconomic damages such as personal injury damages and loss of life damages. Within the categories of potential loss, further assumptions are made regarding items such as the types of structures damaged, estimated replacement values associated with those structures, value of personal property, the types of natural resource damage such as timber, the value of that timber, the nature of noneconomic damages such as those arising from personal injuries, other damages PacifiCorp may be responsible for if found negligent such as punitive damages, and the amount of any penalties or fines that may be imposed by governmental entities. Estimates associated with the Wildfires are subject to change as additional relevant information becomes available. Refer to Note 14 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding PacifiCorp's loss contingencies associated with the Wildfires.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

PacifiCorp's Consolidated Balance Sheets include assets and liabilities with fair values that are subject to market risks. PacifiCorp's significant market risks are primarily associated with commodity prices, interest rates and the extension of credit to counterparties with which PacifiCorp transacts. The following discussion addresses the significant market risks associated with PacifiCorp's business activities. PacifiCorp has established guidelines for credit risk management. Refer to Notes 2 and 12 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding PacifiCorp's contracts accounted for as derivatives.

PacifiCorp has a risk management committee that is responsible for the oversight of market and credit risk relating to the commodity transactions of PacifiCorp. To limit PacifiCorp's exposure to market and credit risk, the risk management committee recommends, and executive management establishes, policies, limits and approved products, which are reviewed frequently to respond to changing market conditions.

Risk is an inherent part of PacifiCorp's business and activities. PacifiCorp has established a risk management process that is designed to identify, assess, manage and report on each of the various types of risk involved in its business. The risk management policy governs energy transactions and is designed for hedging PacifiCorp's existing energy and asset exposures, and to a limited extent, the policy permits arbitrage and trading activities to take advantage of market inefficiencies. The policy also governs the types of transactions authorized for use and establishes guidelines for credit risk management and management information systems required to effectively monitor such transactions. PacifiCorp's risk management policy provides for the use of only those contracts that have a similar volume or price relationship to its portfolio of assets, liabilities or anticipated transactions.

PacifiCorp has controls and procedures in place to monitor compliance with its risk management policy and limit procedures on a regular and on-going basis, including remediation procedures in the event of an incident of non-compliance to the policy.

Commodity Price Risk

PacifiCorp is principally exposed to electricity, natural gas, coal and fuel oil commodity price risk as it has an obligation to serve retail customer load in its service territories. PacifiCorp's load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity and wholesale electricity that is purchased and sold. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, generating facility availability, customer usage, storage, and transmission and transportation constraints. PacifiCorp does not engage in a material amount of proprietary trading activities. To mitigate a portion of its commodity price risk, PacifiCorp uses commodity derivative contracts, which may include forwards, futures, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. PacifiCorp does not hedge all of its commodity price risk, thereby exposing the unhedged portion to changes in market prices. PacifiCorp's exposure to commodity price risk is generally limited by its ability to include commodity costs in rates, which is subject to regulatory lag that occurs between the time the costs are incurred and when the costs are included in rates, as well as the impact of any customer sharing resulting from cost adjustment mechanisms.

PacifiCorp measures, monitors and manages the market risk in its electricity and natural gas portfolio in comparison to established thresholds and measures its open positions subject to price risk in terms of quantity at each delivery location for each forward time period. PacifiCorp has a risk management policy that requires increasing volumes of hedge transactions over a three-year position management and hedging horizon to reduce market risk of its electricity and natural gas portfolio.

The table that follows summarizes PacifiCorp's price risk on commodity contracts accounted for as derivatives, excluding net collateral receivable of $71 million and $6 million as of December 31, 2025 and 2024, respectively, and shows the effects of a hypothetical 10% increase and 10% decrease in forward market prices by the expected volumes for these contracts as of that date. The selected hypothetical change does not reflect what could be considered the best or worst case scenarios (dollars in millions):

	Fair Value - Net (Liability) Asset	Estimated Fair Value after Hypothetical Change in Price	
		10% increase	10% decrease
As of December 31, 2025:			
Total commodity derivative contracts	$ (137)	$ (92)	$ (182)
As of December 31, 2024:			
Total commodity derivative contracts	$ (97)	$ (56)	$ (138)

PacifiCorp's commodity derivative contracts are generally recoverable from customers in rates; therefore, net unrealized gains and losses associated with interim price movements on commodity derivative contracts do not expose PacifiCorp to earnings volatility. As of December 31, 2025 and 2024, a regulatory asset of $137 million and $97 million, respectively, was recorded related to the net derivative liability of $137 million and $97 million, respectively.

Interest Rate Risk

PacifiCorp is exposed to interest rate risk on its outstanding variable-rate short- and long-term debt and future debt issuances. PacifiCorp manages its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. As a result of the fixed interest rates, PacifiCorp's fixed-rate long-term debt does not expose PacifiCorp to the risk of loss due to changes in market interest rates. Additionally, because fixed-rate long-term debt is not carried at fair value on the Consolidated Balance Sheets, changes in fair value would impact earnings and cash flows only if PacifiCorp were to reacquire all or a portion of these instruments prior to their maturity. PacifiCorp may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, to mitigate PacifiCorp's exposure to interest rate risk. The nature and amount of PacifiCorp's short- and long-term debt can be expected to vary from period to period as a result of future business requirements, market conditions and other factors. Refer to Notes 7, 8 and 13 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional discussion of PacifiCorp's short- and long-term debt.

As of December 31, 2025 and 2024, PacifiCorp had short- and long-term variable-rate obligations totaling $1.0 billion and $292 million, respectively, that expose PacifiCorp to the risk of increased interest expense in the event of increases in short-term interest rates. The market risk related to PacifiCorp's variable-rate debt as of December 31, 2025 is not hedged. If variable interest rates were to increase by 10% from December 31 levels, it would not have a material effect on PacifiCorp's consolidated annual interest expense. The carrying value of the variable-rate obligations approximates fair value as of December 31, 2025 and 2024.

Credit Risk

PacifiCorp is exposed to counterparty credit risk associated with wholesale energy supply and marketing activities with other utilities, energy marketing companies, financial institutions and other market participants. Credit risk may be concentrated to the extent PacifiCorp's counterparties have similar economic, industry or other characteristics and due to direct or indirect relationships among the counterparties. Before entering into a transaction, PacifiCorp analyzes the financial condition of each significant wholesale counterparty, establishes limits on the amount of unsecured credit to be extended to each counterparty and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate wholesale counterparty credit risk, PacifiCorp enters into netting and collateral arrangements that may include margining and cross-product netting agreements and obtains third-party guarantees, letters of credit and cash deposits. If required, PacifiCorp exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

As of December 31, 2025, PacifiCorp's aggregate credit exposure with wholesale energy supply and marketing counterparties included counterparties having non-investment grade, internally rated credit ratings. Substantially all of these non-investment grade, internally rated counterparties are associated with long-duration solar and wind power purchase agreements, some of which are from facilities that have not yet achieved commercial operation and for which PacifiCorp has no obligation should the facilities not achieve commercial operation.

Item 8. Financial Statements and Supplementary Data

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of PacifiCorp

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of PacifiCorp and subsidiaries ("PacifiCorp") as of December 31, 2025 and 2024, the related consolidated statements of operations, comprehensive income (loss), changes in shareholders' equity, and cash flows, for each of the three years in the period ended December 31, 2025, 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 PacifiCorp as of December 31, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of PacifiCorp's management. Our responsibility is to express an opinion on PacifiCorp's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to PacifiCorp 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. PacifiCorp is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of PacifiCorp's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current-period audit of the financial statements that were communicated or required to be communicated to the Board of Directors and that (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Regulatory Matters — Effects of Rate Regulation on the Financial Statements — Refer to Note 6 to the financial statements

Critical Audit Matter Description

PacifiCorp is subject to rate regulation by the Federal Energy Regulatory Commission as well as certain other regulatory commissions (collectively, the "Commissions"), which have jurisdiction with respect to the rates of electric and natural gas companies in the respective service territories where PacifiCorp operates. Management has determined its regulated operations meet the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. Accounting for the economic effects of rate regulation has a pervasive effect on the financial statements.

Regulated rates are subject to regulatory rate-setting processes. Rates are determined, approved, and established based on a cost-of-service basis, which is designed to allow PacifiCorp an opportunity to recover its prudently incurred costs of providing services and to earn a reasonable return on its invested capital. Regulatory decisions can have an effect on the recovery of costs, the rate of return earned on investment, and the timing and amount of assets to be recovered by rates. While PacifiCorp has indicated it expects to recover costs from customers through regulated rates, there is a risk that changes to the Commissions' approach to setting rates or other regulatory actions could limit PacifiCorp's ability to recover its costs.

We identified the effects of rate regulation on the financial statements as a critical audit matter due to the significant judgments made by management to support its assertions about certain affected account balances and disclosures and the high degree of subjectivity involved in assessing the impact of 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 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 decisions by the Commissions included the following, among others:

- We evaluated PacifiCorp's disclosures related to the effects of rate regulation by testing certain recorded balances and evaluating regulatory developments.
- We read relevant regulatory orders issued by the Commissions, regulatory statutes, filings made by PacifiCorp and other external information. We evaluated relevant external information and compared it to certain recorded regulatory asset and liability balances for completeness.
- For certain regulatory matters, we inspected PacifiCorp's filings with the Commissions and the filings with the Commissions by intervenors to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedents of the Commissions' treatment of similar costs under similar circumstances.

Wildfires — Contingencies — Refer to Note 14 to the financial statements

Critical Audit Matter Description

As a result of several wildfires that have occurred in PacifiCorp's service territory and surrounding areas in Oregon and California, PacifiCorp is required to evaluate its exposure to potential loss contingencies arising from claims associated with the 2020 Wildfires and the 2022 McKinney Fire (the "Wildfires"). In determining this exposure, PacifiCorp is required to determine whether the likelihood of loss for each of the Wildfires is remote, reasonably possible or probable, which involves complex judgments based on several variables including available information regarding the cause and origin of the Wildfires, investigations, discovery associated with lawsuits and negotiations with claimants.

A provision for a loss contingency is recorded when it is probable that a liability has been incurred and the amount of loss can be reasonably estimated. If deemed reasonably possible, PacifiCorp is required to estimate and disclose the potential loss or range of potential loss.

Management has recorded estimated liabilities which represent its best estimate of probable losses associated with the Wildfires.

We identified wildfire-related contingencies and the related disclosures as a critical audit matter because of the significant judgments made by management to determine the probability of loss and estimate the probable losses. Auditing the reasonableness of management's judgments, estimates and disclosures related to wildfire-related loss contingencies required the application of a high degree of judgment and extensive effort.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to management's judgments regarding the probability of loss, estimated losses and related disclosures for wildfire-related contingencies included the following, among others:

- We evaluated management's judgments related to whether a loss was remote, reasonably possible, or probable for the Wildfires by inquiring of management and PacifiCorp's external and internal legal counsel regarding the likelihood of loss and amounts of probable and reasonably possible losses. We also evaluated the potential impact of information gained through PacifiCorp and third-parties' investigations into the cause of the fires, information from claimants, the advice of legal counsel, and reading external information for any evidence that might contradict management's assertions.
- We evaluated the estimation methodology for determining the amount of probable and reasonably possible losses through inquiries with management and external and internal legal counsel, and we tested the significant assumptions, including certain settlements, used in the estimates of probable and reasonably possible losses.
- We read legal letters from PacifiCorp's external and internal legal counsel regarding known information and evaluated whether the information therein was consistent with the information obtained in our procedures.
- We evaluated whether PacifiCorp's disclosures were appropriate and consistent with the information obtained in our procedures.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 27, 2026

We have served as PacifiCorp's auditor since 2006.

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2025	**2024**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 73	$ 46
Trade receivables, net	1,032	960
Other receivables, net	212	245
Inventories	920	828
Regulatory assets	669	891
Prepaid expenses	148	283
Other current assets	138	44
Total current assets	3,192	3,297
Property, plant and equipment, net	31,113	29,120
Regulatory assets	1,891	2,026
Other assets	994	561
Total assets	$ 37,190	$ 35,004

The accompanying notes are an integral part of these consolidated financial statements.

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (continued)
(Amounts in millions)

	As of December 31,	
	2025	**2024**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 1,378	$ 1,462
Accrued interest	260	239
Accrued property, income and other taxes	96	85
Accrued employee expenses	105	96
Short-term debt	1,000	240
Current portion of senior debt	100	302
Regulatory liabilities	80	92
Wildfires liabilities (Note 14)	734	247
Other current liabilities	529	466
Total current liabilities	4,282	3,229
Senior debt	13,193	13,286
Junior subordinated debt	841	—
Regulatory liabilities	2,577	2,550
Deferred income taxes	3,274	3,222
Wildfires liabilities (Note 14)	427	1,289
Other long-term liabilities	1,449	916
Total liabilities	26,043	24,492
Commitments and contingencies (Note 14)		
Shareholders' equity:		
Preferred stock	—	2
Common stock - 750 shares authorized, no par value, 357 shares issued and outstanding	—	—
Additional paid-in capital	4,479	4,479
Retained earnings	6,678	6,040
Accumulated other comprehensive loss, net	(10)	(9)
Total shareholders' equity	11,147	10,512
Total liabilities and shareholders' equity	$ 37,190	$ 35,004

The accompanying notes are an integral part of these consolidated financial statements.

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2025	**2024**	**2023**
Operating revenue	$ 7,493	$ 6,600	$ 5,936
Operating expenses:			
Cost of fuel and energy	3,190	2,752	2,246
Operations and maintenance	1,783	1,603	1,469
Wildfires losses, net of recoveries (Note 14)	100	346	1,677
Depreciation and amortization	1,289	1,152	1,126
Property and other taxes	239	218	215
Total operating expenses	6,601	6,071	6,733
Operating income (loss)	892	529	(797)
Other income (expense):			
Interest expense	(793)	(756)	(546)
Allowance for borrowed funds	91	120	70
Allowance for equity funds	120	203	144
Interest and dividend income	113	191	98
Other, net	21	16	10
Total other income (expense)	(448)	(226)	(224)
Income (loss) before income tax expense (benefit)	444	303	(1,021)
Income tax expense (benefit)	(196)	(236)	(553)
Net income (loss)	$ 640	$ 539	$ (468)

The accompanying notes are an integral part of these consolidated financial statements.

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(Amounts in millions)

	Years Ended December 31,		
	2025	**2024**	**2023**
Net income (loss)	$ 640	$ 539	$ (468)
Other comprehensive (loss) income, net of tax —			
Unrecognized amounts on retirement benefits, net of tax of $—, $— and $—	(1)	1	(1)
Comprehensive income (loss)	$ 639	$ 540	$ (469)

The accompanying notes are an integral part of these consolidated financial statements.

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
(Amounts in millions)

	Preferred Stock	Common Stock	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss, Net	Total Shareholders' Equity
Balance, December 31, 2022	$ 2	$ —	$ 4,479	$ 6,269	$ (9)	$ 10,741
Net loss	—	—	—	(468)	—	(468)
Other comprehensive loss	—	—	—	—	(1)	(1)
Common stock dividends declared	—	—	—	(300)	—	(300)
Balance, December 31, 2023	2	—	4,479	5,501	(10)	9,972
Net income	—	—	—	539	—	539
Other comprehensive income	—	—	—	—	1	1
Balance, December 31, 2024	2	—	4,479	6,040	(9)	10,512
Net income	—	—	—	640	—	640
Preferred stock redemption	(2)	—	—	(2)	—	(4)
Other comprehensive loss	—	—	—	—	(1)	(1)
Balance, December 31, 2025	$ —	$ —	$ 4,479	$ 6,678	$ (10)	$ 11,147

The accompanying notes are an integral part of these consolidated financial statements.

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Amounts in millions)

	Years Ended December 31,		
	2025	**2024**	**2023**
Cash flows from operating activities:			
Net income (loss)	$ 640	$ 539	$ (468)
Adjustments to reconcile net income (loss) to net cash flows from operating activities:			
Depreciation and amortization	1,289	1,152	1,126
Allowance for equity funds	(120)	(203)	(144)
Net power cost deferrals	(259)	(646)	(760)
Amortization of net power cost deferrals	903	556	231
Other changes in regulatory assets and liabilities	(161)	(146)	(161)
Deferred income taxes and amortization of investment tax credits	(46)	(9)	(224)
Other, net	6	18	11
Changes in other operating assets and liabilities:			
Trade receivables, other receivables and other assets	(139)	(81)	(38)
Inventories	(92)	(296)	(58)
Prepaid expenses	116	(100)	(91)
Derivative collateral, net	(64)	4	(100)
Accrued property, income and other taxes, net	(79)	132	(40)
Accounts payable and other liabilities	4	23	370
Wildfires insurance receivable	98	401	(253)
Wildfires liability	(375)	(187)	1,299
Net cash flows from operating activities	1,721	1,157	700
Cash flows from investing activities:			
Capital expenditures	(2,995)	(3,102)	(3,226)
Other, net	18	11	5
Net cash flows from investing activities	(2,977)	(3,091)	(3,221)
Cash flows from financing activities:			
Proceeds from senior debt	—	3,762	1,189
Proceeds from junior subordinated debt	841	—	—
Repayments of senior debt	(302)	(591)	(449)
Net proceeds from (repayments of) short-term debt	760	(1,364)	1,604
Redemption of preferred stock	(4)	—	—
Dividends paid	—	—	(300)
Other, net	(5)	(4)	(5)
Net cash flows from financing activities	1,290	1,803	2,039
Net change in cash and cash equivalents and restricted cash and cash equivalents	34	(131)	(482)
Cash and cash equivalents and restricted cash and cash equivalents at beginning of period	61	192	674
Cash and cash equivalents and restricted cash and cash equivalents at end of period	$ 95	$ 61	$ 192

The accompanying notes are an integral part of these consolidated financial statements.

(1) Organization and Operations

PacifiCorp, which includes PacifiCorp and its subsidiaries, is a U.S. regulated electric utility company serving retail customers, including residential, commercial, industrial, irrigation and other customers in portions of Utah, Oregon, Wyoming, Washington, Idaho and California. PacifiCorp owns, or has interests in, a number of thermal, hydroelectric, wind-powered and geothermal generating facilities, as well as electric transmission and distribution assets. PacifiCorp also buys and sells electricity on the wholesale market with other utilities, energy marketing companies, financial institutions and other market participants. PacifiCorp is subject to comprehensive state and federal regulation. PacifiCorp's subsidiaries support its electric utility operations by providing coal mining services. PacifiCorp is an indirect subsidiary of Berkshire Hathaway Energy Company ("BHE"), a holding company based in Des Moines, Iowa that has investments in subsidiaries principally engaged in energy businesses. BHE is a wholly owned subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

Subsequent Event

Refer to Note 22 for information associated with the future sale of certain PacifiCorp assets and liabilities associated with PacifiCorp's Washington operations.

(2) Summary of Significant Accounting Policies

Basis of Consolidation and Presentation

The Consolidated Financial Statements include the accounts of PacifiCorp and its subsidiaries in which it holds a controlling financial interest as of the financial statement date. Intercompany accounts and transactions have been eliminated.

Use of Estimates in Preparation of Financial Statements

The preparation of the Consolidated Financial Statements in conformity with accounting principles generally accepted in the United States of America ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the period. These estimates include, but are not limited to, the effects of regulation; certain assumptions made in accounting for pension and other postretirement benefits; asset retirement obligations ("AROs"); income taxes; unbilled revenue; valuation of certain financial assets and liabilities, including derivative contracts; and accounting for loss contingencies and applicable insurance recoveries, including those related to the Oregon and Northern California 2020 wildfires (the "2020 Wildfires") and a wildfire that began in the Oak Knoll Ranger District of the Klamath National Forest in Siskiyou County, California in July 2022 (the "2022 McKinney Fire"), referred to together as "the Wildfires" as discussed in Note 14. Actual results may differ from the estimates used in preparing the Consolidated Financial Statements.

Accounting for the Effects of Certain Types of Regulation

PacifiCorp prepares its financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, PacifiCorp defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in rates occur.

If it becomes no longer probable that the deferred costs or income will be included in future rates, the related regulatory assets and liabilities will be recognized in net income, returned to customers or re-established as accumulated other comprehensive income (loss) ("AOCI").

Fair Value Measurements

As defined under GAAP, fair value is the price that would be received to sell an asset or paid to transfer a liability between market participants in the principal market or in the most advantageous market when no principal market exists. Adjustments to transaction prices or quoted market prices may be required in illiquid or disorderly markets in order to estimate fair value. Different valuation techniques may be appropriate under the circumstances to determine the value that would be received to sell an asset or paid to transfer a liability in an orderly transaction. Market participants are assumed to be independent, knowledgeable, able and willing to transact an exchange and not under duress. Nonperformance or credit risk is considered when determining fair value. Considerable judgment may be required in interpreting market data used to develop the estimates of fair value. Accordingly, estimates of fair value presented herein are not necessarily indicative of the amounts that could be realized in a current or future market exchange.

Cash and Cash Equivalents and Restricted Cash and Cash Equivalents

Cash equivalents consist of funds invested in money market mutual funds, U.S. Treasury Bills and other investments with a maturity of three months or less when purchased. Cash and cash equivalents exclude amounts where availability is restricted by legal requirements, loan agreements or other contractual provisions. Restricted cash and cash equivalents consist substantially of funds representing vendor retention, nuclear decommissioning and custodial funds. A reconciliation of cash and cash equivalents and restricted cash and cash equivalents as of December 31, 2025 and 2024 as presented on the Consolidated Statements of Cash Flows is outlined below and disaggregated by the line items in which they appear on the Consolidated Balance Sheets (in millions):

	As of December 31,	
	2025	**2024**
Cash and cash equivalents	$ 73	$ 46
Restricted cash included in other current assets	19	12
Restricted cash included in other assets	3	3
Total cash and cash equivalents and restricted cash and cash equivalents	$ 95	$ 61

Investments

Available-for-sale securities are carried at fair value with realized gains and losses, as determined on a specific identification basis, recognized in earnings and unrealized gains and losses recognized in AOCI, net of tax. As of December 31, 2025 and 2024, PacifiCorp had no unrealized gains and losses on available-for-sale securities. Trading securities are carried at fair value with realized and unrealized gains and losses recognized in earnings.

Equity Method Investments

PacifiCorp utilizes the equity method of accounting with respect to investments when it possesses the ability to exercise significant influence, but not control, over the operating and financial policies of the investee. The ability to exercise significant influence is presumed when an investor possesses more than 20% of the voting interests of the investee. This presumption may be overcome based on specific facts and circumstances that demonstrate that the ability to exercise significant influence is restricted. In applying the equity method, PacifiCorp records the investment at cost and subsequently increases or decreases the carrying value of the investment by PacifiCorp's proportionate share of the net earnings or losses and other comprehensive income (loss) ("OCI") of the investee. PacifiCorp records dividends or other equity distributions as reductions in the carrying value of the investment.

Allowance for Credit Losses

Trade receivables are primarily short-term in nature with stated collection terms of less than one year from the date of origination, and are stated at the outstanding principal amount, net of an estimated allowance for credit losses. The allowance for credit losses is based on PacifiCorp's assessment of the collectability of amounts owed to PacifiCorp by its customers. This assessment requires judgment regarding the ability of customers to pay or the outcome of any pending disputes. In measuring the allowance for credit losses for trade receivables, PacifiCorp primarily utilizes credit loss history. However, PacifiCorp may adjust the allowance for credit losses to reflect current conditions and reasonable and supportable forecasts that deviate from historical experience. The changes in the balance of the allowance for credit losses, which is included in trade receivables, net on the Consolidated Balance Sheets, is summarized as follows for the years ended December 31 (in millions):

	2025	2024	2023
Beginning balance	$ 22	$ 30	$ 19
Charged to operating costs and expenses, net	33	26	34
Write-offs, net	(35)	(34)	(23)
Ending balance	$ 20	$ 22	$ 30

Derivatives

PacifiCorp employs a number of different derivative contracts, which may include forwards, options, swaps and other agreements, to manage price risk for electricity, natural gas and other commodities and interest rate risk. Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. Derivative balances reflect offsetting permitted under master netting agreements with counterparties and cash collateral paid or received under such agreements.

Commodity derivatives used in normal business operations that are settled by physical delivery, among other criteria, are eligible for and may be designated as normal purchases or normal sales. Normal purchases or normal sales contracts are not marked-to-market and settled amounts are recognized as operating revenue or cost of fuel and energy on the Consolidated Statements of Operations.

For PacifiCorp's derivative contracts, the settled amount is generally included in rates. Accordingly, the net unrealized gains and losses associated with interim price movements on contracts that are accounted for as derivatives and probable of inclusion in rates are recorded as regulatory liabilities or assets. For a derivative contract not probable of inclusion in rates, changes in the fair value are recognized in earnings.

Inventories

Inventories consist mainly of materials, supplies and fuel stocks and are stated at the lower of average cost or net realizable value.

Property, Plant and Equipment, Net

General

Additions to property, plant and equipment are recorded at cost. PacifiCorp capitalizes all construction-related material, direct labor and contract services, as well as indirect construction costs, which include debt and equity allowance for funds used during construction ("AFUDC"). The cost of additions and betterments are capitalized, while costs incurred that do not improve or extend the useful lives of the related assets are generally expensed.

Depreciation and amortization are generally computed on the straight-line method based on composite asset class lives prescribed by PacifiCorp's various regulatory authorities or over the assets' estimated useful lives. Depreciation studies are completed periodically to determine the appropriate composite asset class lives, net salvage and depreciation rates. These studies are reviewed and rates are ultimately approved by the various regulatory authorities. Net salvage includes the estimated future residual values of the assets and any estimated removal costs recovered through approved depreciation rates. Estimated removal costs are recorded as either a cost of removal regulatory liability or an ARO liability on the Consolidated Balance Sheets, depending on whether the obligation meets the requirements of an ARO. As actual removal costs are incurred, the associated liability is reduced.

Generally when PacifiCorp retires or sells a component of regulated property, plant and equipment, it charges the original cost, net of any proceeds from the disposition, to accumulated depreciation. Any gain or loss on disposals of all other assets is recorded through earnings.

Debt and equity AFUDC, which represents the estimated costs of debt and equity funds necessary to finance the construction of property, plant and equipment, is capitalized as a component of property, plant and equipment, with offsetting credits to the Consolidated Statements of Operations. AFUDC is computed based on guidelines set forth by the Federal Energy Regulatory Commission ("FERC"). After construction is completed, PacifiCorp is permitted to earn a return on these costs as a component of the related assets, as well as recover these costs through depreciation expense over the useful lives of the related assets.

Asset Retirement Obligations

PacifiCorp recognizes AROs when it has a legal obligation to perform decommissioning, reclamation or removal activities upon retirement of an asset. PacifiCorp's AROs are primarily associated with its generating facilities. The fair value of an ARO liability is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made, and is added to the carrying amount of the associated asset, which is then depreciated over the remaining useful life of the asset. Subsequent to the initial recognition, the ARO liability is adjusted for any revisions to the original estimate of undiscounted cash flows (with corresponding adjustments to property, plant and equipment, net) and for accretion of the ARO liability due to the passage of time. The difference between the ARO liability, the corresponding ARO asset included in property, plant and equipment, net and amounts recovered in rates to satisfy such liabilities is recorded as a regulatory asset or liability.

Impairment

PacifiCorp evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or when the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Consolidated Statements of Operations. As substantially all property, plant and equipment supports PacifiCorp's regulated operations, the impacts of regulation are considered when evaluating the carrying value of regulated assets.

Leases

PacifiCorp has non-cancelable operating leases primarily for land, office space, office equipment, and generating facilities and finance leases consisting primarily of battery energy storage systems ("Energy Storage"), office buildings, natural gas pipeline facilities, and vehicles. These leases generally require PacifiCorp to pay for insurance, taxes and maintenance applicable to the leased property. Given the capital-intensive nature of the utility industry, it is common for a portion of lease costs to be capitalized when used during construction or maintenance of assets, in which the associated costs will be capitalized with the corresponding asset and depreciated over the remaining life of that asset. Certain leases contain renewal options for varying periods and escalation clauses for adjusting rent to reflect changes in price indices. PacifiCorp does not include options in its lease calculations unless there is a triggering event indicating PacifiCorp is reasonably certain to exercise the option. PacifiCorp's accounting policy is to not recognize right-of-use assets and lease obligations for leases with contract terms of one year or less and not separate lease components from non-lease components and instead account for each separate lease component and the non-lease components associated with a lease as a single lease component. Right-of-use assets are evaluated for impairment in line with Accounting Standards Codification ("ASC") 360, "Property, Plant and Equipment" when a triggering event has occurred that might affect the value and use of the assets being leased.

PacifiCorp's leases of generating facilities generally are in the form of long-term purchases of electricity, also known as power purchase agreements ("PPA"). PPAs are generally signed before or during the early stages of project construction and can yield a lease that has not yet commenced. These agreements are primarily for renewable energy, and the payments are generally considered variable lease payments as they are based on the amount of output. The lease payments associated with PacifiCorp's Energy Storage agreements are considered fixed because they are based on the guaranteed storage capacity.

PacifiCorp's operating and finance right-of-use assets are recorded in other assets and the operating and finance lease liabilities are recorded in current and long-term other liabilities accordingly.

Revenue Recognition

PacifiCorp uses a single five-step model to identify and recognize revenue from contracts with customers ("Customer Revenue") upon transfer of control of promised goods or services in an amount that reflects the consideration to which PacifiCorp expects to be entitled in exchange for those goods or services. PacifiCorp records sales, franchise and excise taxes collected directly from customers and remitted directly to the taxing authorities on a net basis on the Consolidated Statements of Operations.

Substantially all of PacifiCorp's Customer Revenue is derived from tariff-based sales arrangements approved by various regulatory commissions. These tariff-based revenues are mainly comprised of energy, transmission and distribution and have performance obligations to deliver energy products and services to customers which are satisfied over time as energy is delivered or services are provided.

Revenue recognized is equal to what PacifiCorp has the right to invoice as it corresponds directly with the value to the customer of PacifiCorp's performance to date and includes billed and unbilled amounts. Payments for amounts billed are generally due from the customer within 30 days of billing. Rates charged for energy products and services are established by regulators or contractual arrangements that establish the transaction price as well as the allocation of price amongst the separate performance obligations. When preliminary regulated rates are permitted to be billed prior to final approval by the applicable regulator, certain revenue collected may be subject to refund and a liability for estimated refunds is accrued.

The determination of customer billings is based on a systematic reading of meters. At the end of each month, energy provided to customers since the date of the last meter reading is estimated, and the corresponding unbilled revenue is recorded. Factors that can impact the estimate of unbilled energy include, but are not limited to, seasonal weather patterns, total volumes supplied to the system, line losses, economic impacts and composition of sales among customer classes. Unbilled revenue is reversed in the following month and billed revenue is recorded based on the subsequent meter readings.

As of December 31, 2025 and 2024, trade receivables, net on the Consolidated Balance Sheets relate substantially to Customer Revenue, including unbilled revenue of $382 million and $329 million, respectively.

Unamortized Debt Premiums, Discounts and Debt Issuance Costs

Premiums, discounts and debt issuance costs incurred for the issuance of long-term debt are amortized over the term of the related financing using the effective interest method.

Income Taxes

Berkshire Hathaway includes PacifiCorp in its consolidated U.S. federal income tax return. Consistent with established regulatory practice, PacifiCorp's provision for income taxes has been computed on a stand-alone basis.

Deferred income tax assets and liabilities are based on differences between the financial statement and income tax basis of assets and liabilities using enacted income tax rates expected to be in effect for the year in which the differences are expected to reverse. Changes in deferred income tax assets and liabilities associated with components of OCI are charged or credited directly to OCI. Changes in deferred income tax assets and liabilities associated with certain property-related basis differences and other various differences that PacifiCorp deems probable to be passed on to its customers in most state jurisdictions are charged or credited directly to a regulatory asset or liability and will be included in regulated rates when the temporary differences reverse or as otherwise approved by PacifiCorp's various regulatory commissions. Other changes in deferred income tax assets and liabilities are included as a component of income tax expense. Changes in deferred income tax assets and liabilities attributable to changes in enacted income tax rates are charged or credited to income tax expense or a regulatory asset or liability in the period of enactment. Valuation allowances are established when necessary to reduce deferred income tax assets to the amount that is more-likely-than-not to be realized.

Investment tax credits are deferred and amortized over the estimated useful lives of the related properties or as prescribed by various regulatory commissions.

PacifiCorp recognizes the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the Consolidated Financial Statements from such a position are measured based on the largest benefit that is more-likely-than-not to be realized upon ultimate settlement. PacifiCorp's unrecognized tax benefits are primarily included in other long-term liabilities on the Consolidated Balance Sheets. Estimated interest and penalties, if any, related to uncertain tax positions are included as a component of income tax expense (benefit) on the Consolidated Statements of Operations.

Government Grants

From time to time, PacifiCorp enters into grant agreements with federal agencies, as well as agreements with third parties as a subrecipient of a federal grant, subjecting PacifiCorp to various federal compliance requirements. Most commonly these are cost share grants where PacifiCorp expenditures match the amount of grant proceeds. Grant proceeds most frequently support capital projects but are also used to cover operating costs. Grant proceeds received to reimburse capital project costs are applied as a direct offset to construction work-in-progress, ultimately serving to reduce PacifiCorp's investment in property, plant and equipment. Grant proceeds received to reimburse operating costs are applied as an offset to operating expense.

Segment Information

PacifiCorp currently has one reportable segment, its regulated electric utility operations, which derives its revenue from regulated retail sales of electricity to residential, commercial, industrial and irrigation customers and from wholesale sales. PacifiCorp's chief operating decision maker ("CODM") is its Chief Executive Officer. The CODM uses net income, as reported on the Consolidated Statements of Operations, and generally considers actual results versus historical results, budgets or forecasts, as well as unique risks and opportunities, when making decisions about the allocation of resources and capital. The segment expenses regularly provided to the CODM align with the captions presented on the Consolidated Statements of Operations. PacifiCorp's segment capital expenditures are reported on the Consolidated Statements of Cash Flows as capital expenditures. PacifiCorp's segment assets are reported on the Consolidated Balance Sheet as total assets.

New Accounting Pronouncements

In December 2023, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2023-09, Income Taxes Topic 740, "Income Tax—Improvements to Income Tax Disclosures" which requires enhanced disclosures, including specific categories and disaggregation of information in the effective tax rate reconciliation, disaggregated information related to income taxes paid, income or loss from continuing operations before income tax expense or benefit, and income tax expense or benefit from continuing operations. This guidance is effective for annual reporting periods beginning after December 15, 2024. Early adoption is permitted and should be applied on a prospective basis, however retrospective application is permitted. PacifiCorp adopted this guidance for the fiscal year beginning January 1, 2025, under the retrospective method. The adoption did not have a material impact on PacifiCorp's Consolidated Financial Statements, but did expand the disclosures included within Notes to Consolidated Financial Statements. Refer to Note 9 for expanded rate reconciliation disclosures and disaggregation of income taxes paid.

In November 2024, the FASB issued ASU No. 2024-03, Income Statement—Reporting Comprehensive Income—Expense Disaggregation Disclosures Subtopic 220-40, "Disaggregation of Income Statement Expenses" which addresses requests from investors for more detailed information about certain expenses and requires disclosure of the amounts of purchases of inventory, employee compensation, depreciation and intangible asset amortization included in each relevant expense caption presented on the income statement. This guidance, as clarified in ASU 2025-01, is effective for annual reporting periods beginning after December 15, 2026 and interim reporting periods beginning after December 15, 2027. Early adoption is permitted and should be applied on a prospective basis, however retrospective application is permitted. PacifiCorp is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

In December 2025, the FASB issued ASU No. 2025-10, Government Grants Topic 832, "Accounting for Government Grants Received by Business Entities" which establishes accounting for government grants received by an entity, including guidance for a grant related to an asset and a grant related to income. This guidance also requires, consistent with current disclosure requirements, that an entity provide disclosures including the nature of the government grant received, the accounting policies used to account for the grant, and significant terms and conditions of the grant. This guidance is effective for interim and annual reporting periods beginning after December 15, 2028. Early adoption is permitted and can be applied using either a modified prospective approach, a modified retrospective approach or a retrospective approach. PacifiCorp is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

(3) Property, Plant and Equipment, Net

Property, plant and equipment, net consists of the following as of December 31 (in millions):

	Depreciable Life	2025	2024
Utility Plant:			
Generation	15 - 59 years	$ 15,114	$ 14,316
Transmission	60 - 90 years	11,732	10,939
Distribution	20 - 75 years	11,127	9,842
Intangible plant and other	2 - 75 years	2,667	2,958
Utility plant in-service		40,640	38,055
Accumulated depreciation and amortization		(12,875)	(12,504)
Utility plant in-service, net		27,765	25,551
Nonregulated, net of accumulated depreciation and amortization	34 - 75 years	18	19
		27,783	25,570
Construction work-in-progress		3,330	3,550
Property, plant and equipment, net		$ 31,113	$ 29,120

The average depreciation and amortization rate applied to depreciable property, plant and equipment was 3.3%, 3.2% and 3.4% for the years ended December 31, 2025, 2024 and 2023, respectively, including the impacts of accelerated depreciation totaling $87 million associated with Utah's share of certain coal-fueled units and depreciation related regulatory assets pursuant to the April 2025 Utah general rate case order. As discussed in Note 6, existing regulatory deferrals associated with the Utah Sustainability and Transportation Plan ("STEP") were utilized to accelerate depreciation of these assets.

Unallocated Acquisition Adjustments

PacifiCorp has unallocated acquisition adjustments that represent the excess of costs of the acquired interests in property, plant and equipment purchased from the entity that first dedicated the assets to utility service over their net book value in those assets. These unallocated acquisition adjustments included in other property, plant and equipment had an original cost of $156 million as of December 31, 2025 and 2024, and accumulated depreciation of $145 million as of December 31, 2025 and 2024.

Government Grants

In November 2024, PacifiCorp accepted two cost share grants from the U.S. Department of Energy ("DOE") under the DOE's Grid Resilience and Innovation Partnerships ("GRIP") Program supported by the Infrastructure Investment and Jobs Act. The two GRIP grants will provide cash proceeds totaling approximately $150 million as cost reimbursements supporting PacifiCorp's investment in certain wildfire mitigation projects, such as system hardening for fire resistance and prevention and new substation infrastructure, and other investments in technologies that significantly enhance situational awareness to reduce or mitigate wildfires and improve electric grid flexibility, reliability and resiliency. The period of performance for both GRIP grants extends through September 2028 and 2029. No costs incurred after the period of performance will be eligible for reimbursement.

In conjunction with the two GRIP awards, the DOE and U.S. Department of Labor accepted PacifiCorp's request for a temporary exception regarding the Davis-Bacon Act weekly pay and certified payroll reporting requirements with which PacifiCorp is required to comply under the terms of the grants. The parties agreed to a curative plan that provides for a temporary means to achieve the goals of these requirements and allows PacifiCorp to have until April 1, 2026, to fully comply with these requirements.

In December 2024, PacifiCorp accepted four cost share grants from the DOE under the DOE's Hydroelectric Efficiency Improvement Incentive, supported by Section 243 of the Energy Policy Act of 2005. Expected grant proceeds for the hydroelectric grants total approximately $14 million as cost reimbursements to support PacifiCorp's efforts to improve efficiency and extend the life of its generating assets. The period of performance for the hydroelectric grants runs through March 2028.

In December 2025, PacifiCorp entered into three state grant agreements related to grid resiliency, which are intended to support activities focused on wildfire mitigation, outage prevention and overall grid-hardening measures. PacifiCorp participates in these programs as a subrecipient with the state agencies serving as the prime recipients of DOE grants. The total amount allocated to PacifiCorp for these grants is approximately $8 million. The period of performance extends through April 2030.

Previous DOE cost share grants primarily supported electric vehicle infrastructure programs and energy efficiency programs. The period of performance for the electric vehicle infrastructure grant ended December 2024, and was for total cash proceeds of $6 million. The energy efficiency grant was cancelled by the DOE in October 2025.

On January 20, 2025, U.S. federal executive order entitled *Unleashing American Energy* was issued requiring federal agencies to immediately pause disbursement of federal funds appropriated under the Inflation Reduction Act of 2022 and the Infrastructure Investment and Jobs Act, subject to respective agency review within 90 days of the date of the order of the agency's processes, policies and programs for issuing grants consistent with the policies stated in the executive order. The pause was lifted on federal funding disbursements in April 2025 and the invoice process resumed.

Various compliance requirements are associated with the DOE grants, including demonstration that the costs are allowable under the grants. In the event PacifiCorp fails to meet these requirements, it could be required to return funds to the DOE. No costs incurred after the period of performance for a specific grant will be eligible for reimbursement.

During the years ended December 31, 2025 and 2024, approximately $50 million and $11 million, respectively, of federal grant funds reduced additions to Property, plant and equipment – net on the Consolidated Balance Sheets and approximately $18 million and $4 million, respectively, of federal grant funds reduced operating expenses on the Consolidated Statements of Operations. Federal grant funds received prior to 2024 were insignificant.

(4) Jointly Owned Utility Facilities

Under joint facility ownership agreements with other utilities, PacifiCorp, as a tenant in common, has undivided interests in jointly owned generation, transmission and distribution facilities. PacifiCorp accounts for its proportionate share of each facility, and each joint owner has provided financing for its share of each facility. Operating costs of each facility are assigned to joint owners based on their percentage of ownership or energy production, depending on the nature of the cost. Operating costs and expenses on the Consolidated Statements of Operations include PacifiCorp's share of the expenses of these facilities.

The amounts shown in the table below represent PacifiCorp's share in each jointly owned facility included in property, plant and equipment, net as of December 31, 2025 (dollars in millions):

	PacifiCorp Share	Facility in Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
Jim Bridger Nos. 1-4	67 %	$ 1,537	$ 989	$ 2
Hunter No. 1	94	510	273	11
Hunter No. 2	60	317	172	—
Wyodak	80	495	316	—
Colstrip Nos. 3 and 4	10	267	234	2
Hermiston	50	198	122	7
Craig Nos. 1 and 2	19	373	363	—
Hayden No. 1	25	77	61	—
Hayden No. 2	13	45	36	—
Transmission and distribution facilities	Various	963	312	554
Total		$ 4,782	$ 2,878	$ 576

(5) Leases

The following table summarizes PacifiCorp's leases recorded on the Consolidated Balance Sheets as of December 31 (in millions):

	2025 Total	2024 Total
Right-of-use assets:		
Operating leases	$ 10	$ 11
Finance leases[(1)]	427	22
Total right-of-use assets	$ 437	$ 33
Lease liabilities:		
Operating leases	$ 10	$ 11
Finance leases[(1)]	432	24
Total lease liabilities	$ 442	$ 35

(1) Includes amounts associated with an Energy Storage facility that reached commercial operation in December 2025 and for which the associated costs will be subject to recovery as part of regulated net power costs and PacifiCorp's deferred net power cost mechanisms.

The following table summarizes PacifiCorp's lease costs for the years ended December 31 (in millions):

	2025	2024	2023
Variable	$ 33	$ 35	$ 57
Operating	3	4	4
Finance:			
Amortization	5	1	1
Interest	3	2	1
Short-term	4	6	6
Total lease costs	$ 48	$ 48	$ 69
Weighted-average remaining lease term (years):			
Operating leases	12.7	12.0	12.3
Finance leases	20.3	7.3	8.8
Weighted-average discount rate:			
Operating leases	3.8 %	3.8 %	3.8 %
Finance leases	6.1 %	7.8 %	10.6 %

Cash payments associated with operating and finance lease liabilities approximated lease cost for the years ended December 31, 2025, 2024 and 2023.

PacifiCorp has the following remaining lease commitments as of December 31, 2025 (in millions):

	Operating	Finance		Total
		PPAs/Energy Storage Agreement	Other	
2026	$ 3	$ 31	$ 11	$ 45
2027	2	31	10	43
2028	1	31	10	42
2029	1	31	10	42
2030	1	31	9	41
Thereafter	5	533	12	550
Total undiscounted lease payments	13	688	62	763
Less - amounts representing interest	(3)	(305)	(13)	(321)
Lease liabilities	$ 10	$ 383	$ 49	$ 442

Refer to Note 14 for information regarding Energy Storage facilities that have not reached commercial operation and to Note 21 for information regarding a related party sale leaseback transaction that is pending certain regulatory approvals.

(6) Regulatory Matters

Regulatory Assets

Regulatory assets represent costs that are expected to be recovered in future rates. PacifiCorp's regulatory assets reflected on the Consolidated Balance Sheets consist of the following as of December 31 (in millions):

	Weighted Average Remaining Life	2025	2024
Employee benefit plans[1]	14 years	$ 255	$ 265
Utah mine disposition[2]	Various	80	83
Deferred net power costs	1 year	712	1,290
Unrealized loss on regulated derivative contracts	1 year	137	97
Environmental costs	26 years	159	145
Asset retirement obligation	29 years	498	393
Demand side management (DSM)[3]	10 years	372	265
Wildfire mitigation and vegetation management costs	Various	90	104
Other	Various	257	275
Total regulatory assets		$ 2,560	$ 2,917
Reflected as:			
Current assets		$ 669	$ 891
Noncurrent assets		1,891	2,026
Total regulatory assets		$ 2,560	$ 2,917

(1) Represents amounts not yet recognized as a component of net periodic benefit cost that are expected to be included in rates when recognized.

(2) Amounts represent regulatory assets established as a result of the Utah mine disposition in 2015 for the United Mine Workers of America ("UMWA") 1974 Pension Plan withdrawal and closure costs incurred to date considered probable of recovery. Refer to Note 10 for additional information.

(3) At December 31, 2025, DSM regulatory assets were substantially offset by amounts billed to Utah retail customers under Utah STEP. In accordance with the April 2025 Utah general rate case order, $87 million of amounts billed to Utah customers under Utah STEP were used to accelerate depreciation of certain plant balances and depreciation related regulatory assets included in "Other" above as discussed in Note 3.

Regulatory assets totaling approximately $991 million, primarily related to those for Employee benefit plans, Unrealized loss on derivative contracts and Asset retirement obligation, were not accruing interest or included in rate base earning a return on investment as of December 31, 2025. Most other regulatory assets accrue interest but are not included in rate base earning a return on investment. In general, regulatory assets associated with property, plant and equipment are included in rate base and earn a return on investment.

Regulatory Liabilities

Regulatory liabilities represent income to be recognized or amounts to be returned to customers in future periods. PacifiCorp's regulatory liabilities reflected on the Consolidated Balance Sheets consist of the following as of December 31 (in millions):

	Weighted Average Remaining Life	2025	2024
Cost of removal[1]	26 years	$ 1,647	$ 1,560
Deferred income taxes[2]	Various	762	861
Other	Various	248	221
Total regulatory liabilities		$ 2,657	$ 2,642
Reflected as:			
Current liabilities		$ 80	$ 92
Noncurrent liabilities		2,577	2,550
Total regulatory liabilities		$ 2,657	$ 2,642

(1) Amounts represent estimated costs, as generally accrued through depreciation rates, of removing property, plant and equipment in accordance with accepted regulatory practices. Amounts are deducted from rate base or otherwise accrue a carrying cost.

(2) Amounts primarily represent income tax liabilities related to the federal tax rate change from 35% to 21% that are probable of being passed on to customers, partially offset by income tax benefits related to certain property-related basis differences and other various differences that were previously passed on to customers and will be included in regulated rates when the temporary differences reverse.

(7) Short-term Debt and Credit Facilities

PacifiCorp has a $2.0 billion unsecured credit facility expiring in June 2028 with an unlimited number of maturity extension options, subject to lender consent. The credit facility, which supports PacifiCorp's commercial paper program and certain series of its tax-exempt bond obligations and provides for the issuance of a certain level of letters of credit, has a variable interest rate based on the Secured Overnight Financing Rate ("SOFR") or a base rate, at PacifiCorp's option, plus a spread that varies based on PacifiCorp's credit ratings for its senior unsecured long-term debt securities. In addition, PacifiCorp has a $900 million 364-day unsecured credit facility expiring in June 2026 which, similar to its other existing $2.0 billion credit facility provides for loans at variable interest rates based on the SOFR or a base rate, at PacifiCorp's option, plus a spread that varies based on PacifiCorp's credit ratings for its senior unsecured long-term debt securities.

The following table summarizes PacifiCorp's availability under its unsecured credit facility as of December 31 (in millions):

2025:	
Credit facilities	$ 2,900
Less:	
Short-term debt	(1,000)
Net credit facilities	$ 1,900
2024:	
Credit facilities	$ 2,900
Less:	
Short-term debt	(240)
Tax-exempt bond support	(52)
Net credit facilities	$ 2,608

As of December 31, 2025, PacifiCorp was in compliance with all financial covenants that affect access to capital.

As of December 31, 2025 and 2024, PacifiCorp had $1.0 billion and $240 million of short-term debt outstanding at a weighted average rate of 5.23% and 4.65%, respectively. The outstanding short-term debt as of December 31, 2025, was subsequently repaid in February 2026.

The credit facilities require that PacifiCorp's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.65 to 1.0 as of the last day of each quarter. As of December 31, 2025, PacifiCorp's debt to total capitalization ratio was 0.58 to 1.0.

The following table summarizes PacifiCorp's letter of credit capacity and availability under various arrangements as of December 31 (in millions):

	2025		2024	
	Capacity	Availability	Capacity	Availability
Credit facility[1]	$ 255	$ 255	$ 255	$ 255
Bilateral letter of credit agreements[2]	963	949	488	454
Total capacity and availability	$ 1,218	$ 1,204	$ 743	$ 709

(1) Capacity is available under PacifiCorp's $2.0 billion revolving credit facility.

(2) Amounts outstanding were utilized in support of certain transactions required by third parties.

(8) Long-term Debt

Senior Debt

PacifiCorp's senior debt consists of the following as of December 31 (dollars in millions):

	Par Value	2025	2024
First mortgage bonds:			
3.35%, due 2025	$ —	$ —	$ 250
6.71%, due 2026	100	100	100
5.10%, due 2029	500	498	498
3.50%, due 2029	400	399	399
2.70%, due 2030	400	399	398
5.30%, due 2031	700	696	696
7.70%, due 2031	300	299	299
5.45%, due 2034	1,100	1,093	1,093
5.90%, due 2034	200	199	199
5.25%, due 2035	300	299	299
6.10%, due 2036	350	349	348
5.75%, due 2037	600	600	600
6.25%, due 2037	600	598	598
6.35%, due 2038	300	298	298
6.00%, due 2039	650	645	644
4.10%, due 2042	300	298	298
4.125%, due 2049	600	595	594
4.15%, due 2050	600	594	594
3.30%, due 2051	600	592	591
2.90%, due 2052	1,000	986	985
5.35%, due 2053	1,100	1,088	1,088
5.50%, due 2054	1,200	1,189	1,189
5.80%, due 2055	1,500	1,479	1,478
Variable-rate series, tax-exempt bond obligations 2024 - 3.20% to 4.45%:			
Secured[1], due 2025	—	—	27
Unsecured, due 2025	—	—	25
Total senior debt	$ 13,400	$ 13,293	$ 13,588
Reflected as:			
Current portion of senior debt		$ 100	$ 302
Senior debt		13,193	13,286
Total senior debt		$ 13,293	$ 13,588

(1) Secured by pledged first mortgage bonds registered to and held by the tax-exempt bond trustee generally with the same interest rates, maturity dates and redemption provisions as the tax-exempt bond obligations.

PacifiCorp's senior debt generally includes provisions that allow PacifiCorp to redeem the first mortgage bonds in whole or in part at any time through the payment of a make-whole premium.

The issuance of PacifiCorp's first mortgage bonds is limited by available property, earnings tests and other provisions of PacifiCorp's mortgage. Approximately $42.4 billion of PacifiCorp's eligible property (based on original cost) was subject to the lien of the mortgage as of December 31, 2025.

In February 2026, PacifiCorp issued $400 million of 4.25% First Mortgage Bonds due March 2029.

Junior Subordinated Debt

PacifiCorp's junior subordinated debt consists of the following, as of December 31 (dollars in millions):

	Par Value	2025	2024
7.375%, due 2055[1]	$ 850	$ 841	$ —
Total junior subordinated debt - non current	$ 850	$ 841	$ —

(1) PacifiCorp will pay interest on the junior subordinated notes at a rate of 7.375% through September 2030, subject to a reset every five years, not to reset below 7.375%.

In February 2026, PacifiCorp issued $1.1 billion of its 7.125% Fixed-to-Fixed Reset Rate Junior Subordinated Notes due August 2056. PacifiCorp will pay interest on the junior subordinated notes at a rate of 7.125% through August 2031, subject to a reset every five years, not to reset below 7.125%.

Long-Term Debt

PacifiCorp currently has regulatory authority from the Oregon Public Utility Commission and the Idaho Public Utilities Commission to issue an additional $2.7 billion of long-term debt. PacifiCorp must make a notice filing with the Washington Utilities and Transportation Commission prior to any future issuance. PacifiCorp currently has an effective shelf registration statement filed with the U.S. Securities and Exchange Commission to issue an indeterminate amount of first mortgage bonds and unsecured debt securities through July 2027.

Annual Repayments of Long-Term Debt

The annual repayments of long-term debt for the years beginning January 1, 2026 and thereafter, are as follows (in millions):

2026	$ 100
2027	—
2028	—
2029	900
2030	400
Thereafter	12,850
Total	14,250
Unamortized discount and debt issuance costs	(116)
Total	$ 14,134

(9) Income Taxes

Berkshire Hathaway includes BHE and its subsidiaries in its U.S. federal income tax return and BHE includes its subsidiaries in certain state income tax returns. Consistent with established regulatory practice, PacifiCorp's provision for federal and state income tax has been computed on a stand-alone basis, and substantially all of its currently payable or receivable income tax is remitted to or received from BHE pursuant to a tax allocation agreement. Income (loss) before income tax expense (benefit) as reported on the Consolidated Statements of Operations, is all domestic.

Income tax expense (benefit) consists of the following for the years ended December 31 (in millions):

	2025	2024	2023
Current:			
Federal	$ (164)	$ (234)	$ (324)
State	14	7	(5)
Total	(150)	(227)	(329)
Deferred:			
Federal	(61)	(9)	(172)
State	17	1	(51)
Total	(44)	(8)	(223)
Investment tax credits	(2)	(1)	(1)
Total income tax expense (benefit)	$ (196)	$ (236)	$ (553)

The following table presents income taxes paid (received), net of refunds, for the years ended December 31 (in millions):

	2025	2024	2023
Jurisdiction:			
Federal	$ (74)	$ (328)	$ (292)
State	9	(21)	—
Total[(1)]	$ (65)	$ (349)	$ (292)

(1) Substantially all income taxes paid or (received) by PacifiCorp are pursuant to a tax allocation agreement.

Income taxes paid (received), net of refunds exceeded five percent of total income taxes paid (received) in the following jurisdictions (in millions):

	2025	2024	2023
State:			
Oregon[(1)]	$ 9	$ *	$ *

(1) All income taxes paid are pursuant to a tax allocation agreement.

* Jurisdiction below the threshold for the period presented

The effective income tax rate for the year ended December 31, 2023, of 54.2% resulted from a $553 million income tax benefit associated with a $1,021 million pre-tax loss primarily related to a $1,677 million increase in wildfire loss accruals, net of expected recoveries as described in Note 14.

A reconciliation of the federal statutory income tax rate to the effective income tax rate applicable to income (loss) before income tax expense (benefit) is as follows for the years ended December 31:

	2025		2024		2023	
	Amount	Percent	Amount	Percent	Amount	Percent
U.S. federal statutory income tax rate	$ 93	21.0 %	$ 64	21.0 %	$ (214)	21.0 %
State and local income taxes, net of federal income tax[1]	24	5.5	6	2.0	(44)	5.3
Energy-related tax credits	(242)	(54.6)	(201)	(66.5)	(180)	17.7
Nontaxable or non-deductible items	—	—	(2)	(0.8)	(1)	(0.9)
Effects of ratemaking[2]	(71)	(16.0)	(103)	(34.0)	(114)	11.1
Effective income tax rate	$ (196)	(44.1)%	$ (236)	(78.3)%	$ (553)	54.2 %

(1) State taxes in Utah and Oregon made up the majority (greater than 50 percent) of the tax effect in this category.

(2) Effects of ratemaking is primarily attributable to activity associated with excess deferred income taxes.

Energy-related tax credits relate primarily to production tax credits ("PTC") earned by PacifiCorp's wind-powered generating facilities. Federal renewable electricity PTCs are earned as energy from qualifying wind-powered generating facilities is produced and sold and are based on a per-kilowatt hour rate pursuant to the applicable federal income tax law. Wind-powered generating facilities are eligible for the credits for 10 years from the date the qualifying generating facilities are placed in-service.

The net deferred income tax liability consists of the following as of December 31 (in millions):

	2025	2024
Deferred income tax assets:		
Regulatory liabilities	$ 654	$ 651
Employee benefits	48	49
State carryforwards	81	88
Loss contingencies	288	380
Asset retirement obligations	125	102
Other	156	125
Total deferred income tax assets	1,352	1,395
Valuation allowances	(16)	(11)
Total deferred income tax assets, net	1,336	1,384
Deferred income tax liabilities:		
Property-related items	(3,924)	(3,813)
Regulatory assets	(629)	(717)
Other	(57)	(76)
Total deferred income tax liabilities	(4,610)	(4,606)
Net deferred income tax liability	$ (3,274)	$ (3,222)

The following table provides, without regard to valuation allowances, PacifiCorp's net operating loss and tax credit carryforwards and expiration dates as of December 31, 2025 (in millions):

	State
Net operating loss carryforwards	$ 1,481
Deferred income taxes on net operating loss carryforwards	$ 65
Expiration dates	2026 - indefinite
Tax credit carryforwards	$ 16
Expiration dates	2026 - indefinite

The U.S. Internal Revenue Service has closed or effectively settled its examination of PacifiCorp's income tax returns through December 31, 2013. The statute of limitations for PacifiCorp's income tax returns have expired for certain states through December 31, 2011 and December 31, 2013, and for other states through December 31, 2021, except for the impact of any federal audit adjustments.

(10) Employee Benefit Plans

PacifiCorp sponsors defined benefit pension and other postretirement benefit plans that cover certain of its employees, as well as a defined contribution 401(k) employee savings plan ("401(k) Plan"). In addition, PacifiCorp contributes to a joint trustee pension plan and a subsidiary previously contributed to a multiemployer pension plan for benefits offered to certain bargaining units.

Defined Benefit Plans

PacifiCorp's pension plans include non-contributory defined benefit pension plans, the PacifiCorp Retirement Plan ("Retirement Plan"), and the Supplemental Executive Retirement Plan ("SERP"). The Retirement Plan is closed to all non-union employees hired after January 1, 2008. All non-union Retirement Plan participants hired prior to January 1, 2008 that did not elect to receive equivalent fixed contributions to the 401(k) Plan effective January 1, 2009 earned benefits based on a cash balance formula through December 31, 2016. Effective January 1, 2017, non-union employee participants with a cash balance benefit in the Retirement Plan are no longer eligible to receive pay credits in their cash balance formula. In general for union employees, benefits under the Retirement Plan were frozen at various dates from December 31, 2007 through December 31, 2011, as they are now being provided with enhanced 401(k) Plan benefits. However, certain limited union Retirement Plan participants continue to earn benefits under the Retirement Plan based on the employee's years of service and a final average pay formula. The SERP was closed to new participants as of March 21, 2006, and froze future accruals for active participants as of December 31, 2014.

PacifiCorp's other postretirement benefit plan provides healthcare and life insurance benefits to eligible retirees.

Net Periodic Benefit Cost (Credit)

For purposes of calculating the expected return on plan assets, a market-related value is used. The market-related value of plan assets is calculated by spreading the difference between expected and actual investment returns over a five-year period beginning after the first year in which they occur.

Net periodic benefit (credit) cost for the plans included the following components for the years ended December 31 (in millions):

	Pension			Other Postretirement		
	2025	2024	2023	2025	2024	2023
Service cost	$ —	$ —	$ —	$ 1	$ 1	$ 1
Interest cost	37	37	39	11	11	11
Expected return on plan assets	(45)	(47)	(49)	(13)	(14)	(13)
Net amortization	7	9	12	(3)	(2)	(2)
Net periodic benefit (credit) cost	$ (1)	$ (1)	$ 2	$ (4)	$ (4)	$ (3)

Funded Status

The following table is a reconciliation of the fair value of plan assets for the years ended December 31 (in millions):

	Pension		Other Postretirement	
	2025	2024	2025	2024
Plan assets at fair value, beginning of year	$ 728	$ 764	$ 267	$ 271
Employer contributions[(1)]	4	4	—	—
Participant contributions	—	—	3	3
Actual return on plan assets	66	31	12	15
Benefits paid	(74)	(71)	(20)	(22)
Plan assets at fair value, end of year	$ 724	$ 728	$ 262	$ 267

(1) Pension amounts represent employer contributions to the SERP.

The following table is a reconciliation of the benefit obligations for the years ended December 31 (in millions):

	Pension		Other Postretirement	
	2025	2024	2025	2024
Benefit obligation, beginning of year	$ 683	$ 740	$ 196	$ 215
Service cost	—	—	1	1
Interest cost	37	37	11	11
Participant contributions	—	—	3	3
Actuarial loss (gain)	19	(23)	(2)	(12)
Benefits paid	(74)	(71)	(20)	(22)
Benefit obligation, end of year	$ 665	$ 683	$ 189	$ 196
Accumulated benefit obligation, end of year	$ 665	$ 683		

The funded status of the plans and the amounts recognized on the Consolidated Balance Sheets as of December 31 are as follows (in millions):

	Pension		Other Postretirement	
	2025	2024	2025	2024
Plan assets at fair value, end of year	$ 724	$ 728	$ 262	$ 267
Less - Benefit obligation, end of year	665	683	189	196
Funded status	$ 59	$ 45	$ 73	$ 71
Amounts recognized on the Consolidated Balance Sheets:				
Other assets	$ 96	$ 83	$ 73	$ 71
Accrued employee expenses	(4)	(4)	—	—
Other long-term liabilities	(33)	(34)	—	—
Amounts recognized	$ 59	$ 45	$ 73	$ 71

The SERP has no plan assets; however, PacifiCorp has a Rabbi trust that holds corporate-owned life insurance and other investments to provide funding for the future cash requirements of the SERP. The cash surrender value of all of the policies included in the Rabbi trust, net of amounts borrowed against the cash surrender value, plus the fair market value of other Rabbi trust investments, was $84 million and $76 million as of December 31, 2025 and 2024, respectively. These assets are not included in the plan assets in the above table, but are reflected in cash and cash equivalents and noncurrent other assets as of December 31, 2025, and noncurrent other assets as of December 31, 2024, on the Consolidated Balance Sheets. The projected and accumulated benefit obligations for the SERP were $37 million and $38 million at December 31, 2025 and 2024, respectively.

As of December 31, 2025, the fair value of the plan assets for the Retirement Plan was in excess of both the projected benefit obligation and the accumulated benefit obligation.

Unrecognized Amounts

The portion of the funded status of the plans not yet recognized in net periodic benefit cost as of December 31 is as follows (in millions):

	Pension		Other Postretirement	
	2025	2024	2025	2024
Net loss (gain)	$ 250	$ 258	$ (51)	$ (53)
Regulatory deferrals[(1)]	18	19	—	—
Total	$ 268	$ 277	$ (51)	$ (53)

(1) Pension amounts represent the unamortized portion of deferred settlement losses.

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost for the years ended December 31, 2025 and 2024 is as follows (in millions):

	Regulatory Asset	Accumulated Other Comprehensive Loss	Total
Pension			
Balance, December 31, 2023	$ 279	$ 13	$ 292
Net gain arising during the year	(5)	(1)	(6)
Net amortization	(9)	—	(9)
Total	(14)	(1)	(15)
Balance, December 31, 2024	265	12	277
Net (gain) loss arising during the year	(4)	2	(2)
Net amortization	(6)	(1)	(7)
Total	(10)	1	(9)
Balance, December 31, 2025	$ 255	$ 13	$ 268

	Regulatory Liability
Other Postretirement	
Balance, December 31, 2023	$ (42)
Net gain arising during the year	(13)
Net amortization	2
Total	(11)
Balance, December 31, 2024	(53)
Net gain arising during the year	(1)
Net amortization	3
Total	2
Balance, December 31, 2025	$ (51)

Plan Assumptions

Assumptions used to determine benefit obligations and net periodic benefit cost were as follows:

	Pension			Other Postretirement		
	2025	2024	2023	2025	2024	2023
Benefit obligations as of December 31:						
Discount rate	5.50 %	5.80 %	5.20 %	5.50 %	5.75 %	5.20 %
Interest crediting rates for cash balance plan - non-union						
2023	N/A	N/A	4.73 %	N/A	N/A	N/A
2024	N/A	5.98 %	5.98 %	N/A	N/A	N/A
2025	5.03 %	5.03 %	5.98 %	N/A	N/A	N/A
2026	4.36 %	5.03 %	3.10 %	N/A	N/A	N/A
2027	4.36 %	3.60 %	3.10 %	N/A	N/A	N/A
2028 and beyond	4.30 %	3.60 %	3.10 %	N/A	N/A	N/A
Interest crediting rates for cash balance plan - union						
2023	N/A	N/A	3.55 %	N/A	N/A	N/A
2024	N/A	4.47 %	4.47 %	N/A	N/A	N/A
2025	4.04 %	4.04 %	4.47 %	N/A	N/A	N/A
2026	4.74 %	4.04 %	2.70 %	N/A	N/A	N/A
2027	4.74 %	3.10 %	2.70 %	N/A	N/A	N/A
2028 and beyond	3.70 %	3.10 %	2.70 %	N/A	N/A	N/A
Net periodic benefit cost for the years ended December 31:						
Discount rate	5.80 %	5.20 %	5.55 %	5.75 %	5.20 %	5.50 %
Expected return on plan assets	5.90 %	5.90 %	6.00 %	4.42 %	4.87 %	4.78 %

In establishing its assumption as to the expected return on plan assets, PacifiCorp utilizes the asset allocation and return assumptions for each asset class based on historical performance and forward-looking views of the financial markets.

Contributions and Benefit Payments

Employer contributions to the pension and other postretirement benefit plans are expected to be $4 million and $— million, respectively, during 2026. Funding to PacifiCorp's Retirement Plan trust is based upon the actuarially determined costs of the plan and the requirements of the Internal Revenue Code, the Employee Retirement Income Security Act of 1974 ("ERISA") and the Pension Protection Act of 2006, as amended. PacifiCorp considers contributing additional amounts from time to time in order to achieve certain funding levels specified under the Pension Protection Act of 2006. PacifiCorp evaluates a variety of factors, including funded status, income tax laws and regulatory requirements, in determining contributions to its other postretirement benefit plan.

The expected benefit payments to participants in PacifiCorp's pension and other postretirement benefit plans for 2026 through 2030 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments	
	Pension	Other Postretirement
2026	$ 73	$ 20
2027	69	19
2028	65	19
2029	62	18
2030	59	17
2031-2035	255	75

Plan Assets

Investment Policy and Asset Allocations

PacifiCorp's investment policy for its pension and other postretirement benefit plans is to balance risk and return through a diversified portfolio of debt securities, equity securities and other alternative investments. Maturities for debt securities are managed to targets consistent with prudent risk tolerances. The plans retain outside investment consultants to advise on plan investments within the parameters outlined by the Berkshire Hathaway Energy Company Investment Committee. The investment portfolio is managed in line with the investment policy with sufficient liquidity to meet near-term benefit payments.

The target allocations (percentage of plan assets) for PacifiCorp's pension and other postretirement benefit plan assets are as follows as of December 31, 2025:

	Pension[(1)]	Postretirement[(1)]
	%	%
Debt securities[(2)]	50 - 80	76 - 95
Equity securities[(2)]	10 - 50	0 - 19
Other	0 - 10	0 - 5

(1) The trust in which the PacifiCorp Retirement Plan is invested includes a separate account that is used to fund benefits for the other postretirement benefit plan. In addition to this separate account, the assets for the other postretirement benefit plan are held in Voluntary Employees' Beneficiary Association ("VEBA") trusts, each of which has its own investment allocation strategies. Target allocations for the other postretirement benefit plan include the separate account of the Retirement Plan trust and the VEBA trusts.

(2) For purposes of target allocation percentages and consistent with the plans' investment policy, investment funds are allocated based on the underlying investments in debt and equity securities.

Fair Value Measurements

The following table presents the fair value of plan assets, by major category, for PacifiCorp's defined benefit pension plan (in millions):

	Input Levels for Fair Value Measurements			
	Level 1[1]	Level 2[1]	Level 3[1]	Total
As of December 31, 2025:				
Cash equivalents	$ 2	$ 2	$ —	$ 4
Debt securities:				
U.S. government obligations	54	—	—	54
Corporate obligations	—	227	—	227
Municipal obligations	—	11	—	11
Agency, asset and mortgage-backed obligations	—	48	—	48
Equity securities:				
U.S. companies	18	—	—	18
Total assets in the fair value hierarchy	$ 74	$ 288	$ —	362
Investment funds[2] measured at net asset value				341
Limited partnership interests[3] measured at net asset value				21
Investments at fair value				$ 724
As of December 31, 2024:				
Cash equivalents	$ —	$ 3	$ —	$ 3
Debt securities:				
U.S. government obligations	59	—	—	59
Corporate obligations	—	229	—	229
Municipal obligations	—	13	—	13
Agency, asset and mortgage-backed obligations	—	52	—	52
Equity securities:				
U.S. companies	65	—	—	65
Total assets in the fair value hierarchy	$ 124	$ 297	$ —	421
Investment funds[2] measured at net asset value				285
Limited partnership interests[3] measured at net asset value				22
Investments at fair value				$ 728

(1) Refer to Note 13 for additional discussion regarding the three levels of the fair value hierarchy.

(2) Investment funds are substantially comprised of mutual funds and collective trust funds. These funds consist of equity and debt securities of approximately 45% and 55%, respectively, for 2025 and 40% and 60%, respectively, for 2024, and are invested in U.S. and international securities of approximately 87% and 13%, respectively, for 2025 and 88% and 12%, respectively, for 2024.

(3) Limited partnership interests include several funds that invest primarily in real estate.

The following table presents the fair value of plan assets, by major category, for PacifiCorp's defined benefit other postretirement plan (in millions):

	Input Levels for Fair Value Measurements			
	Level 1[1]	Level 2[1]	Level 3[1]	Total
As of December 31, 2025:				
Cash and cash equivalents	$ 17	$ —	$ —	$ 17
Debt securities:				
U.S. government obligations	11	—	—	11
Corporate obligations	—	34	—	34
Municipal obligations	—	54	—	54
Agency, asset and mortgage-backed obligations	—	57	—	57
Total assets in the fair value hierarchy	$ 28	$ 145	$ —	173
Investment funds[2] measured at net asset value				89
Investments at fair value				$ 262
As of December 31, 2024:				
Cash and cash equivalents	$ —	$ 6	$ —	$ 6
Debt securities:				
U.S. government obligations	16	—	—	16
Corporate obligations	—	34	—	34
Municipal obligations	—	18	—	18
Agency, asset and mortgage-backed obligations	—	52	—	52
Equity securities:				
U.S. companies	7	—	—	7
Total assets in the fair value hierarchy	$ 23	$ 110	$ —	133
Investment funds[2] measured at net asset value				134
Investments at fair value				$ 267

(1) Refer to Note 13 for additional discussion regarding the three levels of the fair value hierarchy.

(2) Investment funds are substantially comprised of mutual funds and collective trust funds. These funds consist of equity and debt securities of approximately 0% and 100%, respectively, for 2025 and 39% and 61%, respectively, for 2024, and are invested in U.S. and international securities of approximately 88% and 12%, respectively, for 2025 and 90% and 10%, respectively, for 2024.

For level 1 investments, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value. For level 2 investments, the fair value is determined using pricing models based on observable market inputs. Shares of mutual funds not registered under the Securities Act of 1933, private equity limited partnership interests, common and commingled trust funds and investment entities are reported at fair value based on the net asset value per unit, which is used for expedience purposes. A fund's net asset value is based on the fair value of the underlying assets held by the fund less its liabilities.

Multiemployer and Joint Trustee Pension Plans

PacifiCorp contributes to the PacifiCorp/IBEW Local 57 Retirement Trust Fund ("Local 57 Trust Fund") (plan number 001) and its subsidiary, Energy West Mining Company, previously contributed to the UMWA 1974 Pension Plan (plan number 002). Contributions to these pension plans are based on the terms of collective bargaining agreements.

As a result of the Utah Mine Disposition and UMWA labor settlement, PacifiCorp's subsidiary, Energy West Mining Company, triggered involuntary withdrawal from the UMWA 1974 Pension Plan in June 2015 when the UMWA employees ceased performing work for the subsidiary. PacifiCorp recorded its estimate of the withdrawal obligation in December 2014 when withdrawal was considered probable and deferred the portion of the obligation considered probable of recovery to a regulatory asset. PacifiCorp has subsequently revised its estimate due to changes in facts and circumstances for a withdrawal occurring by July 2015. As communicated in a letter received in August 2016, the plan trustees determined a withdrawal liability of $115 million. Energy West Mining Company began making installment payments in November 2016 and has the option to elect a lump sum payment to settle the withdrawal obligation. In January 2024, the withdrawal liability was recalculated by the plan's actuary to be $80 million as a result of arbitration efforts regarding the interest rate used to compute the obligation. The ultimate amount paid by Energy West Mining Company to settle the obligation is dependent on a variety of factors, including the results of ongoing efforts with the plan trustees and the recent arbitration activities.

The Local 57 Trust Fund is a joint trustee plan such that the board of trustees is represented by an equal number of trustees from PacifiCorp and the union. The Local 57 Trust Fund was established pursuant to the provisions of the Taft-Hartley Act and although formed with the ability for other employers to participate in the plan, there are no other employers that participate in this plan.

The risk of participating in multiemployer pension plans generally differs from single-employer plans in that assets are pooled such that contributions by one employer may be used to provide benefits to employees of other participating employers and plan assets cannot revert to employers. If an employer ceases participation in the plan, the employer may be obligated to pay a withdrawal liability based on the participants' unfunded, vested benefits in the plan. If participating employers withdraw from a multiemployer plan, the unfunded obligations of the plan may be borne by the remaining participating employers.

The following table presents PacifiCorp's participation in individually significant joint trustee and multiemployer pension plans for the years ended December 31 (dollars in millions):

		Pension Protection Act of 2006 zone status or plan funded status percentage for plan years beginning July 1,					Contributions			
Plan name	Employer Identification Number	2025	2024	2023	Funding improvement plan	Surcharge imposed under PPA of 2006	2025	2024	2023	Year contributions to plan exceeded more than 5% of total contributions
Local 57 Trust Fund	87-0640888	At least 80%	At least 80%	At least 80%	None	None	$ 4	$ 5	$ 5	2025, 2024, 2023

PacifiCorp's minimum contributions to the Local 57 Trust Fund are based on the amount of wages paid to employees covered by the Local 57 Trust Fund collective bargaining agreements, subject to ERISA minimum funding requirements. The collective bargaining agreements governing the Local 57 Trust Fund expire in 2028.

Defined Contribution Plan

PacifiCorp's 401(k) Plan covers substantially all employees. PacifiCorp's matching contributions are based on each participant's level of contribution and, as of January 1, 2024, all participants receive contributions based on eligible pre-tax annual compensation. Contributions cannot exceed the maximum allowable for tax purposes. PacifiCorp's contributions to the 401(k) Plan were $60 million, $55 million and $48 million for the years ended December 31, 2025, 2024 and 2023, respectively.

(11) Asset Retirement Obligations

PacifiCorp estimates its ARO liabilities based upon detailed engineering calculations of the amount and timing of the future cash spending for a third party to perform the required work. Spending estimates are escalated for inflation and then discounted at a credit-adjusted, risk-free rate. Changes in estimates could occur for a number of reasons, including changes in laws and regulations, plan revisions, inflation and changes in the amount and timing of the expected work.

PacifiCorp does not recognize liabilities for AROs for which the fair value cannot be reasonably estimated. Due to the indeterminate removal date, the fair value of the associated liabilities on certain transmission, distribution and other assets cannot currently be estimated, and no amounts are recognized on the Consolidated Financial Statements other than those included in the cost of removal regulatory liability established via approved depreciation rates in accordance with accepted regulatory practices.

The following table reconciles the beginning and ending balances of PacifiCorp's ARO liabilities for the years ended December 31 (in millions):

	2025	2024
Beginning balance	$ 427	$ 356
Change in estimated costs	86	73
Additions	8	4
Retirements	(22)	(20)
Accretion	19	14
Ending balance	$ 518	$ 427
Reflected as:		
Other current liabilities	$ 60	$ 49
Other long-term liabilities	458	378
	$ 518	$ 427

Certain of PacifiCorp's decommissioning and reclamation obligations relate to jointly owned facilities and mine sites. PacifiCorp is committed to pay a proportionate share of the decommissioning or reclamation costs. In the event of a default by any of the other joint participants, PacifiCorp may be obligated to absorb, directly or by paying additional sums to the entity, a proportionate share of the defaulting party's liability. PacifiCorp's estimated share of the decommissioning and reclamation obligations are primarily recorded as ARO liabilities.

In May 2024, the United States Environmental Protection Agency published its final rule on legacy coal combustion residuals ("CCR") surface impoundments and CCR management units ("CCRMUs") in the Federal Register. CCRMUs include CCR surface impoundments and landfills closed before October 19, 2015 and inactive CCR landfills. The final rule contains three main components: (1) a definition for legacy CCR surface impoundments, which are inactive surface impoundments at inactive generating facilities that must adhere to the same regulations as inactive CCR impoundments at active generating facilities, barring location restrictions and liner design criteria, with customized compliance deadlines; (2) groundwater monitoring, corrective action, closure, and post closure care requirements for CCRMUs, which may be located at active generating facilities and inactive generating facilities with a legacy CCR surface impoundment; and (3) the owners and operators of inactive generating facilities must identify the presence of legacy CCR surface impoundments and comply with all rule requirements for surface impoundments; and the owners and operators of active generating facilities and inactive generating facilities with a legacy CCR surface impoundment must prepare Facility Evaluation Reports ("FERs") that identify and describe the CCRMUs and determine whether closure is required. In February 2026, the EPA extended certain compliance deadlines with CCRMUs. Accordingly, and in a manner consistent with existing CCR rules, owners and operators must publish FERs on their CCR websites in two parts, within 12 months (Part 1) and 24 months (Part 2) of the final rule's effective date in February 2026. PacifiCorp is currently evaluating the final rule and does not anticipate identifying any legacy surface impoundments, but does anticipate identifying CCRMUs subject to the rule. Due to the number of site investigations warranted by this rule and the nature of engineering and other studies required at each site, PacifiCorp is unable to reasonably estimate the potential impact, which may be material, to its asset retirement obligations.

(12) Risk Management and Hedging Activities

PacifiCorp is exposed to the impact of market fluctuations in commodity prices and interest rates. PacifiCorp is principally exposed to electricity, natural gas, coal and fuel oil commodity price risk as it has an obligation to serve retail customer load in its service territories. PacifiCorp's load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity and wholesale electricity that is purchased and sold. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, generating facility availability, customer usage, storage, and transmission and transportation constraints. Interest rate risk exists on variable-rate debt and future debt issuances. PacifiCorp does not engage in a material amount of proprietary trading activities.

PacifiCorp has established a risk management process that is designed to identify, assess, manage and report on each of the various types of risk involved in its business. To mitigate a portion of its commodity price risk, PacifiCorp uses commodity derivative contracts, which may include forwards, futures, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. PacifiCorp manages its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. Additionally, PacifiCorp may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, to mitigate PacifiCorp's exposure to interest rate risk. No interest rate derivatives were in place during the periods presented. PacifiCorp does not hedge all of its commodity price and interest rate risks, thereby exposing the unhedged portion to changes in market prices.

There have been no significant changes in PacifiCorp's accounting policies related to derivatives. Refer to Notes 2 and 13 for additional information on derivative contracts.

The following table, which reflects master netting arrangements and excludes contracts that have been designated as normal under the normal purchases or normal sales exception afforded by GAAP, summarizes the fair value of PacifiCorp's derivative contracts, on a gross basis, and reconciles those amounts to the amounts presented on a net basis on the Consolidated Balance Sheets (in millions):

	Other Current Assets	Other Assets	Other Current Liabilities	Other Long-term Liabilities	Total
As of December 31, 2025:					
Not designated as hedging contracts[1]:					
Commodity assets	$ 5	$ —	$ 4	$ 1	$ 10
Commodity liabilities	—	—	(119)	(28)	(147)
Total	5	—	(115)	(27)	(137)
Cash collateral receivable	—	—	67	4	71
Total derivatives - net basis	$ 5	$ —	$ (48)	$ (23)	$ (66)
As of December 31, 2024:					
Not designated as hedging contracts[1]:					
Commodity assets	$ 10	$ —	$ 16	$ 1	$ 27
Commodity liabilities	(1)	—	(105)	(18)	(124)
Total	9	—	(89)	(17)	(97)
Cash collateral receivable	—	—	6	—	6
Total derivatives - net basis	$ 9	$ —	$ (83)	$ (17)	$ (91)

(1) PacifiCorp's commodity derivatives are generally included in rates. As of December 31, 2025, a regulatory asset of $137 million was recorded related to the net derivative liability of $137 million. As of December 31, 2024, a regulatory asset of $97 million was recorded related to the net derivative liability of $97 million.

The following table reconciles the beginning and ending balances of PacifiCorp's net regulatory assets (liabilities) and summarizes the pre-tax gains and losses on commodity derivative contracts recognized in net regulatory assets (liabilities), as well as amounts reclassified to earnings for the years ended December 31 (in millions):

	2025	2024	2023
Beginning balance	$ 97	$ 76	$ (270)
Changes in fair value recognized in regulatory assets (liabilities)	177	326	206
Net gains (losses) reclassified to operating revenue	26	18	(8)
Net (losses) gains reclassified to cost of fuel and energy	(163)	(323)	148
Ending balance	$ 137	$ 97	$ 76

Derivative Contract Volumes

The following table summarizes the net notional amounts of outstanding commodity derivative contracts with fixed price terms that comprise the mark-to-market values as of December 31 (in millions):

	Unit of Measure	2025	2024
Electricity sales, net	Megawatt hours	—	(1)
Natural gas purchases	Decatherms	147	124

Credit Risk

PacifiCorp is exposed to counterparty credit risk associated with wholesale energy supply and marketing activities with other utilities, energy marketing companies, financial institutions and other market participants. Credit risk may be concentrated to the extent PacifiCorp's counterparties have similar economic, industry or other characteristics and due to direct or indirect relationships among the counterparties. Before entering into a transaction, PacifiCorp analyzes the financial condition of each significant wholesale counterparty, establishes limits on the amount of unsecured credit to be extended to each counterparty and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate wholesale counterparty credit risk, PacifiCorp enters into netting and collateral arrangements that may include margining and cross-product netting agreements and obtains third-party guarantees, letters of credit and cash deposits. If required, PacifiCorp exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

Collateral and Contingent Features

In accordance with industry practice, certain wholesale energy agreements, including contracts for purchases, sales and transportation of electricity, natural gas and coal, some of which are accounted for as derivatives, contain credit support provisions that in part base certain collateral requirements on credit ratings for senior unsecured debt as reported by one or more of the recognized credit rating agencies. These agreements may provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features"). These agreements and other agreements that do not refer to specified rating-dependent thresholds may provide the right for counterparties to demand "adequate assurance" if there is a material adverse change in PacifiCorp's creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2025, PacifiCorp's issuer credit ratings for senior unsecured debt from the recognized credit rating agencies were investment grade.

The aggregate fair value of PacifiCorp's derivative contracts in liability positions with specific credit-risk-related contingent features totaled $145 million and $123 million as of December 31, 2025 and 2024, respectively, for which PacifiCorp had posted collateral of $71 million and $6 million, respectively, in the form of cash deposits. If all credit-risk-related contingent features for derivative contracts in liability positions had been triggered as of December 31, 2025 and 2024, PacifiCorp would have been required to post $69 million and $100 million, respectively, of additional collateral. PacifiCorp's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation or other factors.

PacifiCorp's collateral requirements associated with wholesale energy agreements could fluctuate considerably due to market price volatility; changes in credit ratings; changes in legislation or regulation or other factors; and if counterparties demand adequate assurance in the event of a material adverse change in PacifiCorp's creditworthiness.

(13) Fair Value Measurements

The carrying value of PacifiCorp's cash, certain cash equivalents, receivables, payables, accrued liabilities and short-term borrowings approximates fair value because of the short-term maturity of these instruments. PacifiCorp has various financial assets and liabilities that are measured at fair value on the Consolidated Financial Statements using inputs from the three levels of the fair value hierarchy. A financial asset or liability classification within the hierarchy is determined based on the lowest level input that is significant to the fair value measurement. The three levels are as follows:

- Level 1 - Inputs are unadjusted quoted prices in active markets for identical assets or liabilities that PacifiCorp has the ability to access at the measurement date.
- Level 2 - Inputs include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means (market corroborated inputs).
- Level 3 - Unobservable inputs reflect PacifiCorp's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. PacifiCorp develops these inputs based on the best information available, including its own data.

The following table presents PacifiCorp's financial assets and liabilities recognized on the Consolidated Balance Sheets and measured at fair value on a recurring basis (in millions):

	Input Levels for Fair Value Measurements				
	Level 1	Level 2	Level 3	Other[1]	Total
As of December 31, 2025:					
Assets:					
Commodity derivatives	$ —	$ 10	$ —	$ (5)	$ 5
Money market mutual funds	84	—	—	—	84
Investment funds	28	—	—	—	28
	$ 112	$ 10	$ —	$ (5)	$ 117
Liabilities:					
Commodity derivatives	$ —	$ (147)	$ —	$ 76	$ (71)
As of December 31, 2024:					
Assets:					
Commodity derivatives	$ —	$ 27	$ —	$ (18)	$ 9
Money market mutual funds	34	—	—	—	34
Investment funds	29	—	—	—	29
	$ 63	$ 27	$ —	$ (18)	$ 72
Liabilities:					
Commodity derivatives	$ —	$ (124)	$ —	$ 24	$ (100)

(1) Represents netting under master netting arrangements and a net cash collateral receivable of $71 million and $6 million as of December 31, 2025 and 2024, respectively.

Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. A discounted cash flow valuation method was used to estimate fair value. When available, the fair value of derivative contracts is estimated using unadjusted quoted prices for identical contracts in the market in which PacifiCorp transacts. When quoted prices for identical contracts are not available, PacifiCorp uses forward price curves. Forward price curves represent PacifiCorp's estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates. PacifiCorp bases its forward price curves upon market price quotations, when available, or internally developed and commercial models, with internal and external fundamental data inputs. Market price quotations are obtained from independent energy brokers, exchanges, direct communication with market participants and actual transactions executed by PacifiCorp. Market price quotations for certain major electricity and natural gas trading hubs are generally readily obtainable for the first three years; therefore, PacifiCorp's forward price curves for those locations and periods reflect observable market quotes. Market price quotations for other electricity and natural gas trading hubs are not as readily obtainable for the first three years. Given that limited market data exists for these contracts, as well as for those contracts that are not actively traded, PacifiCorp uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs that are based on unobservable inputs. The estimated fair value of these derivative contracts is a function of underlying forward commodity prices, interest rates, currency rates, related volatility, counterparty creditworthiness and duration of contracts. Refer to Note 12 for further discussion regarding PacifiCorp's risk management and hedging activities.

PacifiCorp's investments in money market mutual funds and investment funds are stated at fair value. When available, PacifiCorp uses a readily observable quoted market price or net asset value of an identical security in an active market to record the fair value. In the absence of a quoted market price or net asset value of an identical security, the fair value is determined using pricing models or net asset values based on observable market inputs and quoted market prices of securities with similar characteristics.

PacifiCorp's long-term debt is carried at cost on the Consolidated Balance Sheets. The fair value of PacifiCorp's long-term debt is a Level 2 fair value measurement and has been estimated based upon quoted market prices, where available, or at the present value of future cash flows discounted at rates consistent with comparable maturities with similar credit risks. The carrying value of PacifiCorp's variable-rate long-term debt approximates fair value because of the frequent repricing of these instruments at market rates. The following table presents the carrying value and estimated fair value of PacifiCorp's long-term debt as of December 31 (in millions):

	2025		2024	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 14,134	$ 13,005	$ 13,588	$ 12,580

(14) Commitments and Contingencies

Commitments

PacifiCorp has the following firm commitments that are not reflected on the Consolidated Balance Sheets. Certain commitments are with related parties. Refer to Note 21 for transactions associated with these related party contracts. Minimum payments as of December 31, 2025, are as follows (in millions):

	2026	2027	2028	2029	2030	2031 and Thereafter	Total
Contract type:							
PPAs - commercially operable	$ 235	$ 194	$ 197	$ 196	$ 197	$ 1,558	$ 2,577
PPAs and Energy Storage contracts - non-commercially operable	70	128	128	128	128	1,972	2,554
Fuel contracts	716	640	598	596	315	100	2,965
Construction commitments	429	369	174	3	—	23	998
Transmission	134	129	126	102	70	358	919
Easements	16	16	17	17	17	549	632
Maintenance, service and other contracts	178	150	108	55	27	93	611
Total commitments	$ 1,778	$ 1,626	$ 1,348	$ 1,097	$ 754	$ 4,653	$ 11,256

PPAs - Commercially Operable

The table above reflects PPAs with expiration dates ranging from 2026 through 2052. As part of its energy resource portfolio, PacifiCorp acquires a portion of its electricity through long-term purchases and exchange agreements. PacifiCorp has many long-term PPAs primarily with solar-, wind- or hydro-powered generating facilities that are not included in the table above due to there being no minimum payments generally due to being dependent on solar, wind and stream flow conditions. These PPAs generally range from 10 to 30 years in duration, with certain of the PPAs extending through 2055. Future payments associated with these PPAs are expected to be material. Certain PPAs qualify as leases as described in Note 2 and are also excluded from the table above. Refer to Note 5 for variable lease costs associated with these lease commitments.

Included in the minimum fixed annual payments for purchased electricity above are commitments to purchase electricity from several hydroelectric systems under long-term arrangements with public utility districts. These purchases are made on a "cost-of-service" basis for a stated percentage of system output and for a like percentage of system operating expenses and debt service. These costs are included in energy costs on the Consolidated Statements of Operations. PacifiCorp is required to pay its portion of operating costs and its portion of the debt service, whether or not any electricity is produced. These arrangements accounted for less than 5% of PacifiCorp's 2025, 2024 and 2023 energy sources.

PPAs and Energy Storage Contracts - Non-Commercially Operable

PacifiCorp has agreements with facilities that have not achieved commercial operation, including PPAs primarily related to solar-, wind- or hydro-powered generating facilities, as well as Energy Storage agreements.

The table above reflects estimated capacity payments through 2046 for various Energy Storage agreements that are expected to reach commercial operation in 2026, and for which the accounting determination is pending.

Commitments associated with PPAs from primarily solar- and hydro-powered generating facilities are not included in the table above due to there being no minimum payments generally due to being dependent on solar and stream flow conditions. The PPAs generally range from 10 to 20 years in duration, some of which extend through 2046. Future payments associated with these PPAs are expected to be material.

To the extent these facilities do not achieve commercial operation, PacifiCorp has no obligation to the counterparties.

Fuel Contracts

PacifiCorp has "take or pay" coal and natural gas contracts that require minimum payments.

Construction Commitments

PacifiCorp's construction commitments included in the table above relate to firm commitments and include costs associated with certain generating plant, transmission, distribution and operations projects.

In June 2025, PacifiCorp became committed under the terms of a previously existing construction funding agreement with Idaho Power Company to support the development of the Boardman to Hemingway 300-mile, 500-kV transmission line (the "B2H Project"). Under this agreement, PacifiCorp is committed to contributing up to $460 million toward construction costs, representing PacifiCorp's share of the total estimated shared project costs of $843 million. B2H Project costs will also include costs directly incurred by PacifiCorp, a substantial portion of which have already been incurred. Refer to Note 21 for information regarding the sale leaseback transaction associated with the B2H Project.

Transmission

PacifiCorp has contracts for the right to transmit electricity over other entities' transmission lines to facilitate delivery to PacifiCorp's customers.

Easements

PacifiCorp has easements for land on which certain of its assets, primarily wind-powered generating facilities, are located.

Environmental Laws and Regulations

PacifiCorp is subject to federal, state and local laws and regulations regarding air quality, climate change, emissions performance standards, water quality, coal ash disposal, wildfire prevention and mitigation and other environmental matters that have the potential to impact its current and future operations. PacifiCorp believes it is in material compliance with all applicable laws and regulations.

Lower Klamath Hydroelectric Project

PacifiCorp is a party to the 2016 amended Klamath Hydroelectric Settlement Agreement ("KHSA"), which addressed disputes surrounding PacifiCorp's efforts to relicense the Klamath Hydroelectric Project. The KHSA established a process for PacifiCorp, the states of Oregon and California ("States") and other stakeholders to assess whether dam removal could occur consistent with the settlement's terms. For PacifiCorp, the key elements of the settlement include: (1) a contribution from PacifiCorp's Oregon and California customers capped at $200 million plus $250 million in California bond funds; (2) complete indemnification from harms associated with dam removal; (3) transfer of the Federal Energy Regulatory Commission ("FERC") license to a third-party dam removal entity, the Klamath River Renewal Corporation ("KRRC"); and (4) ability for PacifiCorp to operate the facilities for the benefit of customers through commencement of dam removal.

In September 2016, the KRRC and PacifiCorp filed a joint application with the FERC to transfer the license for the four mainstem Klamath hydroelectric dams comprising the Lower Klamath Project (FERC Project No. 14803) from PacifiCorp to the KRRC. The KRRC filed an amended license surrender application for the Lower Klamath Project with FERC in November 2020. In November 2022, the FERC issued a license surrender order for the Lower Klamath Project, which was accepted by the KRRC and the States in December 2022, resulting in the transfer of the Lower Klamath Project dams. Although PacifiCorp no longer owned the Lower Klamath Project, PacifiCorp continued to operate the facilities under an operation and maintenance agreement with the KRRC until each facility was ready for removal. PacifiCorp's obligations under the operations and maintenance agreement terminated in January 2024, when PacifiCorp's customers no longer received generation benefits from the facilities. Removal of the Copco No. 2 facility was completed in November 2023, and removal of the remaining three dams (J.C. Boyle, Copco No. 1, and Iron Gate) was completed in October 2024. The KRRC has $450 million in funding available for dam removal and restoration; $200 million collected from PacifiCorp's Oregon and California customers and $250 million in California bond funds. PacifiCorp and the States have also agreed to equally share cost overruns that may occur above the initial $450 million in funding. Specifically, PacifiCorp and the States have agreed to equally fund an initial $45 million supplemental fund and equally share any additional costs above that amount to ensure dam removal and restoration is complete. In May 2024, the KRRC communicated to PacifiCorp and the States that it expects to require the $45 million of supplemental funds. As a result, PacifiCorp provided supplemental funding to the KRRC of approximately $11 million in October 2024 and approximately $2 million in July 2025, and expects to provide the remaining $2 million in 2026.

Hydroelectric Commitments

Certain of PacifiCorp's hydroelectric licenses and settlement agreements contain requirements for PacifiCorp to make certain capital and operating expenditures related to its hydroelectric facilities, which are estimated to be approximately $278 million over the next 10 years.

Legal Matters

PacifiCorp is party to a variety of legal actions, including litigation, arising out of the normal course of business, some of which assert claims for damages in substantial amounts and are described below. For certain legal actions, parties at times may seek to impose fines, penalties and other costs.

Pursuant to ASC 450, "Contingencies," a provision for a loss contingency is recorded when it is probable a liability is likely to occur and the amount of loss can be reasonably estimated. PacifiCorp evaluates the related range of reasonably estimated losses and records a loss based on its best estimate within that range or the lower end of the range if there is no better estimate.

Wildfires

A significant number of complaints and demands alleging similar claims related to the Wildfires have been filed in Oregon and California, including a class action complaint in Oregon associated with 2020 Wildfires for which certain jury verdicts were issued as described below. The plaintiffs seek damages for economic losses, noneconomic losses, including mental suffering, emotional distress, personal injury and loss of life, punitive damages, other damages and attorneys' fees. Several insurance carriers also filed subrogation complaints in Oregon and California with allegations similar to those made in the aforementioned complaints. Additionally, PacifiCorp received correspondence from the U.S. and Oregon Departments of Justice regarding the potential recovery of certain costs and damages alleged to have occurred on federal and state lands in connection with certain of the 2020 Wildfires. In December 2024, the United States of America filed a complaint against PacifiCorp in conjunction with the correspondence from the U.S. Department of Justice. The civil cover sheet accompanying the complaint demands damages estimated to exceed $900 million. On February 20, 2026, the United States Attorney for the District of Oregon and the United States Attorney for the Eastern District of California approved a settlement agreement for $575 million between PacifiCorp and the United States of America resolving all known federal government complaints and demands associated with the Wildfires, including those associated with the 242, Archie Creek, Echo Mountain Complex, McKinney, Slater and South Obenchain fires. In accordance with the settlement agreement, PacifiCorp will pay the $575 million within 10 calendar days of the February 20, 2026, effective date. PacifiCorp is actively cooperating with the Oregon Department of Justice on resolving the alleged claims.

Amounts sought in outstanding complaints and demands filed in Oregon and in certain demands made in California totaled approximately $50 billion, excluding any doubling or trebling of damages or punitive damages included in the complaints, and of which approximately $48 billion represents the economic and noneconomic damages sought in the *James* mass complaints described below, as amended. Oregon law provides for doubling of economic and property damages in the event the defendant is found to have acted with gross negligence, recklessness, willfulness or malice. Oregon law provides for trebling of damages associated with timber, shrubs and produce in the event the defendant is determined to have willfully and intentionally trespassed. Generally, the complaints filed in California do not specify damages sought and are excluded from this amount. For class actions, amounts specified by the plaintiffs in the complaints include amounts based on estimates of the potential class size, which ultimately may be significantly greater than estimated. Additionally, damages are not limited to the amounts specified in the initially filed complaints as plaintiffs are frequently allowed to amend their complaints to add additional damages and amounts awarded in a court proceeding may be significantly greater than the damages specified. However, plaintiffs included in the *James* mass complaints are required to amend their complaints to align the economic damages to the facts specific to their complaints rather than the common per plaintiff damages specified in the originally filed mass complaints. Refer to "*James* Trial Activity" below for information regarding damages awarded to date in the *James* case.

In California, under inverse condemnation, courts have held that investor-owned utilities can be liable for real and personal property damages from wildfires without the utility being found negligent and regardless of fault. California law also permits inverse condemnation plaintiffs to recover reasonable attorney fees and costs. In both Oregon and California, PacifiCorp has equipment in areas accessed through special use permits, easements or similar agreements that may contain provisions requiring it to pay for damages caused by its equipment regardless of fault. Even if inverse condemnation or other provisions do not apply, PacifiCorp could be found liable for all damage.

Based on available information to date, losses have been and will likely continue to be incurred associated with the Wildfires. Final determinations of liability will only be made following the completion of comprehensive investigations, which may be or have been performed by various entities, including the U.S. Department of Agriculture Forest Service ("USFS"), the California Public Utilities Commission, the Oregon Department of Forestry ("ODF") and the Oregon Department of Justice, as well as litigation or similar processes, the outcome of which, if adverse, could, in the aggregate, have a material adverse effect on PacifiCorp's financial condition.

2020 Wildfires

In September 2020, a severe weather event with high winds, low humidity and warm temperatures contributed to several major wildfires, which resulted in real and personal property and natural resource damage, personal injuries and loss of life and widespread power outages in Oregon and Northern California. The wildfires spread across certain parts of PacifiCorp's service territory and surrounding areas across multiple counties in Oregon and California, including Siskiyou County, California; Jackson County, Oregon; Douglas County, Oregon; Marion County, Oregon; Lincoln County, Oregon; and Klamath County, Oregon, burning over 500,000 acres in aggregate and include the Santiam Canyon, Beachie Creek, South Obenchain, Echo Mountain Complex, 242, Archie Creek, Slater and other fires. The Slater fire occurred in both Oregon and California. Third-party reports for these wildfires indicate over 2,000 structures destroyed, including residences; several structures damaged; multiple individuals injured; and several fatalities.

In May 2022, the USFS issued its report of investigation into the Archie Creek fire concluding that the probable cause of the fire was power lines owned and operated by PacifiCorp. The USFS report for the Archie Creek fire also states that evidence indicates failure of power line infrastructure. The USFS report of investigation into the Slater fire for the investigation period October 5, 2020, to December 8, 2020, concluded that the fire was caused by a downed power line owned and operated by PacifiCorp. The USFS report for the Slater fire also states that evidence indicates a tree fell onto the power line and that wind blew over the 137-foot tree with internal rot that showed no outward signs of distress and would not have been classified or identified as a hazard tree.

Settlements have been reached with substantially all individual plaintiffs, timber companies and insurance subrogation plaintiffs in both the Archie Creek and Slater fires. Additionally, PacifiCorp has settled all wrongful death claims and all federal government demands and complaints associated with the 2020 Wildfires.

In April 2023, the USFS issued its report of investigation into a wildland fire that began in the Opal Creek wilderness outside of the Santiam Canyon that was first reported on August 16, 2020 ("Beachie Creek Fire"), approximately three weeks prior to the September 2020 wind event described above. In March 2025, PacifiCorp received the ODF's final investigation report on the Santiam Canyon fires ("ODF's Report"), which concluded that embers from the pre-existing Beachie Creek Fire caused 12 fires within the Santiam Canyon. The ODF's Report also found that PacifiCorp's power lines did not contribute to the overall spread of fire into the Santiam Canyon even though its power lines ignited seven spot fires within the Santiam Canyon that were each suppressed.

The Beachie Creek fire that spread into the Santiam Canyon burned approximately 193,000 acres; the South Obenchain fire burned approximately 33,000 acres; the Echo Mountain Complex fire burned approximately 3,000 acres; and the 242 fire burned approximately 14,000 acres. The *James* cases described below are associated with the Beachie Creek (Santiam Canyon), South Obenchain, Echo Mountain Complex and 242 fires, which are four distinct fires located hundreds of miles apart.

The James Case

On September 30, 2020, a class action complaint against PacifiCorp was filed, captioned *Jeanyne James et al. v. PacifiCorp*, ("*James*") in Oregon Circuit Court in Multnomah County, Oregon ("*Multnomah County Circuit Court Oregon*"). The complaint was filed by Oregon residents and businesses who sought to represent a class of all Oregon citizens and entities whose real or personal property was harmed beginning on September 7, 2020, by wildfires in Oregon allegedly caused by PacifiCorp. In November 2021, the plaintiffs filed an amended complaint to limit the class to include Oregon citizens allegedly impacted by the Santiam Canyon, Echo Mountain Complex, South Obenchain and 242 fires, as well as to add claims for noneconomic damages. The amended complaint alleged that PacifiCorp's assets contributed to the Oregon wildfires occurring on or after September 7, 2020, and that PacifiCorp acted with gross negligence, among other things. The amended complaint seeks damages similar to those described above, including not less than $600 million of economic damages and in excess of $1 billion of noneconomic damages for the plaintiffs and the class. Since filing of the original class action complaint, numerous James class members have been named and damages specified in various complaints as described below. Additionally, numerous cases were consolidated into the original *James* complaint.

As of December 2025, various mass complaints against PacifiCorp naming 1,760 class members have been filed referencing the *James* case as the lead case with complaints for some of the plaintiffs subsequently dismissed. These *James* mass complaints make damages-only allegations with substantially all plaintiffs individually seeking $5 million of economic damages, $25 million of noneconomic damages and punitive damages equal to 0.25 times the amount of economic and noneconomic damages, as well as doubling of economic damages. As described below under "*James* Court Activity," plaintiffs included in the mass complaints are required to amend their complaints to align the economic damages to the facts specific to their complaints.

An additional approximately 1,500 plaintiffs were granted the ability not to be represented by *James* lead counsel, a small portion of which filed complaints seeking damages similar to those in the mass complaints. In November 2025, PacifiCorp settled with approximately 1,400 of these plaintiffs for $150 million.

As a result of dismissals for the mass complaints and the November 2025 settlement, James complaints for approximately 1,700 individual plaintiffs remain outstanding, substantially all of which are represented by lead counsel. PacifiCorp believes the magnitude of damages sought by the class members in the *James* mass complaints to be of remote likelihood of being awarded based on the amounts awarded in the jury verdicts described below under "*James* Trial Activity" that are being appealed.

James Trial Activity

In June 2023, a jury verdict was issued in the first *James* trial finding PacifiCorp's conduct grossly negligent, reckless and willful as to each of the 17 named plaintiffs and the entire class. The jury awarded economic and noneconomic damages. After the jury verdict, the Multnomah County Circuit Court Oregon doubled the economic damages, in accordance with Oregon law, and added punitive damages by applying a 0.25 multiplier to the awarded economic and noneconomic damages. PacifiCorp filed a motion with the Multnomah County Circuit Court Oregon requesting the court offset the damage awards by deducting insurance proceeds received by any of the plaintiffs. In January 2024, PacifiCorp filed a notice of appeal associated with the June 2023 verdict, including whether the case can proceed as a class action.

Subsequent to the June 2023 *James* verdict, numerous damages phase trials were held with separate jury verdicts issued and damages awarded for each on a basis consistent with the initial trial and relying on the liability determination in the June 2023 *James* verdict. PacifiCorp amended its January 2024 appeal of the June 2023 *James* verdict to include the jury verdicts for the first two damages phase trials. PacifiCorp has filed notices of appeal for the subsequent jury verdicts in the damages phase trials once limited judgments are entered and any post-trial motions filed. Refer to "*James* Court Activity" below regarding the filing of PacifiCorp's appellate briefs. The appeals process and further actions could take several years.

The *James* jury verdicts awarded various damages as follows (in millions):

James Trial Start Date	Number of Plaintiffs	Verdict / Limited Judgment Date	Damages[1]			Insurance Offset[2]	Net Damages	Appeal Notice Filed
			Doubled Economic	Non-economic	Punitive			
Jury verdicts, limited judgments entered[3]								
Initial *James* trial	17	June 2023 / January 2024	$ 9	$ 67	$ 18	$ 2	$ 92	Yes
January 8, 2024	9	January 2024 / April 2024	12	56	16	4	80	Yes
February 26, 2024	10	March 2024 / June 2024	12	23	7	4	38	Yes
February 3, 2025	8	February 2025 / April 2025	8	32	9	4	45	Yes
March 24, 2025	7	March 2025 / June 2025	5	34	9	1	47	Yes
April 21, 2025	9	April 2025 / August 2025	5	11	3	1	18	Yes
May 12, 2025	10	May 2025 / July 2025	11	30	9	2	48	Yes
June 2, 2025	10	June 2025 / August 2025	8	28	8	1	43	Yes
July 7, 2025	11	July 2025 / September 2025	10	36	10	3	53	Yes
September 8, 2025	10	September 2025 / November 2025	11	63	17	3	88	Yes
October 6, 2025	8	October 2025 / December 2025	5	26	7	1	37	Yes
Jury verdicts, limited judgments not yet entered								
December 1, 2025	10	December 2025	10	39	11	3	57	
February 2, 2026	2	February 2026	1	2	1	—	4	
February 9, 2026	8	February 2026	5	36	10	1	50	
February 17, 2026	16	February 2026	2	242	61	—	305	
	145		$ 114	$ 725	$ 196	$ 30	$ 1,005	

(1) For jury verdicts where the limited judgment has not yet been entered, the doubling of economic damages and the application of punitive damages are estimates.

(2) For jury verdicts where limited judgment has been entered, the court offset the awards by the amount of insurance proceeds received by any of the plaintiffs. For jury verdicts where the limited judgment has not yet been entered, the insurance offset is an estimate.

(3) For each limited judgment entered in the court, PacifiCorp has posted or expects to post a supersedeas bond, which stays any effort to seek payment of the judgments pending final resolution of any appeals. Under Oregon Revised Statutes 82.010, interest at a rate of 9% per annum will accrue on the judgments commencing at the date the judgments were entered until the entire money award is paid, amended or reversed by an appellate court. The supersedeas bond posted for the June 2023 *James* verdict covers three years of post-judgment interest while amounts posted for the subsequent verdicts cover two years of post-judgment interest.

Through February 2026, jury verdict awards averaged approximately $7 million per plaintiff, including insurance offset. Additional damages phase trials are scheduled to occur through 2028 as described below.

James Court Activity

In April 2025, PacifiCorp filed its appellate brief with the Oregon Court of Appeals in connection with its appeal of the June 2023 *James* verdict and the January and March 2024 *James* damages phase trial verdicts. In the appellate brief, PacifiCorp addresses numerous procedural and legal issues, including that the class certification is improper due to the plaintiffs being impacted by distinct fires with independent ignition points that were hundreds of miles apart; awarding of non-economic damages is not allowed under Oregon law; plaintiffs failed to prove that PacifiCorp caused harm to every class member; and jury instructions applied incorrect legal standards in assessing class-wide evidence and individual claims. Additionally, PacifiCorp incorporated the ODF's Report into its appellate brief. Various parties who are not party to the *James* case filed supportive amicus briefs with the court. Plaintiffs filed their combined answering and cross-appeal brief on August 21, 2025, after plaintiffs requested three delays from the Oregon Court of Appeals. PacifiCorp has filed additional appellate briefs and will continue to file individual appellate briefs in connection with appeals of each of the verdicts for additional *James* damages phase trials.

In November 2025, the Oregon Court of Appeals issued an order for expedited oral argument in response to PacifiCorp's October 2025 request to facilitate a more prompt decision from the court. As a result of the order, oral argument for the appeal was held on February 4, 2026.

Subsequent to the first two damages phase trials, nine damages phase trials were scheduled to be held in 2025 in accordance with the Multnomah County Circuit Court Oregon's October 2024 case management order, adjudicating the damages of approximately 10 plaintiffs per trial. In March 2025, PacifiCorp filed a motion to stay the additional damages phase trials scheduled under the October 2024 case management order in consideration of the ODF's Report, but the motion was denied in April 2025. Refer to "*James* Trial Activity" above for information regarding the damages phase trials held in 2025.

In July 2025, the Multnomah County Circuit Court Oregon issued Case Management Order No. 11 ("CMO No. 11") in response to the May 2025 hearing that was held to evaluate the scheduling of additional damages phase trials. As ordered, CMO No. 11 proposes to schedule dozens of trials in 2026 and over 100 more in 2027 and 2028. Currently, approximately 1,500 plaintiffs are scheduled for trial under CMO No. 11, including substantially all of those included in the mass complaints described above and reflecting the impacts of settlements and dismissals. CMO No. 11 requires plaintiffs included in the mass complaints to amend their complaints alleging the specific facts that support their claims for economic damages within 180 days before the start of their respective trials. Additionally, CMO No. 11 requires mediation every other month.

In August 2025, PacifiCorp filed a motion with the Oregon Court of Appeals to stay the *James* damages phase trials addressed in CMO No. 11. In September 2025, the Appellate Commissioner of the Oregon Court of Appeals denied PacifiCorp's motion to stay, to which PacifiCorp filed a request for reconsideration of the stay denial with the Chief Judge of the Oregon Court of Appeals. In October 2025, the Oregon Court of Appeals issued an order denying PacifiCorp's request for reconsideration. In November 2025, PacifiCorp petitioned the Oregon Supreme Court to review the Oregon Court of Appeals' decisions. In December 2025, plaintiffs' counsel filed their opposition to the petition, and a decision is expected in 2026.

Potential Effects of *James* CMO No. 11

To stay payment of damages awarded by the limited judgments while on appeal, PacifiCorp is required to bond the judgments. As of the date of this filing, PacifiCorp has posted bonds totaling $606 million associated with the limited judgments entered to date for 109 plaintiffs. These bonding requirements will continue to apply to future judgments associated with the CMO No. 11 trials. As noted above, CMO No. 11 proposes to schedule dozens of trials in 2026 and over 100 more in 2027 and 2028, with trials currently scheduled for approximately 1,500 plaintiffs. Each trial is subject to and dependent on judicial resources and availability, which will be determined six weeks before each trial. The CMO No. 11 proposed schedule is likely to put significant strain on the Multnomah County Circuit Court system, and PacifiCorp believes this may challenge the court's ability to fulfill the schedule in CMO No. 11.

PacifiCorp's liquidity has been materially impacted and its credit ratings have been downgraded as a result of the litigation risk and estimated losses recorded to date associated with the Wildfires. Due to the volume of *James* damages phase trials scheduled under CMO No. 11 combined with the requirement to bond judgments for each verdict to stay payment of damages during the appeals process, PacifiCorp may be unable to obtain the necessary funding to meet its liquidity needs.

While bonding of judgments awarded in *James* verdicts to date have been supported by surety bonds, they can also be supported by posting letters of credit or cash. If the trial schedule and caseload progress as proposed in CMO No. 11 and the future limited judgments follow current trends, damages awarded in additional *James* jury verdicts could exceed PacifiCorp's available surety bond and letter of credit capacity, requiring cash bonding thereafter. PacifiCorp expects additional debt financings, including potential borrowings under its $2.0 billion credit facility to the extent available, or other sources of funding will be needed to provide liquidity to post cash for judgments. These bonding requirements could weaken PacifiCorp's credit metrics. Any further credit rating downgrade may result in the loss of surety bond and letter of credit capacity, trigger cash collateral calls for surety bonds posted and trigger cash collateral calls or other forms of security for wholesale energy agreements that contain credit risk-related contingent features or rights to demand adequate assurance in the event of a material adverse change in PacifiCorp's creditworthiness. Additionally, a downgrade of PacifiCorp's senior secured debt below investment grade would require new regulatory applications and approvals due to certain authorizations or exemptions currently in place with certain regulatory commissions for the issuance of securities. PacifiCorp may also be subject to borrowing limitations under its long-term debt covenants.

In the event of a downgrade below investment grade, PacifiCorp may be unable to secure sufficient debt financings or alternative funding sources to support ongoing operations, including the ability to absorb wholesale power volatility, pay suppliers and meet debt obligations, and such liquidity issues may impact transmission and generation development, purchasing power in the market, building and upgrading substations, connecting new customers, addressing outages and maintaining system resilience. Investors in PacifiCorp's first mortgage bonds may be unable to hold existing bonds or to invest in new bonds, and perceived risks associated with the Wildfires may limit PacifiCorp's ability to attract investors. At a minimum, the cost of any short- or long-term financing is expected to be higher as a result of the wildfire litigation risks and decline in PacifiCorp's credit ratings.

Litigation is inherently difficult to predict, and its potential financial impacts are therefore based on assumptions that will change. Furthermore, there may be judicial decisions and other events or circumstances that could improve or worsen the challenges PacifiCorp faces. PacifiCorp believes it will have sufficient liquidity to cover its operations and obligations beyond a year.

2022 McKinney Fire

According to the California Department of Forestry and Fire Protection, a wildfire began on July 29, 2022, in the Oak Knoll Ranger District of the Klamath National Forest in Siskiyou County, California located in PacifiCorp's service territory, burning over 60,000 acres. Third-party reports indicate that the 2022 McKinney Fire resulted in 11 structures damaged; 185 structures destroyed, including residences; 12 injuries; and four fatalities. The USFS issued a Wildland Fire Origin and Cause Supplemental Incident Report. The report concluded that a tree coming in contact with a power line is the probable cause of the 2022 McKinney Fire. Settlements have been reached with substantially all individual plaintiffs, timber companies and insurance subrogation plaintiffs in the 2022 McKinney Fire. Additionally, PacifiCorp has settled all wrongful death claims associated with the 2022 McKinney Fire and has settled with the federal government as described above.

Estimated Losses for and Settlements Associated with the Wildfires

Based on the facts and circumstances available to PacifiCorp as of the date of this filing, including (i) cause and origin investigations; (ii) ongoing settlement and mediation activities; (iii) other litigation matters and upcoming legal proceedings; and (iv) the status of the *James* case, PacifiCorp recorded cumulative estimated probable losses associated with the Wildfires of $2,853 million through December 31, 2025. PacifiCorp's cumulative accrual includes estimates of probable losses for fire suppression costs, real and personal property damages, natural resource damages and noneconomic damages such as personal injury damages and loss of life damages that it is reasonably able to estimate at this time and which is subject to change as additional relevant information becomes available.

Through December 31, 2025, PacifiCorp paid $1,692 million in settlements associated with the Wildfires, $53 million of which occurred in 2022. As a result of the settlements, various trials have been cancelled. In January and February 2026, PacifiCorp made additional settlement payments related to the Wildfires totaling $2 million.

The following table presents changes in PacifiCorp's liability for estimated losses associated with the Wildfires for the years ended December 31 (in millions):

	2025	2024	2023
Beginning balance	$ 1,536	$ 1,723	$ 424
Accrued losses	100	346	1,930
Payments	(475)	(533)	(631)
Ending balance	$ 1,161	$ 1,536	$ 1,723

As of December 31, 2025, and 2024, $734 million and $247 million of PacifiCorp's liability for estimated losses associated with the Wildfires was classified as a current liability captioned Wildfires liabilities on the Consolidated Balance Sheets. The amounts reflected as current as of December 31, 2025, reflect amounts reasonably expected to be paid out within the next year based on settlements reached as well as ongoing settlement and mediation efforts. The remainder of PacifiCorp's liability for estimated losses associated with the Wildfires as of December 31, 2025, and 2024, was classified as a noncurrent liability captioned Wildfires liabilities on the Consolidated Balance Sheets.

The following table presents changes in PacifiCorp's receivable for expected insurance recoveries associated with the Wildfires for the years ended December 31 (in millions):

	2025	2024	2023
Beginning balance	$ 98	$ 499	$ 246
Accruals	—	—	253
Payments received	(98)	(401)	—
Ending balance	$ —	$ 98	$ 499

As of December 31, 2025, PacifiCorp had received all expected insurance recoveries. As of December 31, 2024, PacifiCorp's receivable for expected insurance recoveries was included in Other receivables, net on the Consolidated Balance Sheets. No additional insurance recoveries beyond those received to date are expected to be available.

During the years ended December 31, 2025, 2024 and 2023, PacifiCorp recognized probable losses net of expected insurance recoveries associated with the Wildfires of $100 million, $346 million and $1,677 million, respectively.

It is reasonably possible PacifiCorp will incur material additional losses beyond the amounts accrued for the Wildfires that could have a material adverse effect on PacifiCorp's financial condition. PacifiCorp is currently unable to reasonably estimate a specific range of possible additional losses that could be incurred due to the number of properties and parties involved, including claimants in the class to the *James* case, the variation in the types of properties and damages and the ultimate outcome of legal actions, including mediation, settlement negotiations, jury verdicts and the appeals process.

Guarantees

PacifiCorp has entered into guarantees as part of the normal course of business and the sale or transfer of certain assets. These guarantees are not expected to have a material impact on PacifiCorp's consolidated financial results.

(15) Revenue from Contracts with Customers

The following table summarizes PacifiCorp's Customer Revenue by line of business, with further disaggregation of retail by customer class, for the years ended December 31 (in millions):

	2025	2024	2023
Customer Revenue:			
Retail:			
Residential	$ 2,649	$ 2,382	$ 2,156
Commercial	2,417	2,096	1,829
Industrial	1,446	1,333	1,179
Other retail	446	351	298
Total retail	6,958	6,162	5,462
Wholesale	87	80	165
Transmission	188	176	151
Other Customer Revenue	134	121	129
Total Customer Revenue	7,367	6,539	5,907
Other revenue	126	61	29
Total operating revenue	$ 7,493	$ 6,600	$ 5,936

(16) Preferred Stock

As of December 31, 2025, PacifiCorp had 350 shares of Serial Preferred Stock authorized at the stated value of $1,000,000 per share, and 16 million shares of Preferred Stock authorized. There are no shares of PacifiCorp Serial Preferred Stock or Preferred Stock issued or outstanding.

As of December 31, 2024, PacifiCorp had 3,500 thousand shares of Serial Preferred Stock authorized at the stated value of $100 per share. PacifiCorp had 24 thousand shares of such Serial Preferred Stock issued and outstanding as of December 31, 2024. The outstanding preferred stock series were non-redeemable and had annual dividend rates of 6.00% and 7.00%.

In the event of voluntary liquidation, all preferred stock was entitled to stated value or a specified preference amount per share plus accrued dividends. Upon involuntary liquidation, all preferred stock was entitled to stated value plus accrued dividends. Dividends on all preferred stock were cumulative. Holders also had the right to elect members to the PacifiCorp Board of Directors in the event dividends payable are in default in an amount equal to four full quarterly payments.

As of December 31, 2024, PacifiCorp had 16 million shares of Preferred Stock authorized, but no shares were issued or outstanding.

On February 10, 2025, PacifiCorp effected a one-for-ten thousand reverse stock split ("Reverse Stock Split") of its Serial Preferred Stock.

As a result of the Reverse Stock Split, every 10,000 shares of each of PacifiCorp's pre-reverse split Serial Preferred Stock were combined and reclassified into one share of Serial Preferred Stock, with a corresponding reduction in the number of authorized shares of Serial Preferred Stock from 3,500 thousand to 350 and change to stated value of $100 to $1,000,000 per share. No fractional shares were issued in connection with the Reverse Stock Split and shareholders who would have otherwise held a fractional share of Serial Preferred Stock received payment in cash. As a result, all issued and outstanding shares of PacifiCorp's preferred stock as of February 10, 2025, were held by PPW Holdings LLC.

On April 23, 2025, PacifiCorp repurchased the sole outstanding share of its 7.00% Serial Preferred Stock from PPW Holdings LLC, for a purchase price of $1,800,000.

(17) Common Shareholder's Equity

Through PPW Holdings LLC, BHE is the sole shareholder of PacifiCorp's common stock. The state regulatory orders that authorized BHE's acquisition of PacifiCorp contain restrictions on PacifiCorp's ability to pay dividends to the extent that they would reduce PacifiCorp's common equity below specified percentages of defined capitalization. As of December 31, 2025, the most restrictive of these commitments prohibits PacifiCorp from making any distribution to PPW Holdings LLC or BHE without prior state regulatory approval to the extent that it would reduce PacifiCorp's common equity below 44.00% of its total capitalization, excluding short-term debt and current maturities of long-term debt. As of December 31, 2025, PacifiCorp's actual common equity percentage, as calculated under this measure, was 44.27%. BHE has indicated that it will suspend dividends for the next several years.

Certain of these commitments also indirectly limit PacifiCorp's capital structure by requiring the consolidated equity of PPW Holdings LLC to be no less than 44.00% of total consolidated PPW Holdings LLC capitalization, excluding short-term debt and current maturities of long-term debt. As of December 31, 2025, consolidated PPW Holdings LLC equity exceeded the threshold.

These commitments also restrict PacifiCorp from making any distributions to either PPW Holdings LLC or BHE if PacifiCorp's senior unsecured debt rating is BBB- or lower by Standard & Poor's Rating Services and Baa3 or lower by Moody's Investor Service. As of December 31, 2025, PacifiCorp met this minimum required senior unsecured debt rating commitment.

PacifiCorp is also subject to a maximum debt-to-total capitalization percentage under various financing agreements as further discussed in Note 7.

(18) Components of Accumulated Other Comprehensive Loss, Net

Accumulated other comprehensive loss, net consists of unrecognized amounts on retirement benefits, net of tax, of $10 million and $9 million as of December 31, 2025 and 2024, respectively.

(19) Variable Interest Entities

PacifiCorp holds a 66.67% interest in Bridger Coal Company ("Bridger Coal"), which supplies coal to the Jim Bridger generating facility that is owned 66.67% by PacifiCorp and 33.33% by PacifiCorp's joint venture partner in Bridger Coal. PacifiCorp purchases 66.67% of the coal produced by Bridger Coal, while the joint venture partner purchases the remaining 33.33% of the coal produced. The power to direct the activities that most significantly impact Bridger Coal's economic performance are shared with the joint venture partner. Each joint venture partner is jointly and severally liable for the obligations of Bridger Coal. Bridger Coal's necessary working capital to carry out its mining operations is financed by contributions from PacifiCorp and its joint venture partner. PacifiCorp's equity investment in Bridger Coal was $34 million and $42 million as of December 31, 2025 and 2024, respectively. Refer to Note 21 for information regarding related party transactions with Bridger Coal.

(20) Supplemental Cash Flow Disclosures

The summary of supplemental cash flow disclosures as of and for the years ended December 31 is as follows (in millions):

	2025	2024	2023
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	$ 664	$ 527	$ 432
Supplemental disclosure of non-cash investing and financing activities:			
Accruals related to property, plant and equipment additions	$ 776	$ 773	$ 862

(21) Related Party Transactions

PacifiCorp has an intercompany administrative services agreement and a mutual assistance agreement with BHE and its subsidiaries. Amounts charged to PacifiCorp by BHE and its subsidiaries under these agreements totaled $111 million, $147 million and $168 million during the years ended December 31, 2025, 2024 and 2023, respectively. Amounts charged to PacifiCorp in 2025 and 2024 were primarily reflected in construction work in progress on the Consolidated Balance Sheets as of December 31, 2025 and 2024. Payables associated with the charges were $150 million and $89 million as of December 31, 2025 and 2024, respectively. Amounts charged by PacifiCorp to BHE and its subsidiaries under these agreements totaled $31 million, $41 million and $44 million during the years ended December 31, 2025, 2024 and 2023, respectively. Receivables associated with the charges were $5 million as of December 31, 2025 and 2024. Such amounts primarily relate to information technology projects and other costs managed at a consolidated level and allocated or passed through to affiliates.

PacifiCorp also engages in various transactions with several subsidiaries of BHE in the ordinary course of business. Services provided by these subsidiaries in the ordinary course of business and charged to PacifiCorp primarily relate to wholesale electricity purchases and transmission of electricity and transportation of natural gas. These expenses totaled $11 million, $8 million and $6 million during the years ended December 31, 2025, 2024 and 2023, respectively.

PacifiCorp has long-term transportation contracts with BNSF Railway Company, an indirect wholly owned subsidiary of Berkshire Hathaway, PacifiCorp's ultimate parent company. Transportation costs under these contracts were $29 million, $22 million and $24 million during the years ended December 31, 2025, 2024 and 2023, respectively.

PacifiCorp is party to a tax allocation agreement and is part of the Berkshire Hathaway consolidated U.S. federal income tax return and certain BHE consolidated state income tax returns. Federal income taxes receivable from BHE were $94 million and state income taxes payable to BHE were $16 million as of December 31, 2025. Federal income taxes receivable from BHE were $3 million and state income taxes payable to BHE were $11 million as of December 31, 2024. For the years ended December 31, 2025, 2024 and 2023, cash refunded from BHE for federal and state income taxes totaled $65 million, $349 million and $292 million, respectively.

PacifiCorp transacts with its equity investees, Bridger Coal and Trapper Mining Inc. Services provided by equity investees to PacifiCorp primarily relate to coal purchases. During the years ended December 31, 2025, 2024 and 2023, coal purchases from PacifiCorp's equity investees totaled $122 million, $132 million and $139 million, respectively. Payables to PacifiCorp's equity investees were $32 million and $36 million as of December 31, 2025 and 2024, respectively.

Receivables from PPW Holdings LLC for invoices temporarily funded by PacifiCorp on PPW Holdings LLC's behalf were $18 million and $20 million as of December 31, 2025 and 2024, respectively.

In November 2025, PacifiCorp executed a Master Purchase and Sale Agreement, Project Schedule to Master Purchase and Sale Agreement and Master Lease Agreement (collectively, the "B2H Agreements") with BHE B2H, LLC ("BHE B2H"), a newly created wholly owned subsidiary of BHE. The B2H Agreements provide for sale and leaseback of the B2H Project that is currently under construction with joint owner Idaho Power Company. The B2H Project is expected to be placed into service by the end of 2027, at which time the sale and leaseback of the B2H Project between PacifiCorp and BHE B2H will occur. The aggregate purchase price paid by BHE B2H to PacifiCorp under the Agreements will be equal to PacifiCorp's total investment in the B2H Project and the lease term is set for 20 years with early purchase options by PacifiCorp available every five years at net book value beginning from the closing date of the proposed transactions. The sale leaseback of the B2H Project is subject to approvals by the FERC and the OPUC. Refer to Note 14 for information regarding construction commitments associated with the B2H Project.

(22) Subsequent Events

On February 15, 2026, PacifiCorp and Portland General Electric Company and an affiliate of Portland General Electric Company (together, the "PGE Entities") entered into an Asset Purchase and Service Area Transfer Agreement (the "Sale Agreement") to sell to the PGE Entities certain PacifiCorp assets and liabilities associated with PacifiCorp's Washington operations for a sales price of $1.9 billion in cash plus additional cash consideration for the value of specified assets delivered at closing, subject to customary purchase price adjustments (the "Transaction").

The Transaction assets and liabilities are associated with PacifiCorp's retail service area in Washington and include certain related distribution assets and infrastructure, as well as PacifiCorp's Chehalis combined cycle natural gas-fueled generating facility located in Chehalis, Washington, Goodnoe Hills wind-powered generating facility located in Goldendale, Washington, and Marengo wind-powered generating facility located in Dayton, Washington.

The Transaction has been approved by PacifiCorp's board of directors but is subject to customary closing conditions including (i) the expiration or termination of the waiting period and other required approvals under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, and (ii) the receipt of all necessary approvals, waivers and rulings from the FERC and each of PacifiCorp's six state public utility commissions. The Transaction is expected to close in the first half of 2027.

The Sale Agreement contains certain termination rights, including if the Transaction is not consummated by August 15, 2027, (subject to a six month extension to the extent certain regulatory approvals have not been received as of such date), and provides that upon termination of the Sale Agreement under certain specified circumstances, the terminating party would be required to pay the other party a termination fee of $35 million.

As a result of the Transaction, PacifiCorp expects that the associated assets and liabilities will be presented as assets held for sale in its first quarter 2026 Form 10-Q. As the Transaction is not expected to have major impact on PacifiCorp's operations or financial results particularly due to the scale of PacifiCorp's Washington operations and retail service territory relative to its overall operations and retail service territory, PacifiCorp does not expect to present the effects of the Transaction as a discontinued operation.

PacifiCorp believes the carrying value of the assets and liabilities are less than fair value and therefore does not expect to record a loss as a result of the Transaction. PacifiCorp expects to continue to depreciate the property, plant and equipment included in the Transaction as it will continue to operate and serve PacifiCorp's customers through closing of the Transaction and the costs to operate such property, plant and equipment will continue to be recovered in PacifiCorp's retail rates. Certain regulatory asset, regulatory liability, asset retirement obligation and deferred income tax balances will also be impacted by the Transaction.

MidAmerican Funding, LLC and its subsidiaries and MidAmerican Energy Company
Consolidated Financial Section

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following is management's discussion and analysis of certain significant factors that have affected the consolidated financial condition and results of operations of MidAmerican Funding and its subsidiaries and MidAmerican Energy during the periods included herein. Information in Management's Discussion and Analysis related to MidAmerican Energy, whether or not segregated, also relates to MidAmerican Funding. Information related to other subsidiaries of MidAmerican Funding pertains only to the discussion of the financial condition and results of operations of MidAmerican Funding. Where necessary, discussions have been segregated under the heading "MidAmerican Funding" to allow the reader to identify information applicable only to MidAmerican Funding. Explanations include management's best estimate of the impact of weather, customer growth, usage trends and other factors. This discussion should be read in conjunction with MidAmerican Funding's historical Consolidated Financial Statements and Notes to Consolidated Financial Statements and MidAmerican Energy's historical Financial Statements and Notes to Financial Statements each in Item 8 of this Form 10-K. MidAmerican Funding's and MidAmerican Energy's actual results in the future could differ significantly from the historical results.

Results of Operations

Overview

MidAmerican Energy -

MidAmerican Energy's net income for 2025 was $1,061 million, an increase of $58 million, or 6%, compared to 2024 primarily due to higher electric utility margin, higher allowances for equity and borrowed funds used during construction, lower interest expense and higher natural gas utility margin. These items were partially offset by an unfavorable income tax benefit, higher operations and maintenance expense, higher depreciation and amortization expense, higher property and other taxes, lower interest income and unfavorable changes in the cash surrender value of corporate-owned life insurance policies. Utility margin increased primarily due to higher wholesale margin, higher electric retail customer usage and the favorable impact of weather, partially offset by unfavorable price impacts from changes in sales mix, lower recoveries through bill riders, lower wind-turbine performance settlements and lower natural gas base rates. Electric retail customer volumes increased 10% primarily due to higher customer usage for certain industrial customers and the favorable impact of weather. Wholesale electricity sales volumes increased 6% due to favorable market conditions. Increased total electric sales of 8% coupled with lower renewable-powered generation from lower wind and lower natural gas generation from higher average fuel costs resulted in increased coal-fueled generation and energy purchased volumes. Natural gas retail customer volumes increased 11% due to the favorable impact of weather.

MidAmerican Energy's net income for 2024 was $1,003 million, an increase of $21 million, or 2%, compared to 2023 primarily due to a favorable income tax benefit, higher natural gas utility margin, higher interest income, higher allowances for equity and borrowed funds used during construction and favorable changes in the cash surrender value of corporate-owned life insurance policies. These items were partially offset by higher depreciation and amortization expense, higher interest expense, higher operations and maintenance expense, lower electric utility margin and higher property and other taxes. Utility margin increased primarily due to higher natural gas base rates and higher electric retail customer usage, partially offset by lower wholesale margin and the unfavorable impact of weather. Electric retail customer volumes increased 1.2% primarily due to higher customer usage for certain industrial customers, partially offset by lower customer usage for commercial and residential customers and the unfavorable impact of weather. Wholesale electricity sales volumes decreased 5% due to unfavorable market conditions. Energy generated increased 2% primarily due to 7% higher renewable-powered generation, partially offset by 13% lower coal-fueled generation. Energy purchased volumes decreased 23% primarily due to the increase in energy generated and decreased total sales of 1%. Natural gas retail customer volumes decreased 5% due to the unfavorable impact of weather.

MidAmerican Funding -

MidAmerican Funding's net income for 2025 was $1,048 million, an increase of $57 million, or 6%, compared to 2024. MidAmerican Funding's net income for 2024 was $991 million, an increase of $11 million, or 1%, compared to 2023. The increases were primarily due to the changes in MidAmerican Energy's earnings discussed above and a one-time gain on the sale of an investment of $10 million in 2023.

Non-GAAP Financial Measure

Management utilizes various key financial measures that are prepared in accordance with GAAP, as well as non-GAAP financial measures such as electric utility margin and natural gas utility margin, to help evaluate results of operations. Electric utility margin is calculated as regulated electric operating revenue less cost of fuel and energy, which are captions presented on the Statements of Operations. Natural gas utility margin is calculated as regulated natural gas operating revenue less cost of natural gas purchased for resale, which are included in regulated natural gas and other and cost of natural gas purchased for resale and other, respectively, on the Statements of Operations.

MidAmerican Energy's cost of fuel and energy and cost of natural gas purchased for resale are generally recovered from its retail customers through regulatory recovery mechanisms and, as a result, changes in MidAmerican Energy's expenses included in regulatory recovery mechanisms result in comparable changes to revenue. As such, management believes electric utility margin and natural gas utility margin more appropriately and concisely explain results of operations rather than a discussion of revenue and cost of sales separately. Management believes the presentation of electric utility margin and natural gas utility margin provides meaningful and valuable insight into the information management considers important to understanding the business and a measure of comparability to others in the industry.

Electric utility margin and natural gas utility margin are not measures calculated in accordance with GAAP and should be viewed as a supplement to, and not a substitute for, operating income, which is the most directly comparable financial measure prepared in accordance with GAAP. The following table provides a reconciliation of utility margin to operating income for the years ended December 31 (in millions):

	2025	2024	Change		2024	2023	Change	
Electric utility margin:								
Operating revenue	$ 3,124	$ 2,584	$ 540	21 %	$ 2,584	$ 2,673	$ (89)	(3)%
Cost of fuel and energy	713	430	283	66	430	501	(71)	(14)
Electric utility margin	2,411	2,154	257	12	2,154	2,172	(18)	(1)
Natural gas utility margin:								
Operating revenue	778	658	120	18	658	713	(55)	(8)
Cost of natural gas purchased for resale	480	367	113	31	367	451	(84)	(19)
Natural gas utility margin	298	291	7	2	291	262	29	11
Utility margin	2,709	2,445	264	11	2,445	2,434	11	—
Other operating revenue	5	9	(4)	(44)	9	7	2	29
Operations and maintenance	933	879	54	6	879	851	28	3
Depreciation and amortization	1,031	1,001	30	3	1,001	908	93	10
Property and other taxes	176	166	10	6	166	161	5	3
Operating income	$ 574	$ 408	$ 166	41 %	$ 408	$ 521	$ (113)	(22)%

Electric Utility Margin

A comparison of key operating results related to electric utility margin is as follows for the years ended December 31:

	2025	2024	Change		2024	2023	Change	
Utility margin (in millions):								
Operating revenue	$ 3,124	$ 2,584	$ 540	21 %	$ 2,584	$ 2,673	$ (89)	(3)%
Cost of fuel and energy	713	430	283	66	430	501	(71)	(14)
Utility margin	$ 2,411	$ 2,154	$ 257	12 %	$ 2,154	$ 2,172	$ (18)	(1)%
Sales (GWhs):								
Residential	7,068	6,691	377	6 %	6,691	6,759	(68)	(1)%
Commercial	4,064	3,926	138	4	3,926	3,992	(66)	(2)
Industrial	20,102	17,773	2,329	13	17,773	17,307	466	3
Other	1,679	1,646	33	2	1,646	1,617	29	2
Total retail	32,913	30,036	2,877	10	30,036	29,675	361	1
Wholesale	15,162	14,329	833	6	14,329	15,129	(800)	(5)
Total sales	48,075	44,365	3,710	8 %	44,365	44,804	(439)	(1)%
Average number of retail customers (in thousands)	838	829	9	1 %	829	820	9	1 %
Average revenue per MWh:								
Retail	$ 78.77	$ 76.13	$ 2.64	3 %	$ 76.13	$ 77.82	$ (1.69)	(2)%
Wholesale	$ 28.21	$ 13.44	$ 14.77	110 %	$ 13.44	$ 17.92	$ (4.48)	(25)%
Heating degree days	5,770	5,045	725	14 %	5,045	5,371	(326)	(6)%
Cooling degree days	1,222	1,188	34	3 %	1,188	1,255	(67)	(5)%
Sources of energy (GWhs)[1]:								
Wind, solar and hydroelectric [2]	26,291	26,691	(400)	(1)%	26,691	24,877	1,814	7 %
Coal	12,013	8,637	3,376	39	8,637	9,961	(1,324)	(13)
Nuclear	3,777	3,873	(96)	(2)	3,873	3,790	83	2
Natural gas	1,955	2,224	(269)	(12)	2,224	2,184	40	2
Total energy generated	44,036	41,425	2,611	6	41,425	40,812	613	2
Energy purchased	4,785	3,676	1,109	30	3,676	4,772	(1,096)	(23)
Total	48,821	45,101	3,720	8 %	45,101	45,584	(483)	(1)%
Average cost of energy per MWh:								
Energy generated[3]	$ 7.58	$ 5.67	$ 1.91	34 %	$ 5.67	$ 6.80	$ (1.13)	(17)%
Energy purchased	$ 77.36	$ 52.86	$ 24.50	46 %	$ 52.86	$ 46.86	$ 6.00	13 %

(1) GWh amounts are net of energy used by the related generating facilities.

(2) All or some of the renewable energy attributes associated with generation from these sources may be: (a) used in future years to comply with RPS or other regulatory requirements or (b) sold to third parties in the form of RECs or other environmental commodities.

(3) The average cost per MWh of energy generated includes only the cost of fuel associated with the generating facilities.

Natural Gas Utility Margin

A comparison of key operating results related to natural gas utility margin is as follows for the years ended December 31:

	2025	2024	Change		2024	2023	Change	
Utility margin (in millions):								
Operating revenue	$ 778	$ 658	$ 120	18 %	$ 658	$ 713	$ (55)	(8)%
Cost of natural gas purchased for resale	480	367	113	31	367	451	(84)	(19)
Utility margin	$ 298	$ 291	$ 7	2 %	$ 291	$ 262	$ 29	11 %
Throughput (000's Dths):								
Residential	49,998	44,615	5,383	12 %	44,615	47,558	(2,943)	(6)%
Commercial	24,239	21,648	2,591	12	21,648	22,715	(1,067)	(5)
Industrial	5,813	5,680	133	2	5,680	5,799	(119)	(2)
Other	89	73	16	22	73	76	(3)	(4)
Total retail sales	80,139	72,016	8,123	11	72,016	76,148	(4,132)	(5)
Wholesale sales	24,846	30,170	(5,324)	(18)	30,170	30,764	(594)	(2)
Total sales	104,985	102,186	2,799	3	102,186	106,912	(4,726)	(4)
Natural gas transportation service	111,772	108,666	3,106	3	108,666	106,422	2,244	2
Total throughput	216,757	210,852	5,905	3 %	210,852	213,334	(2,482)	(1)%
Average number of retail customers (in thousands)	811	803	8	1 %	803	796	7	1 %
Average revenue per retail Dth sold	$ 8.17	$ 7.70	$ 0.47	6 %	$ 7.70	$ 7.80	$ (0.10)	(1)%
Heating degree days	6,040	5,292	748	14 %	5,292	5,668	(376)	(7)%
Average cost of natural gas per retail Dth sold	$ 5.10	$ 4.59	$ 0.51	11 %	$ 4.59	$ 4.98	$ (0.39)	(8)%
Combined retail and wholesale average cost of natural gas per Dth sold	$ 4.57	$ 3.60	$ 0.97	27 %	$ 3.60	$ 4.22	$ (0.62)	(15)%

Year Ended December 31, 2025 Compared to Year Ended December 31, 2024

MidAmerican Energy -

Electric utility margin increased $257 million, or 12%, for 2025 compared to 2024 primarily due to:

- $136 million increase in wholesale utility margin, driven by a $124 million increase in margin per unit reflecting higher market prices, and $12 million, or 5.8%, increase in sales volumes; and
- $121 million increase in retail utility margin primarily due to $133 million from higher customer usage, $56 million from higher recoveries through bill riders (offset in income tax benefit), and $17 million from the favorable impact of weather, partially offset by $66 million of lower recoveries through bill riders (partially offset in operations and maintenance expense), $12 million due to price impacts from changes in sales mix and $7 million of lower wind-turbine performance settlements from higher wind plant availability. Retail customer volumes increased 9.6%.

Natural gas utility margin increased $7 million, or 2%, for 2025 compared to 2024 primarily due to:

- $10 million increase due to the favorable impact of weather; and
- $2 million increase from higher natural gas transportation margin; partially offset by
- $5 million decrease from lower base rates.

Operations and maintenance increased $54 million, or 6%, for 2025 compared to 2024 primarily due to higher other power generation costs of $23 million, higher electric distribution costs of $12 million, higher gas distribution costs of $10 million, higher steam generation costs of $10 million, and higher transmission costs from MISO of $9 million, partially offset by lower administrative and other costs of $11 million.

Depreciation and amortization increased $30 million, or 3%, for 2025 compared to 2024 primarily due to $32 million related to new and repowered wind-powered generating facilities and other plant placed in-service and $29 million from a regulatory mechanism that provides customers the retail energy benefits of certain wind-powered generation projects, partially offset by $31 million from lower Iowa revenue sharing accruals.

Property and other taxes increased $10 million, or 6%, for 2025 compared to 2024 primarily due to higher wind turbine property taxes and higher replacement taxes.

Interest expense decreased $12 million, or 3%, for 2025 compared to 2024 primarily due to lower average outstanding long-term debt balances.

Allowance for borrowed and equity funds increased $20 million, or 22%, for 2025 compared to 2024 primarily due to higher construction work-in-progress balances related to wind- and solar-powered generation projects.

Other, net decreased $17 million, or 20%, for 2025 compared to 2024 primarily due to lower interest income and lower cash surrender values of corporate-owned life insurance policies.

Income tax benefit decreased $123 million, or 15%, for 2025 compared to 2024. The effective tax rate was (208)% and (512)% for 2025 and 2024, respectively. The $123 million decrease was primarily due to lower PTCs of $47 million, higher pre-tax income and lower benefit from the effects of ratemaking.

Federal renewable electricity PTCs are earned as energy from qualifying wind- and solar-powered generating facilities is produced and sold and are based on a prescribed per-kilowatt rate pursuant to the applicable federal income tax law. Qualifying generating facilities are eligible for the credits for 10 years from the date the facilities are placed in-service. Beginning in late 2014, some of MidAmerican Energy's wind-powered generating facilities surpassed the 10-year eligibility period for earning the credits. Most of those facilities have since been repowered, and under IRS rules, qualifying repowered facilities are eligible for the available credits, for 10 years from the date they are returned to service. Refer to "Capital Expenditures" in Liquidity and Capital Resources for additional information about repowering and new wind- and solar-powered generation placed in-service.

Additionally, beginning in 2024, MidAmerican Energy's ownership of the Quad Cities Station qualifies for federal nuclear PTCs which provide a tax credit for qualifying production volumes subject to a phase-out based on annual gross receipts. Both the amount of the PTC and the gross receipt thresholds adjust annually for inflation over the duration of the program.

MidAmerican Funding -

Income tax benefit for MidAmerican Funding decreased $122 million, or 14%, for 2025 compared to 2024. The effective tax rate was (220)% for 2025 and (570)% for 2024. The $122 million decrease was primarily due to the factors discussed for MidAmerican Energy.

Year Ended December 31, 2024 Compared to Year Ended December 31, 2023

MidAmerican Energy -

Electric utility margin decreased $18 million, or 1%, for 2024 compared to 2023 primarily due to:

- $33 million decrease in wholesale utility margin due to lower margin per unit of $19 million, reflecting lower market prices, and lower volumes of $14 million or 5.3%; partially offset by
- $16 million increase in retail utility margin primarily due to $42 million from higher recoveries through bill riders (partially offset in operations and maintenance expense) and $24 million from higher customer usage, partially offset by $42 million of lower recoveries through bill riders (offset in income tax benefit) and $12 million from the unfavorable impact of weather. Retail customer volumes increased 1.2%.

Natural gas utility margin increased $29 million, or 11%, for 2024 compared to 2023 primarily due to:

- $32 million increase from higher base rates; and
- $5 million increase from higher natural gas transportation margin; partially offset by
- $8 million decrease due to the unfavorable impact of weather.

Operations and maintenance increased $28 million, or 3%, for 2024 compared to 2023 primarily due to higher electric distribution costs of $19 million, higher transmission costs from MISO of $9 million and higher energy efficiency costs of $8 million, partially offset by lower nuclear power generation costs of $8 million.

Depreciation and amortization increased $93 million, or 10%, for 2024 compared to 2023 primarily due to $56 million related to new and repowered wind-powered generating facilities and other plant placed in-service, $52 million from higher Iowa revenue sharing accruals and $5 million from a regulatory mechanism that provides customers the retail energy benefits of certain wind-powered generation projects, partially offset by $19 million from the write-off of certain assets in 2023.

Property and other taxes increased $5 million, or 3%, for 2024 compared to 2023 primarily due to higher wind turbine property taxes.

Interest expense increased $71 million, or 21%, for 2024 compared to 2023 primarily due to September 2023 and January 2024 long-term debt issuances.

Allowance for borrowed and equity funds increased $12 million, or 15%, for 2024 compared to 2023 primarily due to higher construction work-in-progress balances related to wind- and solar-powered generation projects.

Other, net increased $47 million, or 131%, for 2024 compared to 2023 primarily due to higher interest income and higher cash surrender values of corporate-owned life insurance policies.

Income tax benefit increased $146 million, or 21%, for 2024 compared to 2023. The effective tax rate was (512)% and (240)% for 2024 and 2023, respectively. The $146 million increase was primarily due to higher PTCs of $129 million and lower pre-tax income.

MidAmerican Funding -

Income tax benefit for MidAmerican Funding increased $148 million, or 21%, for 2024 compared to 2023. The effective tax rate was (570)% and (244)% for 2024 and 2023. The $148 million increase was primarily due to the factors discussed for MidAmerican Energy.

Liquidity and Capital Resources

As of December 31, 2025, MidAmerican Energy's and MidAmerican Funding's total net liquidity were as follows (in millions):

MidAmerican Energy:		
Cash and cash equivalents	$	670
Credit facilities, maturing 2026 and 2028		1,505
Less:		
Tax-exempt bond support		(258)
Net credit facilities		1,247
MidAmerican Energy total net liquidity	$	1,917
MidAmerican Funding:		
MidAmerican Energy total net liquidity	$	1,917
Cash and cash equivalents		2
MHC, Inc. credit facility, maturing 2026		4
MidAmerican Funding total net liquidity	$	1,923

Refer to Note 7 of the Notes to Financial Statements in Item 8 of this Form 10-K for further discussion regarding MidAmerican Energy's credit facilities and letters of credit.

On July 4, 2025, the One Big Beautiful Bill Act (the "OBBBA") was enacted, introducing substantial revisions to federal energy-related tax policy. Among its provisions, the OBBBA accelerates the phase-out of clean electricity production and investment tax credits and establishes new sourcing requirements applicable to facilities commencing construction after December 31, 2025. On July 7, 2025, a federal executive order (the "Executive Order") was issued directing the Secretary of the Treasury to promulgate new or revised guidance consistent with applicable law to ensure that policies concerning the "beginning of construction" requirements are not circumvented for wind and solar-powered generating facilities. In response, the U.S. Secretary of the Treasury issued partial guidance on September 2, 2025, through Notice 2025-42. While the guidance largely reaffirmed existing standards, it notably eliminated the five percent safe harbor method for establishing the beginning of construction for projects commencing construction on or after September 2, 2025. The OBBBA and Notice 2025-42 did not have a material impact on MidAmerican Energy's 2025 consolidated financial results.

MidAmerican Energy's future financial performance and capital expenditures related to renewable energy, storage and technology neutral projects may be affected by the combined effects of the OBBBA, the Executive Order, and broader macroeconomic and geopolitical conditions, including changes in international trade policies and tariff regimes. The pace of change in these areas accelerated during 2025, and uncertainty persists regarding the scope and duration of these external factors. However, MidAmerican Energy currently does not believe these items and any resulting changes to future capital project allocations will significantly impact its business in the near term.

Operating Activities

MidAmerican Energy's net cash flows from operating activities were $1.8 billion, $2.0 billion and $2.2 billion for 2025, 2024 and 2023, respectively. MidAmerican Funding's net cash flows from operating activities were $1.8 billion, $2.0 billion and $2.2 billion for 2025, 2024 and 2023, respectively. Cash flows from operating activities decreased for 2025 compared to 2024 primarily due to lower income tax receipts and higher accounts receivable balances, partially offset by higher utility margin for MidAmerican Energy's regulated electric and natural gas businesses. Cash flows from operating activities decreased for 2024 compared to 2023 primarily due to higher payments to vendors, lower utility margin for MidAmerican Energy's regulated electric business, higher interest payments and higher property tax payments, partially offset by higher income tax receipts, lower asset retirement obligation settlements and higher utility margin for MidAmerican Energy's regulated natural gas business.

The timing of MidAmerican Energy's income tax cash flows from period to period can be significantly affected by the estimated federal income tax payment methods selected and assumptions made for each payment date.

Investing Activities

MidAmerican Energy's net cash flows from investing activities were $(1.8) billion, $(1.7) billion and $(1.8) billion for 2025, 2024 and 2023, respectively. MidAmerican Funding's net cash flows from investing activities were $(1.8) billion, $(1.7) billion and $(1.8) billion for 2025, 2024 and 2023, respectively. Net cash flows from investing activities consist almost entirely of capital expenditures. Refer to "Future Uses of Cash" for further discussion of capital expenditures. Purchases and proceeds related to marketable securities primarily consist of activity within the Quad Cities Generating Station nuclear decommissioning trust and other trust investments.

Financing Activities

MidAmerican Energy's net cash flows from financing activities were $59 million, $(374) million and $(6) million for 2025, 2024 and 2023, respectively. MidAmerican Funding's net cash flows from financing activities were $79 million, $(361) million and $(6) million for 2025, 2024 and 2023, respectively. In 2025, 2024 and 2023, MidAmerican Energy paid $500 million, $425 million and $1,025 million, respectively, in cash dividends to its parent company, MHC Inc. In 2025, 2024 and 2023, MidAmerican Funding paid $474 million, $425 million and $1,025 million, respectively, in cash distributions to its sole member, BHE. Proceeds from long-term debt reflect MidAmerican Energy's issuance in November 2025 of $400 million of its 5.50% First Mortgage Bonds due November 2056, MidAmerican Energy's issuance in January 2024 of $600 million of its 5.30% First Mortgage Bonds due February 2055, and MidAmerican Energy's issuances in September 2023 of $350 million of its 5.350% First Mortgage Bonds due January 2034 and $1 billion of its 5.850% First Mortgage Bonds due September 2054. In 2025, 2024 and 2023, MidAmerican Energy repaid $17 million, $539 million and $317 million of long-term debt, respectively. MidAmerican Funding paid $6 million in 2025 and received $13 million in 2024 through its note payable with BHE.

Debt Authorizations and Related Matters

Short-term Debt

MidAmerican Energy has authority from the FERC to issue, through April 2, 2026, commercial paper and bank notes aggregating $1.5 billion, with new authorization through April 2, 2028, filed and pending approval. MidAmerican Energy has a $1.5 billion unsecured credit facility expiring in June 2028. The credit facility, which supports MidAmerican Energy's commercial paper program and its variable-rate tax-exempt bond obligations and provides for the issuance of letters of credit, has a variable interest rate based on the Secured Overnight Financing Rate, plus a spread that varies based on MidAmerican Energy's credit ratings for senior unsecured long-term debt securities. Additionally, MidAmerican Energy has a $5 million unsecured credit facility for general corporate purposes.

Long-term Debt and Preferred Stock

MidAmerican Energy currently has an effective shelf registration statement filed with the SEC to issue an unspecified amount of long-term debt securities and preferred stock through October 2028. MidAmerican Energy has authorization from the FERC to issue, through June 30, 2027, long-term debt securities up to an aggregate of $2.1 billion and preferred stock up to an aggregate of $500 million. MidAmerican Energy has authorization from the ICC through April 24, 2028, to issue long-term debt securities up to an aggregate of $2.75 billion and preferred stock up to an aggregate of $500 million.

MidAmerican Energy's mortgage dated September 9, 2013, creates a lien on most of MidAmerican Energy's electric utility property within the state of Iowa, allowing the issuance of bonds based on a percentage of eligible utility property additions, bond credits arising from retirement of previously outstanding bonds or deposits of cash. As of December 31, 2025, MidAmerican Energy estimated it would be able to issue up to $9.2 billion of new first mortgage bonds under the mortgage. Any issuances are subject to market conditions, and amounts are further limited by regulatory authorizations and commitments, as well as any more restrictive requirements of covenants and tests contained in other financing agreements. MidAmerican Energy also has the ability to release property from the lien of the mortgage on the basis of property additions, bond credits or deposits of cash.

MidAmerican Funding or one of its subsidiaries, including MidAmerican Energy, may from time to time seek to acquire its outstanding debt securities through cash purchases in the open market, privately negotiated transactions or otherwise. Any debt securities repurchased by MidAmerican Funding or one of its subsidiaries may be reissued or resold by MidAmerican Funding or one of its subsidiaries from time to time and will depend on prevailing market conditions, the issuing company's liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

Future Uses of Cash

MidAmerican Energy and MidAmerican Funding have available a variety of sources of liquidity and capital resources, both internal and external, including net cash flows from operating activities, public and private debt offerings, the issuance of commercial paper, the use of unsecured revolving credit facilities, and other sources. These sources are expected to provide funds required for current operations, capital expenditures, debt retirements and other capital requirements. The availability and terms under which MidAmerican Energy and MidAmerican Funding have access to external financing depends on a variety of factors, including their credit ratings, investors' judgment of risk and conditions in the overall capital markets, including the condition of the utility industry.

Capital Expenditures

MidAmerican Energy has significant future capital requirements. Capital expenditure needs are reviewed regularly by management and may change significantly as a result of these reviews, which may consider, among other factors, impacts to customers' rates; changes in environmental and other rules and regulations; the impact of U.S. federal executive orders; outcomes of regulatory proceedings; changes in income tax laws; general business conditions; load projections; system reliability standards; the cost and efficiency of construction labor, equipment and materials; commodity prices; and the cost and availability of capital.

MidAmerican Energy's historical and forecast capital expenditures, each of which exclude amounts for non-cash equity AFUDC and other non-cash items, for the years ended December 31 are as follows (in millions):

	Historical			Forecast		
	2023	2024	2025	2026	2027	2028
Wind generation	$ 744	$ 507	$ 656	$ 998	$ 874	$ 59
Electric transmission	205	245	247	355	634	561
Solar generation	13	3	40	162	582	873
Electric distribution	369	339	370	360	437	415
Other	502	610	460	695	1,019	895
Total	$ 1,833	$ 1,704	$ 1,773	$ 2,570	$ 3,546	$ 2,803

MidAmerican Energy's capital expenditures provided above consist of the following:

- Wind generation includes the construction, acquisition, repowering and operation of wind-powered generating facilities in Iowa. Growth expenditures include spending for the following:
  - Construction of wind-powered generating facilities totaled $233 million for 2025, $127 million for 2024 and $608 million for 2023. MidAmerican Energy placed in-service 214 MWs and 200 MWs of new wind-powered generation in 2025 and 2023, respectively. Planned spending for the construction of additional wind-powered generating facilities totals $239 million for 2026.
  - Repowering of wind-powered generating facilities totaled $346 million for 2025, $307 million for 2024 and $47 million for 2023. Planned spending for repowering totals $700 million and $815 million in 2026 and 2027, respectively. MidAmerican Energy expects its repowered facilities to meet IRS guidelines for the re-establishment of PTCs under the prevailing wage and apprenticeship guidelines for 10 years from the date the facilities are placed in-service.
- Electric transmission includes expenditures to meet retail demand growth, upgrades to accommodate third-party generator requirements and replacement of existing facilities to maintain system reliability.
- Solar generation includes the construction and operation of solar-powered generating facilities, with total spend of $40 million in 2025, $3 million in 2024 and $13 million in 2023. Planned spending for the construction and operation of solar-powered generating facilities totals $162 million, $582 million and $873 million for 2026, 2027 and 2028, respectively.
- Electric distribution includes expenditures for new facilities to meet retail demand growth and for replacement of existing facilities to maintain system reliability.
- Remaining expenditures primarily relate to the construction of new natural gas-powered generating facilities in Iowa, routine projects for other generation, natural gas distribution, technology, facilities and other operational needs to serve existing and expected demand.

Material Cash Requirements

MidAmerican Energy and MidAmerican Funding have cash requirements that may affect their financial condition that arise primarily from long- and short-term debt (refer to Notes 7 and 8), firm commitments (refer to Note 13) and construction and other development costs (refer to Liquidity and Capital Resources included within this Item 7) and AROs (refer to Note 11). Refer, where applicable, to the respective referenced note in Notes to Financial Statements in Item 8 of this Form 10-K for additional information.

MidAmerican Energy has cash requirements relating to interest payments of $8.1 billion on long-term debt, including $413 million due in 2026. Additionally, MidAmerican Funding has cash requirements relating to interest payments on its long-term debt of $58 million, including $16 million due in 2026.

Regulatory Matters

MidAmerican Energy is subject to comprehensive regulation. Refer to the discussion contained in Item 1 of this Form 10-K for further information regarding MidAmerican Energy's general regulatory framework and current regulatory matters.

Environmental Laws and Regulations

MidAmerican Energy is subject to federal, state and local laws and regulations regarding air quality, climate change, emissions performance standards, water quality, coal ash disposal and other environmental matters that have the potential to impact MidAmerican Energy's current and future operations. In addition to imposing continuing compliance obligations, these laws and regulations provide regulators with the authority to levy substantial penalties for noncompliance including fines, injunctive relief and other sanctions. These laws and regulations are administered by various federal, state and local agencies. MidAmerican Energy believes it is in material compliance with all applicable laws and regulations, although many are subject to interpretation that may ultimately be resolved by the courts. Environmental laws and regulations continue to evolve, and MidAmerican Energy is unable to predict the impact of the changing laws and regulations on its operations and financial results.

Refer to "Environmental Laws and Regulations" in Item 1 of this Form 10-K for further discussion regarding environmental laws and regulations.

Collateral and Contingent Features

Debt securities of MidAmerican Energy are rated by credit rating agencies. Assigned credit ratings are based on each rating agency's assessment of MidAmerican Energy's ability to, in general, meet the obligations of its issued debt securities. The credit ratings are not a recommendation to buy, sell or hold securities, and there is no assurance that a particular credit rating will continue for any given period of time. As of December 31, 2025, MidAmerican Energy's credit ratings for its senior secured debt and its issuer credit ratings for senior unsecured debt from the recognized credit rating agencies were investment grade. As a result of the issuance of first mortgage bonds by MidAmerican Energy in September 2013, its then outstanding senior unsecured debt was equally and ratably secured with such first mortgage bonds. Refer to Note 8 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K for a discussion of MidAmerican Energy's first mortgage bonds.

MidAmerican Funding and MidAmerican Energy have no credit rating downgrade triggers that would accelerate the maturity dates of its outstanding debt, and a change in ratings is not an event of default under the applicable debt instruments. MidAmerican Energy's unsecured revolving credit facilities do not require the maintenance of a minimum credit rating level in order to draw upon their availability. However, commitment fees and interest rates under the credit facilities are tied to credit ratings and increase or decrease when the ratings change. A ratings downgrade could also increase the future cost of commercial paper, short- and long-term debt issuances or new credit facilities.

In accordance with industry practice, certain wholesale agreements, including derivative contracts, contain credit support provisions that in part base MidAmerican Energy's collateral requirements on its credit ratings for senior unsecured debt as reported by one or more of the recognized credit rating agencies. These agreements may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance," or in some cases terminate the contract, in the event of a material adverse change in MidAmerican Energy's creditworthiness. These rights can vary by contract and by counterparty. If all credit-risk-related contingent features or adequate assurance provisions for these agreements had been triggered as of December 31, 2025, MidAmerican Energy would have been required to post $124 million of additional collateral. MidAmerican Energy's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation, or other factors.

Inflation

Historically, overall inflation and changing prices in the economies where MidAmerican Energy operates have not had a significant impact on its financial results. MidAmerican Energy operates under cost-of-service based rate-setting structures administered by various state commissions and the FERC. Under these rate-setting structures, MidAmerican Energy is allowed to include prudent costs in its rates, including the impact of inflation. MidAmerican Energy attempts to minimize the potential impact of inflation on its operations through the use of fuel, energy and other cost adjustment clauses and bill riders, by employing prudent risk management and hedging strategies and by considering, among other areas, inflation's impact on purchases of energy, operating expenses, materials and equipment costs, contract negotiations, future capital spending programs, and long-term debt issuances. There can be no assurance that such actions will be successful.

New Accounting Pronouncements

For a discussion of new accounting pronouncements affecting MidAmerican Energy and MidAmerican Funding, refer to Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Critical Accounting Estimates

Certain accounting measurements require management to make estimates and judgments concerning transactions that will be settled several years in the future. Amounts recognized on the Financial Statements based on such estimates involve numerous assumptions subject to varying and potentially significant degrees of judgment and uncertainty and will likely change in the future as additional information becomes available. The following critical accounting estimates are impacted significantly by MidAmerican Energy's methods, judgments and assumptions used in the preparation of the Financial Statements and should be read in conjunction with MidAmerican Energy's Summary of Significant Accounting Policies included in Note 2 of Notes to Financial Statements in Item 8 of this Form 10-K.

Accounting for the Effects of Certain Types of Regulation

MidAmerican Energy prepares its financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, MidAmerican Energy defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur.

MidAmerican Energy continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future regulated rates by considering factors such as a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation, other regulatory actions or the impact of competition, that could limit MidAmerican Energy's ability to recover its costs. MidAmerican Energy believes its application of the guidance for regulated operations is appropriate, and its existing regulatory assets and liabilities are probable of inclusion in future regulated rates. The evaluation reflects the current political and regulatory climate at both the federal and state levels. If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the related regulatory assets and liabilities will be written off to net income, returned to customers or re-established as AOCI. Total regulatory assets were $304 million and total regulatory liabilities were $1,323 million as of December 31, 2025. Refer to Note 5 of Notes to Financial Statements in Item 8 of this Form 10-K for additional information regarding regulatory assets and liabilities.

Impairment of Goodwill

MidAmerican Funding's Consolidated Balance Sheet as of December 31, 2025, includes goodwill from the acquisition of MHC totaling $1.3 billion. Goodwill is allocated to each reporting unit. MidAmerican Funding evaluates goodwill for impairment at least annually and completed its annual review as of October 31, 2025. Additionally, no indicators of impairment were identified as of December 31, 2025. Significant judgment is required in estimating the fair value of the reporting unit and performing goodwill impairment tests. MidAmerican Funding uses a variety of methods to estimate a reporting unit's fair value, principally discounted projected future net cash flows. Key assumptions used include, but are not limited to, the use of estimated future cash flows; multiples of earnings; and an appropriate discount rate. Estimated future cash flows are impacted by, among other factors, growth rates, changes in regulations and rates, ability to renew contracts and estimates of future commodity prices. In estimating future cash flows, MidAmerican Funding incorporates current market information, as well as historical factors.

Pension and Other Postretirement Benefits

MidAmerican Energy sponsors defined benefit pension and other postretirement benefit plans that cover the majority of the employees of BHE and its domestic energy subsidiaries other than PacifiCorp and NV Energy Inc. MidAmerican Energy recognizes the funded status of its defined benefit pension and other postretirement benefit plans on the Balance Sheets. Funded status is the fair value of plan assets minus the benefit obligation as of the measurement date. As of December 31, 2025, MidAmerican Energy recognized net assets totaling $77 million for the funded status of its defined benefit pension and other postretirement benefit plans. As of December 31, 2025, amounts not yet recognized as a component of net periodic benefit cost that were included in regulatory assets and regulatory liabilities totaled $16 million and $103 million, respectively.

The expense and benefit obligations relating to these defined benefit pension and other postretirement benefit plans are based on actuarial valuations. Inherent in these valuations are key assumptions, including, but not limited to, discount rates, expected long-term rate of return on plan assets and healthcare cost trend rates. These key assumptions are reviewed annually and modified as appropriate. MidAmerican Energy believes that the key assumptions utilized in recording obligations under the plans are reasonable based on prior plan experience and current market and economic conditions. Refer to Note 10 of Notes to Financial Statements in Item 8 of this Form 10-K for disclosures about MidAmerican Energy's defined benefit pension and other postretirement benefit plans, including the key assumptions used to calculate the funded status and net periodic benefit cost for these plans as of and for the year ended December 31, 2025.

MidAmerican Energy chooses a discount rate based upon high quality debt security investment yields in effect as of the measurement date that corresponds to cash flows over the expected benefit period. The pension and other postretirement benefit liabilities increase as the discount rate is reduced.

In establishing its assumption as to the expected long-term rate of return on plan assets, MidAmerican Energy utilizes the expected asset allocation and return assumptions for each asset class based on historical performance and forward-looking views of the financial markets. Pension and other postretirement benefits expense increases as the expected long-term rate of return on plan assets decreases. MidAmerican Energy regularly reviews its actual asset allocations and rebalances its investments to its targeted allocations when considered appropriate.

MidAmerican Energy chooses a healthcare cost trend rate that reflects the near and long-term expectations of increases in medical costs and corresponds to the expected benefit payment periods. The healthcare cost trend rate is assumed to gradually decline to 5.00% by 2035 at which point the rate of increase is assumed to remain constant.

The key assumptions used may differ materially from period to period due to changing market and economic conditions. These differences may result in a significant impact to pension and other postretirement benefits expense and funded status. If changes were to occur for the following key assumptions, the approximate effect on the Financial Statements of the total plan before allocations to affiliates would be as follows (in millions):

	Pension Plans		Other Postretirement Benefit Plans	
	+0.5%	-0.5%	+0.5%	-0.5%
Effect on December 31, 2024 Benefit Obligations:				
Discount rate	$ (20)	$ 22	$ (8)	$ 9
Effect on 2024 Periodic Cost:				
Discount rate	$ 1	$ (1)	$ —	$ —
Expected rate of return on plan assets	(2)	2	(1)	1

A variety of factors affect the funded status of the plans, including discount rates, asset returns, plan changes and MidAmerican Energy's funding policy for each plan.

Income Taxes

In determining MidAmerican Funding's and MidAmerican Energy's income taxes, management is required to interpret complex income tax laws and regulations, which includes consideration of regulatory implications imposed by MidAmerican Energy's various regulatory commissions. MidAmerican Funding's and MidAmerican Energy's income tax returns are subject to continuous examinations by federal, state and local tax authorities that may give rise to different interpretations of these complex laws and regulations. Due to the nature of the examination process, it generally takes years before these examinations are completed and these matters are resolved. MidAmerican Funding and MidAmerican Energy recognize the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the Consolidated Financial Statements from such a position are measured based on the largest benefit that is more-likely-than-not to be realized upon ultimate settlement. Although the ultimate resolution of their federal, state and local tax examinations is uncertain, each company believes it has made adequate provisions for its income tax positions. The aggregate amount of any additional income tax liabilities that may result from these examinations is not expected to have a material impact on its consolidated financial results. Refer to Note 9 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding income taxes.

It is probable that MidAmerican Energy will either refund to, or recover from its customers in certain state jurisdiction income tax benefits and expense related to the federal tax rate change from 35% to 21%, certain property-related basis differences, and other various differences. As of December 31, 2025, these amounts were recognized as a net regulatory asset of $9 million and will be included in regulated rates when the temporary differences reverse.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

MidAmerican Energy's Balance Sheets include assets and liabilities with fair values that are subject to market risks. MidAmerican Energy's significant market risks are primarily associated with commodity prices, interest rates and the extension of credit to counterparties with which it transacts. The following discussion addresses the significant market risks associated with MidAmerican Energy's business activities. MidAmerican Energy has established guidelines for credit risk management. Refer to Note 2 of Notes to Financial Statements in Item 8 of this Form 10-K for additional information regarding MidAmerican Energy's contracts accounted for as derivatives.

Commodity Price Risk

MidAmerican Energy is exposed to the impact of market fluctuations in commodity prices and interest rates. MidAmerican Energy is principally exposed to electricity, natural gas, coal and fuel oil commodity price risk as it has an obligation to serve retail customer load in its regulated service territory. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather; market liquidity; generating facility availability; customer usage; storage; and transmission and transportation constraints. Commodity price risk for MidAmerican Energy's regulated retail electricity and natural gas operations is significantly mitigated by the inclusion of energy costs in energy cost rider mechanisms, which permit the current recovery of such costs from its retail customers. MidAmerican Energy uses commodity derivative contracts, which may include forwards, futures, options, swaps and other agreements to mitigate price volatility on behalf of its customers. MidAmerican Energy does not engage in a material amount of proprietary trading activities.

Interest Rate Risk

MidAmerican Energy and MidAmerican Funding are exposed to interest rate risk on their outstanding variable-rate short- and long-term debt and future debt issuances. MidAmerican Energy and MidAmerican Funding manage interest rate risk by limiting their exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. As a result of the fixed interest rates, the fixed-rate long-term debt does not expose MidAmerican Energy or MidAmerican Funding to the risk of loss due to changes in market interest rates. Additionally, because fixed-rate long-term debt is not carried at fair value on the Consolidated Balance Sheets, changes in fair value would impact earnings and cash flows only if MidAmerican Energy or MidAmerican Funding were to reacquire all or a portion of these instruments prior to their maturity. MidAmerican Energy or MidAmerican Funding may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, to mitigate their exposure to interest rate risk. The nature and amount of their short- and long-term debt can be expected to vary from period to period as a result of future business requirements, market conditions and other factors. Refer to Notes 7, 8 and 12 of Notes to Consolidated Financial Statements in Item 1 of this Form 10-K for additional discussion of MidAmerican Energy's and MidAmerican Funding's short- and long-term debt.

As of December 31, 2025 and 2024, MidAmerican Energy had short- and long-term variable-rate obligations totaling $258 million and $271 million, respectively, that expose MidAmerican Energy to the risk of increased interest expense in the event of increases in short-term interest rates. The market risk related to MidAmerican Energy's variable-rate debt as of December 31, 2025, is not hedged. If variable interest rates were to increase by 10% from December 31 levels, it would not have a material effect on MidAmerican Energy's annual interest expense. The carrying value of the variable-rate obligations approximates fair value as of December 31, 2025 and 2024.

Credit Risk

MidAmerican Energy is exposed to counterparty credit risk associated with wholesale energy supply and marketing activities with other utilities, energy marketing companies, financial institutions and other market participants. Additionally, MidAmerican Energy participates in the RTO markets and has indirect credit exposure related to other participants, although RTO credit policies are designed to limit exposure to credit losses from individual participants. Credit risk may be concentrated to the extent MidAmerican Energy's counterparties have similar economic, industry or other characteristics and due to direct or indirect relationships among the counterparties. Before entering into a transaction, MidAmerican Energy analyzes the financial condition of each significant wholesale counterparty, establishes limits on the amount of unsecured credit to be extended to each counterparty, and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate wholesale counterparty credit risk, MidAmerican Energy enters into netting and collateral arrangements that may include margining and cross-product netting agreements and obtains third-party guarantees, letters of credit and cash deposits. If required, MidAmerican Energy exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

Substantially all of MidAmerican Energy's electric wholesale sales revenue results from participation in RTOs, including the MISO and the PJM. MidAmerican Energy's share of historical losses from defaults by other RTO market participants has not been material. Additionally, as of December 31, 2025, MidAmerican Energy's aggregate direct credit exposure from electric wholesale marketing counterparties was not material.

Item 8. Financial Statements and Supplementary Data

MidAmerican Energy Company

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
MidAmerican Energy Company
Des Moines, Iowa

Opinion on the Financial Statements

We have audited the accompanying balance sheets of MidAmerican Energy Company ("MidAmerican Energy") as of December 31, 2025 and 2024, the related statements of operations, changes in shareholder's equity, and cash flows for each of the three years in the period ended December 31, 2025, 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 MidAmerican Energy as of December 31, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of MidAmerican Energy's management. Our responsibility is to express an opinion on MidAmerican Energy's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to MidAmerican Energy 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. MidAmerican Energy is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of MidAmerican Energy's internal control over financial reporting. Accordingly, we express no such opinion.

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 Board of Directors 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 — Effects of Rate Regulation on the Financial Statements — Refer to Note 5 to the financial statements

Critical Audit Matter Description

MidAmerican Energy is subject to rate regulation by state public service commissions as well as the Federal Energy Regulatory Commission (collectively, the "Commissions"), which have jurisdiction with respect to the rates of electric and natural gas companies in the respective service territories where MidAmerican Energy operates. Management has determined its regulated operations meet the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. Accounting for the economic effects of rate regulation has a pervasive effect on the financial statements.

Regulated rates are subject to regulatory rate-setting processes. Rates are determined, approved, and established based on a cost-of-service basis, which is designed to allow MidAmerican Energy an opportunity to recover its prudently incurred costs of providing services and to earn a reasonable return on its invested capital. Regulatory decisions can have an effect on the recovery of costs, the rate of return earned on investment, and the timing and amount of assets to be recovered by rates. While MidAmerican Energy has indicated it expects to recover costs from customers through regulated rates, there is a risk that changes to the Commissions' approach to setting rates or other regulatory actions could limit MidAmerican Energy's ability to recover its costs.

We identified the effects of rate regulation on the financial statements 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 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) a refund to customers. Given that management's accounting judgments are based on assumptions about the outcome of 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 decisions by the Commissions included the following, among others:

- We evaluated MidAmerican Energy's disclosures related to the effects of rate regulation by testing recorded balances and evaluating regulatory developments.
- We read relevant regulatory orders issued by the Commissions, regulatory statutes, filings made by MidAmerican Energy and other external information. We evaluated relevant external information and compared it to certain recorded regulatory asset and liability balances for completeness.
- For certain regulatory matters, we inspected MidAmerican Energy's filings with the Commissions and the filings with the Commissions by intervenors to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedents of the Commissions' treatment of similar costs under similar circumstances.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
February 27, 2026

We have served as MidAmerican Energy's auditor since 1999.

MIDAMERICAN ENERGY COMPANY
BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2025	**2024**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 670	$ 549
Trade receivables, net	453	230
Income tax receivable	82	2
Inventories	334	369
Prepayments	119	117
Other current assets	63	63
Total current assets	1,721	1,330
Property, plant and equipment, net	24,056	22,765
Regulatory assets	304	622
Investments and restricted investments	1,274	1,147
Other assets	288	252
Total assets	$ 27,643	$ 26,116

The accompanying notes are an integral part of these financial statements.

MIDAMERICAN ENERGY COMPANY
BALANCE SHEETS (continued)
(Amounts in millions)

	As of December 31,	
	2025	**2024**
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Accounts payable	$ 505	$ 375
Accrued interest	120	117
Accrued property, income and other taxes	198	192
Current portion of long-term debt	4	17
Other current liabilities	96	91
Total current liabilities	923	792
Long-term debt	9,203	8,807
Regulatory liabilities	1,323	1,264
Deferred income taxes	3,760	3,626
Asset retirement obligations	870	823
Other long-term liabilities	822	623
Total liabilities	16,901	15,935
Commitments and contingencies (Note 13)		
Shareholder's equity:		
Common stock - 350 shares authorized, no par value, 71 shares issued and outstanding	—	—
Additional paid-in capital	561	561
Retained earnings	10,181	9,620
Total shareholder's equity	10,742	10,181
Total liabilities and shareholder's equity	$ 27,643	$ 26,116

The accompanying notes are an integral part of these financial statements.

MIDAMERICAN ENERGY COMPANY
STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2025	**2024**	**2023**
Operating revenue:			
Regulated electric	$ 3,124	$ 2,584	$ 2,673
Regulated natural gas and other	783	667	720
Total operating revenue	3,907	3,251	3,393
Operating expenses:			
Cost of fuel and energy	713	430	501
Cost of natural gas purchased for resale and other	480	367	451
Operations and maintenance	933	879	851
Depreciation and amortization	1,031	1,001	908
Property and other taxes	176	166	161
Total operating expenses	3,333	2,843	2,872
Operating income	574	408	521
Other income (expense):			
Interest expense	(405)	(417)	(346)
Allowance for borrowed funds	31	25	19
Allowance for equity funds	79	65	59
Other, net	66	83	36
Total other income (expense)	(229)	(244)	(232)
Income before income tax expense (benefit)	345	164	289
Income tax expense (benefit)	(716)	(839)	(693)
Net income	$ 1,061	$ 1,003	$ 982

The accompanying notes are an integral part of these financial statements.

MIDAMERICAN ENERGY COMPANY
STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY
(Amounts in millions)

	Common Stock	Additional Paid-in Capital	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2022	$ —	$ 561	$ 9,084	$ 9,645
Net income	—	—	982	982
Common stock dividends	—	—	(1,025)	(1,025)
Other equity transactions	—	—	1	1
Balance, December 31, 2023	—	561	9,042	9,603
Net income	—	—	1,003	1,003
Common stock dividends	—	—	(425)	(425)
Balance, December 31, 2024	—	561	9,620	10,181
Net income	—	—	1,061	1,061
Common stock dividends	—	—	(500)	(500)
Balance, December 31, 2025	$ —	$ 561	$ 10,181	$ 10,742

The accompanying notes are an integral part of these financial statements.

MIDAMERICAN ENERGY COMPANY
STATEMENTS OF CASH FLOWS
(Amounts in millions)

	Years Ended December 31,		
	2025	**2024**	**2023**
Cash flows from operating activities:			
Net income	$ 1,061	$ 1,003	$ 982
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	1,031	1,001	908
Amortization of utility plant to other operating expenses	37	35	34
Allowance for equity funds	(79)	(65)	(59)
Deferred income taxes and amortization of investment tax credits	77	81	90
Settlements of asset retirement obligations	(1)	(1)	(21)
Other, net	(22)	19	46
Changes in other operating assets and liabilities:			
Trade receivables and other assets	(212)	15	254
Inventories	35	(5)	(87)
Pension and other postretirement benefit plans, net	(5)	2	3
Accrued property, income and other taxes, net	(65)	(18)	76
Accounts payable and other liabilities	(26)	(89)	(9)
Net cash flows from operating activities	1,831	1,978	2,217
Cash flows from investing activities:			
Capital expenditures	(1,773)	(1,704)	(1,833)
Purchases of marketable securities	(439)	(327)	(243)
Proceeds from sales of marketable securities	434	313	227
Other investment proceeds	—	12	—
Other, net	9	15	12
Net cash flows from investing activities	(1,769)	(1,691)	(1,837)
Cash flows from financing activities:			
Common stock dividends	(500)	(425)	(1,025)
Proceeds from long-term debt	393	592	1,338
Repayments of long-term debt	(17)	(539)	(317)
Other, net	183	(2)	(2)
Net cash flows from financing activities	59	(374)	(6)
Net change in cash and cash equivalents and restricted cash and cash equivalents	121	(87)	374
Cash and cash equivalents and restricted cash and cash equivalents at beginning of year	555	642	268
Cash and cash equivalents and restricted cash and cash equivalents at end of year	$ 676	$ 555	$ 642

The accompanying notes are an integral part of these financial statements.

(1) Organization and Operations

MidAmerican Energy Company ("MidAmerican Energy") is a public utility with electric and natural gas operations and is the principal subsidiary of MHC Inc. ("MHC"). MHC is a holding company that conducts no business other than the ownership of its subsidiaries. MHC's nonregulated subsidiary is Midwest Capital Group, Inc. MHC is the direct wholly owned subsidiary of MidAmerican Funding, LLC ("MidAmerican Funding"), which is an Iowa limited liability company with Berkshire Hathaway Energy Company ("BHE") as its sole member. BHE is a holding company based in Des Moines, Iowa, that has investments in subsidiaries principally engaged in energy businesses. BHE is a wholly owned subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

(2) Summary of Significant Accounting Policies

Basis of Presentation

The Statements of Comprehensive Income have been omitted as net income equals comprehensive income for the years ended December 31, 2025, 2024 and 2023.

Use of Estimates in Preparation of Financial Statements

The preparation of the Financial Statements in conformity with accounting principles generally accepted in the United States of America ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the period. These estimates include, but are not limited to, the effects of regulation; certain assumptions made in accounting for pension and other postretirement benefits; asset retirement obligations ("AROs"); income taxes; unbilled revenue; valuation of certain financial assets and liabilities, including derivative contracts; and accounting for contingencies. Actual results may differ from the estimates used in preparing the Financial Statements.

A*ccounting for the Effects of Certain Types of Regulation*

MidAmerican Energy's utility operations are subject to the regulation of the Iowa Utilities Commission ("IUC"), the Illinois Commerce Commission ("ICC"), the South Dakota Public Utilities Commission, and the Federal Energy Regulatory Commission ("FERC"). MidAmerican Energy's accounting policies and the accompanying Financial Statements conform to GAAP applicable to rate-regulated enterprises and reflect the effects of the ratemaking process.

MidAmerican Energy prepares its financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, MidAmerican Energy defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur. If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the related regulatory assets and liabilities will be written off to net income, returned to customers or re-established as accumulated other comprehensive income (loss) ("AOCI").

Fair Value Measurements

As defined under GAAP, fair value is the price that would be received to sell an asset or paid to transfer a liability between market participants in the principal market or in the most advantageous market when no principal market exists. Adjustments to transaction prices or quoted market prices may be required in illiquid or disorderly markets in order to estimate fair value. Different valuation techniques may be appropriate under the circumstances to determine the value that would be received to sell an asset or paid to transfer a liability in an orderly transaction. Market participants are assumed to be independent, knowledgeable, able and willing to transact an exchange and not under duress. Nonperformance or credit risk is considered when determining fair value. Considerable judgment may be required in interpreting market data used to develop the estimates of fair value. Accordingly, estimates of fair value presented herein are not necessarily indicative of the amounts that could be realized in a current or future market exchange.

Cash and Cash Equivalents and Restricted Cash and Cash Equivalents

Cash equivalents consist of funds invested in money market mutual funds, U.S. Treasury Bills and other investments with a maturity of three months or less when purchased. Cash and cash equivalents exclude amounts where availability is restricted by legal requirements, loan agreements or other contractual provisions. Restricted cash and cash equivalents consist substantially of funds restricted for wildlife preservation. A reconciliation of cash and cash equivalents and restricted cash and cash equivalents as of December 31, 2025 and 2024 as presented on the Statements of Cash Flows is outlined below and disaggregated by the line items in which they appear on the Balance Sheets (in millions):

	As of December 31,	
	2025	2024
Cash and cash equivalents	$ 670	$ 549
Restricted cash and cash equivalents in other current assets	6	6
Total cash and cash equivalents and restricted cash and cash equivalents	$ 676	$ 555

Investments

Fixed Maturity Securities

MidAmerican Energy's management determines the appropriate classification of investments in fixed maturity securities at the acquisition date and reevaluates the classification at each balance sheet date. Investments that management does not intend to use or is restricted from using in current operations are presented as noncurrent on the Balance Sheets.

Available-for-sale investments are carried at fair value with realized gains and losses, as determined on a specific identification basis, recognized in earnings and unrealized gains and losses recognized in AOCI, net of tax. Realized and unrealized gains and losses on fixed maturity securities in a trust related to the decommissioning of the Quad Cities Generating Station Units 1 and 2 ("Quad Cities Station") are recorded as a net regulatory liability because MidAmerican Energy expects to refund to customers any decommissioning funds in excess of costs for these activities through regulated rates. Trading investments are carried at fair value with changes in fair value recognized in earnings. Held-to-maturity securities are carried at amortized cost, reflecting the ability and intent to hold the securities to maturity. The difference between the original cost and maturity value of a fixed maturity security is amortized to earnings using the interest method.

Investments gains and losses arise when investments are sold (as determined on a specific identification basis) or are other-than-temporarily impaired with respect to securities classified as available-for-sale. If the fair value of a fixed maturity investment declines to below amortized cost and the decline is deemed other than temporary, the amortized cost of the investment is reduced to fair value, with a corresponding charge to earnings. Any resulting impairment loss is recognized in earnings if MidAmerican Energy intends to sell, or expects to be required to sell, the debt security before its amortized cost is recovered. If MidAmerican Energy does not expect to ultimately recover the amortized cost basis even if it does not intend to sell the security, the credit loss component is recognized in earnings and any difference between fair value and the amortized cost basis, net of the credit loss, is reflected in other comprehensive income (loss) ("OCI"). For regulated investments, any impairment charge is offset by the establishment of a regulatory asset to the extent recovery in regulated rates is probable.

Equity Securities

All changes in fair value of equity securities in a trust related to the decommissioning of the Quad Cities Station are recorded as a net regulatory liability since MidAmerican Energy expects to refund to customers any decommissioning funds in excess of costs for these activities through regulated rates.

Allowance for Credit Losses

Trade receivables are primarily short-term in nature with stated collection terms of less than one year from the date of origination and are stated at the outstanding principal amount, net of an estimated allowance for credit losses. The allowance for credit losses is based on MidAmerican Energy's assessment of the collectability of amounts owed to it by its customers. This assessment requires judgment regarding the ability of customers to pay or the outcome of any pending disputes. In measuring the allowance for credit losses for trade receivables, MidAmerican Energy primarily utilizes credit loss history. However, it may adjust the allowance for credit losses to reflect current conditions and reasonable and supportable forecasts that deviate from historical experience. The changes in the balance of the allowance for credit losses, which is included in trade receivables, net on the Balance Sheets, is summarized as follows for the years ended December 31 (in millions):

	2025	2024	2023
Beginning balance	$ 11	$ 12	$ 14
Charged to operating costs and expenses, net	8	8	8
Write-offs, net	(11)	(9)	(10)
Ending balance	$ 8	$ 11	$ 12

Derivatives

MidAmerican Energy employs a number of different derivative contracts, including forwards, futures, options, swaps and other agreements, to manage price risk for electricity, natural gas and other commodities, and interest rate risk. Derivative contracts are recorded on the Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. Derivative balances reflect offsetting permitted under master netting agreements with counterparties and cash collateral paid or received under such agreements. Cash collateral received from or paid to counterparties to secure derivative contract assets or liabilities in excess of amounts offset is included in other current assets on the Balance Sheets.

Commodity derivatives used in normal business operations that are settled by physical delivery, among other criteria, are eligible for and may be designated as normal purchases or normal sales. Normal purchases or normal sales contracts are not marked to market, and settled amounts are recognized as operating revenue or cost of sales on the Statements of Operations.

For MidAmerican Energy's derivatives not designated as hedging contracts, the settled amount is generally included in regulated rates. Accordingly, the net unrealized gains and losses associated with interim price movements on contracts that are accounted for as derivatives and probable of inclusion in regulated rates are recorded as regulatory assets and liabilities.

Inventories

Inventories consist mainly of materials and supplies, totaling $244 million and $249 million as of December 31, 2025 and 2024, respectively, coal stocks, totaling $57 million and $86 million as of December 31, 2025 and 2024, respectively, and natural gas in storage, totaling $28 million and $29 million as of December 31, 2025 and 2024, respectively. The cost of materials and supplies, coal stocks and fuel oil is determined using the average cost method. The cost of stored natural gas is determined using the last-in-first-out method. With respect to stored natural gas, the replacement cost would be $26 million and $18 million higher as of December 31, 2025 and 2024, respectively.

Property, Plant and Equipment, Net

General

Additions to utility plant are recorded at cost. MidAmerican Energy capitalizes all construction-related material, direct labor and contract services, as well as indirect construction costs. Indirect construction costs include debt allowance for funds used during construction ("AFUDC") and equity AFUDC. The cost of additions and betterments are capitalized, while costs incurred that do not improve or extend the useful lives of the related assets are generally expensed. Additionally, MidAmerican Energy has regulatory arrangements in Iowa in which the carrying cost of certain utility plant has been reduced for amounts associated with electric returns on equity exceeding specified thresholds and retail energy benefits associated with certain wind-powered generation. Amounts expensed under these arrangements are included as a component of depreciation and amortization.

Depreciation and amortization for MidAmerican Energy's utility operations are computed by applying the composite or straight-line method based on either estimated useful lives or mandated recovery periods as prescribed by its various regulatory authorities. Depreciation studies are completed by MidAmerican Energy to determine the appropriate group lives, net salvage and group depreciation rates. These studies are reviewed and rates are ultimately approved by the applicable regulatory commission. Net salvage includes the estimated future residual values of the assets and any estimated removal costs recovered through approved depreciation rates. Estimated removal costs are recorded as either a cost of removal regulatory liability or an ARO liability on the Balance Sheets, depending on whether the obligation meets the requirements of an ARO. As actual removal costs are incurred, the associated liability is reduced.

Generally, when MidAmerican Energy retires or sells a component of utility plant, it charges the original cost, net of any proceeds from the disposition to accumulated depreciation. Any gain or loss on disposals of nonregulated assets is recorded through earnings.

Debt and equity AFUDC, which represent the estimated costs of debt and equity funds necessary to finance the construction of its regulated facilities, is capitalized by MidAmerican Energy as a component of utility plant, with offsetting credits to the Statements of Operations. AFUDC is computed based on guidelines set forth by the FERC. After construction is completed, MidAmerican Energy is permitted to earn a return on these costs as a component of the related assets, as well as recover these costs through depreciation expense over the useful lives of the related assets.

Asset Retirement Obligations

MidAmerican Energy recognizes AROs when it has a legal obligation to perform decommissioning or removal activities upon retirement of an asset. MidAmerican Energy's AROs are primarily related to decommissioning of the Quad Cities Station and obligations associated with its other generating facilities. The fair value of an ARO liability is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made, and is added to the carrying amount of the associated asset, which is then depreciated over the remaining useful life of the asset. Subsequent to the initial recognition, the ARO liability is adjusted for any revisions to the original estimate of undiscounted cash flows (with corresponding adjustments to utility plant) and for accretion of the ARO liability due to the passage of time. The difference between the ARO liability, the corresponding ARO asset included in utility plant, net and amounts recovered in rates to satisfy such liabilities is recorded as a regulatory asset or liability.

Impairment

MidAmerican Energy evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or when the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. Additionally, when evaluating the carrying value of regulated assets, MidAmerican Energy considers the impact of regulation on recoverability. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Statements of Operations.

Revenue Recognition

MidAmerican Energy uses a single five-step model to identify and recognize revenue from contracts with customers ("Customer Revenue") upon transfer of control of promised goods or services in an amount that reflects the consideration to which MidAmerican Energy expects to be entitled in exchange for those goods and services. MidAmerican Energy records sales, franchise and excise taxes collected directly from customers and remitted directly to the taxing authorities on a net basis on the Statements of Operations.

A majority of MidAmerican Energy's energy revenue is derived from tariff-based sales arrangements approved by various regulatory commissions. These tariff-based revenues are mainly comprised of energy, transmission, distribution and natural gas and have performance obligations to deliver energy products and services to customers which are satisfied over time as energy is delivered or services are provided.

Revenue from electric and natural gas customers is recognized as electricity or natural gas is delivered or services are provided. Revenue recognized includes billed and unbilled amounts. As of December 31, 2025 and 2024, unbilled revenue was $111 million and $109 million, respectively, and is included in trade receivables, net on the Balance Sheets.

The determination of customer billings is based on a systematic reading of customer meters and applicable rates. At the end of each month, amounts of energy provided to customers since the date of the last meter reading are estimated, and the corresponding unbilled revenue is recorded. Factors that can impact the estimate of unbilled revenue include, but are not limited to, seasonal weather patterns, total volumes supplied to the system, line losses and composition of customer classes. Unbilled revenue is reversed in the following month and billed revenue is recorded based on the subsequent meter readings.

All of MidAmerican Energy's regulated retail electric and natural gas sales are subject to energy adjustment clauses. MidAmerican Energy also has costs that are recovered, at least in part, through bill riders, including demand-side management and certain transmission costs. The clauses and riders allow MidAmerican Energy to adjust the amounts charged for electric and natural gas service as the related costs change. The costs recovered in revenue through use of the adjustment clauses and bill riders are charged to expense in the same year the related revenue is recognized. At any given time, these costs may be over or under collected from customers. The total under collection included in trade receivables, net at December 31, 2025, was $147 million and the total over collection included in trade receivables, net at December 31, 2024, was $16 million.

Unamortized Debt Premiums, Discounts and Issuance Costs

Premiums, discounts and issuance costs incurred for the issuance of long-term debt are amortized over the term of the related financing using the effective interest method.

Income Taxes

Berkshire Hathaway includes MidAmerican Funding and MidAmerican Energy in its consolidated U.S. federal and Iowa state income tax returns. MidAmerican Funding's and MidAmerican Energy's provisions for income taxes have been computed on a stand-alone basis.

Deferred income tax assets and liabilities are based on differences between the financial statement and income tax basis of assets and liabilities using enacted income tax rates expected to be in effect for the year in which the differences are expected to reverse. Changes in deferred income tax assets and liabilities associated with certain property-related basis differences and other various differences that MidAmerican Energy deems probable to be passed on to its customers in most state jurisdictions are charged or credited directly to a regulatory asset or liability and will be included in regulated rates when the temporary differences reverse. Other changes in deferred income tax assets and liabilities are included as a component of income tax expense. Changes in deferred income tax assets and liabilities attributable to changes in enacted income tax rates are charged or credited to income tax expense or a regulatory asset or liability in the period of enactment. Valuation allowances are established when necessary to reduce deferred income tax assets to the amount that is more-likely-than-not to be realized.

Investment tax credits are deferred and amortized over the estimated useful lives of the related properties or as prescribed by various regulatory commissions.

MidAmerican Funding and MidAmerican Energy recognize the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the Consolidated Financial Statements from such a position are measured based on the largest benefit that is more-likely-than-not to be realized upon ultimate settlement. MidAmerican Funding's and MidAmerican Energy's unrecognized tax benefits are primarily included in taxes accrued and other long-term liabilities on their respective Consolidated Balance Sheets. Estimated interest and penalties, if any, related to uncertain tax positions are included as a component of income tax expense (benefit) on the Consolidated Statements of Operations.

New Accounting Pronouncements

In December 2023, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2023-09, Income Taxes Topic 740, "Income Tax—Improvements to Income Tax Disclosures" which requires enhanced disclosures, including specific categories and disaggregation of information in the effective tax rate reconciliation, disaggregated information related to income taxes paid, income or loss from continuing operations before income tax expense or benefit, and income tax expense or benefit from continuing operations. This guidance is effective for annual reporting periods beginning after December 15, 2024. Early adoption is permitted and should be applied on a prospective basis, however retrospective application is permitted. MidAmerican Energy adopted this guidance for the fiscal year beginning January 1, 2025, under the retrospective method. The adoption did not have a material impact on MidAmerican Energy's Financial Statements, but did expand the disclosures included within Notes to Financial Statements. Refer to Note 9 for expanded rate reconciliation disclosures and disaggregation of income taxes paid.

In November 2024, the FASB issued ASU No. 2024-03, Income Statement—Reporting Comprehensive Income—Expense Disaggregation Disclosures Subtopic 220-40, "Disaggregation of Income Statement Expenses" which addresses requests from investors for more detailed information about certain expenses and requires disclosure of the amounts of purchases of inventory, employee compensation, depreciation and intangible asset amortization included in each relevant expense caption presented on the income statement. This guidance, as clarified in ASU 2025-01, is effective for annual reporting periods beginning after December 15, 2026 and interim reporting periods beginning after December 15, 2027. Early adoption is permitted and should be applied on a prospective basis, however retrospective application is permitted. MidAmerican Energy is currently evaluating the impact of adopting this guidance on its Financial Statements and disclosures included within Notes to Financial Statements.

(3) Property, Plant and Equipment, Net

Property, plant and equipment, net consists of the following as of December 31 (in millions):

	Depreciable Life	2025	2024
Utility plant:			
Generation	20-62 years	$ 18,804	$ 18,446
Transmission	55-80 years	3,297	3,029
Electric distribution	15-80 years	6,326	5,890
Natural gas distribution	30-75 years	2,600	2,413
Utility plant in-service		31,027	29,778
Accumulated depreciation and amortization		(8,304)	(8,572)
Utility plant in-service, net		22,723	21,206
Nonregulated property, net of accumulated depreciation and amortization	20-50 years	10	6
		22,733	21,212
Construction work-in-progress		1,323	1,553
Property, plant and equipment, net		$ 24,056	$ 22,765

Nonregulated property, net consists primarily of land not recoverable for regulated utility purposes.

The average depreciation and amortization rates applied to depreciable utility plant for the years ended December 31 were as follows:

	2025	2024	2023
Electric	3.1 %	3.1 %	3.3 %
Natural gas	3.0 %	3.0 %	2.8 %

Under a revenue sharing arrangement in Iowa, MidAmerican Energy accrues throughout the year a regulatory liability based on the extent to which its anticipated annual equity return exceeds specified thresholds, with an equal amount recorded in depreciation and amortization expense. The annual regulatory liability accrual reduces utility plant upon final determination of the amount. For the years ended December 31, 2025, 2024 and 2023, $49 million, $81 million, and $29 million, respectively, is reflected in depreciation and amortization expense on the Statements of Operations.

(4) Jointly Owned Utility Facilities

Under joint facility ownership agreements with other utilities, MidAmerican Energy, as a tenant in common, has undivided interests in jointly owned generation and transmission facilities. MidAmerican Energy accounts for its proportionate share of each facility, and each joint owner has provided financing for its share of each facility. Operating costs of each facility are assigned to joint owners based on their percentage of ownership or energy production, depending on the nature of the cost. Operating expenses on the Statements of Operations include MidAmerican Energy's share of the expenses of these facilities.

The amounts shown in the table below represent MidAmerican Energy's share in each jointly owned facility included in property, plant and equipment, net as of December 31, 2025 (dollars in millions):

	Company Share	Plant in Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
Louisa No. 1	88 %	$ 901	$ 576	$ 7
Quad Cities Nos. 1 and 2[1]	25	774	526	46
Walter Scott, Jr. No. 3	79	1,038	701	12
Walter Scott, Jr. No. 4[2]	60	218	124	5
George Neal No. 4	41	339	204	11
Ottumwa No. 1[2]	52	405	289	7
George Neal No. 3	72	599	349	10
Transmission facilities	Various	282	107	3
Total		$ 4,556	$ 2,876	$ 101

(1) Includes amounts related to nuclear fuel.

(2) Plant in-service and accumulated depreciation and amortization amounts are net of credits applied under Iowa regulatory arrangements totaling $1,067 million and $257 million, respectively.

(5) Regulatory Matters

Regulatory Assets

Regulatory assets represent costs that are expected to be recovered in future regulated rates. MidAmerican Energy's regulatory assets reflected on the Balance Sheets consist of the following as of December 31 (in millions):

	Weighted Average Remaining Life	2025	2024
Asset retirement obligations[1]	24 years	$ 201	$ 546
Demand side management	1 year	35	16
Unrealized loss on regulated derivative contracts	1 year	17	13
Employee benefit plans[2]	9 years	16	17
Deferred income taxes[3]	Various	9	—
Other	Various	26	30
Total		$ 304	$ 622

(1) Amount predominantly relates to AROs for fossil-fueled and wind-powered generating facilities. Refer to Note 11 for a discussion of AROs.

(2) Represents amounts not yet recognized as a component of net periodic benefit cost that are expected to be included in regulated rates when recognized.

(3) Amounts primarily represent income tax benefits related to state accelerated tax depreciation and certain property-related basis differences that were previously passed on to customers and will be included in regulated rates when the temporary differences reverse, offset by income tax liabilities primarily related to the federal tax rate change from 35% to 21% that are probable to be passed on to customers.

MidAmerican Energy had regulatory assets not earning a return on investment of $302 million and $620 million as of December 31, 2025 and 2024, respectively.

Regulatory Liabilities

Regulatory liabilities represent amounts expected to be returned to customers in future periods. MidAmerican Energy's regulatory liabilities reflected on the Balance Sheets consist of the following as of December 31 (in millions):

	Weighted Average Remaining Life	2025	2024
Asset retirement obligations[1]	28 years	$ 524	$ 443
Cost of removal[2]	25 years	488	452
Iowa electric revenue sharing[3]	Various	157	186
Employee benefit plans[4]	N/A	103	73
Pre-funded AFUDC on transmission MVPs[5]	54 years	31	33
Deferred income taxes[6]	Various	—	47
Other	Various	20	30
Total		$ 1,323	$ 1,264

(1) Amount represents the excess of nuclear decommission trust assets over the related ARO. Refer to Note 11 for a discussion of AROs.

(2) Amounts represent estimated costs, as accrued through depreciation rates and exclusive of ARO liabilities, of removing utility plant in accordance with accepted regulatory practices. Amounts are deducted from rate base or otherwise accrue a carrying cost.

(3) Represents accruals associated with a regulatory arrangement in Iowa in which equity returns exceeding specified thresholds reduce utility plant and retail electric energy cost recoveries as required.

(4) Represents amounts not yet recognized as a component of net periodic benefit cost that are to be returned to customers in future periods when recognized.

(5) Represents AFUDC accrued on transmission MVPs that is deducted from rate base as a result of the inclusion of related construction work-in-progress in rate base.

(6) Amounts primarily represent income tax liabilities primarily related to the federal tax rate change from 35% to 21% that are probable to be passed on to customers, offset by income tax benefits related to state accelerated tax depreciation and certain property-related basis differences that were previously passed on to customers and will be included in regulated rates when the temporary differences reverse.

(6) Investments and Restricted Investments

Investments and restricted investments consists of the following amounts as of December 31 (in millions):

	2025	2024
Nuclear decommissioning trust	$ 979	$ 871
Rabbi trusts	275	252
Other	20	24
Total	$ 1,274	$ 1,147

MidAmerican Energy has established a trust for the investment of funds for decommissioning the Quad Cities Station. The debt and equity securities in the trust are reported at fair value. Funds are invested in the trust in accordance with applicable federal and state investment guidelines and are restricted for use as reimbursement for costs of decommissioning the Quad Cities Station, which is currently licensed for operation until December 2032. As of December 31, 2025 and 2024, the fair value of the trust's funds was invested as follows: 56% and 55%, respectively, in domestic common equity securities, 29% and 31%, respectively, in U.S. government securities, 14% and 13%, respectively, in domestic corporate debt securities and 1% and 1%, respectively, in other securities.

Rabbi trusts primarily hold corporate-owned life insurance on certain current and former key executives and directors. The Rabbi trusts were established to hold investments used to fund the obligations of various nonqualified executive and director compensation plans and to pay the costs of the trusts. The amount represents the cash surrender value of all of the policies included in the Rabbi trusts, net of amounts borrowed against the cash surrender value. Changes in the cash surrender value of the policies are reflected in other income (expense) - other, net on the Statements of Operations.

(7) Short-term Debt and Credit Facilities

Interim financing of working capital needs and the construction program is obtained from unaffiliated parties through the sale of commercial paper or short-term borrowing from banks. The following table summarizes MidAmerican Energy's availability under its unsecured revolving credit facilities as of December 31 (in millions):

	2025	2024
Credit facilities	$ 1,505	$ 1,505
Less:		
Variable-rate tax-exempt bond support	(258)	(271)
Net credit facilities	$ 1,247	$ 1,234

As of December 31, 2025, MidAmerican Energy has a $1.5 billion unsecured credit facility expiring in June 2028 with an unlimited number of maturity extension options, subject to lender consent. The credit facility, which supports MidAmerican Energy's commercial paper program and its variable-rate tax-exempt bond obligations and provides for the issuance of letters of credit, has a variable interest rate based on the Secured Overnight Financing Rate ("SOFR") or a base rate, at MidAmerican Energy's option, plus a spread that varies based on MidAmerican Energy's credit ratings for senior unsecured long-term debt securities. Additionally, MidAmerican Energy has a $5 million unsecured credit facility, which expires June 2026 and has a variable interest rate based on SOFR, plus a spread.

MidAmerican Energy had no commercial paper borrowings outstanding of as of December 31, 2025 and 2024. The $1.5 billion credit facility requires that MidAmerican Energy's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.65 to 1.0 as of the last day of any quarter.

As of December 31, 2025, MidAmerican Energy was in compliance with the covenants of its credit facilities. MidAmerican Energy has authority from the FERC to issue commercial paper and bank notes aggregating $1.5 billion through April 2, 2026, with new authorization through April 2, 2028, filed and pending approval.

As of December 31, 2025 and 2024, MidAmerican Energy had $135 million of letter of credit capacity under its $1.5 billion unsecured credit facility, of which no amounts were outstanding. Additionally, as of December 31, 2025 and 2024, MidAmerican Energy had $57 million and $53 million, respectively, of letters of credit outstanding outside of its $1.5 billion unsecured credit facility in support of certain transactions required by third parties that generally have provisions that automatically extend the annual expiration dates for an additional year unless the issuing bank elects not to renew a letter of credit prior to the expiration date.

(8) Long-term Debt

MidAmerican Energy's long-term debt consists of the following, including amounts maturing within one year and unamortized premiums, discounts and debt issuance costs, as of December 31 (dollars in millions):

	Par Value	2025	2024
First mortgage bonds:			
3.10%, due 2027	$ 375	$ 375	$ 374
3.65%, due 2029	850	854	857
5.35%, due 2034	350	348	347
4.80%, due 2043	350	347	347
4.40%, due 2044	400	396	396
4.25%, due 2046	450	446	446
3.95%, due 2047	475	471	471
3.65%, due 2048	700	691	690
4.25%, due 2049	900	878	876
3.15%, due 2050	600	593	593
2.70%, due 2052	500	493	493
5.85%, due 2054	1,000	990	990
5.30%, due 2055	600	592	592
5.50%, due 2056	400	393	—
Notes:			
6.75% Series, due 2031	400	398	398
5.75% Series, due 2035	300	299	299
5.80% Series, due 2036	350	349	348
Transmission upgrade obligations, 3.201% to 7.812%, due 2036 to 2043	64	37	37
Variable-rate tax-exempt bond obligation series: (weighted average interest rate-2025-2.494%, 2024-3.359%):			
Due 2025	—	—	13
Due 2036	33	33	33
Due 2038	45	45	45
Due 2046	30	30	30
Due 2047	150	149	149
Total long-term debt	$ 9,322	$ 9,207	$ 8,824

Reflected as:

	2025	2024
Current portion of long-term debt	$ 4	$ 17
Long-term debt	9,203	8,807
Total long-term debt	$ 9,207	$ 8,824

Annual Repayments of Long-Term Debt

The annual repayments of MidAmerican Energy's long-term debt for the years beginning January 1, 2026, and thereafter, excluding unamortized premiums, discounts and debt issuance costs, are as follows (in millions):

2026	$ 4
2027	379
2028	4
2029	854
2030	4
2031 and thereafter	8,077
Total	$ 9,322

Pursuant to MidAmerican Energy's mortgage dated September 9, 2013, MidAmerican Energy's first mortgage bonds, currently and from time to time outstanding, are secured by a first mortgage lien on substantially all of its electric generating, transmission and distribution property within the state of Iowa, subject to certain exceptions and permitted encumbrances. Approximately $26 billion of MidAmerican Energy's eligible property, based on original cost, was subject to the lien of the mortgage as of December 31, 2025. Additionally, MidAmerican Energy's senior notes outstanding are equally and ratably secured with the first mortgage bonds as required by the indentures under which the senior notes were issued.

MidAmerican Energy's variable-rate tax-exempt bond obligations bear interest at rates that are periodically established through remarketing of the bonds in the short-term tax-exempt market. MidAmerican Energy, at its option, may change the mode of interest calculation for these bonds by selecting from among several floating or fixed rate alternatives. The interest rates shown in the table above are the weighted average interest rates as of December 31, 2025 and 2024. MidAmerican Energy maintains revolving credit facility agreements to provide liquidity for holders of these issues. Additionally, MidAmerican Energy's obligations associated with the $30 million and $150 million variable rate, tax-exempt bond obligations due 2046 and 2047, respectively, are secured by an equal amount of first mortgage bonds pursuant to MidAmerican Energy's mortgage dated September 9, 2013, as supplemented and amended.

As of December 31, 2025, MidAmerican Energy was in compliance with all of its applicable long-term debt covenants.

In March 1999, MidAmerican Energy committed to the IUC to use commercially reasonable efforts to maintain an investment grade rating on its long-term debt and to maintain its common equity level above 42% of total capitalization unless circumstances beyond its control result in the common equity level decreasing to below 39% of total capitalization. MidAmerican Energy must seek the approval from the IUC of a reasonable utility capital structure if MidAmerican Energy's common equity level decreases below 42% of total capitalization, unless the decrease is beyond the control of MidAmerican Energy. MidAmerican Energy is also required to seek the approval of the IUC if MidAmerican Energy's equity level decreases to below 39%, even if the decrease is due to circumstances beyond the control of MidAmerican Energy. As of December 31, 2025, MidAmerican Energy's common equity ratio was 54% computed on a basis consistent with its commitment. As a result of its regulatory commitment to maintain its common equity level above certain thresholds, MidAmerican Energy could dividend $4.0 billion as of December 31, 2025, without falling below 42%.

(9) Income Taxes

Berkshire Hathaway includes BHE and subsidiaries in its U.S. federal income tax return and BHE includes its subsidiaries in certain state income tax returns. Consistent with established regulatory practice, MidAmerican Energy's provision for income tax has been computed on a stand-alone basis, and substantially all of its currently payable or receivable income tax is remitted to or received from BHE pursuant to a tax allocation agreement. Income before income tax expense (benefit) as reported on the Statements of Operations, is all domestic.

MidAmerican Energy's income tax expense (benefit) consists of the following for the years ended December 31 (in millions):

	2025	2024	2023
Current:			
Federal	$ (782)	$ (885)	$ (755)
State	(11)	(35)	(28)
	(793)	(920)	(783)
Deferred:			
Federal	79	80	109
State	(1)	2	(18)
	78	82	91
Investment tax credits	(1)	(1)	(1)
Total	$ (716)	$ (839)	$ (693)

The following table presents income taxes paid (received), net of refunds, for the years ended December 31 (in millions):

	2025	2024	2023
Jurisdiction:			
Federal	$ (702)	$ (865)	$ (821)
State	(18)	(33)	(31)
Total[1]	$ (720)	$ (898)	$ (852)

(1) Substantially all income taxes paid or (received) by MidAmerican Energy are pursuant to a tax allocation agreement.

A reconciliation of the federal statutory income tax rate to MidAmerican Energy's effective income tax rate applicable to income before income tax expense (benefit) is as follows for the years ended December 31:

	2025		2024		2023	
	Amount	Percent	Amount	Percent	Amount	Percent
U.S. federal statutory income tax rate	$ 72	21.0 %	$ 34	21.0 %	$ 61	21.0 %
State income tax, net of federal income tax[1]	(10)	(2.9)	(26)	(15.9)	(36)	(12.5)
Energy-related tax credits	(762)	(221.5)	(811)	(494.5)	(682)	(236.0)
Nontaxable or nondeductible items	(3)	(0.9)	(5)	(3.3)	(2)	(0.7)
Changes in unrecognized tax benefits	1	0.3	1	0.6	1	0.3
Other adjustments:						
Effects of ratemaking	(15)	(4.4)	(32)	(19.5)	(34)	(11.8)
Other	1	0.3	—	—	(1)	(0.1)
Effective income tax rate	$ (716)	(208.1)%	$ (839)	(511.6)%	$ (693)	(239.8)%

(1) State tax in Iowa made up the majority (greater than 50%) of the tax effect in this category.

Energy-related tax credits relate primarily to production tax credits ("PTC") earned by MidAmerican Energy's wind- and solar-powered generating facilities. Federal renewable electricity PTCs are earned as energy from qualifying wind- and solar-powered generating facilities is produced and sold and are based on a per-kilowatt hour rate pursuant to the applicable federal income tax law. Wind- and solar-powered generating facilities are eligible for the credits for 10 years from the date the qualifying generating facilities are placed in-service.

MidAmerican Energy's net deferred income tax liability consists of the following as of December 31 (in millions):

	2025	2024
Deferred income tax assets:		
Regulatory liabilities	$ 271	$ 249
Asset retirement obligations	228	216
State carryforwards	65	66
Revenue sharing	39	47
Employee benefits	1	10
Other	47	80
Total deferred income tax assets	651	668
Valuation allowances	(2)	(2)
Total deferred income tax assets, net	649	666
Deferred income tax liabilities:		
Property-related items	(4,364)	(4,154)
Regulatory assets	(42)	(134)
Other	(3)	(4)
Total deferred income tax liabilities	(4,409)	(4,292)
Net deferred income tax liability	$ (3,760)	$ (3,626)

As of December 31, 2025, MidAmerican Energy's state tax carryforwards, principally related to $968 million of net operating losses, expire at various intervals between 2026 and 2046.

The U.S. Internal Revenue Service has closed or effectively settled its examination of MidAmerican Energy's income tax returns through December 31, 2013. The statute of limitations for MidAmerican Energy's income tax returns have expired for certain states through December 31, 2011 and December 31, 2013, and for other states through December 31, 2021, except for the impact of any federal audit adjustments.

A reconciliation of the beginning and ending balances of MidAmerican Energy's net unrecognized tax benefits is as follows for the years ended December 31 (in millions):

	2025	2024
Beginning balance	$ 22	$ 22
Additions based on tax positions related to the current year	8	5
Interest	2	2
Reductions based on tax positions related to the current year	(6)	(7)
Ending balance	$ 26	$ 22

As of December 31, 2025, MidAmerican Energy had unrecognized tax benefits totaling $60 million that, if recognized, would have an impact on the effective tax rate. The remaining unrecognized tax benefits relate to tax positions for which ultimate deductibility is highly certain but for which there is uncertainty as to the timing of such deductibility. Recognition of these tax benefits, other than applicable interest and penalties, would not affect MidAmerican Energy's effective income tax rate.

(10) Employee Benefit Plans

Defined Benefit Plan

MidAmerican Energy sponsors a noncontributory defined benefit pension plan covering a majority of all employees of BHE and its domestic energy subsidiaries other than PacifiCorp and NV Energy, Inc. Benefit obligations under the plan are based on a cash balance arrangement for salaried employees and most union employees and final average pay formulas for other union employees. MidAmerican Energy also maintains noncontributory, nonqualified defined benefit supplemental executive retirement plans ("SERP") for certain active and retired participants. In 2024, the defined benefit pension plan recorded a curtailment gain of $1 million as a result of certain plan amendments. In 2023, the defined benefit pension plan recorded a settlement gain of $3 million for previously unrecognized gains and losses as a result of excess lump sum distributions over the defined threshold.

MidAmerican Energy also sponsors certain postretirement healthcare and life insurance benefits covering substantially all retired employees of BHE and its domestic energy subsidiaries other than PacifiCorp and NV Energy, Inc. Under the plans, a majority of all employees of the participating companies may become eligible for these benefits if they reach retirement age. New employees are not eligible for benefits under the plans. MidAmerican Energy has been allowed to recover accrued pension and other postretirement benefit costs in its electric and gas service rates.

Net Periodic Benefit Cost

For purposes of calculating the expected return on pension plan assets, a market-related value is used. The market-related value of plan assets is calculated by spreading the difference between expected and actual investment returns on equity investments over a five-year period beginning after the first year in which they occur.

MidAmerican Energy bills to and is reimbursed currently for affiliates' share of the net periodic benefit costs from all plans in which such affiliates participate. In 2025, 2024 and 2023, MidAmerican Energy's share of the pension net periodic benefit cost was $(4) million, $(4) million and $(5) million, respectively. MidAmerican Energy's share of the other postretirement net periodic benefit cost in 2025, 2024 and 2023 totaled $(3) million, $1 million and $2 million, respectively.

Net periodic benefit cost for the plans of MidAmerican Energy and the aforementioned affiliates included the following components for the years ended December 31 (in millions):

	Pension			Other Postretirement		
	2025	2024	2023	2025	2024	2023
Service cost	$ 8	$ 9	$ 10	$ 3	$ 5	$ 5
Interest cost	31	31	32	12	13	13
Expected return on plan assets	(31)	(31)	(30)	(18)	(16)	(14)
Curtailment	—	(1)	—	—	—	—
Settlement	—	—	(3)	—	—	—
Net amortization	(1)	(1)	—	(2)	1	—
Net periodic benefit cost	$ 7	$ 7	$ 9	$ (5)	$ 3	$ 4

Funded Status

The following table is a reconciliation of the fair value of plan assets for the years ended December 31 (in millions):

	Pension		Other Postretirement	
	2025	2024	2025	2024
Plan assets at fair value, beginning of year	$ 522	$ 516	$ 306	$ 278
Employer contributions	7	7	2	3
Participant contributions	—	—	1	1
Actual return on plan assets	60	45	39	41
Benefits paid	(52)	(46)	(18)	(17)
Plan assets at fair value, end of year	$ 537	$ 522	$ 330	$ 306

The following table is a reconciliation of the benefit obligations for the years ended December 31 (in millions):

	Pension		Other Postretirement	
	2025	2024	2025	2024
Benefit obligation, beginning of year	$ 572	$ 598	$ 219	$ 241
Service cost	8	9	3	5
Interest cost	31	31	12	13
Participant contributions	—	—	1	1
Actuarial (gain) loss	4	(17)	8	(24)
Amendment	—	(3)	2	—
Benefits paid	(52)	(46)	(18)	(17)
Benefit obligation, end of year	$ 563	$ 572	$ 227	$ 219
Accumulated benefit obligation, end of year	$ 534	$ 542		

The funded status of the plans and the amounts recognized on the Balance Sheets as of December 31 are as follows (in millions):

	Pension		Other Postretirement	
	2025	2024	2025	2024
Plan assets at fair value, end of year	$ 537	$ 522	$ 330	$ 306
Less - Benefit obligation, end of year	563	572	227	219
Funded status	$ (26)	$ (50)	$ 103	$ 87
Amounts recognized on the Balance Sheets:				
Other assets	$ 49	$ 29	$ 103	$ 87
Other current liabilities	(7)	(7)	—	—
Other long-term liabilities	(68)	(72)	—	—
Amounts recognized	$ (26)	$ (50)	$ 103	$ 87

The SERP has no plan assets; however, MidAmerican Energy and BHE have Rabbi trusts that hold corporate-owned life insurance and other investments to provide funding for the future cash requirements of the SERP. The cash surrender value of all of the policies included in MidAmerican Energy's Rabbi trusts, net of amounts borrowed against the cash surrender value, plus the fair market value of other Rabbi trust investments, was $171 million and $157 million as of December 31, 2025 and 2024, respectively. These assets are not included in the plan assets in the above table, but are reflected in investments and restricted investments on the Balance Sheets. The projected and accumulated benefit obligations for the SERP were $74 million and $79 million at December 31, 2025 and 2024, respectively.

Unrecognized Amounts

The portion of the funded status of the plans not yet recognized in net periodic benefit cost as of December 31 is as follows (in millions):

	Pension		Other Postretirement	
	2025	2024	2025	2024
Net gain	$ (75)	$ (49)	$ (89)	$ (79)
Prior service (credit) cost	(4)	(5)	18	17
Total	$ (79)	$ (54)	$ (71)	$ (62)

MidAmerican Energy sponsors pension and other postretirement benefit plans on behalf of certain of its affiliates in addition to itself, and therefore, the portion of the funded status of the respective plans that has not yet been recognized in net periodic benefit cost is attributable to multiple entities. Additionally, substantially all of MidAmerican Energy's portion of such amounts is either refundable to or recoverable from its customers and is reflected as regulatory liabilities and regulatory assets.

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost for the years ended December 31, 2025 and 2024 is as follows (in millions):

	Regulatory Asset	Regulatory Liability	Receivables (Payables) with Affiliates	Total
Pension				
Balance, December 31, 2023	$ 16	$ (20)	$ (18)	$ (22)
Net loss (gain) arising during the year	1	(22)	(9)	(30)
Net prior service credit arising during the year	—	—	(3)	(3)
Net amortization	—	—	1	1
Total	1	(22)	(11)	(32)
Balance, December 31, 2024	17	(42)	(29)	(54)
Net gain arising during the year	(2)	(24)	—	(26)
Net amortization	—	—	1	1
Total	(2)	(24)	1	(25)
Balance, December 31, 2025	$ 15	$ (66)	$ (28)	$ (79)

	Regulatory Asset	Regulatory Liability	Receivables (Payables) with Affiliates	Total
Other Postretirement				
Balance, December 31, 2023	$ —	$ 4	$ (16)	$ (12)
Net gain arising during the year	—	(35)	(14)	(49)
Net amortization	—	—	(1)	(1)
Total	—	(35)	(15)	(50)
Balance, December 31, 2024	—	(31)	(31)	(62)
Net gain arising during the year	—	(7)	(7)	(14)
Net prior service cost arising during the year	—	—	3	3
Net amortization	—	1	1	2
Total	—	(6)	(3)	(9)
Balance, December 31, 2025	$ —	$ (37)	$ (34)	$ (71)

Plan Assumptions

Assumptions used to determine benefit obligations and net periodic benefit cost were as follows:

	Pension			Other Postretirement		
	2025	2024	2023	2025	2024	2023
Benefit obligations as of December 31:						
Discount rate	5.60 %	5.75 %	5.45 %	5.45 %	5.70 %	5.45 %
Rate of compensation increase	3.00 %	3.00 %	3.00 %	N/A	N/A	N/A
Interest crediting rates for cash balance plan						
2023	N/A	N/A	3.50 %	N/A	N/A	N/A
2024	N/A	3.81 %	3.50 %	N/A	N/A	N/A
2025	3.67 %	3.81 %	3.50 %	N/A	N/A	N/A
2026	3.67 %	3.81 %	3.50 %	N/A	N/A	N/A
2027	3.67 %	3.81 %	3.50 %	N/A	N/A	N/A
2028 and beyond	3.67 %	3.81 %	3.50 %	N/A	N/A	N/A
Net periodic benefit cost for the years ended December 31:						
Discount rate	5.75 %	5.45 %	5.70 %	5.70 %	5.45 %	5.60 %
Expected return on plan assets[(1)]	6.60 %	6.55 %	6.35 %	6.80 %	6.65 %	6.80 %
Rate of compensation increase	3.00 %	3.00 %	3.00 %	N/A	N/A	N/A
Interest crediting rates for cash balance plan	3.67 %	3.81 %	3.50 %	N/A	N/A	N/A

(1) Amounts reflected are pretax values. Assumed after-tax returns for a taxable, non-union other postretirement plan were 5.56% for 2025, 5.45% for 2024 and 5.52% for 2023.

In establishing its assumption as to the expected return on plan assets, MidAmerican Energy utilizes the asset allocation and return assumptions for each asset class based on historical performance and forward-looking views of the financial markets.

	2025	2024
Assumed healthcare cost trend rates as of December 31:		
Healthcare cost trend rate assumed for next year	7.00 %	7.00 %
Rate that the cost trend rate gradually declines to	5.00 %	5.00 %
Year that the rate reaches the rate it is assumed to remain at	2035	2033

Contributions and Benefit Payments

Employer contributions to the pension and other postretirement benefit plans are expected to be $7 million and $1 million, respectively, during 2026. Funding to MidAmerican Energy's qualified pension benefit plan trust is based upon the actuarially determined costs of the plan and the requirements of the Internal Revenue Code, the Employee Retirement Income Security Act of 1974 and the Pension Protection Act of 2006, as amended. MidAmerican Energy considers contributing additional amounts from time to time in order to achieve certain funding levels specified under the Pension Protection Act of 2006, as amended. MidAmerican Energy evaluates a variety of factors, including funded status, income tax laws and regulatory requirements, in determining contributions to its other postretirement benefit plans.

Net periodic benefit costs assigned to MidAmerican Energy affiliates are reimbursed currently in accordance with its intercompany administrative services agreement. The expected benefit payments to participants in MidAmerican Energy's pension and other postretirement benefit plans for 2026 through 2030 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments	
	Pension	Other Postretirement
2026	$ 56	$ 22
2027	53	23
2028	51	23
2029	51	23
2030	49	23
2031-2035	220	98

Plan Assets

Investment Policy and Asset Allocations

MidAmerican Energy's investment policy for its pension and other postretirement benefit plans is to balance risk and return through a diversified portfolio of debt securities, equity securities and other alternative investments. Maturities for debt securities are managed to targets consistent with prudent risk tolerances. The plans retain outside investment consultants to advise on plan investments within the parameters outlined by the Berkshire Hathaway Energy Company Investment Committee. The investment portfolio is managed in line with the investment policy with sufficient liquidity to meet near-term benefit payments.

The target allocations (percentage of plan assets) for MidAmerican Energy's pension and other postretirement benefit plan assets are as follows as of December 31, 2025:

	Pension	Other Postretirement
	%	%
Debt securities[(1)]	40-60	20-40
Equity securities[(1)]	30-60	60-80
Other	0-15	0-5

(1) For purposes of target allocation percentages and consistent with the plans' investment policy, investment funds are allocated based on the underlying investments in debt and equity securities.

Fair Value Measurements

The following table presents the fair value of plan assets, by major category, for MidAmerican Energy's defined benefit pension plan (in millions):

	Input Levels for Fair Value Measurements[1]			
	Level 1	Level 2	Level 3	Total
As of December 31, 2025:				
Cash equivalents	$ 8	$ —	$ —	$ 8
Debt securities:				
U.S. government obligations	26	—	—	26
Corporate obligations	—	115	—	115
Municipal obligations	—	5	—	5
Agency, asset and mortgage-backed obligations	—	14	—	14
Equity securities:				
U.S. companies	18	—	—	18
International companies	1	—	—	1
Total assets in the fair value hierarchy	$ 53	$ 134	$ —	187
Investment funds[2] measured at net asset value				350
Total assets measured at fair value				$ 537
As of December 31, 2024:				
Cash equivalents	$ —	$ 11	$ —	$ 11
Debt securities:				
U.S. government obligations	27	—	—	27
Corporate obligations	—	117	—	117
Municipal obligations	—	5	—	5
Agency, asset and mortgage-backed obligations	—	15	—	15
Equity securities:				
U.S. companies	53	—	—	53
International companies	1	—	—	1
Total assets in the fair value hierarchy	$ 81	$ 148	$ —	229
Investment funds[2] measured at net asset value				293
Total assets measured at fair value				$ 522

(1) Refer to Note 12 for additional discussion regarding the three levels of the fair value hierarchy.

(2) Investment funds are comprised of mutual funds and collective trust funds. These funds consist of equity and debt securities of approximately 73% and 27%, respectively, for 2025 and 71% and 29%, respectively, for 2024. Additionally, these funds are invested in U.S. and international securities of approximately 91% and 9%, respectively, for 2025 and 94% and 6%, respectively, for 2024.

The following table presents the fair value of plan assets, by major category, for MidAmerican Energy's defined benefit other postretirement plans (in millions):

	Input Levels for Fair Value Measurements[1]			
	Level 1	Level 2	Level 3	Total
As of December 31, 2025:				
Cash equivalents	$ 22	$ —	$ —	$ 22
Debt securities:				
U.S. government obligations	2	—	—	2
Corporate obligations	—	4	—	4
Municipal obligations	—	28	—	28
Agency, asset and mortgage-backed obligations	—	3	—	3
Equity securities:				
Investment funds[2]	271	—	—	271
Total assets measured at fair value	$ 295	$ 35	$ —	$ 330
As of December 31, 2024:				
Cash equivalents	$ 9	$ —	$ —	$ 9
Debt securities:				
U.S. government obligations	2	—	—	2
Corporate obligations	—	3	—	3
Municipal obligations	—	25	—	25
Agency, asset and mortgage-backed obligations	—	3	—	3
Equity securities:				
Investment funds[2]	264	—	—	264
Total assets measured at fair value	$ 275	$ 31	$ —	$ 306

(1) Refer to Note 12 for additional discussion regarding the three levels of the fair value hierarchy.

(2) Investment funds are comprised of mutual funds and collective trust funds. These funds consist of equity and debt securities of approximately 83% and 17%, respectively, for 2025 and 84% and 16%, respectively, for 2024. Additionally, these funds are invested in U.S. and international securities of approximately 100% and 0%, respectively, for 2025 and 84% and 16%, respectively, for 2024.

For level 1 investments, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value. For level 2 investments, the fair value is determined using pricing models based on observable market inputs. Shares of mutual funds not registered under the Securities Act of 1933, private equity limited partnership interests, common and commingled trust funds and investment entities are reported at fair value based on the net asset value per unit, which is used for expedience purposes. A fund's net asset value is based on the fair value of the underlying assets held by the fund less its liabilities.

Defined Contribution Plan

MidAmerican Energy sponsors a defined contribution plan ("401(k) plan") covering substantially all employees. MidAmerican Energy's matching contributions are based on each participant's level of contribution, and certain participants receive contributions based on eligible pretax annual compensation. Contributions cannot exceed the maximum allowable for tax purposes. Certain participants now receive enhanced benefits in the 401(k) plan and no longer accrue benefits in the noncontributory defined benefit pension plans. MidAmerican Energy's contributions to the plan were $37 million, $36 million, and $34 million for the years ended December 31, 2025, 2024 and 2023, respectively.

(11) Asset Retirement Obligations

MidAmerican Energy estimates its ARO liabilities based upon detailed engineering calculations of the amount and timing of the future cash spending for a third party to perform the required work. Spending estimates are escalated for inflation and then discounted at a credit-adjusted, risk-free rate. Changes in estimates could occur for a number of reasons, including changes in laws and regulations, plan revisions, inflation and changes in the amount and timing of the expected work.

MidAmerican Energy does not recognize liabilities for AROs for which the fair value cannot be reasonably estimated. Due to the indeterminate removal date, the fair value of the associated liabilities on certain generation, transmission, distribution and other assets cannot currently be estimated, and no amounts are recognized on the Financial Statements other than those included in the cost of removal regulatory liability established via approved depreciation rates in accordance with accepted regulatory practices. These accruals totaled $488 million and $452 million as of December 31, 2025 and 2024, respectively.

The following table presents MidAmerican Energy's ARO liabilities by asset type as of December 31 (in millions):

	2025	2024
Quad Cities Station	$ 455	$ 428
Wind-powered generating facilities	337	318
Fossil-fueled generating facilities	81	79
Solar-powered generating facilities and other	3	4
Total asset retirement obligations	$ 876	$ 829
Quad Cities Station nuclear decommissioning trust funds[(1)]	$ 979	$ 871

(1) Refer to Note 6 for a discussion of the Quad Cities Station nuclear decommissioning trust funds.

The following table reconciles the beginning and ending balances of MidAmerican Energy's ARO liabilities for the years ended December 31 (in millions):

	2025	2024
Beginning balance	$ 829	$ 778
Change in estimated costs	9	(2)
Additions	3	20
Retirements	(1)	(1)
Accretion	36	34
Ending balance	$ 876	$ 829
Reflected as:		
Other current liabilities	$ 6	$ 6
Asset retirement obligations	870	823
	$ 876	$ 829

Retirements in 2025 and 2024 relate to settlements of MidAmerican Energy's coal combustion residuals ARO liabilities.

The Nuclear Regulatory Commission regulates the decommissioning of the Quad Cities Station, which includes the planning and funding for the decommissioning. In accordance with these regulations, MidAmerican Energy submits a biennial report to the Nuclear Regulatory Commission providing reasonable assurance that funds will be available to pay for its share of the Quad Cities Station decommissioning.

Certain of MidAmerican Energy's decommissioning and reclamation obligations relate to jointly owned facilities. MidAmerican Energy is committed to pay a proportionate share of the decommissioning or reclamation costs. In the event of a default by any of the other joint participants, MidAmerican Energy may be obligated to absorb, directly or by paying additional sums to the entity, a proportionate share of the defaulting party's liability. MidAmerican Energy's estimated share of the decommissioning and reclamation obligations are primarily recorded as ARO liabilities.

In May 2024, the United States Environmental Protection Agency published its final rule on legacy coal combustion residuals ("CCR") surface impoundments and CCR management units ("CCRMUs") in the Federal Register. CCRMUs include CCR surface impoundments and landfills closed before October 19, 2015 and inactive CCR landfills. The final rule contains three main components: (1) a definition for legacy CCR surface impoundments, which are inactive surface impoundments at inactive generating facilities that must adhere to the same regulations as inactive CCR impoundments at active generating facilities, barring location restrictions and liner design criteria, with customized compliance deadlines; (2) groundwater monitoring, corrective action, closure, and post closure care requirements for CCRMUs, which may be located at active generating facilities and inactive generating facilities with a legacy CCR surface impoundment; and (3) the owners and operators of inactive generating facilities must identify the presence of legacy CCR surface impoundments and comply with all rule requirements for surface impoundments; and the owners and operators of active generating facilities and inactive generating facilities with a legacy CCR surface impoundment must prepare Facility Evaluation Reports ("FERs") that identify and describe the CCRMUs and determine whether closure is required. In February 2026, the EPA extended certain compliance deadlines with CCRMUs. Accordingly, and in a manner consistent with existing CCR rules, owners and operators must publish FERs on their CCR websites in two parts, within 12 months (Part 1) and 24 months (Part 2) of the final rule's effective date in February 2026. MidAmerican Energy is currently evaluating the final rule and does not anticipate identifying any legacy surface impoundments, but does anticipate identifying CCRMUs subject to the rule. Due to the number of site investigations warranted by this rule and the nature of engineering and other studies required at each site, MidAmerican Energy is unable to reasonably estimate the potential impact, which may be material, to its asset retirement obligations.

(12) Fair Value Measurements

The carrying value of MidAmerican Energy's cash, certain cash equivalents, receivables, payables, accrued liabilities and short-term borrowings approximates fair value because of the short-term maturity of these instruments. MidAmerican Energy has various financial assets and liabilities that are measured at fair value on the Financial Statements using inputs from the three levels of the fair value hierarchy. A financial asset or liability classification within the hierarchy is determined based on the lowest level input that is significant to the fair value measurement. The three levels are as follows:

- Level 1 - Inputs are unadjusted quoted prices in active markets for identical assets or liabilities that MidAmerican Energy has the ability to access at the measurement date.
- Level 2 - Inputs include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means (market corroborated inputs).
- Level 3 - Unobservable inputs reflect MidAmerican Energy's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. MidAmerican Energy develops these inputs based on the best information available, including its own data.

The following table presents MidAmerican Energy's financial assets and liabilities recognized on the Balance Sheets and measured at fair value on a recurring basis (in millions):

	Input Levels for Fair Value Measurements				
	Level 1	Level 2	Level 3	Other[1]	Total
As of December 31, 2025:					
Assets:					
Commodity derivatives	$ —	$ 3	$ 1	$ (2)	$ 2
Money market mutual funds	622				622
Debt securities:					
U.S. government obligations	284				284
Corporate obligations		133			133
Municipal obligations		2			2
Equity securities:					
U.S. companies	548				548
International companies	9				9
Investment funds	20				20
	$ 1,483	$ 138	$ 1	$ (2)	$ 1,620
Liabilities:					
Commodity derivatives	$ —	$ (18)	$ (3)	$ 7	$ (14)
As of December 31, 2024:					
Assets:					
Commodity derivatives	$ —	$ 5	$ 1	$ (3)	$ 3
Money market mutual funds	538	—	—	—	538
Debt securities:					
U.S. government obligations	271	—	—	—	271
Corporate obligations	—	109	—	—	109
Municipal obligations	—	2	—	—	2
Equity securities:					
U.S. companies	479	—	—	—	479
International companies	9	—	—	—	9
Investment funds	23	—	—	—	23
	$ 1,320	$ 116	$ 1	$ (3)	$ 1,434
Liabilities:					
Commodity derivatives	$ —	$ (15)	$ (3)	$ 6	$ (12)

(1) Represents netting under master netting arrangements and a net cash collateral receivable of $5 million and $3 million as of December 31, 2025 and 2024, respectively.

MidAmerican Energy's investments in money market mutual funds and debt and equity securities are stated at fair value, with debt securities accounted for as available-for-sale securities. When available, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value. In the absence of a quoted market price or net asset value of an identical security, the fair value is determined using pricing models or net asset values based on observable market inputs and quoted market prices of securities with similar characteristics.

The following table reconciles the beginning and ending balances of MidAmerican Energy's commodity derivative assets and liabilities measured at fair value on a recurring basis using significant Level 3 inputs (in millions):

	2025	2024	2023
Beginning balance	$ (2)	$ (11)	$ 5
Changes in fair value recognized in net regulatory assets	(6)	(13)	(40)
Settlements	6	22	24
Ending balance	$ (2)	$ (2)	$ (11)

MidAmerican Energy's long-term debt is carried at cost on the Financial Statements. The fair value of MidAmerican Energy's long-term debt is a Level 2 fair value measurement and has been estimated based upon quoted market prices, where available, or at the present value of future cash flows discounted at rates consistent with comparable maturities with similar credit risks. The carrying value of MidAmerican Energy's variable-rate long-term debt approximates fair value because of the frequent repricing of these instruments at market rates. The following table presents the carrying value and estimated fair value of MidAmerican Energy's long-term debt as of December 31 (in millions):

	2025		2024	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 9,207	$ 8,416	$ 8,824	$ 7,911

(13) Commitments and Contingencies

Commitments

MidAmerican Energy had the following firm commitments that are not reflected on the Balance Sheet. Minimum payments as of December 31, 2025, are as follows (in millions):

	2026	2027	2028	2029	2030	2031 and Thereafter	Total
Contract type:							
Coal and natural gas for generation	$ 128	$ 66	$ 35	$ —	$ —	$ —	$ 229
Electric capacity and transmission	35	34	34	26	26	36	191
Natural gas contracts for gas operations	242	122	67	37	33	44	545
Construction commitments	351	337	17	7	—	—	712
Easements	49	49	51	51	52	1,589	1,841
Maintenance, services and other	164	138	101	80	9	12	504
	$ 969	$ 746	$ 305	$ 201	$ 120	$ 1,681	$ 4,022

Coal, Natural Gas, Electric Capacity and Transmission Commitments

MidAmerican Energy has coal supply and related transportation and lime contracts for its coal-fueled generating facilities. MidAmerican Energy expects to supplement the coal contracts with additional contracts and spot market purchases to fulfill its future coal supply needs. Additionally, MidAmerican Energy has a natural gas transportation contract for a natural gas-fueled generating facility. The contracts have minimum payment commitments ranging through 2028.

MidAmerican Energy has various natural gas supply and transportation contracts for its regulated natural gas operations that have minimum payment commitments ranging through 2037.

MidAmerican Energy has contracts to purchase electric capacity that have minimum payment commitments ranging through 2028. MidAmerican Energy also has contracts for the right to transmit electricity over other entities' transmission lines with minimum payment commitments ranging through 2032.

Construction Commitments

MidAmerican Energy's firm construction commitments reflected in the table above consist primarily of contracts for the repowering of wind-powered generating facilities and construction of new natural gas-powered and solar-powered generating facilities.

In January 2026, MidAmerican Energy entered into firm construction commitments totaling $255 million for 2026 through 2028 related to the construction of new natural gas-powered generating facilities in Iowa.

Easements

MidAmerican Energy has non-cancelable easements with minimum payment commitments ranging through 2065 for land in Iowa on which certain of its assets, primarily wind- and solar-powered generating facilities, are located.

Maintenance, Services and Other Contracts

MidAmerican Energy has other non-cancelable contracts primarily related to maintenance and services for various generating facilities with minimum payment commitments ranging through 2035.

Environmental Laws and Regulations

MidAmerican Energy is subject to federal, state and local laws and regulations regarding air quality, climate change, emissions performance standards, water quality, coal ash disposal and other environmental matters that have the potential to impact its current and future operations. MidAmerican Energy believes it is in material compliance with all applicable laws and regulations.

Legal Matters

MidAmerican Energy is party to a variety of legal actions arising out of the normal course of business. MidAmerican Energy does not believe that such normal and routine litigation will have a material impact on its financial results.

(14) Revenue from Contracts with Customers

MidAmerican Energy uses a single five-step model to identify and recognize Customer Revenue upon transfer of control of promised goods or services to customers in an amount that reflects the consideration to which it expects to be entitled in exchange for those goods or services. The following table summarizes MidAmerican Energy's revenue by line of business and customer class, including a reconciliation to MidAmerican Energy's reportable segment information included in Note 19, (in millions):

	For the Year Ended December 31, 2025			
	Electric	**Natural Gas**	**Other**	**Total**
Customer Revenue:				
Retail:				
Residential	$ 783	$ 454	$ —	$ 1,237
Commercial	359	169	—	528
Industrial	1,293	26	—	1,319
Natural gas transportation services	—	54	—	54
Other retail	158	4	—	162
Total retail	2,593	707	—	3,300
Wholesale	409	71	—	480
Multi-value transmission projects	53	—	—	53
Other Customer Revenue	—	—	5	5
Total Customer Revenue	3,055	778	5	3,838
Other revenue	69	—	—	69
Total operating revenue	$ 3,124	$ 778	$ 5	$ 3,907

	For the Year Ended December 31, 2024			
	Electric	Natural Gas	Other	Total
Customer Revenue:				
Retail:				
Residential	$ 729	$ 392	$ —	$ 1,121
Commercial	333	138	—	471
Industrial	1,069	17	—	1,086
Natural gas transportation services	—	51	—	51
Other retail	156	6	—	162
Total retail	2,287	604	—	2,891
Wholesale	168	53	—	221
Multi-value transmission projects	53	—	—	53
Other Customer Revenue	—	—	9	9
Total Customer Revenue	2,508	657	9	3,174
Other revenue	76	1	—	77
Total operating revenue	$ 2,584	$ 658	$ 9	$ 3,251

	For the Year Ended December 31, 2023			
	Electric	Natural Gas	Other	Total
Customer Revenue:				
Retail:				
Residential	$ 735	$ 420	$ —	$ 1,155
Commercial	344	152	—	496
Industrial	1,075	20	—	1,095
Natural gas transportation services	—	46	—	46
Other retail	155	—	—	155
Total retail	2,309	638	—	2,947
Wholesale	230	73	—	303
Multi-value transmission projects	54	—	—	54
Other Customer Revenue	—	—	7	7
Total Customer Revenue	2,593	711	7	3,311
Other revenue	80	2	—	82
Total operating revenue	$ 2,673	$ 713	$ 7	$ 3,393

(15) Shareholder's Equity

In 2025 and 2024, MidAmerican Energy paid $500 million and $425 million, respectively, in cash dividends to its parent company, MHC.

(16) Other Income (Expense)

Other, net, as shown on the Statements of Operations, includes the following other income (expense) items for the years ended December 31 (in millions):

	2025	2024	2023
Corporate-owned life insurance income	$ 22	$ 29	$ 23
Non-service cost components of postretirement employee benefit plans	10	8	8
Interest income and other, net	34	46	5
Total	$ 66	$ 83	$ 36

(17) Supplemental Cash Flow Disclosures

The summary of supplemental cash flow disclosures as of and for the years ending December 31 is as follows (in millions):

	2025	2024	2023
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	$ 365	$ 374	$ 300
Supplemental disclosure of non-cash investing transactions:			
Accruals related to property, plant and equipment additions	$ 239	$ 108	$ 193

(18) Related Party Transactions

The companies identified as affiliates of MidAmerican Energy are Berkshire Hathaway and its subsidiaries, including BHE and its subsidiaries. The basis for the following transactions is provided for in service agreements between MidAmerican Energy and the affiliates.

MidAmerican Energy is reimbursed for charges incurred on behalf of its affiliates. The majority of these reimbursed expenses are for general costs, such as insurance and building rent, and for employee wages, benefits and costs related to corporate functions such as information technology, human resources, treasury, legal and accounting. The amount of such reimbursements was $85 million, $88 million and $94 million for 2025, 2024 and 2023, respectively.

MidAmerican Energy reimbursed BHE in the amount of $76 million, $124 million and $123 million in 2025, 2024 and 2023, respectively, for its share of technology costs, corporate expenses and other costs. Amounts charged to MidAmerican Energy in 2025 and 2024 were primarily reflected in construction work-in-progress on the Balance Sheets as of December 31, 2025 and 2024.

MidAmerican Energy purchases, in the normal course of business at either tariffed or market prices, natural gas transportation and storage capacity services from Northern Natural Gas Company, a wholly owned subsidiary of BHE, and coal transportation services from BNSF Railway Company, an indirect wholly owned subsidiary of Berkshire Hathaway. These purchases totaled $142 million, $133 million and $141 million in 2025, 2024 and 2023, respectively.

MidAmerican Energy had accounts receivable from affiliates of $35 million and $19 million as of December 31, 2025 and 2024, respectively, that are included in other current assets on the Balance Sheets. MidAmerican Energy also had accounts payable to affiliates of $34 million and $16 million as of December 31, 2025 and 2024, respectively, that are included in accounts payable on the Balance Sheets.

MidAmerican Energy is party to a tax allocation agreement and is part of the Berkshire Hathaway consolidated U.S. federal income tax return and certain BHE consolidated state income tax returns. For current federal and state income taxes, MidAmerican Energy had a net receivable from BHE of $79 million and $1 million as of December 31, 2025 and 2024, respectively. MidAmerican Energy received net cash payments for federal and state income taxes from BHE totaling $720 million, $898 million and $852 million for the years ended December 31, 2025, 2024 and 2023, respectively.

MidAmerican Energy recognizes the full amount of the funded status for its pension and postretirement plans, and amounts attributable to MidAmerican Energy's affiliates that have not previously been recognized through income are recognized as an intercompany balance with such affiliates. MidAmerican Energy adjusts these balances when changes to the funded status of the respective plans are recognized and does not intend to settle the balances currently. Amounts receivable from affiliates attributable to the funded status of employee benefit plans totaled $73 million and $70 million as of December 31, 2025 and 2024, respectively, and are included in other assets on the Balance Sheets. Similar amounts payable to affiliates totaled $77 million and $69 million as of December 31, 2025 and 2024, respectively, and are included in other long-term liabilities on the Balance Sheets. See Note 10 for further information pertaining to pension and postretirement accounting.

(19) Segment Information

MidAmerican Energy's chief operating decision maker ("CODM") is its President and Chief Executive Officer. Net income for each reportable segment is considered by the CODM in allocating resources and capital. The CODM generally considers actual results versus historical results, budgets or forecasts, as well as unique risks and opportunities, when making decisions about the allocation of resources and capital to each reportable segment.

MidAmerican Energy has identified two reportable operating segments: regulated electric and regulated natural gas. The regulated electric segment derives most of its revenue from regulated retail sales of electricity to residential, commercial, and industrial customers and from wholesale sales. The regulated natural gas segment derives most of its revenue from regulated retail sales of natural gas to residential, commercial, and industrial customers and also obtains revenue by transporting natural gas owned by others through its distribution system. Pricing for regulated electric and regulated natural gas sales are established separately by regulatory agencies; therefore, management also reviews each segment separately to make decisions regarding allocation of resources and in evaluating performance. Common operating costs are allocated to each segment based on certain factors, which primarily relate to the nature of the cost.

The following tables provide information on a reportable segment basis for the year ended December 31 (in millions):

	2025			
	Electric	Natural Gas	Other[1]	Total
Operating revenue	$ 3,124	$ 778	$ 5	$ 3,907
Cost of sales	713	480	—	1,193
Operations and maintenance	784	148	1	933
Depreciation and amortization	962	69	—	1,031
Property and other taxes	162	14	—	176
Interest expense	374	31	—	405
Interest and dividend income	30	3	—	33
Income tax expense (benefit)	(724)	8	—	(716)
Other segment items[2]	134	12	(3)	143
Net income	$ 1,017	$ 43	$ 1	$ 1,061
Capital expenditures	$ 1,622	$ 150	$ 1	$ 1,773

	2024			
	Electric	Natural Gas	Other[1]	Total
Operating revenue	$ 2,584	$ 658	$ 9	$ 3,251
Cost of sales	430	367	—	797
Operations and maintenance	757	121	1	879
Depreciation and amortization	935	66	—	1,001
Property and other taxes	152	14	—	166
Interest expense	387	30	—	417
Interest and dividend income	37	3	—	40
Income tax expense (benefit)	(841)	(1)	3	(839)
Other segment items[2]	129	7	(3)	133
Net income	$ 930	$ 71	$ 2	$ 1,003
Capital expenditures	$ 1,580	$ 114	$ 10	$ 1,704

	2023			
	Electric	Natural Gas	Other[1]	Total
Operating revenue	$ 2,673	$ 713	$ 7	$ 3,393
Cost of sales	501	451	—	952
Operations and maintenance	711	138	2	851
Depreciation and amortization	846	62	—	908
Property and other taxes	144	17	—	161
Interest expense	320	26	—	346
Interest and dividend income	22	2	—	24
Income tax expense (benefit)	(676)	(14)	(3)	(693)
Other segment items[2]	80	15	(5)	90
Net income	$ 929	$ 50	$ 3	$ 982
Capital expenditures	$ 1,683	$ 149	$ 1	$ 1,833

	As of December 31,		
	2025	2024	2023
Assets:			
Regulated electric	$ 25,495	$ 24,159	$ 23,334
Regulated natural gas	2,145	1,956	1,900
Other[1]	3	1	1
Total assets	$ 27,643	$ 26,116	$ 25,235

(1) The differences between the reportable segment amounts and the consolidated amounts, described as Other, relate to nonregulated activities of the Company.

(2) Other segment items include allowance for borrowed and equity funds, gains (losses) on marketable securities and other income (expense).

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Managers and Member of
MidAmerican Funding, LLC
Des Moines, Iowa

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of MidAmerican Funding, LLC and subsidiaries ("MidAmerican Funding") as of December 31, 2025 and 2024, the related consolidated statements of operations, changes in member's equity, and cash flows for each of the three years in the period ended December 31, 2025, the related notes and the schedule listed in the Index at Item 15(a)(2) (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of MidAmerican Funding as of December 31, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of MidAmerican Funding's management. Our responsibility is to express an opinion on MidAmerican Funding's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to MidAmerican Funding 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 and in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. MidAmerican Funding is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of MidAmerican Funding's internal control over financial reporting. Accordingly, we express no such opinion.

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 Board of Directors 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 — Effects of Rate Regulation on the Financial Statements — Refer to Note 5 to the financial statements

Critical Audit Matter Description

MidAmerican Funding is subject to rate regulation by state public service commissions as well as the Federal Energy Regulatory Commission (collectively, the "Commissions"), which have jurisdiction with respect to the rates of electric and natural gas companies in the respective service territories where MidAmerican Funding operates. Management has determined its regulated operations meet the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. Accounting for the economic effects of rate regulation has a pervasive effect on the financial statements.

Regulated rates are subject to regulatory rate-setting processes. Rates are determined, approved, and established based on a cost-of-service basis, which is designed to allow MidAmerican Funding an opportunity to recover its prudently incurred costs of providing services and to earn a reasonable return on its invested capital. Regulatory decisions can have an effect on the recovery of costs, the rate of return earned on investment, and the timing and amount of assets to be recovered by rates. While MidAmerican Funding has indicated it expects to recover costs from customers through regulated rates, there is a risk that changes to the Commissions' approach to setting rates or other regulatory actions could limit MidAmerican Funding's ability to recover its costs.

We identified the effects of rate regulation on the financial statements 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 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) a refund to customers. Given that management's accounting judgments are based on assumptions about the outcome of 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 decisions by the Commissions included the following, among others:

- We evaluated MidAmerican Funding's disclosures related to the effects of rate regulation by testing recorded balances and evaluating regulatory developments.
- We read relevant regulatory orders issued by the Commissions, regulatory statutes, filings made by MidAmerican Funding and other external information. We evaluated relevant external information and compared it to certain recorded regulatory asset and liability balances for completeness.
- For certain regulatory matters, we inspected MidAmerican Funding's filings with the Commissions and the filings with the Commissions by intervenors to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedents of the Commissions' treatment of similar costs under similar circumstances.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
February 27, 2026

We have served as MidAmerican Funding's auditor since 1999.

MIDAMERICAN FUNDING, LLC AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2025	**2024**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 672	$ 552
Trade receivables, net	453	230
Income tax receivable	82	2
Inventories	334	369
Prepayments	119	117
Other current assets	57	62
Total current assets	1,717	1,332
Property, plant and equipment, net	24,065	22,766
Goodwill	1,270	1,270
Regulatory assets	304	622
Investments and restricted investments	1,276	1,149
Other assets	286	251
Total assets	$ 28,918	$ 27,390

The accompanying notes are an integral part of these consolidated financial statements.

MIDAMERICAN FUNDING, LLC AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (continued)
(Amounts in millions)

	As of December 31,	
	2025	**2024**
LIABILITIES AND MEMBER'S EQUITY		
Current liabilities:		
Accounts payable	$ 498	$ 375
Accrued interest	126	122
Accrued property, income and other taxes	198	192
Note payable to affiliate	7	13
Current portion of long-term debt	4	17
Other current liabilities	96	92
Total current liabilities	929	811
Long-term debt	9,443	9,047
Regulatory liabilities	1,323	1,264
Deferred income taxes	3,758	3,624
Asset retirement obligations	870	823
Other long-term liabilities	822	622
Total liabilities	17,145	16,191
Commitments and contingencies (Note 13)		
Member's equity:		
Paid-in capital	1,679	1,679
Retained earnings	10,094	9,520
Total member's equity	11,773	11,199
Total liabilities and member's equity	$ 28,918	$ 27,390

The accompanying notes are an integral part of these consolidated financial statements.

MIDAMERICAN FUNDING, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2025	**2024**	**2023**
Operating revenue:			
Regulated electric	$ 3,124	$ 2,584	$ 2,673
Regulated natural gas and other	783	667	720
Total operating revenue	3,907	3,251	3,393
Operating expenses:			
Cost of fuel and energy	713	430	501
Cost of natural gas purchased for resale and other	480	367	451
Operations and maintenance	933	879	851
Depreciation and amortization	1,031	1,001	908
Property and other taxes	176	166	161
Total operating expenses	3,333	2,843	2,872
Operating income	574	408	521
Other income (expense):			
Interest expense	(423)	(434)	(362)
Allowance for borrowed funds	31	25	19
Allowance for equity funds	79	65	59
Other, net	66	84	48
Total other income (expense)	(247)	(260)	(236)
Income before income tax expense (benefit)	327	148	285
Income tax expense (benefit)	(721)	(843)	(695)
Net income	$ 1,048	$ 991	$ 980

The accompanying notes are an integral part of these consolidated financial statements.

MIDAMERICAN FUNDING, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN MEMBER'S EQUITY
(Amounts in millions)

	Paid-in Capital	Retained Earnings	Total Member's Equity
Balance, December 31, 2022	$ 1,679	$ 9,000	$ 10,679
Net income	—	980	980
Distributions to member	—	(1,025)	(1,025)
Other equity transactions	—	(1)	(1)
Balance, December 31, 2023	1,679	8,954	10,633
Net income	—	991	991
Distribution to member	—	(425)	(425)
Balance, December 31, 2024	1,679	9,520	11,199
Net income	—	1,048	1,048
Distribution to member	—	(474)	(474)
Balance, December 31, 2025	$ 1,679	$ 10,094	$ 11,773

The accompanying notes are an integral part of these consolidated financial statements.

MIDAMERICAN FUNDING, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Amounts in millions)

	Years Ended December 31,		
	2025	**2024**	**2023**
Cash flows from operating activities:			
Net income	$ 1,048	$ 991	$ 980
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	1,031	1,001	908
Amortization of utility plant to other operating expenses	37	35	34
Allowance for equity funds	(79)	(65)	(59)
Deferred income taxes and amortization of investment tax credits	77	81	90
Settlements of asset retirement obligations	(1)	(1)	(21)
Other, net	(21)	20	33
Changes in other operating assets and liabilities:			
Trade receivables and other assets	(207)	16	254
Inventories	35	(5)	(87)
Pension and other postretirement benefit plans, net	(5)	2	3
Accrued property, income and other taxes, net	(65)	(18)	77
Accounts payable and other liabilities	(33)	(90)	(9)
Net cash flows from operating activities	1,817	1,967	2,203
Cash flows from investing activities:			
Capital expenditures	(1,780)	(1,704)	(1,833)
Purchases of marketable securities	(439)	(327)	(243)
Proceeds from sales of marketable securities	434	313	227
Other investment proceeds	—	12	12
Other, net	9	15	12
Net cash flows from investing activities	(1,776)	(1,691)	(1,825)
Cash flows from financing activities:			
Distributions to member	(474)	(425)	(1,025)
Proceeds from long-term debt	393	592	1,338
Repayments of long-term debt	(17)	(539)	(317)
Net change in note payable to affiliate	(6)	13	—
Other, net	183	(2)	(2)
Net cash flows from financing activities	79	(361)	(6)
Net change in cash and cash equivalents and restricted cash and cash equivalents	120	(85)	372
Cash and cash equivalents and restricted cash and cash equivalents at beginning of year	558	643	271
Cash and cash equivalents and restricted cash and cash equivalents at end of year	$ 678	$ 558	$ 643

The accompanying notes are an integral part of these consolidated financial statements.

(1) Organization and Operations

MidAmerican Funding, LLC ("MidAmerican Funding") is an Iowa limited liability company with Berkshire Hathaway Energy Company ("BHE") as its sole member. BHE is a holding company based in Des Moines, Iowa that has investments in subsidiaries principally engaged in energy businesses. BHE is a wholly owned subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway"). MidAmerican Funding's direct wholly owned subsidiary is MHC Inc. ("MHC"), which constitutes substantially all of MidAmerican Funding's assets, liabilities and business activities except those related to MidAmerican Funding's long-term debt securities. MHC conducts no business other than the ownership of its subsidiaries. MHC's principal subsidiary is MidAmerican Energy Company ("MidAmerican Energy"), a public utility with electric and natural gas operations, and its direct, wholly owned nonregulated subsidiary is Midwest Capital Group, Inc. ("Midwest Capital Group").

(2) Summary of Significant Accounting Policies

In addition to the following significant accounting policies, refer to Note 2 of MidAmerican Energy's Notes to Financial Statements for significant accounting policies of MidAmerican Funding.

Basis of Consolidation and Presentation

The Consolidated Financial Statements include the accounts of MidAmerican Funding and its subsidiaries in which it held a controlling financial interest as of the financial statement date. Intercompany accounts and transactions have been eliminated, other than those between rate-regulated operations. The Consolidated Statements of Comprehensive Income have been omitted as net income equals comprehensive income for the years ended December 31, 2025, 2024 and 2023.

Cash and Cash Equivalents and Restricted Cash and Cash Equivalents

Cash equivalents consist of funds invested in money market mutual funds, U.S. Treasury Bills and other investments with a maturity of three months or less when purchased. Cash and cash equivalents exclude amounts where availability is restricted by legal requirements, loan agreements or other contractual provisions. Restricted cash and cash equivalents consist substantially of funds restricted for wildlife preservation. A reconciliation of cash and cash equivalents and restricted cash and cash equivalents as of December 31, 2025 and 2024 as presented on the Consolidated Statements of Cash Flows is outlined below and disaggregated by the line items in which they appear on the Consolidated Balance Sheets (in millions):

	As of December 31,	
	2025	2024
Cash and cash equivalents	$ 672	$ 552
Restricted cash and cash equivalents in other current assets	6	6
Total cash and cash equivalents and restricted cash and cash equivalents	$ 678	$ 558

Goodwill

Goodwill represents the excess of the purchase price over the fair value of identifiable net assets acquired when MidAmerican Funding purchased MHC. MidAmerican Funding evaluates goodwill for impairment at least annually and completed its annual review as of October 31, 2025. When evaluating goodwill for impairment, MidAmerican Funding estimates the fair value of its reporting units. If the carrying amount of a reporting unit, including goodwill, exceeds the estimated fair value, then the identifiable assets, including identifiable intangible assets, and liabilities of the reporting unit are estimated at fair value as of the current testing date. The excess of the estimated fair value of the reporting unit over the current estimated fair value of net assets establishes the implied value of goodwill. The excess of the recorded goodwill over the implied goodwill value is charged to earnings as an impairment loss. Significant judgment is required in estimating the fair value of the reporting unit and performing goodwill impairment tests. The determination of fair value incorporates significant unobservable inputs. During 2025, 2024 and 2023, MidAmerican Funding did not record any goodwill impairments.

(3) Property, Plant and Equipment, Net

Refer to Note 3 of MidAmerican Energy's Notes to Financial Statements. In addition to MidAmerican Energy's property, plant and equipment, net, MidAmerican Funding had nonregulated property gross of $9 million and $1 million as of December 31, 2025 and 2024, respectively.

(4) Jointly Owned Utility Facilities

Refer to Note 4 of MidAmerican Energy's Notes to Financial Statements.

(5) Regulatory Matters

Refer to Note 5 of MidAmerican Energy's Notes to Financial Statements.

(6) Investments and Restricted Investments

Refer to Note 6 of MidAmerican Energy's Notes to Financial Statements. In addition to MidAmerican Energy's investments and restricted investments, MHC had corporate-owned life insurance policies in a Rabbi trust owned by MHC with a total cash surrender value of $2 million as of December 31, 2025 and 2024.

(7) Short-term Debt and Credit Facilities

Refer to Note 7 of MidAmerican Energy's Notes to Financial Statements. In addition to MidAmerican Energy's credit facilities, MHC has a $4 million unsecured credit facility, which expires in June 2026 and has a variable interest rate based on the Secured Overnight Financing Rate, plus a spread. As of December 31, 2025 and 2024, there were no borrowings outstanding under this credit facility. As of December 31, 2025, MHC was in compliance with the covenants of its credit facility.

(8) Long-term Debt

Refer to Note 8 of MidAmerican Energy's Notes to Financial Statements for detail and a discussion of its long-term debt. In addition to MidAmerican Energy's annual repayments of long-term debt, MidAmerican Funding parent company has $239 million of 6.927% Senior Bonds due in 2029, with a carrying value of $240 million as of December 31, 2025 and 2024.

The MidAmerican Funding parent company bonds are the direct senior secured obligations of MidAmerican Funding and effectively rank junior to all indebtedness and other liabilities of the direct and indirect subsidiaries of MidAmerican Funding, to the extent of the assets of these subsidiaries. MidAmerican Funding may redeem the bonds in whole or in part at any time at a redemption price equal to the sum of any accrued and unpaid interest to the date of redemption and the greater of (1) 100% of the principal amount of the bonds or (2) the sum of the present values of the remaining scheduled payments of principal and interest on the bonds, discounted to the date of redemption on a semiannual basis at the treasury yield plus 25 basis points.

MidAmerican Funding parent company long-term debt is secured by a pledge of the common stock of MHC, which is not publicly traded. In the event of any triggering event under the related debt indenture, the common stock of MHC would be available to satisfy the applicable debt obligations. Triggering events include, among other specified circumstances, (1) default on the payment of interest for 30 days or principal for three days; (2) a material default in the performance of any material covenants or obligations in the indenture continuing for a period of 90 days after written notice in accordance with the indenture; or (3) the failure generally of MidAmerican Funding or any significant subsidiary to pay its debts when due.

Subsidiaries of MidAmerican Funding must make payments on their own indebtedness before making distributions to MidAmerican Funding. Refer to Note 8 of MidAmerican Energy's Notes to Financial Statements for a discussion of utility regulatory restrictions affecting distributions from MidAmerican Energy. As a result of the utility regulatory restrictions agreed to by MidAmerican Energy in March 1999, MidAmerican Funding had restricted net assets of $7 billion as of December 31, 2025.

As of December 31, 2025, MidAmerican Funding was in compliance with all of its applicable long-term debt covenants.

Each of MidAmerican Funding's direct or indirect subsidiaries is organized as a legal entity separate and apart from MidAmerican Funding and its other subsidiaries. It should not be assumed that any asset of any subsidiary of MidAmerican Funding will be available to satisfy the obligations of MidAmerican Funding or any of its other subsidiaries; provided, however, that unrestricted cash or other assets which are available for distribution may, subject to applicable law and the terms of financing arrangements of such parties, be advanced, loaned, paid as dividends or otherwise distributed or contributed to MidAmerican Funding, one of its subsidiaries or affiliates thereof.

(9) Income Taxes

Berkshire Hathaway includes BHE and subsidiaries in its U.S. federal income tax return and BHE includes its subsidiaries in certain state income tax returns. Consistent with established regulatory practice, MidAmerican Funding's provision for federal and state income tax have been computed on a stand-alone basis, and substantially all of its currently payable or receivable income tax is remitted to or received from BHE pursuant to a tax allocation agreement. Income before income tax expense (benefit) as reported on the Consolidated Statements of Operations, is all domestic.

MidAmerican Funding's income tax expense (benefit) consists of the following for the years ended December 31 (in millions):

	2025	2024	2023
Current:			
Federal	$ (785)	$ (888)	$ (756)
State	(13)	(36)	(29)
	(798)	(924)	(785)
Deferred:			
Federal	79	80	109
State	(1)	2	(18)
	78	82	91
Investment tax credits	(1)	(1)	(1)
Total	$ (721)	$ (843)	$ (695)

The following table presents the income taxes paid (received), net of refunds, for the years ended December 31 (in millions):

	2025	2024	2023
Jurisdiction:			
Federal	$ (705)	$ (868)	$ (823)
State	(19)	(35)	(32)
Total[1]	$ (724)	$ (903)	$ (855)

(1) Substantially all income taxes paid or (received) by MidAmerican Funding are pursuant to a tax allocation agreement.

A reconciliation of the federal statutory income tax rate to MidAmerican Funding's effective income tax rate applicable to income before income tax expense (benefit) is as follows for the years ended December 31:

	2025		2024		2023	
	Amount	Percent	Amount	Percent	Amount	Percent
U.S. federal statutory tax rate	$ 69	21.0 %	$ 31	21.0 %	$ 60	21.0 %
State income tax, net of federal income tax effect[1]	(11)	(3.4)	(27)	(18.2)	(37)	(13.0)
Energy-related tax credits	(762)	(233.0)	(811)	(548.0)	(682)	(239.3)
Nontaxable or nondeductible items	(3)	(0.9)	(5)	(3.5)	(3)	(1.1)
Changes in unrecognized tax benefits	1	0.4	1	0.7	1	0.4
Effects of ratemaking	(15)	(4.6)	(32)	(21.6)	(34)	(11.9)
Effective income tax rate	$ (721)	(220.5)%	$ (843)	(569.6)%	$ (695)	(243.9)%

(1) State tax in Iowa made up the majority (greater than 50%) of the tax effect in this category.

Energy-related tax credits relate primarily to production tax credits ("PTC") earned by MidAmerican Energy's wind- and solar-powered generating facilities. Federal renewable electricity PTCs are earned as energy from qualifying wind- and solar-powered generating facilities is produced and sold and are based on a per-kilowatt hour rate pursuant to the applicable federal income tax law. Wind- and solar-powered generating facilities are eligible for the credits for 10 years from the date the qualifying generating facilities are placed in-service.

MidAmerican Funding's net deferred income tax liability consists of the following as of December 31 (in millions):

	2025	2024
Deferred income tax assets:		
Regulatory liabilities	$ 271	$ 249
Asset retirement obligations	228	216
State carryforwards	65	66
Revenue sharing	39	47
Employee benefits	1	10
Other	48	81
Total deferred income tax assets	652	669
Valuation allowances	(2)	(2)
Total deferred income tax assets, net	650	667
Deferred income tax liabilities:		
Property-related items	(4,364)	(4,154)
Regulatory assets	(42)	(134)
Other	(2)	(3)
Total deferred income tax liabilities	(4,408)	(4,291)
Net deferred income tax liability	$ (3,758)	$ (3,624)

As of December 31, 2025, MidAmerican Funding's state tax carryforwards, principally related to $968 million of net operating losses, expire at various intervals between 2026 and 2046.

The U.S. Internal Revenue Service has closed or effectively settled its examination of MidAmerican Funding's income tax returns through December 31, 2013. The statute of limitations for MidAmerican Funding's income tax returns have expired for certain states through December 31, 2011 and December 31, 2013, and for other states through December 31, 2021, except for the impact of any federal audit adjustments.

A reconciliation of the beginning and ending balances of MidAmerican Funding's net unrecognized tax benefits is as follows for the years ended December 31 (in millions):

	2025	2024
Beginning balance	$ 22	$ 22
Additions based on tax positions related to the current year	8	5
Interest	2	2
Reductions based on tax positions related to the current year	(6)	(7)
Ending balance	$ 26	$ 22

As of December 31, 2025, MidAmerican Funding had unrecognized tax benefits totaling $60 million that, if recognized, would have an impact on the effective tax rate. The remaining unrecognized tax benefits relate to tax positions for which ultimate deductibility is highly certain but for which there is uncertainty as to the timing of such deductibility. Recognition of these tax benefits, other than applicable interest and penalties, would not affect MidAmerican Funding's effective income tax rate.

(10) Employee Benefit Plans

Refer to Note 10 of MidAmerican Energy's Notes to Financial Statements for additional information regarding MidAmerican Funding's pension, supplemental retirement and postretirement benefit plans.

Pension and postretirement costs allocated by MidAmerican Funding to its parent and other affiliates in each of the years ended December 31, were as follows (in millions):

	2025	2024	2023
Pension costs	$ 11	$ 11	$ 14
Other postretirement costs	(2)	2	2

(11) Asset Retirement Obligations

Refer to Note 11 of MidAmerican Energy's Notes to Financial Statements.

(12) Fair Value Measurements

Refer to Note 12 of MidAmerican Energy's Notes to Financial Statements.

MidAmerican Funding's long-term debt is carried at cost on the Consolidated Financial Statements. The fair value of MidAmerican Funding's long-term debt is a Level 2 fair value measurement and has been estimated based upon quoted market prices, where available, or at the present value of future cash flows discounted at rates consistent with comparable maturities with similar credit risks. The carrying value of MidAmerican Funding's variable-rate long-term debt approximates fair value because of the frequent repricing of these instruments at market rates. The following table presents the carrying value and estimated fair value of MidAmerican Funding's long-term debt as of December 31 (in millions):

	2025		2024	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 9,447	$ 8,672	$ 9,064	$ 8,166

(13) Commitments and Contingencies

Refer to Note 13 of MidAmerican Energy's Notes to Financial Statements.

Legal Matters

MidAmerican Funding is party to a variety of legal actions arising out of the normal course of business. MidAmerican Funding does not believe that such normal and routine litigation will have a material impact on its consolidated financial results.

(14) Revenue from Contracts with Customers

Refer to Note 14 of MidAmerican Energy's Notes to Financial Statements.

(15) Member's Equity

In 2025 and 2024, MidAmerican Funding paid $474 million and $425 million, respectively, in cash distributions to its parent company, BHE.

(16) Other Income (Expense)

Other, net, as shown on the Consolidated Statements of Operations, includes the following other income (expense) items for the years ended December 31 (in millions):

	2025	2024	2023
Corporate-owned life insurance income	$ 22	$ 29	$ 23
Gains on sales of assets and other investments	—	—	12
Non-service cost components of postretirement employee benefit plans	10	8	8
Interest income and other, net	34	47	5
Total	$ 66	$ 84	$ 48

(17) Supplemental Cash Flow Information

The summary of supplemental cash flow information as of and for the years ending December 31 is as follows (in millions):

	2025	2024	2023
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	$ 381	$ 391	$ 317
Supplemental disclosure of non-cash investing and financing transactions:			
Accruals related to property, plant and equipment additions	$ 239	$ 108	$ 193

(18) Related Party Transactions

The companies identified as affiliates of MidAmerican Funding are Berkshire Hathaway and its subsidiaries, including BHE and its subsidiaries. The basis for the following transactions is provided for in-service agreements between MidAmerican Funding and the affiliates.

MidAmerican Funding is reimbursed for charges incurred on behalf of its affiliates. The majority of these reimbursed expenses are for allocated general costs, such as insurance and building rent, and for employee wages, benefits and costs for corporate functions, such as information technology, human resources, treasury, legal and accounting. The amount of such reimbursements was $85 million, $88 million and $94 million for 2025, 2024 and 2023, respectively.

MidAmerican Funding reimbursed BHE in the amount of $76 million, $124 million and $123 million in 2025, 2024 and 2023, respectively, for its share of technology costs, corporate expenses and other costs. Amounts charged to MidAmerican Funding in 2025 and 2024 were primarily reflected in construction work-in-progress on the Consolidated Balance Sheets as of December 31, 2025 and 2024.

MidAmerican Energy purchases, in the normal course of business at either tariffed or market prices, natural gas transportation and storage capacity services from Northern Natural Gas Company, a wholly owned subsidiary of BHE and coal transportation services from BNSF Railway Company, a wholly owned subsidiary of Berkshire Hathaway. These purchases totaled $142 million, $133 million and $141 million in 2025, 2024 and 2023, respectively.

MHC has a $300 million revolving credit arrangement carrying interest at the One Month Term Secured Overnight Financing Rate, plus a spread, to borrow from BHE. Outstanding balances are unsecured and due on demand. The outstanding balance was $7 million at an interest rate of 4.193% as of December 31, 2025, and $13 million at an interest rate of 4.875% as of December 31, 2024, and is reflected as note payable to affiliate on the Consolidated Balance Sheet.

MidAmerican Funding had accounts receivable from affiliates of $29 million and $19 million as of December 31, 2025 and 2024, respectively, that are included in other current assets on the Consolidated Balance Sheets. MidAmerican Funding also had accounts payable to affiliates of $27 million and $16 million as of December 31, 2025 and 2024, respectively, that are included in accounts payable on the Consolidated Balance Sheets.

MidAmerican Funding is party to a tax allocation agreement and is part of the Berkshire Hathaway consolidated U.S. federal income tax return and certain BHE consolidated state income tax returns. For current federal and state income taxes, MidAmerican Funding had a net receivable from BHE of $79 million and $1 million as of December 31, 2025 and 2024, respectively. MidAmerican Funding received net cash payments for federal and state income taxes from BHE totaling $724 million, $903 million and $855 million for the years ended December 31, 2025, 2024 and 2023, respectively.

MidAmerican Funding recognizes the full amount of the funded status for its pension and postretirement plans, and amounts attributable to MidAmerican Funding's affiliates that have not previously been recognized through income are recognized as an intercompany balance with such affiliates. MidAmerican Funding adjusts these balances when changes to the funded status of the respective plans are recognized and does not intend to settle the balances currently. Amounts receivable from affiliates attributable to the funded status of employee benefit plans totaled $73 million and $70 million as of December 31, 2025 and 2024, respectively, and are included in other assets on the Consolidated Balance Sheets. Similar amounts payable to affiliates totaled $76 million and $68 million as of December 31, 2025 and 2024, respectively, and are included in other long-term liabilities on the Consolidated Balance Sheets. See Note 10 for further information pertaining to pension and postretirement accounting.

The indenture pertaining to MidAmerican Funding's long-term debt restricts MidAmerican Funding from paying a distribution on its equity securities, unless after making such distribution either its debt to total capital ratio does not exceed 0.67:1.0 and its interest coverage ratio is not less than 2.2:1.0 or its senior secured long-term debt rating is at least BBB or its equivalent. MidAmerican Funding may seek a release from this restriction upon delivery to the indenture trustee of written confirmation from the ratings agencies that without this restriction MidAmerican Funding's senior secured long-term debt would be rated at least BBB+.

(19) Segment Information

MidAmerican Funding's chief operating decision maker ("CODM") is its President. Net income for each reportable segment is considered by the CODM in allocating resources and capital. The CODM generally considers actual results versus historical results, budgets or forecasts, as well as unique risks and opportunities, when making decisions about the allocation of resources and capital to each reportable segment.

MidAmerican Funding has identified two reportable operating segments: regulated electric and regulated natural gas. The regulated electric segment derives most of its revenue from regulated retail sales of electricity to residential, commercial, and industrial customers and from wholesale sales. The regulated natural gas segment derives most of its revenue from regulated retail sales of natural gas to residential, commercial, and industrial customers and also obtains revenue by transporting natural gas owned by others through its distribution system. Pricing for regulated electric and regulated natural gas sales are established separately by regulatory agencies; therefore, management also reviews each segment separately to make decisions regarding allocation of resources and in evaluating performance. Common operating costs are allocated to each segment based on certain factors, which primarily relate to the nature of the cost.

The following tables provide information on a reportable segment basis for the year ended December 31 (in millions):

	2025			
	Electric	Natural Gas	Other[1]	Total
Operating revenue	$ 3,124	$ 778	$ 5	$ 3,907
Cost of sales	713	480	—	1,193
Operations and maintenance	784	148	1	933
Depreciation and amortization	962	69	—	1,031
Property and other taxes	162	14	—	176
Interest expense	374	31	18	423
Interest and dividend income	30	3	—	33
Income tax expense (benefit)	(724)	8	(5)	(721)
Other segment items[2]	134	12	(3)	143
Net income	$ 1,017	$ 43	$ (12)	$ 1,048
Capital expenditures	$ 1,622	$ 150	$ 8	$ 1,780

	2024			
	Electric	Natural Gas	Other[1]	Total
Operating revenue	$ 2,584	$ 658	$ 9	$ 3,251
Cost of sales	430	367	—	797
Operations and maintenance	757	121	1	879
Depreciation and amortization	935	66	—	1,001
Property and other taxes	152	14	—	166
Interest expense	387	30	17	434
Interest and dividend income	37	3	—	40
Income tax expense (benefit)	(841)	(1)	(1)	(843)
Other segment items[2]	129	7	(2)	134
Net income	$ 930	$ 71	$ (10)	$ 991
Capital expenditures	$ 1,580	$ 114	$ 10	$ 1,704

	2023			
	Electric	Natural Gas	Other[1]	Total
Operating revenue	$ 2,673	$ 713	$ 7	$ 3,393
Cost of sales	501	451	—	952
Operations and maintenance	711	138	2	851
Depreciation and amortization	846	62	—	908
Property and other taxes	144	17	—	161
Interest expense	320	26	16	362
Interest and dividend income	22	2	—	24
Income tax expense (benefit)	(676)	(14)	(5)	(695)
Other segment items[2]	80	15	7	102
Net income	$ 929	$ 50	$ 1	$ 980
Capital expenditures	$ 1,683	$ 149	$ 1	$ 1,833

	As of December 31,		
	2025	2024	2023
Assets:			
Regulated electric	$ 26,686	$ 25,350	$ 24,525
Regulated natural gas	2,224	2,035	1,979
Other[1]	8	5	5
Total assets	$ 28,918	$ 27,390	$ 26,509
Goodwill:			
Regulated electric	$ 1,191	$ 1,191	$ 1,191
Regulated natural gas	79	79	79
Total goodwill	$ 1,270	$ 1,270	$ 1,270

(1) The differences between the reportable segment amounts and the consolidated amounts, described as Other, consists of the nonregulated subsidiaries of MidAmerican Funding not engaged in the energy business.

(2) Other segment items include allowance for borrowed and equity funds, gains (losses) on marketable securities and other income (expense).

Nevada Power Company and its subsidiaries
Consolidated Financial Section

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following is management's discussion and analysis of certain significant factors that have affected the consolidated financial condition and results of operations of Nevada Power during the periods included herein. Explanations include management's best estimate of the impact of weather, customer growth, usage trends and other factors. This discussion should be read in conjunction with Nevada Power's historical Consolidated Financial Statements and Notes to Consolidated Financial Statements in Item 8 of this Form 10-K. Nevada Power's actual results in the future could differ significantly from the historical results.

Results of Operations

Overview

Net income for the year ended December 31, 2025 was $247 million, a decrease of $102 million, or 29%, compared to 2024, primarily due to lower utility margin, higher operations and maintenance expense, increased depreciation and amortization expense, higher interest expense and unfavorable interest and dividend income. These items were partially offset by favorable income tax expense and higher capitalized interest and allowance for equity funds. Utility margin decreased primarily due to an accrual in connection with a potential customer refund arising from an ongoing regulatory proceeding, unfavorable price impacts from changes in sales mix, lower transmission and wholesale revenue and lower energy efficiency implementation revenue, partially offset by higher power purchase agreement sales and higher other retail revenue. Retail customer volumes, including distribution only service customers, decreased 3.3% primarily due to the unfavorable impact of weather and customer usage patterns, offset by an increase in the average number of customers. Energy generated decreased 3% for 2025 compared to 2024 primarily due to lower natural gas-fueled generation. Wholesale electricity sales volumes decreased 10% and purchased electricity volumes were consistent with 2024.

Net income for the year ended December 31, 2024 was $349 million, an increase of $89 million, or 34%, compared to 2023, primarily due to higher utility margin, lower depreciation and amortization expense, higher capitalized interest and allowance for equity funds. These items were partially offset by unfavorable interest and dividend income, higher income tax expense, partially offset by increased federal income tax credits and higher interest expense. Utility margin increased primarily due to higher retail customer volumes, higher retail rates from the 2023 regulatory rate review with new rates effective January 2024 and higher power purchase agreement sales, partially offset by lower other revenue from expiring regulatory amortizations and the impact of lower regulatory amortizations approved in the 2023 regulatory rate review. Retail customer volumes, including distribution only service customers, increased 7.8% primarily due to the favorable impact of weather, higher customer usage and an increase in the average number of customers. Energy generated increased 14% for 2024 compared to 2023 primarily due to higher natural gas-fueled generation. Wholesale electricity sales volumes increased 102% and purchased electricity volumes increased 4%.

Non-GAAP Financial Measure

Management utilizes various key financial measures that are prepared in accordance with GAAP, as well as non-GAAP financial measures such as utility margin, to help evaluate results of operations. Utility margin is calculated as operating revenue less cost of fuel and energy, which are captions presented on the Consolidated Statements of Operations.

Nevada Power's cost of fuel and energy is generally recovered from its retail customers through regulatory recovery mechanisms and, as a result, changes in Nevada Power's expenses included in regulatory recovery mechanisms result in comparable changes to revenue. As such, management believes utility margin more appropriately and concisely explains results of operations rather than a discussion of revenue and cost of fuel and energy separately. Management believes the presentation of utility margin provides meaningful and valuable insight into the information management considers important to understanding the business and a measure of comparability to others in the industry.

Utility margin is not a measure calculated in accordance with GAAP and should be viewed as a supplement to, and not a substitute for, operating income, which is the most directly comparable financial measure prepared in accordance with GAAP. The following table provides a reconciliation of utility margin to operating income for the years ended December 31 (in millions):

	2025	2024	Change		2024	2023	Change	
Utility margin:								
Operating revenue	$ 2,357	$ 2,873	$ (516)	(18)%	$ 2,873	$ 3,088	$ (215)	(7)%
Cost of fuel and energy	1,162	1,608	(446)	(28)	1,608	1,942	(334)	(17)
Utility margin	1,195	1,265	(70)	(6)	1,265	1,146	119	10
Operations and maintenance	344	311	33	11	311	312	(1)	—
Depreciation and amortization	400	376	24	6	376	432	(56)	(13)
Property and other taxes	58	58	—	—	58	56	2	4
Operating income	$ 393	$ 520	$ (127)	(24)%	$ 520	$ 346	$ 174	50 %

Utility Margin

A comparison of key operating results related to utility margin is as follows for the years ended December 31:

	2025	2024	Change		2024	2023	Change	
Utility margin (in millions):								
Operating revenue	$ 2,357	$ 2,873	$ (516)	(18)%	$ 2,873	$ 3,088	$ (215)	(7)%
Cost of fuel and energy	1,162	1,608	(446)	(28)	1,608	1,942	(334)	(17)
Utility margin	$ 1,195	$ 1,265	$ (70)	(6)%	$ 1,265	$ 1,146	$ 119	10 %
Sales (GWhs):								
Residential	9,839	10,535	(696)	(7)%	10,535	9,584	951	10 %
Commercial	4,894	5,045	(151)	(3)	5,045	4,807	238	5
Industrial	6,383	6,356	27	—	6,356	5,827	529	9
Other	176	179	(3)	(2)	179	179	—	—
Total fully bundled[1]	21,292	22,115	(823)	(4)	22,115	20,397	1,718	8
Distribution only service	2,908	2,918	(10)	—	2,918	2,831	87	3
Total retail	24,200	25,033	(833)	(3)	25,033	23,228	1,805	8
Wholesale	418	465	(47)	(10)	465	230	235	*
Total GWhs sold	24,618	25,498	(880)	(3)%	25,498	23,458	2,040	9 %
Average number of retail customers (in thousands)	1,053	1,035	18	2 %	1,035	1,015	20	2 %
Average revenue per MWh:								
Retail - fully bundled[1]	$107.58	$126.73	$ (19.15)	(15)%	$126.73	$147.38	$ (20.65)	(14)%
Wholesale	$ 41.72	$ 30.33	$ 11.39	38 %	$ 30.33	$ 62.73	$ (32.40)	(52)%
Heating degree days	1,422	1,798	(376)	(21)%	1,798	1,962	(164)	(8)%
Cooling degree days	4,015	4,557	(542)	(12)%	4,557	3,651	906	25 %
Sources of energy (GWhs)[2][3]:								
Natural gas	14,823	15,377	(554)	(4)%	15,377	13,719	1,658	12 %
Renewables	425	402	23	6	402	66	336	509
Total energy generated	15,248	15,779	(531)	(3)	15,779	13,785	1,994	14
Energy purchased	7,890	7,914	(24)	—	7,914	7,606	308	4
Total	23,138	23,693	(555)	(2)%	23,693	21,391	2,302	11 %
Average cost of energy per MWh[2][4]:								
Energy generated	$ 27.82	$ 37.42	$ (9.59)	(26)%	$ 37.42	$ 65.25	$ (27.83)	(43)%
Energy purchased	$ 93.53	$128.54	$ (35.01)	(27)%	$128.54	$137.08	$ (8.54)	(6)%

* Not meaningful

(1) Fully bundled includes sales to customers for combined energy, transmission and distribution services.

(2) The average cost of energy per MWh and sources of energy excludes 386, 404 and 846 GWhs of natural gas generated energy that is purchased at cost by related parties for the years ended December 31, 2025, 2024 and 2023, respectively.

(3) GWh amounts are net of energy used by the related generating facilities.

(4) The average cost of energy per MWh includes only the cost of fuel associated with the generating facilities, purchased power and deferrals.

Year Ended December 31, 2025 Compared to Year Ended December 31, 2024

Utility margin decreased $70 million, or 6%, for 2025 compared to 2024 primarily due to:

- $46 million of lower revenue related to an accrual in connection with a potential customer refund arising from an ongoing regulatory proceeding;
- $28 million of lower electric retail utility margin primarily due to price impacts from changes in sales mix. Retail customer volumes, including distribution only service customers, decreased 3.3% primarily due to the unfavorable impacts of weather and customer usage patterns, offset by an increase in the average number of customers;
- $5 million of lower transmission and wholesale revenue and
- $4 million of lower energy efficiency implementation revenue.

The decrease in utility margin was partially offset by:

- $5 million of higher power purchase agreement sales from the Dry Lake renewable generation facility;
- $5 million of higher other retail revenue from the impact of regulatory amortizations and
- $4 million of higher energy efficiency program revenue (offset in operations and maintenance expense).

Operations and maintenance increased $33 million, or 11%, for 2025 compared to 2024 primarily due to increased technology costs, higher plant operations and maintenance expenses, regulatory impacts from the 2025 regulatory rate review and higher insurance premiums due to additional wildfire and general excess liability coverage, partially offset by lower general and administrative costs and lower energy efficiency program costs (offset in operating revenue).

Depreciation and amortization increased $24 million, or 6%, for 2025 compared to 2024 primarily due to higher plant placed in-service, partially offset by lower amortization.

Interest expense increased $15 million, or 7%, for 2025 compared to 2024 primarily due to higher long-term debt and higher average interest rate.

Capitalized interest and allowance for equity funds increased $12 million, or 24%, for 2025 compared to 2024 primarily due to higher construction work-in-progress.

Interest and dividend income decreased $11 million, or 46%, for 2025 compared to 2024 primarily due to unfavorable interest income, mainly from lower carrying charges on regulatory balances.

Income tax expense decreased $39 million, or 68%, for 2025 compared to 2024. The effective tax rate was 7% and 14% for 2025 and 2024, respectively. The $39 million decrease was primarily due to lower pretax income, higher benefit from the effects of ratemaking and higher PTCs.

Year Ended December 31, 2024 Compared to Year Ended December 31, 2023

Utility margin increased $119 million for 2024 compared to 2023 primarily due to:

- $118 million of higher electric retail utility margin primarily due to higher retail customer volumes and higher retail rates from the 2023 regulatory rate review with new rates effective January 2024. Retail customer volumes, including distribution only service customers, increased 7.8% primarily due to the favorable impacts of weather, customer usage patterns and an increase in the average number of customers;
- $13 million of higher power purchase agreement sales from the Dry Lake renewable generation facility;
- $7 million of higher energy efficiency program revenue (offset in operations and maintenance expense);
- $4 million of higher energy efficiency implementation revenue and
- $4 million of higher transmission and wholesale revenue.

The increase in utility margin was partially offset by:

- $14 million of lower other revenue from expiring regulatory amortizations and
- $14 million of lower other retail revenue from the impact of regulatory amortizations.

Operations and maintenance decreased $1 million for 2024 compared to 2023 primarily due to the impact of regulatory amortizations approved in the 2023 regulatory rate review, partially offset by higher plant operations and maintenance expenses, higher energy efficiency program costs (offset in operating revenue) and higher insurance premiums due to additional wildfire and general excess liability coverage.

Depreciation and amortization decreased $56 million, or 13%, for 2024 compared to 2023 primarily due to lower regulatory amortizations, partially offset by higher amortization from an increased rate for intangible software approved in the 2023 regulatory rate review.

Property and other taxes increased $2 million, or 4%, for 2024 compared to 2023 primarily due to a decrease in the amount of abatements available, higher plant placed in-service and an increase in commerce and franchise tax from higher revenue.

Interest expense increased $11 million, or 6% for 2024 compared to 2023 primarily due to higher long-term debt and higher average interest rate.

Capitalized interest and allowance for equity funds increased $5 million for 2024 compared to 2023 primarily due to higher construction work-in-progress.

Interest and dividend income decreased $48 million, or 67%, for 2024 compared to 2023 primarily due to unfavorable interest income, mainly from carrying charges on regulatory balances.

Other, net was favorable by $4 million for 2024 compared to 2023 primarily due to lower pension expense.

Income tax expense increased $35 million or 159%, for 2024 compared to 2023. The effective tax rate was 14% and 8% for 2024 and 2023, respectively. The $35 million increase was primarily due to higher pretax income and lower benefit from the effects of ratemaking, partially offset by higher PTCs and ITCs.

Liquidity and Capital Resources

As of December 31, 2025, Nevada Power's total net liquidity was $572 million as follows (in millions):

Cash and cash equivalents	$	22
Credit facilities		600
Less:		
Short-term debt		(50)
Net credit facilities		550
Total net liquidity	$	572
Credit facilities:		
Maturity dates		2028

Refer to Note 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for further discussion regarding Nevada Power's credit facility and letters of credit.

Operating Activities

Net cash flows from operating activities for the years ended December 31, 2025 and 2024 were $839 million and $989 million, respectively. The change was primarily due to higher payments related to fuel and energy costs, the timing of payments for operating costs, higher interest payments and decreased customer and vendor deposits, partially offset by lower income tax payments.

Net cash flows from operating activities for the years ended December 31, 2024 and 2023 were $989 million and $761 million, respectively. The change was primarily due to lower payments related to fuel and energy costs and the timing of payments for operating costs, partially offset by higher income tax payments, lower collections from customers, higher interest payments and decreased vendor deposits.

The timing of Nevada Power's income tax cash flows from period to period can be significantly affected by the estimated federal income tax payment methods selected and assumptions made for each payment date.

Investing Activities

Net cash flows from investing activities for the years ended December 31, 2025 and 2024 were $(1,207) million and $(1,099) million, respectively. The change was primarily due to increased capital expenditures and a decrease in proceeds from the sale of assets. Refer to "Future Uses of Cash" for further discussion of capital expenditures.

Net cash flows from investing activities for the years ended December 31, 2024 and 2023 were $(1,099) million and $(1,309) million, respectively. The change was primarily due to decreased capital expenditures, offset by decreased proceeds from an affiliate note receivable. Refer to "Future Uses of Cash" for further discussion of capital expenditures.

Financing Activities

Net cash flows from financing activities for the years ended December 31, 2025 and 2024 were $361 million and $115 million, respectively. The change was primarily due to higher net proceeds from the issuance of junior subordinated debt, proceeds from borrowings under credit facility and higher customer receipts from contributions in aid of construction, partially offset by higher dividends paid to NV Energy, Inc. and lower contributions from NV Energy, Inc.

Net cash flows from financing activities for the years ended December 31, 2024 and 2023 were $115 million and $525 million, respectively. The change was primarily due to a decrease in proceeds from long-term debt, lower contributions from NV Energy, Inc. and higher dividends paid to NV Energy, Inc., partially offset by a decrease in repayments of long-term debt.

In January 2026, Nevada Power received contributions from NV Energy, Inc. of $200 million.

Debt Authorizations

Nevada Power currently has an effective shelf registration statement with the SEC to issue an additional $1.8 billion of general and refunding mortgage securities through December 19, 2027. Additionally, Nevada Power's ability to issue debt is primarily impacted by its financing authority from the PUCN. As of December 31, 2025, Nevada Power has financing authority from the PUCN consisting of the ability to issue long-term and short-term debt securities so long as the total amount of debt outstanding (excluding borrowings under Nevada Power's $600 million secured credit facility) does not exceed $5.5 billion and to issue common and preferred stock so long as the total amounts outstanding do not exceed $6.5 billion and $800 million, respectively, as measured at the end of each calendar quarter. Nevada Power's revolving credit facility contains a financial maintenance covenant which Nevada Power was in compliance with as of December 31, 2025. In addition, certain financing agreements contain covenants which are currently suspended as Nevada Power's senior secured and subordinated debt is rated investment grade. However, if Nevada Power's debt ratings fall below investment grade by either Moody's Investor Service or Standard & Poor's, Nevada Power would be subject to limitations under these covenants.

General and Refunding Mortgage Securities

To the extent Nevada Power has the ability to issue debt under the most restrictive covenants in its financing agreements and has financing authority to do so from the PUCN, Nevada Power's ability to issue secured debt is limited by the amount of bondable property or retired bonds that can be used to issue debt under Nevada Power's indenture.

Nevada Power's indenture creates a lien on substantially all of Nevada Power's properties in Nevada. As of December 31, 2025, Nevada Power had approximately $11.8 billion in bondable property, of which $6.2 billion had been pledged. Nevada Power had the capacity to issue $3.9 billion of additional general and refunding mortgage securities as of December 31, 2025, determined on the basis of 70% of net utility property additions. Property additions include plant-in-service and specific assets in construction work-in-progress. The amount of bond capacity listed above does not include eligible property in construction work-in-progress. Nevada Power also has the ability to release property from the lien of Nevada Power's indenture on the basis of net property additions, cash or retired bonds. To the extent Nevada Power releases property from the lien of Nevada Power's indenture, it will reduce the amount of securities issuable under the indenture.

Future Uses of Cash

Nevada Power has available a variety of sources of liquidity and capital resources, both internal and external, including net cash flows from operating activities, public and private debt offerings, the use of secured revolving credit facilities, capital contributions and other sources. These sources are expected to provide funds required for current operations, capital expenditures, debt retirements and other capital requirements. The availability and terms under which Nevada Power has access to external financing depends on a variety of factors, including Nevada Power's credit ratings, investors' judgment of risk associated with Nevada Power and conditions in the overall capital markets, including the condition of the utility industry.

Capital Expenditures

Capital expenditure needs are reviewed regularly by management and may change significantly as a result of these reviews, which may consider, among other factors, changes in environmental and other rules and regulations; impacts to customers' rates; outcomes of regulatory proceedings; changes in income tax laws; general business conditions; load projections; system reliability standards; the cost and efficiency of construction labor, equipment and materials; commodity prices; and the cost and availability of capital. Prudently incurred expenditures for compliance-related items such as pollution control technologies, replacement generation and associated operating costs are generally incorporated into Nevada Power's regulated retail rates. Expenditures for certain assets may ultimately include acquisition of existing assets.

Historical and forecasted capital expenditures, each of which exclude amounts for non-cash equity AFUDC and other non-cash items, for the years ending December 31 are as follows (in millions):

	Historical			Forecast		
	2023	2024	2025	2026	2027	2028
Electric transmission	$ 124	$ 221	$ 452	$ 754	$ 937	$ 420
Electric distribution	335	328	357	433	368	374
Wildfire prevention	17	19	21	35	38	30
Solar generation	188	28	51	22	6	—
Electric battery storage	338	14	29	13	—	—
Other	407	493	297	252	322	233
Total	$ 1,409	$ 1,103	$ 1,207	$ 1,509	$ 1,671	$ 1,057

Nevada Power receives PUCN approval through its IRP filings for various projects and has included estimates from IRP filings as well as potential future filings in its forecast capital expenditures for 2026 through 2028. These estimates are likely to change as a result of the RFP process, continued evaluation and future IRP filing refinements. Nevada Power's historical and forecast capital expenditures include the following:

- Electric transmission includes both growth projects and operating expenditures. Growth projects primarily relate to the Nevada Utilities' Greenlink Nevada transmission expansion program totaling $428 million for 2025, $181 million for 2024 and $62 million for 2023. Planned spending for the Greenlink Nevada transmission expansion program expected to be placed in-service in 2027 and 2028 totals $730 million in 2026, $902 million in 2027 and $411 million in 2028. Operating expenditures consist of routine expenditures for transmission and other infrastructure needed to serve existing and expected demand.
- Electric distribution includes both growth projects and operating expenditures consisting of routine expenditures for distribution needed to serve existing and expected demand.
- Wildfire prevention includes growth and operating expenditures related to projects included in a comprehensive natural disaster protection plan filed and approved by the PUCN. These projects include, but are not limited to, rebuilding distribution lines with covered conductor, converting overhead distribution lines to underground and copper wire and pole replacement projects.

- Solar generation and electric battery storage primarily consist of a 150-MW solar photovoltaic facility with an additional 100-MWs of co-located battery storage that was developed in Clark County, Nevada which commenced commercial operation in May 2024 and a 400-MW solar photovoltaic facility with an additional 400 MWs of co-located battery storage that is being developed in Churchill County, Nevada with an ownership share approved by the PUCN of 10% for Nevada Power and 90% for Sierra Pacific. Commercial operation of the solar facility is expected by early 2027 and commercial operation of the co-located battery storage is expected by mid-2026. Also included was a 220-MW grid-tied battery energy storage system that was developed on the site of the retired Reid Gardner generating station in Clark County, Nevada that commenced operations in December 2023.
- Other includes both growth projects and operating expenditures. Growth projects primarily consist of additional completed costs for the peaking combustion turbines developed at the Silverhawk generating facility in Clark County, Nevada. Operating expenditures consist of turbine upgrades at several generating facilities, information technology expenditures, routine expenditures for generation, other operating projects and other infrastructure needed to serve existing and expected demand.

2021 Joint Integrated Resource Plan

In August 2023, the Nevada Utilities filed its Joint Application for approval of the Fifth Amendment to the 2021 Joint Integrated Resource Plan. The Fifth Amendment sought, in part (1) to convert the existing coal-fueled generating facility at North Valmy Generating Station to a cleaner natural gas-fueled generating facility (2) to purchase, install, and operate a company-owned 400 MW solar plant along with a 400 MW, four-hour battery storage system in Northern Nevada; (3) to continue operation of Tracy units 4 and 5 to 2049; (4) to purchase development assets for the 149 MW photovoltaic and 149 MW battery energy storage system Crescent Valley Solar project; (5) to construct the Esmeralda and Sagebrush substations transformers; and (6) to construct the necessary infrastructure in the APEX Area Master Plan. The Nevada Utilities sought approval of approximately $1.8 billion in total costs of new projects of which Nevada Power's share is approximately $1.0 billion. An order was issued in March 2024 in which the Nevada Utilities filed a motion for clarification and petition for reconsideration. In April 2024, a modified final order was issued, which granted in part and denied in part including the denial of the 149 MW photovoltaic and 149 MW battery energy storage system Crescent Valley Solar project as delineated in the final modified order.

2024 Joint Integrated Resource Plan

In May 2024, the Nevada Utilities filed its joint Application for approval of the 2024 Joint Integrated Resources Plan. The 2024 joint Application sought, in part (1) the addition of three power purchase agreements for solar generating resources totaling more than 1,000 MW, each with co-located battery storage systems; (2) the addition of 400 MW of company-owned hydrogen-capable natural gas simple cycle combustion turbine peakers at the North Valmy generation station; (3) to approve an update of the Greenlink Nevada Transmission project costs; and (4) to construct the necessary transmission infrastructure to support growing customer demand. In December 2024, the PUCN largely accepted the filing as filed but denied opining on the additional costs associated with the Greenlink Nevada project as all costs expended to construct the previously approved Greenlink Nevada project are subject to a prudency review in the GRC as delineated in the final 2024 Joint Integrated Resource Plan order.

In October 2025, the Nevada Utilities submitted a Joint Application for approval of the First Amendment to the 2024 Joint Integrated Resource Plan. The First Amendment seeks approval to enter into a 20-year power purchase agreement with the developer for an additional 150-MW battery energy storage system that will reduce the Nevada Utilities' open position beginning in the summer of 2027. The battery energy storage system will be co-located with existing Dodge Flat solar and battery facility in Washoe County, Nevada. In January 2026, the Nevada Utilities filed a stipulation with the PUCN that reflected a settlement among participating parties and largely accepted the First Amendment as filed, including approval of the 150-MW battery energy storage system power purchase agreement. A final order approving the stipulation was received in February 2026.

Material Cash Requirements

Nevada Power has cash requirements that may affect its consolidated financial condition that arise primarily from long- and short-term debt (refer to Notes 7 and 8), operating and financing leases (refer to Note 5), purchased electricity contracts (refer to Note 14), fuel contracts (refer to Note 14), construction and other development costs (refer to Liquidity and Capital Resources included within this Item 7 and Note 14) and AROs (refer to Note 11). Refer to the respective referenced note in Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

Nevada Power has cash requirements relating to interest payments of $3.4 billion on long-term debt, including $187 million due in 2026.

Regulatory Matters

Nevada Power is subject to comprehensive regulation. Refer to the discussion contained in Item 1 of this Form 10-K for further information regarding Nevada Power's general regulatory framework and current regulatory matters.

Environmental Laws and Regulations

Nevada Power is subject to federal, state and local laws and regulations regarding air quality, climate change, emissions performance standards, water quality, coal ash disposal and other environmental matters that have the potential to impact Nevada Power's current and future operations. In addition to imposing continuing compliance obligations, these laws and regulations provide regulators with the authority to levy substantial penalties for noncompliance including fines, injunctive relief and other sanctions. These laws and regulations are administered by various federal, state and local agencies. Nevada Power believes it is in material compliance with all applicable laws and regulations, although many are subject to interpretation that may ultimately be resolved by the courts. Environmental laws and regulations continue to evolve, and Nevada Power is unable to predict the impact of the changing laws and regulations on its operations and consolidated financial results.

Refer to "Environmental Laws and Regulations" in Item 1 of this Form 10-K for further discussion regarding environmental laws and regulations.

Collateral and Contingent Features

Debt of Nevada Power is rated by credit rating agencies. Assigned credit ratings are based on each rating agency's assessment of Nevada Power's ability to, in general, meet the obligations of its issued debt. The credit ratings are not a recommendation to buy, sell or hold securities, and there is no assurance that a particular credit rating will continue for any given period of time.

Nevada Power has no credit rating downgrade triggers that would accelerate the maturity dates of outstanding debt, and a change in ratings is not an event of default under the applicable debt instruments. Nevada Power's secured revolving credit facility does not require the maintenance of a minimum credit rating level in order to draw upon its availability. However, commitment fees and interest rates under the credit facility are tied to credit ratings and increase or decrease when the ratings change. A ratings downgrade could also increase the future cost of commercial paper, short- and long-term debt issuances or new credit facilities.

In accordance with industry practice, certain wholesale agreements, including derivative contracts, contain credit support provisions that in part base certain collateral requirements on credit ratings for unsecured debt as reported by one or more of the recognized credit rating agencies. These agreements may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance," or in some cases terminate the contract, in the event of a material adverse change in creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2025, the applicable credit ratings obtained from recognized credit rating agencies were investment grade. If all credit-risk-related contingent features or adequate assurance provisions for these agreements had been triggered as of December 31, 2025, Nevada Power would have been required to post $41 million of additional collateral. Nevada Power's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation, or other factors.

Inflation

Historically, overall inflation and changing prices in the economies where Nevada Power operates has not had a significant impact on Nevada Power's consolidated financial results. Nevada Power operates under a cost-of-service based rate-setting structure administered by the PUCN and the FERC. Under this rate-setting structure, Nevada Power is allowed to include prudent costs in its rates, including the impact of inflation after Nevada Power experiences cost increases. Fuel and purchase power costs are recovered through a balancing account, minimizing the impact of inflation related to these costs. Nevada Power attempts to minimize the potential impact of inflation on its operations through the use of periodic rate adjustments for fuel and energy costs, by employing prudent risk management and hedging strategies and by considering, among other areas, its impact on purchases of energy, operating expenses, materials and equipment costs, contract negotiations, future capital spending programs and long-term debt issuances. There can be no assurance that such actions will be successful.

New Accounting Pronouncements

For a discussion of new accounting pronouncements affecting Nevada Power, refer to Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Critical Accounting Estimates

Certain accounting measurements require management to make estimates and judgments concerning transactions that will be settled several years in the future. Amounts recognized on the Consolidated Financial Statements based on such estimates involve numerous assumptions subject to varying and potentially significant degrees of judgment and uncertainty and will likely change in the future as additional information becomes available. The following critical accounting estimates are impacted significantly by Nevada Power's methods, judgments and assumptions used in the preparation of the Consolidated Financial Statements and should be read in conjunction with Nevada Power's Summary of Significant Accounting Policies included in Nevada Power's Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Accounting for the Effects of Certain Types of Regulation

Nevada Power prepares its Consolidated Financial Statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, Nevada Power defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur.

Nevada Power continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future regulated rates by considering factors such as a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation, other regulatory actions or the impact of competition that could limit Nevada Power's ability to recover its costs. Nevada Power believes its application of the guidance for regulated operations is appropriate and its existing regulatory assets and liabilities are probable of inclusion in future regulated rates. The evaluation reflects the current political and regulatory climate at both the federal and state levels. If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the related regulatory assets and liabilities will be written off to net income, returned to customers or re-established as AOCI. Total regulatory assets were $0.6 billion and total regulatory liabilities were $1.0 billion as of December 31, 2025. Refer to Nevada Power's Note 6 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding Nevada Power's regulatory assets and liabilities.

Impairment of Long-Lived Assets

Nevada Power evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or when the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Consolidated Statements of Operations. As substantially all property, plant and equipment was used in regulated businesses as of December 31, 2025, the impacts of regulation are considered when evaluating the carrying value of regulated assets.

The estimate of cash flows arising from the future use of an asset, for the purposes of impairment analysis, requires the exercise of judgment. Circumstances that could significantly alter the calculation of fair value or the recoverable amount of an asset may include significant changes in the regulatory environment, the business climate, management's plans, legal factors, market price of the asset, the use of the asset, the physical condition of the asset, future market prices, load growth, competition and many other factors over the life of the asset. Any resulting impairment loss is highly dependent on the underlying assumptions and could significantly affect Nevada Power's results of operations.

Income Taxes

In determining Nevada Power's income taxes, management is required to interpret complex income tax laws and regulations, which includes consideration of regulatory implications imposed by Nevada Power's various regulatory commissions. Nevada Power's income tax returns are subject to continuous examinations by federal, state and local income tax authorities that may give rise to different interpretations of these complex laws and regulations. Due to the nature of the examination process, it generally takes years before these examinations are completed and these matters are resolved. Nevada Power recognizes the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the Consolidated Financial Statements from such a position are measured based on the largest benefit that is more-likely-than-not to be realized upon ultimate settlement. Although the ultimate resolution of Nevada Power's federal, state and local income tax examinations is uncertain, Nevada Power believes it has made adequate provisions for these income tax positions. The aggregate amount of any additional income tax liabilities that may result from these examinations is not expected to have a material impact on Nevada Power's consolidated financial results. Refer to Nevada Power's Note 9 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding Nevada Power's income taxes.

It is probable that Nevada Power will pass income tax benefit and expense related to the federal tax rate change from 35% to 21%, certain property related basis differences and other various differences on to its customers. As of December 31, 2025, these amounts were recognized as a net regulatory liability of $484 million and will be included in regulated rates when the temporary differences reverse.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Nevada Power's Consolidated Balance Sheets include assets and liabilities with fair values that are subject to market risks. Nevada Power's significant market risks are primarily associated with commodity prices, interest rates and the extension of credit to counterparties with which Nevada Power transacts. The following discussion addresses the significant market risks associated with Nevada Power's business activities. Nevada Power has established guidelines for credit risk management. Refer to Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding Nevada Power's contracts accounted for as derivatives.

Commodity Price Risk

Nevada Power is exposed to the impact of market fluctuations in commodity prices and interest rates. Nevada Power is principally exposed to electricity and natural gas market fluctuations primarily through Nevada Power's obligation to serve retail customer load in its regulated service territory. Nevada Power's load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity and wholesale electricity that is purchased and sold. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, generating facility availability, customer usage, storage, and transmission and transportation constraints. The actual cost of fuel and purchased power is recoverable through the deferred energy mechanism. Interest rate risk exists on variable-rate debt and future debt issuances. Nevada Power does not engage in proprietary trading activities. To mitigate a portion of its commodity price risk, Nevada Power uses commodity derivative contracts, which may include forwards, futures, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. Nevada Power does not hedge all of its commodity price risk, thereby exposing the unhedged portion to changes in market prices. Nevada Power's exposure to commodity price risk is generally limited by its ability to include commodity costs in regulated rates through its deferred energy mechanism, which is subject to disallowance and regulatory lag that occurs between the time the costs are incurred and when the costs are included in regulated rates, as well as the impact of any customer sharing resulting from cost adjustment mechanisms.

The table that follows summarizes Nevada Power's price risk on commodity contracts accounted for as derivatives and shows the effects of a hypothetical 10% increase and 10% decrease in forward market prices by the expected volumes for these contracts as of that date. The selected hypothetical change does not reflect what could be considered the best or worse case scenarios (dollars in millions).

	Fair Value - Net Asset (Liability)	Estimated Fair Value after Hypothetical Change in Price	
		10% increase	10% decrease
As of December 31, 2025:			
Total commodity derivative contracts	$ (41)	$ (37)	$ (44)
As of December 31, 2024:			
Total commodity derivative contracts	$ (57)	$ (53)	$ (61)

Nevada Power's commodity derivative contracts not designated as hedging contracts are recoverable from customers in regulated rates and therefore, net unrealized gains and losses associated with interim price movements on commodity derivative contracts do not expose Nevada Power to earnings volatility. As of December 31, 2025 and 2024, a net regulatory asset of $41 million and $57 million, respectively, was recorded related to the net derivative liability of $41 million and $57 million, respectively. The settled cost of these commodity derivative contracts is generally included in regulated rates.

Interest Rate Risk

Nevada Power is exposed to interest rate risk on its outstanding variable-rate short- and long-term debt and future debt issuances. Nevada Power manages its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. As a result of the fixed interest rates, Nevada Power's fixed-rate long-term debt does not expose Nevada Power to the risk of loss due to changes in market interest rates. Additionally, because fixed-rate long-term debt is not carried at fair value on the Consolidated Balance Sheets, changes in fair value would impact earnings and cash flows only if Nevada Power were to reacquire all or a portion of these instruments prior to their maturity. The nature and amount of Nevada Power's short- and long-term debt can be expected to vary from period to period as a result of future business requirements, market conditions and other factors. Refer to Notes 7 and 8 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional discussion of Nevada Power's short- and long-term debt.

As of December 31, 2025 and 2024, Nevada Power had no short- and long-term variable-rate obligations that expose Nevada Power to the risk of increased interest expense in the event of increases in short-term interest rates.

Credit Risk

Nevada Power is exposed to counterparty credit risk associated with wholesale energy supply and marketing activities with other utilities, energy marketing companies, financial institutions and other market participants. Credit risk may be concentrated to the extent Nevada Power's counterparties have similar economic, industry or other characteristics and due to direct and indirect relationships among the counterparties. Before entering into a transaction, Nevada Power analyzes the financial condition of each significant wholesale counterparty, establishes limits on the amount of unsecured credit to be extended to each counterparty and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate wholesale counterparty credit risk, Nevada Power enters into netting and collateral arrangements that may include margining and cross-product netting agreements and obtain third-party guarantees, letters of credit and cash deposits. If required, Nevada Power exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

As of December 31, 2025, Nevada Power's aggregate credit exposure from energy related transactions were not material, based on settlement and mark-to-market exposures, net of collateral.

Item 8. Financial Statements and Supplementary Data

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Nevada Power Company

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Nevada Power Company and subsidiaries ("Nevada Power") as of December 31, 2025 and 2024, the related consolidated statements of operations, changes in shareholder's equity, and cash flows, for each of the three years in the period ended December 31, 2025, 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 Nevada Power as of December 31, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of Nevada Power's management. Our responsibility is to express an opinion on Nevada Power's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to Nevada Power 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. Nevada Power is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of Nevada Power's internal control over financial reporting. Accordingly, we express no such opinion.

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 Board of Directors 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 — Effects of Rate Regulation on the Financial Statements — Refer to Note 6 to the financial statements

Critical Audit Matter Description

Nevada Power is subject to rate regulation by a state public service commission as well as the Federal Energy Regulatory Commission (collectively, the "Commissions"), which have jurisdiction with respect to the rates of electric and natural gas companies in the respective service territories where Nevada Power operates. Management has determined its regulated operations meet the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. Accounting for the economic effects of rate regulation has a pervasive effect on the financial statements.

Regulated rates are subject to regulatory rate-setting processes. Rates are determined, approved, and established based on a cost-of-service basis, which is designed to allow Nevada Power an opportunity to recover its prudently incurred costs of providing services and to earn a reasonable return on its invested capital. Regulatory decisions can have an effect on the recovery of costs, the rate of return earned on investment, and the timing and amount of assets to be recovered by rates. While Nevada Power Company has indicated it expects to recover costs from customers through regulated rates, there is a risk that changes to the Commissions' approach to setting rates or other regulatory actions could limit Nevada Power's ability to recover its costs.

We identified the effects of rate regulation on the financial statements as a critical audit matter due to the significant judgments made by management to support its assertions about certain affected account balances and disclosures and the high degree of subjectivity involved in assessing the impact of regulatory orders on the financial statements. Management judgments include assessing the likelihood of (1) recovery in future rates of incurred costs and (2) 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 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 decisions by the Commissions included the following, among others:

- We evaluated Nevada Power's disclosures related to the effects of rate regulation by testing certain recorded balances and evaluating regulatory developments.
- We read relevant regulatory orders issued by the Commissions, regulatory statutes filings made by Nevada Power and other external information. We evaluated relevant external information and compared it to certain recorded regulatory asset and liability balances for completeness.
- For certain regulatory matters, we inspected Nevada Power's filings with the Commissions and the filings with the Commissions by intervenors to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedents of the Commissions' treatment of similar costs under similar circumstances.

/s/ Deloitte & Touche LLP

Las Vegas, Nevada
February 27, 2026

We have served as Nevada Power's auditor since 1987.

NEVADA POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Amounts in millions, except share data)

	As of December 31,	
	2025	**2024**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 22	$ 23
Trade receivables, net	243	291
Amounts due from affiliates	40	23
Inventories	230	190
Income tax receivable	3	77
Regulatory assets	120	124
Prepayments	60	67
Other current assets	22	23
Total current assets	740	818
Property, plant and equipment, net	10,423	9,401
Regulatory assets	433	459
Other assets	379	400
Total assets	$ 11,975	$ 11,078
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Accounts payable	$ 536	$ 337
Amounts due to affiliates	88	6
Accrued interest	48	46
Accrued property, income and other taxes	23	34
Accrued employee expenses	79	21
Short-term debt	50	—
Current portion of long-term debt	93	—
Regulatory liabilities	33	41
Customer deposits	56	93
Derivative contracts	27	53
Other current liabilities	34	29
Total current liabilities	1,067	660
Long-term debt	3,305	3,395
Junior subordinated debt	297	—
Finance lease obligations	248	266
Regulatory liabilities	980	997
Deferred income taxes	837	802
Other long-term liabilities	551	510
Total liabilities	7,285	6,630
Commitments and contingencies (Note 14)		
Shareholder's equity:		
Common stock - $1.00 stated value, 1,000 shares authorized, issued and outstanding	—	—
Additional paid-in capital	3,123	2,943
Retained earnings	1,568	1,506
Accumulated other comprehensive loss, net	(1)	(1)
Total shareholder's equity	4,690	4,448
Total liabilities and shareholder's equity	$ 11,975	$ 11,078

The accompanying notes are an integral part of these consolidated financial statements.

NEVADA POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2025	**2024**	**2023**
Operating revenue	$ 2,357	$ 2,873	$ 3,088
Operating expenses:			
Cost of fuel and energy	1,162	1,608	1,942
Operations and maintenance	344	311	312
Depreciation and amortization	400	376	432
Property and other taxes	58	58	56
Total operating expenses	1,964	2,353	2,742
Operating income	393	520	346
Other income (expense):			
Interest expense	(222)	(207)	(196)
Capitalized interest	21	20	25
Allowance for equity funds	42	31	21
Interest and dividend income	13	24	72
Other, net	18	18	14
Total other income (expense)	(128)	(114)	(64)
Income before income tax expense (benefit)	265	406	282
Income tax expense (benefit)	18	57	22
Net income	$ 247	$ 349	$ 260

The accompanying notes are an integral part of these consolidated financial statements.

NEVADA POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY
(Amounts in millions, except shares)

	Common Stock		Other Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss, Net	Total Shareholder's Equity
	Shares	Amount				
Balance, December 31, 2022	1,000	$ —	$ 2,333	$ 1,022	$ (1)	$ 3,354
Net income	—	—	—	260	—	260
Dividends declared	—	—	—	(50)	—	(50)
Contributions	—	—	400	—	—	400
Balance, December 31, 2023	1,000	—	2,733	1,232	(1)	3,964
Net income	—	—	—	349	—	349
Dividends declared	—	—	—	(75)	—	(75)
Contributions	—	—	210	—	—	210
Balance, December 31, 2024	1,000	—	2,943	1,506	(1)	4,448
Net income	—	—	—	247	—	247
Dividends declared	—	—	—	(185)	—	(185)
Contributions	—	—	180	—	—	180
Balance, December 31, 2025	1,000	$ —	$ 3,123	$ 1,568	$ (1)	$ 4,690

The accompanying notes are an integral part of these consolidated financial statements.

NEVADA POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Amounts in millions)

	Years Ended December 31,		
	2025	**2024**	**2023**
Cash flows from operating activities:			
Net income	$ 247	$ 349	$ 260
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	400	376	432
Allowance for equity funds	(42)	(31)	(21)
Deferred energy	(60)	470	14
Amortization of deferred energy	61	(5)	40
Other changes in regulatory assets and liabilities	(10)	(33)	(13)
Deferred income taxes and amortization of investment tax credits	3	(8)	26
Other, net	3	(4)	(1)
Changes in other operating assets and liabilities:			
Trade receivables and other assets	80	43	(3)
Inventories	(41)	(60)	(36)
Accrued property, income and other taxes	54	(116)	39
Accounts payable and other liabilities	144	8	24
Net cash flows from operating activities	839	989	761
Cash flows from investing activities:			
Capital expenditures	(1,207)	(1,103)	(1,409)
Proceeds from sale of assets	—	4	—
Net proceeds from (issuance of) affiliate note receivable	—	—	100
Net cash flows from investing activities	(1,207)	(1,099)	(1,309)
Cash flows from financing activities:			
Proceeds from long-term debt	297	—	494
Repayments of long-term debt	—	—	(300)
Proceeds from short-term debt	50	—	—
Dividends paid	(185)	(75)	(50)
Contributions from parent	180	210	400
Other, net	19	(20)	(19)
Net cash flows from financing activities	361	115	525
Net change in cash and cash equivalents and restricted cash and cash equivalents	(7)	5	(23)
Cash and cash equivalents and restricted cash and cash equivalents at beginning of period	42	37	60
Cash and cash equivalents and restricted cash and cash equivalents at end of period	$ 35	$ 42	$ 37

The accompanying notes are an integral part of these consolidated financial statements.

(1) Organization and Operations

Nevada Power Company and its subsidiaries ("Nevada Power"), is a wholly owned subsidiary of NV Energy, Inc. ("NV Energy"), a holding company that also owns Sierra Pacific Power Company and its subsidiaries ("Sierra Pacific") and certain other subsidiaries. Nevada Power is a U.S. regulated electric utility company serving retail customers, including residential, commercial and industrial customers primarily in Las Vegas, North Las Vegas, Henderson and adjoining areas. NV Energy is an indirect wholly owned subsidiary of Berkshire Hathaway Energy Company ("BHE"). BHE is a holding company based in Des Moines, Iowa that has investments in subsidiaries principally engaged in energy businesses. BHE is a wholly owned subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

(2) Summary of Significant Accounting Policies

Basis of Consolidation and Presentation

The Consolidated Financial Statements include the accounts of Nevada Power and its subsidiaries in which it holds a controlling financial interest as of the financial statement date. Intercompany accounts and transactions have been eliminated. The Consolidated Statements of Comprehensive Income have been omitted as net income equals comprehensive income for the years ended December 31, 2025, 2024 and 2023.

Use of Estimates in Preparation of Financial Statements

The preparation of the Consolidated Financial Statements in conformity with accounting principles generally accepted in the United States of America ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the period. These estimates include, but are not limited to, the effects of regulation; recovery of long-lived assets; certain assumptions made in accounting for pension and other postretirement benefits; asset retirement obligations ("AROs"); income taxes; unbilled revenue; valuation of certain financial assets and liabilities, including derivative contracts; and accounting for contingencies. Actual results may differ from the estimates used in preparing the Consolidated Financial Statements.

Accounting for the Effects of Certain Types of Regulation

Nevada Power prepares its Consolidated Financial Statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, Nevada Power defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur. If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the related regulatory assets and liabilities will be written off to net income, returned to customers or re-established as accumulated other comprehensive income (loss) ("AOCI").

Fair Value Measurements

As defined under GAAP, fair value is the price that would be received to sell an asset or paid to transfer a liability between market participants in the principal market or in the most advantageous market when no principal market exists. Adjustments to transaction prices or quoted market prices may be required in illiquid or disorderly markets in order to estimate fair value. Different valuation techniques may be appropriate under the circumstances to determine the value that would be received to sell an asset or paid to transfer a liability in an orderly transaction. Market participants are assumed to be independent, knowledgeable, able and willing to transact an exchange and not under duress. Nonperformance or credit risk is considered when determining fair value. Considerable judgment may be required in interpreting market data used to develop the estimates of fair value. Accordingly, estimates of fair value presented herein are not necessarily indicative of the amounts that could be realized in a current or future market exchange.

Cash and Cash Equivalents and Restricted Cash

Cash equivalents consist of funds invested in money market mutual funds, U.S. Treasury Bills and other investments with a maturity of three months or less when purchased. Cash and cash equivalents exclude amounts where availability is restricted by legal requirements, loan agreements or other contractual provisions. Restricted cash and cash equivalents consist of funds restricted by the Public Utilities Commission of Nevada ("PUCN") for a certain renewable energy contract. A reconciliation of cash and cash equivalents and restricted cash and cash equivalents as of December 31, 2025 and December 31, 2024, as presented on the Consolidated Statements of Cash Flows is outlined below and disaggregated by the line items in which they appear on the Consolidated Balance Sheets (in millions):

	As of December 31,	
	2025	2024
Cash and cash equivalents	$ 22	$ 23
Restricted cash and cash equivalents included in other current assets	13	19
Total cash and cash equivalents and restricted cash and cash equivalents	$ 35	$ 42

Allowance for Credit Losses

Trade receivables are primarily short-term in nature with stated collection terms of less than one year from the date of origination and are stated at the outstanding principal amount, net of an estimated allowance for credit losses. The allowance for credit losses is based on Nevada Power's assessment of the collectability of amounts owed to Nevada Power by its customers. This assessment requires judgment regarding the ability of customers to pay or the outcome of any pending disputes. In measuring the allowance for credit losses for trade receivables, Nevada Power primarily utilizes credit loss history. However, Nevada Power may adjust the allowance for credit losses to reflect current conditions and reasonable and supportable forecasts that deviate from historical experience. Nevada Power also has the ability to assess deposits on customers who have delayed payments or who are deemed to be a credit risk. The changes in the balance of the allowance for credit losses, which is included in trade receivables, net on the Consolidated Balance Sheets, is summarized as follows for the years ended December 31, (in millions):

	2025	2024	2023
Beginning balance	$ 17	$ 20	$ 20
Charged to operating costs and expenses, net	15	19	18
Write-offs, net	(19)	(22)	(18)
Ending balance	$ 13	$ 17	$ 20

Derivatives

Nevada Power employs a number of different derivative contracts, which may include forwards, futures, options, swaps and other agreements, to manage its commodity price and interest rate risks. Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. Derivative balances reflect offsetting permitted under master netting agreements with counterparties and cash collateral paid or received under such agreements.

Commodity derivatives used in normal business operations that are settled by physical delivery, among other criteria, are eligible for and may be designated as normal purchases or normal sales. Normal purchases or normal sales contracts are not marked-to-market and settled amounts are recognized as cost of fuel, energy and capacity on the Consolidated Statements of Operations.

For Nevada Power's derivative contracts, the settled amount is generally included in regulated rates. Accordingly, the net unrealized gains and losses associated with interim price movements on contracts that are accounted for as derivatives and probable of inclusion in regulated rates are recorded as regulatory assets and liabilities. For a derivative contract not probable of inclusion in rates, changes in the fair value are recognized in earnings.

Inventories

Inventories consist mainly of materials and supplies totaling $230 million and $190 million as of December 31, 2025 and 2024. The cost is determined using the average cost method. Materials are charged to inventory when purchased and are expensed or capitalized to construction work in process, as appropriate, when used.

Property, Plant and Equipment, Net

General

Additions to property, plant and equipment are recorded at cost. Nevada Power capitalizes all construction-related material, direct labor and contract services, as well as indirect construction costs. Indirect construction costs include debt allowance for funds used during construction ("AFUDC"), and equity AFUDC, as applicable. The cost of additions and betterments are capitalized, while costs incurred that do not improve or extend the useful lives of the related assets are generally expensed. The cost of repairs and minor replacements are charged to expense when incurred with the exception of costs for generation plant maintenance under certain long-term service agreements. Costs under these agreements are expensed straight-line over the term of the agreements as approved by the PUCN.

Depreciation and amortization are generally computed by applying the composite or straight-line method based on either estimated useful lives or mandated recovery periods as prescribed by Nevada Power's various regulatory authorities. Depreciation studies are completed by Nevada Power to determine the appropriate group lives, net salvage and group depreciation rates. These studies are reviewed and rates are ultimately approved by the applicable regulatory commission. Net salvage includes the estimated future residual values of the assets and any estimated removal costs recovered through approved depreciation rates. Estimated removal costs are recorded as a noncurrent regulatory liability on the Consolidated Balance Sheets. As actual removal costs are incurred, the associated liability is reduced.

Generally when Nevada Power retires or sells a component of regulated property, plant and equipment depreciated using the composite method, it charges the original cost, net of any proceeds from the disposition, to accumulated depreciation. Any gain or loss on disposals of all other assets is recorded through earnings with the exception of material gains or losses on regulated property, plant and equipment depreciated on a straight-line basis, which is then recorded to a regulatory liability or asset, respectively.

Debt and equity AFUDC, which represent the estimated costs of debt and equity funds necessary to finance the construction of regulated facilities, are capitalized as a component of property, plant and equipment, with offsetting credits to the Consolidated Statements of Operations. The rate applied to construction costs is the lower of the PUCN allowed rate of return and rates computed based on guidelines set forth by the Federal Energy Regulatory Commission ("FERC"). After construction is completed, Nevada Power is permitted to earn a return on these costs as a component of the related assets, as well as recover these costs through depreciation expense over the useful lives of the related assets. Nevada Power's AFUDC rate used during 2025 and 2024 was 7.44% and 7.43%, respectively.

Asset Retirement Obligations

Nevada Power recognizes AROs when it has a legal obligation to perform decommissioning, reclamation or removal activities upon retirement of an asset. Nevada Power's AROs are primarily associated with its generating facilities. The fair value of an ARO liability is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made, and is added to the carrying amount of the associated asset, which is then depreciated over the remaining useful life of the asset. Subsequent to the initial recognition, the ARO liability is adjusted for any revisions to the original estimate of undiscounted cash flows (with corresponding adjustments to property, plant and equipment, net) and for accretion of the ARO liability due to the passage of time. The difference between the ARO liability, the corresponding ARO asset included in property, plant and equipment, net and amounts recovered in rates to satisfy such liabilities is recorded as a regulatory asset or liability on the Consolidated Balance Sheets. The costs are not recovered in rates until the work has been completed.

Impairment

Nevada Power evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or when the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Consolidated Statements of Operations. As substantially all property, plant and equipment was used in regulated businesses, the impacts of regulation are considered when evaluating the carrying value of regulated assets.

Leases

Nevada Power has non-cancelable operating leases primarily for land, generating facilities, vehicles and office equipment and finance leases consisting primarily of transmission assets, generating facilities, office space and vehicles. These leases generally require Nevada Power to pay for insurance, taxes and maintenance applicable to the leased property. Given the capital-intensive nature of the utility industry, it is common for a portion of lease costs to be capitalized when used during construction or maintenance of assets, in which the associated costs will be capitalized with the corresponding asset and depreciated over the remaining life of that asset. Certain leases contain renewal options for varying periods and escalation clauses for adjusting rent to reflect changes in price indices. Nevada Power does not include options in its lease calculations unless there is a triggering event indicating Nevada Power is reasonably certain to exercise the option. Nevada Power's accounting policy is to not recognize right-of-use assets and lease obligations for leases with contract terms of one year or less and not separate lease components from non-lease components and instead account for each separate lease component and the non-lease components associated with a lease as a single lease component. Right-of-use assets are evaluated for impairment in line with Accounting Standards Codification ("ASC") Topic 360, "Property, Plant and Equipment" when a triggering event has occurred that might affect the value and use of the assets being leased.

Nevada Power's leases of generating facilities generally are for the long-term purchase of electric energy, also known as power purchase agreements ("PPA"). PPAs are generally signed before or during the early stages of project construction and can yield a lease that has not yet commenced. These agreements are primarily for renewable energy and the payments are considered variable lease payments as they are based on the amount of output.

Nevada Power's operating and right-of-use assets are recorded in other assets and the operating lease liabilities are recorded in current and long-term other liabilities accordingly.

Revenue Recognition

Nevada Power uses a single five-step model to identify and recognize revenue from contracts with customers ("Customer Revenue") upon transfer of control of promised goods or services in an amount that reflects the consideration to which Nevada Power expects to be entitled in exchange for those goods or services. Nevada Power records sales, franchise and excise taxes collected directly from customers and remitted directly to the taxing authorities on a net basis on the Consolidated Statements of Operations.

Substantially all of Nevada Power's Customer Revenue is derived from tariff-based sales arrangements approved by various regulatory commissions. These tariff-based revenues are mainly comprised of energy, transmission and distribution and have performance obligations to deliver energy products and services to customers which are satisfied over time as energy is delivered or services are provided. Other revenue consists primarily of amounts not considered Customer Revenue within ASC 606, "Revenue from Contracts with Customers" and revenue recognized in accordance with ASC 842, "Leases."

Revenue recognized is equal to what Nevada Power has the right to invoice as it corresponds directly with the value to the customer of Nevada Power's performance to date and includes billed and unbilled amounts. As of December 31, 2025 and 2024, trade receivables, net on the Consolidated Balance Sheets relate substantially to Customer Revenue, including unbilled revenue of $131 million and $132 million, respectively. Payments for amounts billed are generally due from the customer within 30 days of billing. Rates charged for energy products and services are established by regulators or contractual arrangements that establish the transaction price as well as the allocation of price amongst the separate performance obligations. When preliminary regulated rates are permitted to be billed prior to final approval by the applicable regulator, certain revenue collected may be subject to refund and a liability for estimated refunds is accrued. In addition, Nevada Power has recognized contract assets of $1 million and $1 million as of December 31, 2025 and 2024, respectively, due to Nevada Power's performance on certain contracts.

Unamortized Debt Premiums, Discounts and Issuance Costs

Premiums, discounts and financing costs incurred for the issuance of long-term debt are amortized over the term of the related financing using the effective interest method.

Income Taxes

Berkshire Hathaway includes Nevada Power in its consolidated U.S. federal income tax return. Consistent with established regulatory practice, Nevada Power's provision for income taxes has been computed on a stand-alone basis.

Deferred income tax assets and liabilities are based on differences between the financial statement and income tax basis of assets and liabilities using enacted income tax rates expected to be in effect for the year in which the differences are expected to reverse. Changes in deferred income tax assets and liabilities associated with components of other comprehensive income ("OCI") are charged or credited directly to OCI. Changes in deferred income tax assets and liabilities associated with certain property-related basis differences and other various differences that Nevada Power deems probable to be passed on to its customers are charged or credited directly to a regulatory asset or liability and will be included in regulated rates when the temporary differences reverse. Other changes in deferred income tax assets and liabilities are included as a component of income tax expense. Changes in deferred income tax assets and liabilities attributable to changes in enacted income tax rates are charged or credited to income tax expense or a regulatory asset or liability in the period of enactment. Valuation allowances are established when necessary to reduce deferred income tax assets to the amount that is more-likely-than-not to be realized.

Investment tax credits are deferred and amortized over the estimated useful lives of the related properties.

Nevada Power recognizes the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the Consolidated Financial Statements from such a position are measured based on the largest benefit that is more-likely-than-not to be realized upon ultimate settlement. Nevada Power's unrecognized tax benefits are primarily included in other long-term liabilities on the Consolidated Balance Sheets. Estimated interest and penalties, if any, related to uncertain tax positions are included as a component of income tax expense (benefit) on the Consolidated Statements of Operations.

Segment Information

Nevada Power currently has one reportable segment, its regulated electric utility operations, which derives its revenue from regulated retail sales of electricity to residential, commercial, and industrial customers and from wholesale sales. Nevada Power's chief operating decision maker ("CODM") is its President and Chief Executive Officer. The CODM uses net income, as reported on the Consolidated Statements of Operations, and generally considers actual results versus historical results, budgets or forecasts, and state regulatory ratemaking results as well as unique risks and opportunities, when making decisions about the allocation of resources and capital. The significant segment expenses regularly provided to the CODM align with the captions presented on the Consolidated Statements of Operations. Nevada Power's segment capital expenditures are reported on the Consolidated Statements of Cash Flows as capital expenditures. Nevada Power's segment assets are reported on the Consolidated Balance Sheets as total assets.

New Accounting Pronouncements

In December 2023, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2023-09, Income Taxes Topic 740, "Income Tax—Improvements to Income Tax Disclosures" which requires enhanced disclosures, including specific categories and disaggregation of information in the effective tax rate reconciliation, disaggregated information related to income taxes paid, income or loss from continuing operations before income tax expense or benefit, and income tax expense or benefit from continuing operations. This guidance is effective for annual reporting periods beginning after December 15, 2024. Early adoption is permitted and should be applied on a prospective basis, however retrospective application is permitted. Nevada Power adopted this guidance for the fiscal year beginning January 1, 2025, under the retrospective method. The adoption did not have a material impact on Nevada Power's Consolidated Financial Statements, but did expand the disclosures included within Notes to Consolidated Financial Statements. Refer to Note 9 for expanded rate reconciliation disclosures and disaggregation of income taxes paid.

In November 2024, the FASB issued ASU No. 2024-03, Income Statement—Reporting Comprehensive Income—Expense Disaggregation Disclosures Subtopic 220-40, "Disaggregation of Income Statement Expenses" which addresses requests from investors for more detailed information about certain expenses and requires disclosure of the amounts of purchases of inventory, employee compensation, depreciation and intangible asset amortization included in each relevant expense caption presented on the income statement. This guidance, as clarified in ASU 2025-01, is effective for annual reporting periods beginning after December 15, 2026 and interim reporting periods beginning after December 15, 2027. Early adoption is permitted and should be applied on a prospective basis, however retrospective application is permitted. Nevada Power is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

In December 2025, the FASB issued ASU No. 2025-10, Government Grants Topic 832, "Accounting for Government Grants Received by Business Entities" which establishes accounting for government grants received by an entity, including guidance for a grant related to an asset and a grant related to income. This guidance also requires, consistent with current disclosure requirements, that an entity provide disclosures including the nature of the government grant received, the accounting policies used to account for the grant, and significant terms and conditions of the grant. This guidance is effective for interim and annual reporting periods beginning after December 15, 2028. Early adoption is permitted and can be applied using either a modified prospective approach, a modified retrospective approach or a retrospective approach. Nevada Power is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

(3) Property, Plant and Equipment, Net

Property, plant and equipment, net consists of the following as of December 31 (in millions):

	Depreciable Life	2025	2024
Utility plant:			
Generation	30 - 65 years	$ 5,542	$ 5,369
Transmission	55 - 75 years	1,886	1,660
Distribution	24 - 70 years	5,031	4,754
Intangible plant and other	5 - 65 years	951	900
Utility plant		13,410	12,683
Accumulated depreciation and amortization		(4,383)	(4,093)
Utility plant, net		9,027	8,590
Nonregulated, net of accumulated depreciation and amortization	40 years	1	1
		9,028	8,591
Construction work-in-progress		1,395	810
Property, plant and equipment, net		$ 10,423	$ 9,401

Almost all of Nevada Power's plant is subject to the ratemaking jurisdiction of the PUCN and the FERC. Nevada Power's depreciation and amortization expense, as authorized by the PUCN, stated as a percentage of the depreciable property balances as of December 31, 2025, 2024 and 2023 was 3.0%, 2.8%, and 3.1%, respectively. Nevada Power is required to file a utility plant depreciation study every six years as a companion filing with the triennial general rate review filings. The most recent study was filed in 2023 and the approved rates were effective January 1, 2024.

Construction work-in-progress is primarily related to the construction of regulated assets.

(4) Jointly Owned Utility Facilities

Under joint facility ownership agreements, Nevada Power, as tenants in common, has undivided interests in jointly owned generation and transmission facilities. Nevada Power accounts for its proportionate share of each facility and each joint owner has provided financing for its share of each facility. Operating costs of each facility are assigned to joint owners based on their percentage of ownership or energy production, depending on the nature of the cost. Operating costs and expenses on the Consolidated Statements of Operations include Nevada Power's share of the expenses of these facilities.

The amounts shown in the table below represent Nevada Power's share in each jointly owned facility included in property, plant and equipment, net as of December 31, 2025 (dollars in millions):

	Nevada Power's Share	Utility Plant	Accumulated Depreciation	Construction Work-in-Progress
ON Line Transmission Line	19 %	$ 122	$ 31	$ 1
Other transmission facilities	Various	60	30	—
Total		$ 182	$ 61	$ 1

(5) Leases

The following table summarizes Nevada Power's leases recorded on the Consolidated Balance Sheet as of December 31 (in millions):

	2025	2024
Right-of-use assets:		
Operating leases	$ 3	$ 5
Finance leases	268	279
Total right-of-use assets	$ 271	$ 284
Lease liabilities:		
Operating leases	$ 5	$ 7
Finance leases	271	287
Total lease liabilities	$ 276	$ 294

The following table summarizes Nevada Power's lease costs for the years ended December 31 (in millions):

	2025	2024	2023
Variable	$ 372	$ 270	$ 264
Operating	3	2	2
Finance:			
Amortization	19	16	15
Interest	23	24	26
Total lease costs	$ 417	$ 312	$ 307
Weighted-average remaining lease term (years):			
Operating leases	1.8	2.8	3.7
Finance leases	26.2	27.4	28.2
Weighted-average discount rate:			
Operating leases	4.4 %	4.5 %	4.5 %
Finance leases	8.6 %	8.6 %	8.6 %

The following table summarizes Nevada Power's supplemental cash flow information relating to leases for the years ended December 31 (in millions):

	2025	2024	2023
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows from operating leases	$ (3)	$ (3)	$ (3)
Operating cash flows from finance leases	(23)	(25)	(26)
Financing cash flows from finance leases	(22)	(20)	(18)
Right-of-use assets obtained in exchange for lease liabilities:			
Operating leases	$ —	$ —	$ 1
Finance leases	8	9	4

Nevada Power has the following remaining lease commitments as of December 31, 2025 (in millions):

	Operating	Finance	Total
2026	$ 3	$ 43	$ 46
2027	3	41	44
2028	—	39	39
2029	—	25	25
2030	—	24	24
Thereafter	—	343	343
Total undiscounted lease payments	6	515	521
Less - amounts representing interest	(1)	(244)	(245)
Lease liabilities	$ 5	$ 271	$ 276

Operating and Finance Lease Obligations

Nevada Power's lease obligation primarily consists of a transmission line, One Nevada Transmission Line ("ON Line"), which was placed in-service on December 31, 2013. Nevada Power and Sierra Pacific, collectively the ("Nevada Utilities"), entered into a long-term transmission use agreement, in which the Nevada Utilities have a 25% interest and Great Basin Transmission South, LLC has a 75% interest. The Nevada Utilities' share of the long-term transmission use agreement and ownership interest is split at 75% for Nevada Power and 25% for Sierra Pacific. The term of the lease is 41 years with the agreement ending December 31, 2054. Total ON Line finance lease obligations of $239 million and $253 million were included on the Consolidated Balance Sheets as of December 31, 2025 and 2024, respectively. See Note 2 for further discussion of Nevada Power's other lease obligations.

(6) Regulatory Matters

Regulatory Assets

Regulatory assets represent costs that are expected to be recovered in future rates. Nevada Power's regulatory assets reflected on the Consolidated Balance Sheets consist of the following as of December 31 (in millions):

	Weighted Average Remaining Life	2025	2024
Deferred energy costs	1 year	$ 108	$ 110
Merger costs from 1999 merger	19 years	91	95
Decommissioning costs	4 years	71	57
Asset retirement obligations	6 years	67	66
Unrealized loss on regulated derivative contracts	1 year	41	57
ON Line deferrals	28 years	41	38
Deferred operating costs	17 years	40	39
Legacy meters	7 years	26	30
Other	Various	68	91
Total regulatory assets		$ 553	$ 583
Reflected as:			
Current assets		$ 120	$ 124
Noncurrent assets		433	459
Total regulatory assets		$ 553	$ 583

Nevada Power had regulatory assets not earning a return on investment of $263 million and $313 million as of December 31, 2025 and 2024, respectively. The regulatory assets not earning a return on investment primarily consist of merger costs from the 1999 merger, AROs, unrealized losses on regulated derivative contracts, deferred operating costs, losses on reacquired debt and a portion of the employee benefit plans.

Regulatory Liabilities

Regulatory liabilities represent amounts that are expected to be returned to customers in future periods. Nevada Power's regulatory liabilities reflected on the Consolidated Balance Sheets consist of the following as of December 31 (in millions):

	Weighted Average Remaining Life	2025	2024
Deferred income taxes[1]	Various	$ 484	$ 510
Cost of removal[2]	37 years	417	399
Earning sharing mechanism	3 years	44	77
Other	Various	68	52
Total regulatory liabilities		$ 1,013	$ 1,038
Reflected as:			
Current liabilities		$ 33	$ 41
Noncurrent liabilities		980	997
Total regulatory liabilities		$ 1,013	$ 1,038

(1) Amounts primarily represent income tax liabilities related to the federal tax rate change from 35% to 21% that are probable to be passed on to customers, offset by income tax benefits related to accelerated tax depreciation and certain property-related basis differences that were previously passed on to customers and will be included in regulated rates when the temporary differences reverse.

(2) Amounts represent estimated costs, as accrued through depreciation rates and exclusive of ARO liabilities, of removing regulated property, plant and equipment in accordance with accepted regulatory practices.

Deferred Energy

Nevada statutes permit regulated utilities to adopt deferred energy accounting procedures. The intent of these procedures is to ease the effect on customers of fluctuations in the cost of purchased natural gas, fuel and electricity and are subject to annual prudency review by the PUCN. Under deferred energy accounting, to the extent actual fuel and purchased power costs exceed fuel and purchased power costs recoverable through current rates that excess is not recorded as a current expense on the Consolidated Statements of Operations but rather is deferred and recorded as a regulatory asset on the Consolidated Balance Sheets and would be included in the regulatory assets table above as deferred energy costs. Conversely, a regulatory liability is recorded to the extent fuel and purchased power costs recoverable through current rates exceed actual fuel and purchased power costs and is included in the regulatory liabilities table above as deferred energy costs. These excess amounts are reflected in quarterly adjustments to rates and recorded as cost of fuel, energy and capacity in future time periods.

Regulatory Rate Review

In February 2025, Nevada Power filed an electric regulatory rate review with the PUCN that requested an annual revenue increase of $215 million, or 9.0%. Nevada Power filed its certification filing in April 2025 that updated the requested annual revenue increase to $224 million, or 9.4%. In May 2025, a settlement was reached in the cost of capital phase, resulting in the return on equity remaining at 9.5% and the capital structure as well as the cost of debt being approved as filed. Hearings for the revenue requirement and rate design phases were held in July 2025. In September 2025, the PUCN issued an order approving an increase in the revenue requirement of $118 million, which includes 50% of construction work in progress in rate base for the Greenlink project, with rates effective October 1, 2025. In October 2025, Nevada Power filed a petition for reconsideration and clarification of certain aspects of the PUCN's order, including recovery of the Flex Pay Program implementation costs. In November 2025, the PUCN issued a final modified order largely reaffirming its original order.

Wildfire Self-Insurance Policy Filing

In January 2025, Nevada Power filed an application for approval of the establishment and associated cost recovery of a Wildfire Self-Insurance Policy. In the application, Nevada Power request that the PUCN issue an order determining that it is reasonable and prudent for the Nevada Utilities to establish a $500 million wildfire self-insurance policy (the "Policy") in order to have additional wildfire liability insurance in place in the event that a catastrophic wildfire in Nevada is alleged to be caused or exacerbated by utility equipment. The Policy would provide $500 million in additional coverage for the Nevada Utilities for third-party claims, and it would be in excess to the commercial wildfire liability insurance the Nevada Utilities possess. In addition, the application requests approval to collect the costs for the Policy in rates over a ten-year period. Hearings before the Commission concluded in June 2025. In July 2025, the PUCN issued an order that approved the application in part and denied the application in part. The PUCN found that $1.0-$1.5 billion in insurance coverage is a prudent range for the Nevada Utilities based on its wildfire risk profile and that the Nevada Utilities sufficiently supported its initial request for an additional $500 million of excess insurance. However, the PUCN also determined that additional information is necessary to assess whether the self-insurance policy proposed by the Nevada Utilities is prudent under the circumstances and reasonable considering other options, if any. The Nevada Utilities filed the additional information requested by the PUCN in October 2025. The PUCN has set a hearing in April 2026 to assess the prudency of self-insurance.

(7) Short-term Debt and Credit Facilities

Nevada Power has a $600 million secured credit facility expiring in June 2028 with an unlimited number of maturity extension options, subject to lender consent. The credit facility, which is for general corporate purposes and provide for the issuance of letters of credit, has a variable interest rate based on the Secured Overnight Financing Rate ("SOFR") or a base rate, at Nevada Power's option, plus a spread that varies based on Nevada Power's credit ratings for its senior secured long-term debt securities.

As of December 31, 2025 and 2024, Nevada Power had $50 million and $— million of short-term debt outstanding at a weighted average rate of 4.71% and —%, respectively.

Amounts due under Nevada Power's credit facility are collateralized by Nevada Power's general and refunding mortgage bonds. The credit facility requires Nevada Power's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.65 to 1.0 as of the last day of each quarter.

As of December 31, 2025 and 2024, Nevada Power had $50 million of letter of credit capacity under its $600 million secured credit facility, of which no amount was outstanding.

(8) Long-term Debt

Nevada Power's long-term debt consists of the following, including unamortized premiums, discounts and debt issuance costs, as of December 31 (dollars in millions):

	Par Value	2025	2024
General and refunding mortgage securities:			
3.70% Series CC, due 2029	$ 500	$ 498	$ 498
2.40% Series DD, due 2030	425	423	423
6.65% Series N, due 2036	367	362	361
6.75% Series R, due 2037	349	347	347
5.375% Series X, due 2040	250	248	248
5.45% Series Y, due 2041	250	241	240
3.125% Series EE, due 2050	300	298	298
5.90% Series GG, due 2053	400	395	394
6.00% Series 2023A, due 2054	500	495	495
Tax-exempt refunding revenue bond obligations:			
Fixed-rate series:			
4.125% Pollution Control Bonds Series 2017A, due 2032[1]	40	39	39
3.75% Pollution Control Bonds Series 2017, due 2036[1]	40	39	39
3.75% Pollution Control Bonds Series 2017B, due 2039[1]	13	13	13
Total long-term debt	$ 3,434	$ 3,398	$ 3,395
Reflected as:			
Current portion of long-term debt		$ 93	$ —
Long-term debt		3,305	3,395
Total long-term debt		$ 3,398	$ 3,395

(1) Subject to mandatory purchase by Nevada Power in March 2026 at which date the interest rate may be adjusted.

Junior Subordinated Debt

Nevada Power's junior subordinated debt consists of the following, as of December 31 (dollars in millions):

	Par Value	2025	2024
6.25% JSN 2025A, due 2055[1]	$ 300	$ 297	$ —
Total junior subordinated debt - non current	$ 300	$ 297	$ —

(1) Nevada Power will pay interest on the junior subordinated notes at a rate of 6.25% through May 2030, subject to a reset every five years.

Annual Repayments of Long-Term Debt

The annual repayments of long-term debt for the years beginning January 1, 2026 and thereafter, are as follows (in millions):

2026	$ 93
2027	—
2028	—
2029	500
2030	425
2031 and thereafter	2,717
Total	3,735
Unamortized premium, discount and debt issuance cost	(40)
Total	$ 3,695

The issuance of General and Refunding Mortgage Securities by Nevada Power is subject to PUCN approval and is limited by available property and other provisions of the mortgage indentures. As of December 31, 2025, approximately $11.8 billion (based on original cost) of Nevada Power's property was subject to the liens of the mortgages.

(9) Income Taxes

Berkshire Hathaway includes BHE and its subsidiaries in its U.S. federal income tax return. Consistent with established regulatory practice, Nevada Power's provision for federal income tax has been computed on a stand-alone basis, and substantially all of its currently payable or receivable income tax is remitted to or received from BHE pursuant to a tax allocation agreement. Income before income tax expense (benefit) as reported on the Consolidated Statement of Operations, is all domestic.

Income tax expense consists of the following for the years ended December 31 (in millions):

	2025	2024	2023
Current - Federal	$ 15	$ 65	$ (4)
Deferred - Federal	8	(49)	(74)
Investment tax credits	(5)	41	100
Total income tax expense	$ 18	$ 57	$ 22

The following table presents income taxes paid (received), net of refunds, for the years ended December 31 (in millions):

	2025	2024	2023
Jurisdiction:			
Federal[1]	$ (60)	$ 177	$ (52)

(1) Substantially all income taxes paid or (received) by Nevada Power are pursuant to a tax allocation agreement.

A reconciliation of the federal statutory income tax rate to the effective income tax rate applicable to income before income tax expense is as follows for the years ended December 31:

	2025		2024		2023	
	Amount	Percent	Amount	Percent	Amount	Percent
U.S federal statutory income tax rate	$ 56	21.0 %	$ 85	21.0 %	$ 59	21.0 %
Energy-related tax credits	(20)	(7.6)	(15)	(3.8)	—	—
Effects of ratemaking	(18)	(6.8)	(13)	(3.3)	(37)	(13.2)
Effective income tax rate	$ 18	6.6 %	$ 57	13.9 %	$ 22	7.8 %

Effects of ratemaking is primarily attributable to the recognition of excess deferred income taxes related to the federal tax rate change from 35% to 21% pursuant to an order issued by the PUCN effective January 1, 2021.

Energy-related tax credits relate to production tax credits ("PTC") and investment tax credits ("ITC") from Nevada Power's solar-powered generating facilities and energy storage properties. Federal renewable electricity PTCs are earned as energy from qualifying solar-powered generating facilities is produced and sold and are based on a per-kilowatt hour rate pursuant to the applicable federal income tax law. Solar-powered generating facilities are eligible for the credits for 10 years from the date the qualifying generating facilities are placed in-service. Federal renewable electricity ITCs are tax credits that reduce the income tax liability by a percentage of the cost from certain qualifying solar-powered generating facilities or energy storage properties over their useful lives. The percentage of the credit varies depending on attributes of the project up to a maximum of 50 percent. PTCs recognized for the for the years ended December 31, 2025, 2024 and 2023 totaled $12 million, $8 million and $— million, respectively. ITCs recognized for the years ended December 31, 2025, 2024 and 2023 totaled $8 million, $7 million and $— million, respectively.

The net deferred income tax liability consists of the following as of December 31 (in millions):

	2025	2024
Deferred income tax assets:		
Regulatory liabilities	$ 189	$ 201
Operating and finance leases	59	62
Customer advances	51	44
Unamortized contract value	9	12
Other	14	8
Total deferred income tax assets	322	327
Deferred income tax liabilities:		
Property-related items	(916)	(884)
Regulatory assets	(163)	(163)
Operating and finance leases	(57)	(59)
Other	(23)	(23)
Total deferred income tax liabilities	(1,159)	(1,129)
Net deferred income tax liability	$ (837)	$ (802)

The U.S. Internal Revenue Service has closed or effectively settled its examination of Nevada Power's income tax return through the short year ended December 31, 2014. The closure of examinations, or the expiration of the statute of limitations, may not preclude the U.S. Internal Revenue Service from adjusting the federal net operating loss carryforward utilized in a year for which the statute of limitations is not closed.

(10) Employee Benefit Plans

Nevada Power is a participant in benefit plans sponsored by NV Energy. The NV Energy Retirement Plan includes a qualified pension plan ("Qualified Pension Plan") and a supplemental executive retirement plan and a restoration plan (collectively, "Non-Qualified Pension Plans") that provide pension benefits for eligible employees. The NV Energy Comprehensive Welfare Benefit and Cafeteria Plan provides certain postretirement health care and life insurance benefits for eligible retirees ("Other Postretirement Plans") on behalf of Nevada Power. Nevada Power did not make any contributions to the Qualified Pension Plan for the years ended December 31, 2025, 2024 and 2023. Nevada Power contributed $1 million to the Non-Qualified Pension Plans for the years ended December 31, 2025, 2024 and 2023. Nevada Power did not make any contributions to the Other Postretirement Plans for the years ended December 31, 2025, 2024 and 2023. Amounts attributable to Nevada Power were allocated from NV Energy based upon the current, or in the case of retirees, previous, employment location. Offsetting regulatory assets and liabilities have been recorded related to the amounts not yet recognized as a component of net periodic benefit costs that will be included in regulated rates. Net periodic benefit costs not included in regulated rates are included in accumulated other comprehensive loss, net.

Amounts receivable from (payable to) NV Energy are included on the Consolidated Balance Sheets and consist of the following as of December 31 (in millions):

	2025	2024
Qualified Pension Plan -		
Other noncurrent assets	$ 46	$ 39
Non-Qualified Pension Plans:		
Other current liabilities	(1)	(1)
Other long-term liabilities	(5)	(6)
Other Postretirement Plans -		
Other noncurrent assets	16	19

(11) Asset Retirement Obligations

Nevada Power estimates its ARO liabilities based upon detailed engineering calculations of the amount and timing of the future cash spending for a third party to perform the required work. Spending estimates are escalated for inflation and then discounted at a credit-adjusted, risk-free rate. Changes in estimates could occur for a number of reasons, including changes in laws and regulations, plan revisions, inflation and changes in the amount and timing of the expected work.

Nevada Power does not recognize liabilities for AROs for which the fair value cannot be reasonably estimated. Due to the indeterminate removal date, the fair value of the associated liabilities on certain generation, transmission, distribution and other assets cannot currently be estimated, and no amounts are recognized on the Consolidated Financial Statements other than those included in the cost of removal regulatory liability established via approved depreciation rates in accordance with accepted regulatory practices. These accruals totaled $417 million and $399 million as of December 31, 2025 and 2024, respectively.

The following table presents Nevada Power's ARO liabilities by asset type as of December 31 (in millions):

	2025	2024
Waste water remediation	$ 35	$ 31
Evaporative ponds and dry ash landfills	17	12
Solar-powered generating facilities	6	6
Other	6	8
Total asset retirement obligations	$ 64	$ 57

The following table reconciles the beginning and ending balances of Nevada Power's ARO liabilities for the years ended December 31 (in millions):

	2025	2024
Beginning balance	$ 57	$ 62
Change in estimated costs	11	(3)
Additions	3	3
Retirements	(10)	(8)
Accretion	3	3
Ending balance	$ 64	$ 57
Reflected as:		
Other current liabilities	$ 4	$ 5
Other long-term liabilities	60	52
	$ 64	$ 57

In 2008, Nevada Power signed an administrative order of consent as owner and operator of Reid Gardner Generating Station Unit Nos. 1, 2 and 3 and as co-owner and operating agent of Unit No. 4. Based on the administrative order of consent, Nevada Power recorded estimated AROs and capital remediation costs. However, actual costs of work under the administrative order of consent may vary significantly once the scope of work is defined and additional site characterization has been completed. In connection with the termination of the co-ownership arrangement, effective October 22, 2013, between Nevada Power and California Department of Water Resources ("CDWR") for the Reid Gardner Generating Station Unit No. 4, Nevada Power and CDWR entered into a cost-sharing agreement that sets forth how the parties will jointly share in costs associated with all investigation, characterization and, if necessary, remedial activities as required under the administrative order of consent.

Certain of Nevada Power's decommissioning and reclamation obligations relate to jointly-owned facilities. Nevada Power is committed to pay a proportionate share of the decommissioning or reclamation costs. In the event of a default by any of the other joint participants, the respective subsidiary may be obligated to absorb, directly or by paying additional sums to the entity, a proportionate share of the defaulting party's liability. Management has identified legal obligations to retire generation plant assets specified in land leases for Nevada Power's jointly-owned Navajo Generating Station, retired in November 2019, and the Higgins Generating Station. Provisions of the lease require the lessees to remove the facilities upon request of the lessors at the expiration of the leases. Nevada Power's estimated share of the decommissioning and reclamation obligations are primarily recorded as ARO liabilities in other long-term liabilities on the Consolidated Balance Sheets.

In May 2024, the United States Environmental Protection Agency published its final rule on legacy coal combustion residuals ("CCR") surface impoundments and CCR management units ("CCRMUs") in the Federal Register. CCRMUs include CCR surface impoundments and landfills closed before October 19, 2015 and inactive CCR landfills. The final rule contains three main components: (1) a definition for legacy CCR surface impoundments, which are inactive surface impoundments at inactive generating facilities that must adhere to the same regulations as inactive CCR impoundments at active generating facilities, barring location restrictions and liner design criteria, with customized compliance deadlines; (2) groundwater monitoring, corrective action, closure, and post closure care requirements for CCRMUs, which may be located at active generating facilities and inactive generating facilities with a legacy CCR surface impoundment; and (3) the owners and operators of inactive generating facilities must identify the presence of legacy CCR surface impoundments and comply with all rule requirements for surface impoundments; and the owners and operators of active generating facilities and inactive generating facilities with a legacy CCR surface impoundment must prepare Facility Evaluation Reports ("FERs") that identify and describe the CCRMUs and determine whether closure is required. In February 2026, the EPA extended certain compliance deadlines with CCRMUs. Accordingly, and in a manner consistent with existing CCR rules, owners and operators must publish FERs on their CCR websites in two parts, within 12 months (Part 1) and 24 months (Part 2) of the final rule's effective date in February 2026. Nevada Power is currently evaluating the final rule and does not anticipate identifying any legacy surface impoundments, but does anticipate identifying CCRMUs subject to the rule. Due to the number of site investigations warranted by this rule and the nature of engineering and other studies required at each site, Nevada Power is unable to reasonably estimate the potential impact, which may be material, to its asset retirement obligations.

(12) Risk Management and Hedging Activities

Nevada Power is exposed to the impact of market fluctuations in commodity prices and interest rates. Nevada Power is principally exposed to electricity and natural gas market fluctuations primarily through Nevada Power's obligation to serve retail customer load in its regulated service territory. Nevada Power's load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity and wholesale electricity that is purchased and sold. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, generating facility availability, customer usage, storage, and transmission and transportation constraints. The actual cost of fuel and purchased power is recoverable through the deferred energy mechanism. Interest rate risk exists on variable-rate debt and future debt issuances. Nevada Power does not engage in proprietary trading activities.

Nevada Power has established a risk management process that is designed to identify, assess, manage and report on each of the various types of risk involved in its business. To mitigate a portion of its commodity price risk, Nevada Power uses commodity derivative contracts, which may include forwards, futures, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. Nevada Power manages its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. Additionally, Nevada Power may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, to mitigate Nevada Power's exposure to interest rate risk. Nevada Power does not hedge all of its commodity price and interest rate risks, thereby exposing the unhedged portion to changes in market prices.

There have been no significant changes in Nevada Power's accounting policies related to derivatives. Refer to Notes 2 and 13 for additional information on derivative contracts.

The following table, which excludes contracts that have been designated as normal under the normal purchases and normal sales exception afforded by GAAP, summarizes the fair value of Nevada Power's derivative contracts, on a gross basis, and reconciles those amounts presented on a net basis on the Consolidated Balance Sheets (in millions):

	Other Current Assets	Derivative Contracts - Current Liabilities	Other Long-term Liabilities	Total
As of December 31, 2025:				
Not designated as hedging contracts [1] -				
Commodity liabilities	$ —	$ (27)	$ (14)	$ (41)
As of December 31, 2024:				
Not designated as hedging contracts [1] -				
Commodity liabilities	$ —	$ (53)	$ (4)	$ (57)

(1) Nevada Power's commodity derivatives not designated as hedging contracts are included in regulated rates. As of December 31, 2025 and 2024, a regulatory asset of $41 million and $57 million, respectively, was recorded related to the net derivative liability of $41 million and $57 million, respectively.

Derivative Contract Volumes

The following table summarizes the net notional amounts of outstanding commodity derivative contracts with fixed price terms that comprise the mark-to-market values as of December 31 (in millions):

	Unit of Measure	2025	2024
Electricity purchases	Megawatt hours	2	2
Natural gas purchases	Decatherms	131	127

Credit Risk

Nevada Power is exposed to counterparty credit risk associated with wholesale energy supply and marketing activities with other utilities, energy marketing companies, financial institutions and other market participants. Credit risk may be concentrated to the extent Nevada Power's counterparties have similar economic, industry or other characteristics and due to direct and indirect relationships among the counterparties. Before entering into a transaction, Nevada Power analyzes the financial condition of each significant wholesale counterparty, establishes limits on the amount of unsecured credit to be extended to each counterparty and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate wholesale counterparty credit risk, Nevada Power enters into netting and collateral arrangements that may include margining and cross-product netting agreements and obtain third-party guarantees, letters of credit and cash deposits. If required, Nevada Power exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

Collateral and Contingent Features

In accordance with industry practice, certain wholesale agreements, including derivative contracts, contain credit support provisions that in part base certain collateral requirements on credit ratings for senior unsecured debt as reported by one or more of the recognized credit rating agencies. These agreements may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance" if there is a material adverse change in Nevada Power's creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2025, Nevada Power's credit ratings for its senior secured debt and its issuer credit ratings for subordinated debt from the recognized credit rating agencies were investment grade.

The aggregate fair value of Nevada Power's derivative contracts in liability positions with specific credit-risk-related contingent features totaled $5 million and $13 million as of December 31, 2025 and 2024, respectively, which represents the amount of collateral to be posted if all credit risk related contingent features for derivative contracts in liability positions had been triggered. Nevada Power's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation or other factors.

(13) Fair Value Measurements

The carrying value of Nevada Power's cash, certain cash equivalents, receivables, payables, accrued liabilities and short-term borrowings approximates fair value because of the short-term maturity of these instruments. Nevada Power has various financial assets and liabilities that are measured at fair value on the Consolidated Balance Sheets using inputs from the three levels of the fair value hierarchy. A financial asset or liability classification within the hierarchy is determined based on the lowest level input that is significant to the fair value measurement. The three levels are as follows:

- Level 1 - Inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Nevada Power has the ability to access at the measurement date.
- Level 2 - Inputs include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means (market corroborated inputs).
- Level 3 - Unobservable inputs reflect Nevada Power's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. Nevada Power develops these inputs based on the best information available, including its own data.

The following table presents Nevada Power's financial assets and liabilities recognized on the Consolidated Balance Sheets and measured at fair value on a recurring basis (in millions):

	Input Levels for Fair Value Measurements			
	Level 1	Level 2	Level 3	Total
As of December 31, 2025:				
Assets:				
Money market mutual funds	$ 19	$ —	$ —	$ 19
Investment funds	5	—	—	5
	$ 24	$ —	$ —	$ 24
Liabilities - commodity derivatives	$ —	$ —	$ (41)	$ (41)
As of December 31, 2024:				
Assets:				
Money market mutual funds	$ 15	$ —	$ —	$ 15
Investment funds	4	—	—	4
	$ 19	$ —	$ —	$ 19
Liabilities - commodity derivatives	$ —	$ —	$ (57)	$ (57)

Nevada Power's investments in money market mutual funds and investment funds are accounted for as available-for-sale securities and are stated at fair value. When available, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value.

Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. When available, the fair value of derivative contracts is estimated using unadjusted quoted prices for identical contracts in the market in which Nevada Power transacts. When quoted prices for identical contracts are not available, Nevada Power uses forward price curves. Forward price curves represent Nevada Power's estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates. Nevada Power bases its forward price curves upon internally developed models, with internal and external fundamental data inputs. Market price quotations for certain electricity and natural gas trading hubs are not as readily obtainable due to markets that are not active. Given that limited market data exists for these contracts, Nevada Power uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs that are based on unobservable inputs. The model incorporates a mid-market pricing convention (the mid-point price between bid and ask prices) as a practical expedient for valuing its assets and liabilities measured and reported at fair value. The determination of the fair value for derivative contracts not only includes counterparty risk, but also the impact of Nevada Power's nonperformance risk on its liabilities, which as of December 31, 2025, had an immaterial impact to the fair value of its derivative contracts. As such, Nevada Power considers its derivative contracts to be valued using Level 3 inputs.

The following table reconciles the beginning and ending balances of Nevada Power's net commodity derivative assets and liabilities measured at fair value on a recurring basis using significant Level 3 inputs for the years ended December 31 (in millions):

	2025	2024	2023
Beginning balance	$ (57)	$ (68)	$ (52)
Changes in fair value recognized in regulatory assets or liabilities	(68)	(95)	(166)
Settlements	84	106	150
Ending balance	$ (41)	$ (57)	$ (68)

Nevada Power's long-term debt is carried at cost on the Consolidated Balance Sheets. The fair value of Nevada Power's long-term debt is a Level 2 fair value measurement and has been estimated based upon quoted market prices, where available, or at the present value of future cash flows discounted at rates consistent with comparable maturities with similar credit risks. The following table presents the carrying value and estimated fair value of Nevada Power's long-term debt as of December 31 (in millions):

	2025		2024	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 3,695	$ 3,688	$ 3,395	$ 3,299

(14) Commitments and Contingencies

Commitments

Nevada Power has the following firm commitments that are not reflected on the Consolidated Balance Sheet. Minimum payments as of December 31, 2025 are as follows (in millions):

	2026	2027	2028	2029	2030	2031 and Thereafter	Total
Contract type:							
Purchased electricity contracts - commercially operable	$ 11	$ 12	$ 12	$ 12	$ 12	$ 616	$ 675
Purchased electricity and Energy Storage contracts - non-commercially operable	3	42	158	168	168	2,850	3,389
Fuel contracts	55	53	47	45	45	35	280
Construction commitments	596	489	195	22	2	2	1,306
Transmission	35	21	7	9	6	24	102
Easements	4	4	4	1	1	30	44
Maintenance, service and other contracts	15	12	9	8	8	17	69
Total commitments	$ 719	$ 633	$ 432	$ 265	$ 242	$ 3,574	$ 5,865

Purchased Electricity Contracts - Commercially Operable

Nevada Power has several contracts for long-term purchase of electric energy which have been approved by the PUCN. The expiration of these contracts range from 2026 to 2067. Nevada Power has many long-term PPAs primarily with solar-powered and geothermal generating facilities that are not included in the table above due to there being no minimum payments generally due to being dependent on solar and geothermal conditions. These PPAs generally range from 15 to 25 years in duration. Future payments associated with these PPAs are expected to be material. Certain PPAs qualify as leases as described in Note 2 and are also excluded from the table above. Refer to Note 5 for variable lease costs associated with these lease commitments.

Purchased Electricity Contracts - Non-Commercially Operable

Nevada Power has several contracts for long-term purchase of electric energy in which the facility remains under development. Amounts represent the estimated payments under renewable energy power purchase contracts, which have been approved by the PUCN and are contingent upon the developers obtaining commercial operation and their ability to deliver power.

Fuel Contracts

Nevada Power's gas transportation contracts expire from 2026 to 2039.

Construction Commitments

Nevada Power's construction commitments included in the table above relate to firm commitments and include costs associated with a 400-MW solar photovoltaic facility with an additional 400-MWs of co-located battery storage that is being developed in Churchill County, Nevada, with ownership share approved by the PUCN of 10% Nevada Power and 90% Sierra Pacific and the Greenlink Nevada transmission expansion program that is being developed in western and northern Nevada and certain other generation plant projects.

Transmission

Nevada Power has contracts for the right to transmit electricity over other entities' transmission lines to facilitate delivery to Nevada Power's customers.

Easements

Nevada Power has non-cancelable easements for land. Operations and maintenance expense on non-cancelable easements totaled $4 million for the years ended December 31, 2025, 2024 and 2023.

Maintenance, Service and Other Contracts

Nevada Power has long-term service agreements for the performance of maintenance on generation units. Obligation amounts are based on estimated usage. The estimated expiration of these service agreements range from 2025 to 2029.

Environmental Laws and Regulations

Nevada Power is subject to federal, state and local laws and regulations regarding air quality, climate change, emissions performance standards, water quality, coal ash disposal and other environmental matters that have the potential to impact its current and future operations. Nevada Power believes it is in material compliance with all applicable laws and regulations.

Accrual for Customer Refund

In 2025, Nevada Power recorded an accrual totaling $46 million in connection with a potential customer refund arising from an ongoing regulatory proceeding. The estimated accrual is based on currently available information to date and Nevada Power believes it is probable that losses will be incurred associated with the ongoing regulatory proceeding which reflects Nevada Power's commitment to transparency and regulatory compliance. Nevada Power filed an Offer of Compromise with the PUCN in January 2026 to settle the regulatory proceeding, inclusive of the amount accrued in 2025, that was accepted by the PUCN in February 2026.

Legal Matters

Nevada Power is party to a variety of legal actions arising out of the normal course of business. Nevada Power does not believe that such normal and routine litigation will have a material impact on its consolidated financial results.

(15) Revenues from Contracts with Customers

The following table summarizes Nevada Power's Customer Revenue by customer class for the years ended December 31 (in millions):

	2025	2024	2023
Customer Revenue:			
Retail:			
Residential	$ 1,225	$ 1,602	$ 1,633
Commercial	500	572	647
Industrial	542	608	689
Other	8	6	23
Total fully bundled	2,275	2,788	2,992
Distribution-only service	16	15	14
Total retail	2,291	2,803	3,006
Wholesale, transmission and other	64	66	63
Total Customer Revenue	2,355	2,869	3,069
Other revenue	2	4	19
Total operating revenue	$ 2,357	$ 2,873	$ 3,088

(16) Supplemental Cash Flow Disclosures

The summary of supplemental cash flow disclosures as of and for the years ended December 31 is as follows (in millions):

	2025	2024	2023
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	$ 188	$ 173	$ 159
Supplemental disclosure of non-cash investing and financing transactions:			
Accruals related to property, plant and equipment additions	$ 134	$ 169	$ 230

(17) Related Party Transactions

Nevada Power has an intercompany administrative services agreement with BHE and its subsidiaries. Amounts charged to Nevada Power under this agreement, either directly or through NV Energy, totaled $20 million, $82 million and $55 million for the years ended December 31, 2025, 2024 and 2023, respectively. Amounts charged to Nevada Power in 2025 and 2024 primarily relate to information technology projects billed at a consolidated level and passed through to affiliates.

Kern River Gas Transmission Company, an indirect subsidiary of BHE, provided natural gas transportation and other services to Nevada Power of $52 million, $51 million, $50 million for the years ended December 31, 2025, 2024 and 2023, respectively. As of December 31, 2025 and 2024, Nevada Power's Consolidated Balance Sheets included amounts due to Kern River Gas Transmission Company of $4 million.

Nevada Power provided electricity and other services to PacifiCorp, an indirect subsidiary of BHE, of $2 million, $2 million and $1 million for the years ended December 31, 2025, 2024 and 2023, respectively. There were no receivables associated with these services as of December 31, 2025 and 2024.

Nevada Power provided electricity to Sierra Pacific of $199 million, $188 million and $230 million for the years ended December 31, 2025, 2024 and 2023, respectively. Receivables associated with these transactions were $15 million and $7 million as of December 31, 2025 and 2024, respectively. Nevada Power purchased electricity from Sierra Pacific of $35 million, $29 million and $70 million for the years ended December 31, 2025, 2024 and 2023, respectively. Payables associated with these transactions were $2 million and $1 million as of December 31, 2025 and 2024, respectively.

Nevada Power incurs intercompany administrative and shared facility costs with NV Energy and Sierra Pacific. These transactions are governed by an intercompany service agreement and are priced at cost. Nevada Power provided services to NV Energy of $12 million, $8 million and $4 million for each of the years ending December 31, 2025, 2024 and 2023, respectively. NV Energy provided services to Nevada Power of $8 million, $8 million and $9 million for the years ending December 31, 2025, 2024 and 2023, respectively. Nevada Power provided services to Sierra Pacific of $63 million, $31 million and $28 million for the years ended December 31, 2025, 2024 and 2023, respectively. Sierra Pacific provided primarily project related services to Nevada Power of $60 million, $19 million and $19 million for the years ended December 31, 2025, 2024 and 2023, respectively. As of December 31, 2025 and 2024, Nevada Power's Consolidated Balance Sheets included amounts due to NV Energy of $37 million and $51 million, respectively. As of December 31, 2025, amounts due from NV Energy to Nevada Power were $37 million and there were no amounts due from 2024. As of December 31, 2025 and 2024, Nevada Power's Consolidated Balance Sheets included no receivables due from Sierra Pacific. There were $26 million and $65 million payables due to Sierra Pacific as of December 31, 2025 and 2024, respectively.

Nevada Power is party to a tax allocation agreement and is part of the Berkshire Hathaway consolidated U.S. federal income tax return. Federal income taxes payable to BHE were $10 million and $82 million as of December 31, 2025 and 2024, respectively. Nevada Power received cash refunds from BHE of $60 million for federal income taxes for the year ended December 31, 2025, made cash payments for federal income tax to BHE of $177 million for the year ended December 31, 2024, and received cash refunds from BHE of $52 million for federal income taxes for the years ended December 31, 2023.

Certain disbursements for accounts payable and payroll are made by NV Energy on behalf of Nevada Power and reimbursed automatically when settled by the bank. These amounts are recorded as accounts payable at the time of disbursement.

Sierra Pacific Power Company and its subsidiaries
Consolidated Financial Section

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following is management's discussion and analysis of certain significant factors that have affected the consolidated financial condition and results of operations of Sierra Pacific during the periods included herein. Explanations include management's best estimate of the impact of weather, customer growth, usage trends and other factors. This discussion should be read in conjunction with Sierra Pacific's historical Consolidated Financial Statements and Notes to Consolidated Financial Statements in Item 8 of this Form 10-K. Sierra Pacific's actual results in the future could differ significantly from the historical results.

Results of Operations

Overview

Net income for the year ended December 31, 2025 was $146 million, an increase of $61 million, or 72%, compared to 2024, primarily due to higher allowance for borrowed and equity funds, lower depreciation and amortization expense, higher utility margin and decreased operations and maintenance expense. These items were partially offset by higher interest expense and higher income tax expense. Electric utility margin increased primarily due to higher retail rates from the 2024 regulatory rate review with new rates effective October 2024 and price impacts from changes in sales mix, partially offset by an accrual in connection with a potential customer refund arising from an ongoing regulatory proceeding. Electric retail customer volumes, including distribution only service customers, increased 0.2% primarily due to an increase in the average number of customers, offset by unfavorable impact of weather. Energy generated decreased 3% for 2025 compared to 2024 primarily due to lower natural gas- and coal-fueled generation. Wholesale electricity sales volumes decreased 9% and purchased electricity volumes decreased 1%.

Net income for the year ended December 31, 2024 was $85 million, a decrease of $32 million, or 27%, compared to 2023, primarily due to increased operations and maintenance expense, higher interest expense and lower interest and dividend income. These items were partially offset by higher electric utility margin, higher allowance for equity funds, lower income tax expense and favorable other, net from lower pension expense. Electric utility margin increased primarily due to higher retail rates from the 2024 regulatory rate review with new rates effective October 2024 and higher retail customer volumes, partially offset by lower transmission and wholesale revenue. Electric retail customer volumes, including distribution only service customers, increased 3.9% primarily due to the favorable impact of weather and an increase in the average number of customers. Energy generated increased 8% for 2024 compared to 2023 primarily due to higher coal-fueled generation, offset by higher natural gas-fueled generation. Wholesale electricity sales volumes increased 10% and purchased electricity volumes decreased 17%.

Non-GAAP Financial Measure

Management utilizes various key financial measures that are prepared in accordance with GAAP, as well as non-GAAP financial measures such as electric utility margin and natural gas utility margin, to help evaluate results of operations. Electric utility margin is calculated as electric operating revenue less cost of fuel and energy while natural gas utility margin is calculated as natural gas operating revenue less cost of natural gas purchased for resale, which are captions presented on the Consolidated Statements of Operations.

Sierra Pacific's cost of fuel and energy and cost of natural gas purchased for resale are generally recovered from its retail customers through regulatory recovery mechanisms and, as a result, changes in Sierra Pacific's expenses included in regulatory recovery mechanisms result in comparable changes to revenue. As such, management believes electric utility margin and natural gas utility margin more appropriately and concisely explain results of operations rather than a discussion of revenue and cost of sales separately. Management believes the presentation of electric utility margin and natural gas utility margin provides meaningful and valuable insight into the information management considers important to understanding the business and a measure of comparability to others in the industry.

Electric utility margin and natural gas utility margin are not measures calculated in accordance with GAAP and should be viewed as a supplement to, and not a substitute for, operating income, which is the most directly comparable financial measure prepared in accordance with GAAP. The following table provides a reconciliation of utility margin to operating income for the years ended December 31 (in millions):

	2025	2024	Change		2024	2023	Change	
Electric utility margin:								
Operating revenue	$ 964	$ 1,080	$ (116)	(11)%	$ 1,080	$ 1,194	$ (114)	(10)%
Cost of fuel and energy	435	561	(126)	(22)	561	689	(128)	(19)
Electric utility margin	529	519	10	2	519	505	14	3
Natural gas utility margin:								
Operating revenue	124	182	(58)	(32)	182	237	(55)	(23)
Cost of natural gas purchased for resale	58	121	(63)	(52)	121	176	(55)	(31)
Natural gas utility margin	66	61	5	8	61	61	—	—
Utility margin	595	580	15	3	580	566	14	2
Operations and maintenance	241	245	(4)	(2)	245	204	41	20
Depreciation and amortization	161	181	(20)	(11)	181	185	(4)	(2)
Property and other taxes	25	24	1	4	24	25	(1)	(4)
Operating income	$ 168	$ 130	$ 38	29 %	$ 130	$ 152	$ (22)	(14)%

Electric Utility Margin

A comparison of key operating results related to electric utility margin is as follows for the years ended December 31:

	2025	2024	Change		2024	2023	Change	
Utility margin (in millions):								
Operating revenue	$ 964	$ 1,080	$ (116)	(11)%	$ 1,080	$ 1,194	$ (114)	(10)%
Cost of fuel and energy	435	561	(126)	(22)	561	689	(128)	(19)
Utility margin	$ 529	$ 519	$ 10	2 %	$ 519	$ 505	$ 14	3 %
Sales (GWhs):								
Residential	2,666	2,726	(60)	(2)%	2,726	2,655	71	3 %
Commercial	3,095	3,108	(13)	—	3,108	2,998	110	4
Industrial	2,987	2,811	176	6	2,811	2,684	127	5
Other	9	9	—	—	9	11	(2)	(18)
Total fully bundled[1]	8,757	8,654	103	1	8,654	8,348	306	4
Distribution only service	2,882	2,958	(76)	(3)	2,958	2,829	129	5
Total retail	11,639	11,612	27	—	11,612	11,177	435	4
Wholesale	623	683	(60)	(9)	683	621	62	10
Total GWhs sold	12,262	12,295	(33)	— %	12,295	11,798	497	4 %
Average number of retail customers (in thousands)	386	382	4	1 %	382	376	6	2 %
Average revenue per MWh:								
Retail - fully bundled[1]	$101.50	$116.12	$ (14.62)	(13)%	$116.12	$132.97	$ (16.85)	(13)%
Wholesale	$ 62.58	$ 58.60	$ 3.98	7 %	$ 58.60	$ 79.63	$ (21.03)	(26)%
Heating degree days	4,105	4,379	(274)	(6)%	4,379	4,950	(571)	(12)%
Cooling degree days	1,198	1,422	(224)	(16)%	1,422	1,097	325	30 %
Sources of energy (GWhs)[2][3]:								
Natural gas	4,479	4,566	(87)	(2)%	4,566	4,310	256	6 %
Coal	847	910	(63)	(7)	910	759	151	20
Renewables	7	23	(16)	(70)	23	24	(1)	(4)
Total energy generated	5,333	5,499	(166)	(3)	5,499	5,093	406	8
Energy purchased	3,775	3,808	(33)	(1)	3,808	4,612	(804)	(17)
Total	9,108	9,307	(199)	(2)%	9,307	9,705	(398)	(4)%
Average cost of energy per MWh[2][4]:								
Energy generated	$ 35.47	$ 40.79	$ (5.32)	(13)%	$ 40.79	$ 64.82	$ (24.03)	(37)%
Energy purchased	$ 65.07	$ 88.33	$ (23.26)	(26)%	$ 88.33	$ 77.85	$ 10.48	13 %

(1) Fully bundled includes sales to customers for combined energy, transmission and distribution services.

(2) The average cost of energy per MWh and sources of energy excludes —, 3 and 4 GWhs of coal and — GWhs of natural gas generated energy that is purchased at cost by related parties for the years ended December 31, 2025, 2024 and 2023, respectively.

(3) GWh amounts are net of energy used by the related generating facilities.

(4) The average cost of energy per MWh includes only the cost of fuel associated with the generating facilities, purchased power and deferrals.

Natural Gas Utility Margin

A comparison of key operating results related to natural gas utility margin is as follows for the years ended December 31:

	2025	2024	Change		2024	2023	Change	
Utility margin (in millions):								
Operating revenue	$ 124	$ 182	$ (58)	(32)%	$ 182	$ 237	$ (55)	(23)%
Cost of natural gas purchased for resale	58	121	(63)	(52)	121	176	(55)	(31)
Utility margin	$ 66	$ 61	$ 5	8 %	$ 61	$ 61	$ —	— %
Sold (000's Dths):								
Residential	10,356	10,902	(546)	(5)%	10,902	12,200	(1,298)	(11)%
Commercial	5,475	5,597	(122)	(2)	5,597	6,276	(679)	(11)
Industrial	2,287	2,423	(136)	(6)	2,423	2,870	(447)	(16)
Total retail	18,118	18,922	(804)	(4)%	18,922	21,346	(2,424)	(11)%
Average number of retail customers (in thousands)	188	185	3	2 %	185	183	2	1 %
Average revenue per retail Dth sold	$ 6.84	$ 9.62	$ (2.78)	(29)%	$ 9.62	$ 11.10	$ (1.48)	(13)%
Heating degree days	4,105	4,379	(274)	(6)%	4,379	4,950	(571)	(12)%
Average cost of natural gas per retail Dth sold	$ 3.20	$ 6.39	$ (3.19)	(50)%	$ 6.39	$ 8.25	$ (1.85)	(23)%

Year Ended December 31, 2025 Compared to Year Ended December 31, 2024

Electric utility margin increased $10 million, or 2%, for 2025 compared to 2024 primarily due to:

- $19 million of higher electric retail utility margin primarily due to higher retail rates from the 2024 regulatory rate review with new rates effective October 2024 and price impacts from changes in sales mix. Retail customer volumes, including distribution only service customers, increased 0.2% primarily due to an increase in the average number of customers, offset by the unfavorable impact of weather;
- $3 million of higher energy efficiency program revenue (offset in operations and maintenance expense) and
- $2 million of other revenues.

The increase in electric utility margin was offset by:

- $14 million of lower revenue related to an accrual in connection with a potential customer refund arising from an ongoing regulatory proceeding and
- $1 million of lower transmission and wholesale revenue.

Natural gas utility margin increased $5 million, or 8%, for 2025 compared to 2024 primarily due to higher retail rates due to the 2024 regulatory rate review with new rates effective October 2024 and an increase in the average number of customers, offset by lower customer volumes from the unfavorable impact of weather.

Operations and maintenance decreased $4 million, or 2%, for 2025 compared to 2024 primarily due to lower administrative and general costs, lower regulatory amortizations and disallowances and decreased energy efficiency program costs (offset in operating revenue), offset by higher insurance premiums due to additional wildfire coverage and increased technology costs.

Depreciation and amortization decreased $20 million, or 11%, for 2025 compared to 2024 primarily due to lower depreciation rates and regulatory amortizations as a result of extending the life of the Valmy generation facility with the conversion to natural gas.

Interest expense increased $15 million, or 17%, for 2025 compared to 2024 primarily due to higher long-term debt with higher average interest rates and higher carrying charges on regulatory balances.

Allowance for borrowed and equity funds increased $46 million for 2025 compared to 2024 primarily due to higher construction work-in-progress.

Interest and dividend income decreased $1 million, or 8%, for 2025 compared to 2024 primarily due to unfavorable interest income, mainly from lower carrying charges on regulatory balances.

Other, net was favorable by $2 million for 2025 compared to 2024 primarily due to lower pension expense.

Income tax expense increased $9 million, or 90%, for 2025 compared to 2024. The effective tax rate was 12% and 11% for 2025 and 2024, respectively. The $9 million increase was primarily due to higher pretax income, partially offset by higher benefit from the effects of ratemaking.

Year Ended December 31, 2024 Compared to Year Ended December 31, 2023

Electric utility margin increased $14 million, or 3%, for 2024 compared to 2023 primarily due to:

- $19 million of higher electric retail utility margin primarily due to higher retail rates from the 2024 regulatory rate review with new rates effective October 2024 and higher retail customer volumes. Retail customer volumes, including distribution only service customers, increased 3.9% primarily due to the favorable impact of weather and an increase in the average number of customers.

The increase in electric utility margin was offset by:

- $5 million of lower transmission and wholesale revenue.

Operations and maintenance increased $41 million, or 20%, for 2024 compared to 2023 primarily due to higher insurance premiums due to additional wildfire coverage, increased reserve costs, higher plant operations and maintenance expenses, higher regulatory expenses primarily related to mill tax, increased technology costs, higher administrative and general costs, higher energy efficiency program costs (offset in operating revenue) and regulatory impacts from the 2024 general rate review.

Depreciation and amortization decreased $4 million, or 2%, for 2024 compared to 2023 primarily due to lower plant amortizations.

Interest expense increased $20 million, or 30%, for 2024 compared to 2023 primarily due to higher long-term debt and higher average interest rates.

Allowance for equity funds increased $8 million for 2024 compared to 2023 primarily due to higher construction work-in-progress.

Interest and dividend income decreased $10 million, or 45%, for 2024 compared to 2023 primarily due to unfavorable interest income, mainly from lower carrying charges on regulatory balances.

Other, net favorable $6 million for 2024 compared to 2023 primarily due to lower pension expense.

Income tax expense decreased $6 million, or 38%, for 2024 compared to 2023. The effective tax rate was 11% and 12% for 2024 and 2023, respectively. The $6 million decrease was primarily due lower pretax income.

Liquidity and Capital Resources

As of December 31, 2025, Sierra Pacific's total net liquidity was $405 million as follows (in millions):

Cash and cash equivalents	$	5
Credit facilities		400
Total net liquidity	$	405
Credit facilities:		
Maturity dates		2028

Refer to Note 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for further discussion regarding Sierra Pacific's credit facility and letters of credit.

Operating Activities

Net cash flows from operating activities for the years ended December 31, 2025 and 2024 were $395 million and $470 million, respectively. The change was primarily due to higher payments related to fuel energy costs and decreased collections from customers, partially offset by the timing of payments for operating costs and lower income tax payments.

Net cash flows from operating activities for the years ended December 31, 2024 and 2023 were $470 million and $419 million, respectively. The change was primarily due to lower payments related to fuel energy costs and increased customer deposits, partially offset by lower collections from customers, the timing of payments for operating costs, higher interest payments and higher income tax payments.

The timing of Sierra Pacific's income tax cash flows from period to period can be significantly affected by the estimated federal income tax payment methods selected and assumptions made for each payment date.

Investing Activities

Net cash flows from investing activities for the years ended December 31, 2025 and 2024 were $(1,650) million and $(673) million, respectively. The change was primarily due to increased capital expenditures. Refer to "Future Uses of Cash" for further discussion of capital expenditures.

Net cash flows from investing activities for the years ended December 31, 2024 and 2023 were $(673) million and $(388) million, respectively. The change was primarily due to increased capital expenditures. Refer to "Future Uses of Cash" for further discussion of capital expenditures.

Financing Activities

Net cash flows from financing activities for the years ended December 31, 2025 and 2024 were $1,241 million and $175 million, respectively. The change was primarily due to higher contributions from NV Energy, Inc., higher proceeds from the issuance of junior subordinated debt and lower dividends paid to NV Energy, Inc.

Net cash flows from financing activities for the years ended December 31, 2024 and 2023 were $175 million and $(35) million, respectively. The change was primarily due to a decrease in repayments of long-term debt, higher contributions from NV Energy, Inc. and lower repayments of an affiliate note payable, partially offset by a decrease in proceeds from long-term debt and higher dividends paid to NV Energy, Inc.

In January 2026, Sierra Pacific received contributions from NV Energy, Inc. of $300 million.

Debt Authorizations

Sierra Pacific currently has an effective shelf registration statement with the SEC to issue an additional $2.1 billion of general and refunding mortgage securities through April 1, 2028. Additionally, Sierra Pacific's ability to issue debt is primarily impacted by its financing authority from the PUCN. As of December 31, 2025, Sierra Pacific has financing authority from the PUCN consisting of the ability to issue long-term and short-term debt securities so long as the total amount of debt outstanding (excluding borrowings under Sierra Pacific's $400 million secured credit facility) does not exceed $4.0 billion and to issue common and preferred stock so long as the total amounts outstanding do not exceed $5.1 billion and $500 million, respectively, as measured at the end of each calendar quarter. Sierra Pacific's revolving credit facility contains a financial maintenance covenant which Sierra Pacific was in compliance with as of December 31, 2025. In addition, certain financing agreements contain covenants which are currently suspended as Sierra Pacific's senior secured and subordinated debt is rated investment grade. However, if Sierra Pacific's debt ratings fall below investment grade by either Moody's Investor Service or Standard & Poor's, Sierra Pacific would be subject to limitations under these covenants.

General and Refunding Mortgage Securities

To the extent Sierra Pacific has the ability to issue debt under the most restrictive covenants in its financing agreements and has financing authority to do so from the PUCN, Sierra Pacific's ability to issue secured debt is limited by the amount of bondable property or retired bonds that can be used to issue debt under Sierra Pacific's indenture.

Sierra Pacific's indenture creates a lien on substantially all of Sierra Pacific's properties in Nevada. As of December 31, 2025, Sierra Pacific had approximately $5.6 billion in bondable property, of which $3.6 billion of those had been pledged. Sierra Pacific had the capacity to issue $1.4 billion of additional general and refunding mortgage securities as of December 31, 2025 determined on the basis of 70% of net utility property additions. Property additions include plant-in-service and specific assets in construction work-in-progress. The amount of bond capacity listed above does not include eligible property in construction work-in-progress. Sierra Pacific also has the ability to release property from the lien of Sierra Pacific's indenture on the basis of net property additions, cash or retired bonds. To the extent Sierra Pacific releases property from the lien of Sierra Pacific's indenture, it will reduce the amount of securities issuable under the indenture.

Future Uses of Cash

Sierra Pacific has available a variety of sources of liquidity and capital resources, both internal and external, including net cash flows from operating activities, public and private debt offerings, the use of secured revolving credit facilities, capital contributions and other sources. These sources are expected to provide funds required for current operations, capital expenditures, debt retirements and other capital requirements. The availability and terms under which Sierra Pacific has access to external financing depends on a variety of factors, including Sierra Pacific's credit ratings, investors' judgment of risk associated with Sierra Pacific and conditions in the overall capital markets, including the condition of the utility industry.

Capital Expenditures

Capital expenditure needs are reviewed regularly by management and may change significantly as a result of these reviews, which may consider, among other factors, changes in environmental and other rules and regulations; impacts to customers' rates; outcomes of regulatory proceedings; changes in income tax laws; general business conditions; load projections; system reliability standards; the cost and efficiency of construction labor, equipment and materials; commodity prices; and the cost and availability of capital. Prudently incurred expenditures for compliance-related items such as pollution-control technologies, replacement generation and associated operating costs are generally incorporated into Sierra Pacific's regulated retail rates. Expenditures for certain assets may ultimately include acquisition of existing assets.

Historical and forecasted capital expenditures, each of which exclude amounts for non-cash equity AFUDC and other non-cash items, for the years ending December 31 are as follows (in millions):

	Historical			Forecast		
	2023	2024	2025	2026	2027	2028
Electric transmission	$ 114	$ 161	$ 384	$ 434	$ 576	$ 283
Electric distribution	148	194	201	214	190	278
Wildfire prevention	21	40	29	94	71	81
Solar generation	1	96	619	187	56	—
Electric battery storage	14	102	227	119	3	—
Other	90	81	190	265	246	229
Total	$ 388	$ 674	$ 1,650	$ 1,313	$ 1,142	$ 871

Sierra Pacific receives PUCN approval through its IRP filings for various projects and has included estimates from IRP filings as well as potential future filings in its forecast capital expenditures for 2026 through 2028. These estimates are likely to change as a result of the RFP process, continued evaluation and future IRP filing refinements. Sierra Pacific's historical and forecast capital expenditures include the following:

- Electric transmission includes both growth projects and operating expenditures. Growth projects primarily relate to the Nevada Utilities' Greenlink Nevada transmission expansion program totaling $290 million for 2025, $84 million for 2024, $68 million for 2023. Planned spending for the expansion program expected to be placed in-service in 2027 and 2028 totals $384 million in 2026, $546 million in 2027 and $208 million in 2028. Operating expenditures consist of routine expenditures for transmission and other infrastructure needed to serve existing and expected demand.
- Electric distribution includes both growth projects and operating expenditures consisting of routine expenditures for distribution needed to serve existing and expected demand.
- Wildfire prevention includes growth and operating expenditures related to projects included in a comprehensive natural disaster protection plan filed and approved by the PUCN. These projects include, but are not limited to, rebuilding distribution lines with covered conductor, converting overhead distribution lines to underground and copper wire and pole replacement projects.
- Solar generation and electric battery storage primarily consist of a 400-MW solar photovoltaic facility with an additional 400 MWs of co-located battery storage that is being developed in Churchill County, Nevada with an ownership share approved by the PUCN of 90% for Sierra Pacific and 10% for Nevada Power. Commercial operation of the solar facility is expected by early 2027 and commercial operation of the co-located battery storage is expected by mid-2026. Also included was solar photovoltaic panels procured for future growth projects.
- Other includes both growth projects and operating expenditures consisting of a repower project at the Valmy generating station to convert existing coal-fired combustion to natural gas-fired combustion, information technology expenditures, routine expenditures for generation, other operating projects and other infrastructure needed to serve existing and expected demand.

2021 Joint Integrated Resource Plan

In August 2023, the Nevada Utilities filed its Joint Application for approval of the Fifth Amendment to the 2021 Joint Integrated Resource Plan. The Fifth Amendment sought, in part (1) to convert the existing coal-fueled generating facility at North Valmy Generating Station to a cleaner natural gas-fueled generating facility (2) to purchase, install, and operate a company-owned 400 MW solar plant along with a 400 MW, four-hour battery storage system in Northern Nevada; (3) to continue operation of Tracy units 4 and 5 to 2049; (4) to purchase development assets for the 149 MW photovoltaic and 149 MW battery energy storage system Crescent Valley Solar project; (5) to construct the Esmeralda and Sagebrush substations transformers; and (6) to construct the necessary infrastructure in the APEX Area Master Plan. The Nevada Utilities seek approval of approximately $1.8 billion in total costs of new projects of which Sierra Pacific's share is approximately $0.8 billion. An order was issued in March 2024 in which the Nevada Utilities filed a motion for clarification and petition for reconsideration. In April 2024, a modified final order was issued, which granted in part and denied in part including the denial of the 149 MW photovoltaic and 149 MW battery energy storage system Crescent Valley Solar project as delineated in the final modified order.

2024 Joint Integrated Resource Plan

In May 2024, the Nevada Utilities filed its joint Application for approval of the 2024 Joint Integrated Resources Plan. The 2024 joint Application sought, in part (1) the addition of three power purchase agreements for solar generating resources totaling more than 1,000 MW, each with co-located battery storage systems; (2) the addition of 400 MW of company-owned hydrogen-capable natural gas simple cycle combustion turbine peakers at the North Valmy generation station; (3) to approve an update of the Greenlink Nevada Transmission project costs; and (4) to construct the necessary transmission infrastructure to support growing customer demand. In December 2024, the PUCN largely accepted the filing as filed but denied opining on the additional costs associated with the Greenlink Nevada project as all costs expended to construct the previously approved Greenlink Nevada project are subject to a prudency review in the GRC as delineated in the final 2024 Joint Integrated Resource Plan order.

In October 2025, the Nevada Utilities submitted a Joint Application for approval of the First Amendment to the 2024 Joint Integrated Resource Plan. The First Amendment seeks approval to enter into a 20-year power purchase agreement with the developer for an additional 150-MW battery energy storage system that will reduce the Nevada Utilities' open position beginning in the summer of 2027. The battery energy storage system will be co-located with existing Dodge Flat solar and battery facility in Washoe County, Nevada. In January 2026, the Nevada Utilities filed a stipulation with the PUCN that reflected a settlement among participating parties and largely accepted the First Amendment as filed, including approval of the 150-MW battery energy storage system power purchase agreement. A final order approving the stipulation was received in February 2026.

Material Cash Requirements

Sierra Pacific has cash requirements that may affect its consolidated financial condition that arise primarily from long- and short-term debt (refer to Notes 7 and 8), operating and financing leases (refer to Note 5), purchased electricity contracts (refer to Note 14), fuel contracts (refer to Note 14), construction and other development costs (refer to Liquidity and Capital Resources included within this Item 7 and Note 14) and AROs (refer to Note 11). Refer to the respective referenced note in Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

Sierra Pacific has cash requirements relating to interest payments of $2.1 billion on long-term debt, including $94 million due in 2026.

Regulatory Matters

Sierra Pacific is subject to comprehensive regulation. Refer to the discussion contained in Item 1 of this Form 10-K for further information regarding Sierra Pacific's general regulatory framework and current regulatory matters.

Environmental Laws and Regulations

Sierra Pacific is subject to federal, state and local laws and regulations regarding air quality, climate change, emissions performance standards, water quality, coal ash disposal and other environmental matters that have the potential to impact Sierra Pacific's current and future operations. In addition to imposing continuing compliance obligations, these laws and regulations provide regulators with the authority to levy substantial penalties for noncompliance including fines, injunctive relief and other sanctions. These laws and regulations are administered by various federal, state and local agencies. Sierra Pacific believes it is in material compliance with all applicable laws and regulations, although many are subject to interpretation that may ultimately be resolved by the courts. Environmental laws and regulations continue to evolve, and Sierra Pacific is unable to predict the impact of the changing laws and regulations on its operations and consolidated financial results.

Refer to "Environmental Laws and Regulations" in Item 1 of this Form 10-K for further discussion regarding environmental laws and regulations.

Collateral and Contingent Features

Debt of Sierra Pacific is rated by credit rating agencies. Assigned credit ratings are based on each rating agency's assessment of Sierra Pacific's ability to, in general, meet the obligations of its issued debt. The credit ratings are not a recommendation to buy, sell or hold securities, and there is no assurance that a particular credit rating will continue for any given period of time.

Sierra Pacific has no credit rating downgrade triggers that would accelerate the maturity dates of outstanding debt, and a change in ratings is not an event of default under the applicable debt instruments. Sierra Pacific's secured revolving credit facility does not require the maintenance of a minimum credit rating level in order to draw upon its availability. However, commitment fees and interest rates under the credit facility are tied to credit ratings and increase or decrease when the ratings change. A ratings downgrade could also increase the future cost of commercial paper, short- and long-term debt issuances or new credit facilities.

In accordance with industry practice, certain wholesale agreements, including derivative contracts, contain credit support provisions that in part base certain collateral requirements on credit ratings for unsecured debt as reported by one or more of the recognized credit rating agencies. These agreements may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance," or in some cases terminate the contract, in the event of a material adverse change in creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2025, the applicable credit ratings obtained from recognized credit rating agencies were investment grade. If all credit-risk-related contingent features or adequate assurance provisions for these agreements had been triggered as of December 31, 2025, Sierra Pacific would have been required to post $32 million of additional collateral. Sierra Pacific's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation, or other factors.

Inflation

Historically, overall inflation and changing prices in the economies where Sierra Pacific operates has not had a significant impact on Sierra Pacific's consolidated financial results. Sierra Pacific operates under a cost-of-service based rate-setting structure administered by the PUCN and the FERC. Under this rate-setting structure, Sierra Pacific is allowed to include prudent costs in its rates, including the impact of inflation after Sierra Pacific experiences cost increases. Fuel and purchase power costs are recovered through a balancing account, minimizing the impact of inflation related to these costs. Sierra Pacific attempts to minimize the potential impact of inflation on its operations through the use of periodic rate adjustments for fuel and energy costs, by employing prudent risk management and hedging strategies and by considering, among other areas, its impact on purchases of energy, operating expenses, materials and equipment costs, contract negotiations, future capital spending programs and long-term debt issuances. There can be no assurance that such actions will be successful.

New Accounting Pronouncements

For a discussion of new accounting pronouncements affecting Sierra Pacific, refer to Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Critical Accounting Estimates

Certain accounting measurements require management to make estimates and judgments concerning transactions that will be settled several years in the future. Amounts recognized on the Consolidated Financial Statements based on such estimates involve numerous assumptions subject to varying and potentially significant degrees of judgment and uncertainty and will likely change in the future as additional information becomes available. The following critical accounting estimates are impacted significantly by Sierra Pacific's methods, judgments and assumptions used in the preparation of the Consolidated Financial Statements and should be read in conjunction with Sierra Pacific's Summary of Significant Accounting Policies included in Sierra Pacific's Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Accounting for the Effects of Certain Types of Regulation

Sierra Pacific prepares its Consolidated Financial Statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, Sierra Pacific defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur.

Sierra Pacific continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future regulated rates by considering factors such as a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation, other regulatory actions or the impact of competition that could limit Sierra Pacific's ability to recover its costs. Sierra Pacific believes its application of the guidance for regulated operations is appropriate and its existing regulatory assets and liabilities are probable of inclusion in future regulated rates. The evaluation reflects the current political and regulatory climate at both the federal and state levels. If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the related regulatory assets and liabilities will be written off to net income, returned to customers or re-established as AOCI. Total regulatory assets were $274 million and total regulatory liabilities were $463 million as of December 31, 2025. Refer to Sierra Pacific's Note 6 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding Sierra Pacific's regulatory assets and liabilities.

Impairment of Long-Lived Assets

Sierra Pacific evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or when the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Consolidated Statements of Operations. As substantially all property, plant and equipment was used in regulated businesses as of December 31, 2025, the impacts of regulation are considered when evaluating the carrying value of regulated assets.

The estimate of cash flows arising from the future use of an asset, for the purposes of impairment analysis, requires the exercise of judgment. Circumstances that could significantly alter the calculation of fair value or the recoverable amount of an asset may include significant changes in the regulatory environment, the business climate, management's plans, legal factors, market price of the asset, the use of the asset, the physical condition of the asset, future market prices, load growth, competition and many other factors over the life of the asset. Any resulting impairment loss is highly dependent on the underlying assumptions and could significantly affect Sierra Pacific's results of operations.

Income Taxes

In determining Sierra Pacific's income taxes, management is required to interpret complex income tax laws and regulations, which includes consideration of regulatory implications imposed by Sierra Pacific's various regulatory commissions. Sierra Pacific's income tax returns are subject to continuous examinations by federal, state and local income tax authorities that may give rise to different interpretations of these complex laws and regulations. Due to the nature of the examination process, it generally takes years before these examinations are completed and these matters are resolved. Sierra Pacific recognizes the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the Consolidated Financial Statements from such a position are measured based on the largest benefit that is more-likely-than-not to be realized upon ultimate settlement. Although the ultimate resolution of Sierra Pacific's federal, state and local income tax examinations is uncertain, Sierra Pacific believes it has made adequate provisions for these income tax positions. The aggregate amount of any additional income tax liabilities that may result from these examinations is not expected to have a material impact on Sierra Pacific's consolidated financial results. Refer to Sierra Pacific's Note 9 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding Sierra Pacific's income taxes.

It is probable that Sierra Pacific will pass income tax benefit and expense related to the federal tax rate change from 35% to 21%, certain property-related basis differences and other various differences on to its customers. As of December 31, 2025, these amounts were recognized as a net regulatory liability of $173 million and will be included in regulated rates when the temporary differences reverse.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Sierra Pacific's Consolidated Balance Sheets include assets and liabilities with fair values that are subject to market risks. Sierra Pacific's significant market risks are primarily associated with commodity prices, interest rates and the extension of credit to counterparties with which Sierra Pacific transacts. The following discussion addresses the significant market risks associated with Sierra Pacific's business activities. Sierra Pacific has established guidelines for credit risk management. Refer to Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding Sierra Pacific's contracts accounted for as derivatives.

Commodity Price Risk

Sierra Pacific is exposed to the impact of market fluctuations in commodity prices and interest rates. Sierra Pacific is principally exposed to electricity, natural gas and coal market fluctuations primarily through Sierra Pacific's obligation to serve retail customer load in its regulated service territory. Sierra Pacific's load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity, wholesale electricity that is purchased and sold, and natural gas supply for retail customers. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, generating facility availability, customer usage, storage, and transmission and transportation constraints. The actual cost of fuel and purchased power is recoverable through the deferred energy mechanism. Interest rate risk exists on variable-rate debt and future debt issuances. Sierra Pacific does not engage in proprietary trading activities. To mitigate a portion of its commodity price risk, Sierra Pacific uses commodity derivative contracts, which may include forwards, futures, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. Sierra Pacific does not hedge all of its commodity price risk, thereby exposing the unhedged portion to changes in market prices. Sierra Pacific's exposure to commodity price risk is generally limited by its ability to include commodity costs in regulated rates through its deferred energy mechanism, which is subject to disallowance and regulatory lag that occurs between the time the costs are incurred and when the costs are included in regulated rates, as well as the impact of any customer sharing resulting from cost adjustment mechanisms.

The table that follows summarizes Sierra Pacific's price risk on commodity contracts accounted for as derivatives and shows the effects of a hypothetical 10% increase and 10% decrease in forward market prices by the expected volumes for these contracts as of that date. The selected hypothetical change does not reflect what could be considered the best or worse case scenarios (dollars in millions).

	Fair Value - Net Asset (Liability)	Estimated Fair Value after Hypothetical Change in Price	
		10% increase	10% decrease
As of December 31, 2025:			
Total commodity derivative contracts	$ (11)	$ (10)	$ (13)
As of December 31, 2024:			
Total commodity derivative contracts	$ (13)	$ (12)	$ (14)

Sierra Pacific's commodity derivative contracts not designated as hedging contracts are recoverable from customers in regulated rates and therefore, net unrealized gains and losses associated with interim price movements on commodity derivative contracts do not expose Sierra Pacific to earnings volatility. As of December 31, 2025 and 2024, a net regulatory asset of $11 million and $13 million, respectively, was recorded related to the net derivative liability of $11 million and $13 million, respectively. The settled cost of these commodity derivative contracts is generally included in regulated rates.

Interest Rate Risk

Sierra Pacific is exposed to interest rate risk on its outstanding variable-rate short- and long-term debt and future debt issuances. Sierra Pacific manages its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. As a result of the fixed interest rates, Sierra Pacific's fixed-rate long-term debt does not expose Sierra Pacific to the risk of loss due to changes in market interest rates. Additionally, because fixed-rate long-term debt is not carried at fair value on the Consolidated Balance Sheets, changes in fair value would impact earnings and cash flows only if Sierra Pacific were to reacquire all or a portion of these instruments prior to their maturity. The nature and amount of Sierra Pacific's short- and long-term debt can be expected to vary from period to period as a result of future business requirements, market conditions and other factors. Refer to Notes 7 and 8 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional discussion of Sierra Pacific's short- and long-term debt.

As of December 31, 2025 and 2024, Sierra Pacific had no short- and long-term variable-rate obligations that expose Sierra Pacific to the risk of increased interest expense in the event of increases in short-term interest rates.

Credit Risk

Sierra Pacific is exposed to counterparty credit risk associated with wholesale energy supply and marketing activities with other utilities, energy marketing companies, financial institutions and other market participants. Credit risk may be concentrated to the extent Sierra Pacific's counterparties have similar economic, industry or other characteristics and due to direct and indirect relationships among the counterparties. Before entering into a transaction, Sierra Pacific analyzes the financial condition of each significant wholesale counterparty, establishes limits on the amount of unsecured credit to be extended to each counterparty and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate wholesale counterparty credit risk, Sierra Pacific enters into netting and collateral arrangements that may include margining and cross-product netting agreements and obtain third-party guarantees, letters of credit and cash deposits. If required, Sierra Pacific exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

As of December 31, 2025, Sierra Pacific's aggregate credit exposure from energy related transactions were not material, based on settlement and mark-to-market exposures, net of collateral.

Item 8. Financial Statements and Supplementary Data

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Sierra Pacific Power Company

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Sierra Pacific Power Company and subsidiaries ("Sierra Pacific") as of December 31, 2025 and 2024, the related consolidated statements of operations, changes in shareholder's equity, and cash flows, for each of the three years in the period ended December 31, 2025, 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 Sierra Pacific as of December 31, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of Sierra Pacific's management. Our responsibility is to express an opinion on Sierra Pacific's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to Sierra Pacific 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. Sierra Pacific is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of Sierra Pacific's internal control over financial reporting. Accordingly, we express no such opinion.

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 Board of Directors 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 — Effects of Rate Regulation on the Financial Statements — Refer to Note 6 to the financial statements

Critical Audit Matter Description

Sierra Pacific is subject to rate regulation by a state public service commission as well as the Federal Energy Regulatory Commission (collectively, the "Commissions"), which have jurisdiction with respect to the rates of electric and natural gas companies in the respective service territories where Sierra Pacific operates. Management has determined its regulated operations meet the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. Accounting for the economic effects of rate regulation has a pervasive effect on the financial statements.

Regulated rates are subject to regulatory rate-setting processes. Rates are determined, approved, and established based on a cost-of-service basis, which is designed to allow Sierra Pacific an opportunity to recover its prudently incurred costs of providing services and to earn a reasonable return on its invested capital. Regulatory decisions can have an effect on the recovery of costs, the rate of return earned on investment, and the timing and amount of assets to be recovered by rates. While Sierra Pacific Power Company has indicated it expects to recover costs from customers through regulated rates, there is a risk that changes to the Commissions' approach to setting rates or other regulatory actions could limit Sierra Pacific's ability to recover its costs.

We identified the effects of rate regulation on the financial statements as a critical audit matter due to the significant judgments made by management to support its assertions about certain affected account balances and disclosures and the high degree of subjectivity involved in assessing the impact of regulatory orders on the financial statements. Management judgments include assessing the likelihood of (1) recovery in future rates of incurred costs, (2) disallowance of part of the cost of recently completed plant or plant under construction, and (3) a refund to customers. Given that management's accounting judgments are based on assumptions about the outcome of 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 decisions by the Commissions included the following, among others:

- We evaluated Sierra Pacific's disclosures related to the effects of rate regulation by testing certain recorded balances and evaluating regulatory developments.
- We read relevant regulatory orders issued by the Commissions, regulatory statutes, filings made by Sierra Pacific and other external information. We evaluated relevant external information and compared it to certain recorded regulatory asset and liability balances for completeness.
- For certain regulatory matters, we inspected Sierra Pacific's filings with the Commissions and the filings with the Commissions by intervenors to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedents of the Commissions' treatment of similar costs under similar circumstances.

/s/ Deloitte & Touche LLP

Las Vegas, Nevada
February 27, 2026

We have served as Sierra Pacific's auditor since 1996.

SIERRA PACIFIC POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Amounts in millions, except share data)

	As of December 31,	
	2025	**2024**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 5	$ 17
Trade receivables, net	108	137
Amounts due from affiliates	196	1
Inventories	151	161
Regulatory assets	56	90
Prepayments	20	54
Other current assets	19	22
Total current assets	555	482
Property, plant and equipment, net	6,056	4,439
Regulatory assets	218	202
Other assets	216	204
Total assets	$ 7,045	$ 5,327
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Accounts payable	$ 519	$ 284
Amounts due to affiliates	208	126
Accrued interest	20	19
Accrued property, income and other taxes	15	16
Accrued employee expenses	85	17
Current portion of long-term debt	410	—
Regulatory liabilities	72	106
Customer deposits	45	42
Other current liabilities	5	33
Total current liabilities	1,379	643
Long-term debt	1,116	1,527
Junior subordinated debt	446	—
Regulatory liabilities	391	416
Deferred income taxes	390	369
Other long-term liabilities	342	272
Total liabilities	4,064	3,227
Commitments and contingencies (Note 14)		
Shareholder's equity:		
Common stock - $3.75 stated value, 1,000 shares authorized, issued and outstanding	—	—
Additional paid-in capital	2,561	1,726
Retained earnings	421	375
Accumulated other comprehensive loss, net	(1)	(1)
Total shareholder's equity	2,981	2,100
Total liabilities and shareholder's equity	$ 7,045	$ 5,327

The accompanying notes are an integral part of these consolidated financial statements.

SIERRA PACIFIC POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2025	**2024**	**2023**
Operating revenue:			
Regulated electric	$ 964	$ 1,080	$ 1,194
Regulated natural gas	124	182	237
Total operating revenue	1,088	1,262	1,431
Operating expenses:			
Cost of fuel and energy	435	561	689
Cost of natural gas purchased for resale	58	121	176
Operations and maintenance	241	245	204
Depreciation and amortization	161	181	185
Property and other taxes	25	24	25
Total operating expenses	920	1,132	1,279
Operating income	168	130	152
Other income (expense):			
Interest expense	(101)	(86)	(66)
Allowance for borrowed funds	18	7	7
Allowance for equity funds	57	22	14
Interest and dividend income	11	12	22
Other, net	12	10	4
Total other income (expense)	(3)	(35)	(19)
Income before income tax expense	165	95	133
Income tax expense	19	10	16
Net income	$ 146	$ 85	$ 117

The accompanying notes are an integral part of these consolidated financial statements.

SIERRA PACIFIC POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY
(Amounts in millions, except shares)

	Common Stock		Other Paid-in Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Loss, Net	Total Shareholder's Equity
	Shares	Amount				
Balance, December 31, 2022	1,000	$ —	$ 1,576	$ 473	$ (1)	$ 2,048
Net income	—	—	—	117	—	117
Dividends declared	—	—	—	(100)	—	(100)
Balance, December 31, 2023	1,000	—	1,576	490	(1)	2,065
Net income	—	—	—	85	—	85
Dividends declared	—	—	—	(200)	—	(200)
Contributions	—	—	150	—	—	150
Balance, December 31, 2024	1,000	—	1,726	375	(1)	2,100
Net income	—	—	—	146	—	146
Dividends declared	—	—	—	(100)	—	(100)
Contributions	—	—	835	—	—	835
Balance, December 31, 2025	1,000	$ —	$ 2,561	$ 421	$ (1)	$ 2,981

The accompanying notes are an integral part of these consolidated financial statements.

SIERRA PACIFIC POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Amounts in millions)

	Years Ended December 31,		
	2025	**2024**	**2023**
Cash flows from operating activities:			
Net income	$ 146	$ 85	$ 117
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	161	181	185
Allowance for equity funds	(57)	(22)	(14)
Deferred energy	(3)	135	117
Amortization of deferred energy	(39)	28	83
Other changes in regulatory assets and liabilities	19	5	1
Deferred income taxes and amortization of investment tax credits	1	(49)	(56)
Other, net	(1)	(1)	—
Changes in other operating assets and liabilities:			
Trade receivables and other assets	(131)	13	(7)
Inventories	10	(44)	(38)
Accrued property, income and other taxes	1	(10)	18
Accounts payable and other liabilities	288	149	13
Net cash flows from operating activities	395	470	419
Cash flows from investing activities:			
Capital expenditures	(1,650)	(674)	(388)
Proceeds from sale of marketable securities	—	1	—
Net cash flows from investing activities	(1,650)	(673)	(388)
Cash flows from financing activities:			
Proceeds from long-term debt	446	233	393
Repayments of long-term debt	—	—	(250)
Repayments of affiliate note payable	—	—	(70)
Dividends paid	(100)	(200)	(100)
Contributions from parent	835	150	—
Other, net	60	(8)	(8)
Net cash flows from financing activities	1,241	175	(35)
Net change in cash and cash equivalents and restricted cash and cash equivalents	(14)	(28)	(4)
Cash and cash equivalents and restricted cash and cash equivalents at beginning of period	24	52	56
Cash and cash equivalents and restricted cash and cash equivalents at end of period	$ 10	$ 24	$ 52

The accompanying notes are an integral part of these consolidated financial statements.

(1) Organization and Operations

Sierra Pacific Power Company and its subsidiaries ("Sierra Pacific") is a wholly owned subsidiary of NV Energy, Inc. ("NV Energy"), a holding company that also owns Nevada Power Company and its subsidiaries ("Nevada Power") and certain other subsidiaries. Sierra Pacific is a U.S. regulated electric utility company serving retail customers, including residential, commercial and industrial customers and regulated retail natural gas customers primarily in northern Nevada. NV Energy is an indirect wholly owned subsidiary of Berkshire Hathaway Energy Company ("BHE"). BHE is a holding company based in Des Moines, Iowa that has investments in subsidiaries principally engaged in energy businesses. BHE is a wholly owned subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

(2) Summary of Significant Accounting Policies

Basis of Consolidation and Presentation

The Consolidated Financial Statements include the accounts of Sierra Pacific and its subsidiaries in which it holds a controlling financial interest as of the financial statement date. Intercompany accounts and transactions have been eliminated. The Consolidated Statements of Comprehensive Income have been omitted as net income equals comprehensive income for the years ended December 31, 2025, 2024 and 2023.

Use of Estimates in Preparation of Financial Statements

The preparation of the Consolidated Financial Statements in conformity with accounting principles generally accepted in the United States of America ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the period. These estimates include, but are not limited to, the effects of regulation; recovery of long-lived assets; certain assumptions made in accounting for pension and other postretirement benefits; asset retirement obligations ("AROs"); income taxes; unbilled revenue; valuation of certain financial assets and liabilities, including derivative contracts; and accounting for contingencies. Actual results may differ from the estimates used in preparing the Consolidated Financial Statements.

Accounting for the Effects of Certain Types of Regulation

Sierra Pacific prepares its Consolidated Financial Statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, Sierra Pacific defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur. If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the related regulatory assets and liabilities will be written off to net income, returned to customers or re-established as accumulated other comprehensive income (loss) ("AOCI").

Fair Value Measurements

As defined under GAAP, fair value is the price that would be received to sell an asset or paid to transfer a liability between market participants in the principal market or in the most advantageous market when no principal market exists. Adjustments to transaction prices or quoted market prices may be required in illiquid or disorderly markets in order to estimate fair value. Different valuation techniques may be appropriate under the circumstances to determine the value that would be received to sell an asset or paid to transfer a liability in an orderly transaction. Market participants are assumed to be independent, knowledgeable, able and willing to transact an exchange and not under duress. Nonperformance or credit risk is considered when determining fair value. Considerable judgment may be required in interpreting market data used to develop the estimates of fair value. Accordingly, estimates of fair value presented herein are not necessarily indicative of the amounts that could be realized in a current or future market exchange.

Cash and Cash Equivalents and Restricted Cash

Cash equivalents consist of funds invested in money market mutual funds, U.S. Treasury Bills and other investments with a maturity of three months or less when purchased. Cash and cash equivalents exclude amounts where availability is restricted by legal requirements, loan agreements or other contractual provisions. Restricted cash and cash equivalents consist of funds restricted by the Public Utilities Commission of Nevada ("PUCN") for a certain renewable energy contract. A reconciliation of cash and cash equivalents and restricted cash and cash equivalents as of December 31, 2025 and December 31, 2024, as presented on the Consolidated Statements of Cash Flows is outlined below and disaggregated by the line items in which they appear on the Consolidated Balance Sheets (in millions):

	As of December 31,	
	2025	2024
Cash and cash equivalents	$ 5	$ 17
Restricted cash and cash equivalents included in other current assets	5	7
Total cash and cash equivalents and restricted cash and cash equivalents	$ 10	$ 24

Allowance for Credit Losses

Trade receivables are primarily short-term in nature with stated collection terms of less than one year from the date of origination and are stated at the outstanding principal amount, net of an estimated allowance for credit losses. The allowance for credit losses is based on Sierra Pacific's assessment of the collectability of amounts owed to Sierra Pacific by its customers. This assessment requires judgment regarding the ability of customers to pay or the outcome of any pending disputes. In measuring the allowance for credit losses for trade receivables, Sierra Pacific primarily utilizes credit loss history. However, Sierra Pacific may adjust the allowance for credit losses to reflect current conditions and reasonable and supportable forecasts that deviate from historical experience. Sierra Pacific also has the ability to assess deposits on customers who have delayed payments or who are deemed to be a credit risk. The changes in the balance of the allowance for credit losses, which is included in trade receivables, net on the Consolidated Balance Sheets, is summarized as follows for the years ended December 31, (in millions):

	2025	2024	2023
Beginning balance	$ 4	$ 3	$ 2
Charged to operating costs and expenses, net	3	4	4
Write-offs, net	(5)	(3)	(3)
Ending balance	$ 2	$ 4	$ 3

Derivatives

Sierra Pacific employs a number of different derivative contracts, which may include forwards, futures, options, swaps and other agreements, to manage its commodity price and interest rate risks. Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. Derivative balances reflect offsetting permitted under master netting agreements with counterparties and cash collateral paid or received under such agreements.

Commodity derivatives used in normal business operations that are settled by physical delivery, among other criteria, are eligible for and may be designated as normal purchases or normal sales. Normal purchases or normal sales contracts are not marked-to-market and settled amounts are recognized as cost of fuel, energy and capacity or natural gas purchased for resale on the Consolidated Statements of Operations.

For Sierra Pacific's derivative contracts, the settled amount is generally included in regulated rates. Accordingly, the net unrealized gains and losses associated with interim price movements on contracts that are accounted for as derivatives and probable of inclusion in regulated rates are recorded as regulatory assets and liabilities. For a derivative contract not probable of inclusion in rates, changes in the fair value are recognized in earnings.

Inventories

Inventories consist mainly of materials and supplies totaling $150 million and $129 million as of December 31, 2025 and 2024, respectively, and fuel, which includes coal stock, stored natural gas and fuel oil, totaling $1 million and $32 million as of December 31, 2025 and 2024, respectively. The cost is determined using the average cost method. Materials are charged to inventory when purchased and are expensed or capitalized to construction work in process, as appropriate, when used. Fuel costs are recovered from retail customers through the base tariff energy rates and deferred energy accounting adjustment charges approved by the PUCN.

Property, Plant and Equipment, Net

General

Additions to property, plant and equipment are recorded at cost. Sierra Pacific capitalizes all construction-related material, direct labor and contract services, as well as indirect construction costs. Indirect construction costs include debt allowance for funds used during construction ("AFUDC"), and equity AFUDC, as applicable. The cost of additions and betterments are capitalized, while costs incurred that do not improve or extend the useful lives of the related assets are generally expensed. The cost of repairs and minor replacements are charged to expense when incurred with the exception of costs for generation plant maintenance under certain long-term service agreements. Costs under these agreements are expensed straight-line over the term of the agreements as approved by the PUCN.

Depreciation and amortization are generally computed by applying the composite or straight-line method based on either estimated useful lives or mandated recovery periods as prescribed by Sierra Pacific's various regulatory authorities. Depreciation studies are completed by Sierra Pacific to determine the appropriate group lives, net salvage and group depreciation rates. These studies are reviewed and rates are ultimately approved by the applicable regulatory commission. Net salvage includes the estimated future residual values of the assets and any estimated removal costs recovered through approved depreciation rates. Estimated removal costs are recorded as a noncurrent regulatory liability on the Consolidated Balance Sheets. As actual removal costs are incurred, the associated liability is reduced.

Generally when Sierra Pacific retires or sells a component of regulated property, plant and equipment depreciated using the composite method, it charges the original cost, net of any proceeds from the disposition, to accumulated depreciation. Any gain or loss on disposals of all other assets is recorded through earnings with the exception of material gains or losses on regulated property, plant and equipment depreciated on a straight-line basis, which is then recorded to a regulatory liability or asset, respectively.

Debt and equity AFUDC, which represent the estimated costs of debt and equity funds necessary to finance the construction of regulated facilities, are capitalized as a component of property, plant and equipment, with offsetting credits to the Consolidated Statements of Operations. The rate applied to construction costs is the lower of the PUCN allowed rate of return and rates computed based on guidelines set forth by the Federal Energy Regulatory Commission ("FERC"). After construction is completed, Sierra Pacific is permitted to earn a return on these costs as a component of the related assets, as well as recover these costs through depreciation expense over the useful lives of the related assets. Sierra Pacific's AFUDC rate used during 2025 and 2024 was 7.38% and 7.06%, respectively, for electric, 7.31% and 6.14%, respectively, for natural gas and 7.38% and 7.06%, respectively, for common facilities.

Asset Retirement Obligations

Sierra Pacific recognizes AROs when it has a legal obligation to perform decommissioning, reclamation or removal activities upon retirement of an asset. Sierra Pacific's AROs are primarily associated with its generating facilities. The fair value of an ARO liability is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made, and is added to the carrying amount of the associated asset, which is then depreciated over the remaining useful life of the asset. Subsequent to the initial recognition, the ARO liability is adjusted for any revisions to the original estimate of undiscounted cash flows (with corresponding adjustments to property, plant and equipment, net) and for accretion of the ARO liability due to the passage of time. The difference between the ARO liability, the corresponding ARO asset included in property, plant and equipment, net and amounts recovered in rates to satisfy such liabilities is recorded as a regulatory asset or liability on the Consolidated Balance Sheets. The costs are not recovered in rates until the work has been completed.

Impairment

Sierra Pacific evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or when the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Consolidated Statements of Operations. As substantially all property, plant and equipment was used in regulated businesses, the impacts of regulation are considered when evaluating the carrying value of regulated assets.

Leases

Sierra Pacific has non-cancelable operating leases primarily for transmission and delivery assets, generating facilities, vehicles and office equipment and finance leases consisting primarily of transmission assets, generating facilities and vehicles. These leases generally require Sierra Pacific to pay for insurance, taxes and maintenance applicable to the leased property. Given the capital-intensive nature of the utility industry, it is common for a portion of lease costs to be capitalized when used during construction or maintenance of assets, in which the associated costs will be capitalized with the corresponding asset and depreciated over the remaining life of that asset. Certain leases contain renewal options for varying periods and escalation clauses for adjusting rent to reflect changes in price indices. Sierra Pacific does not include options in its lease calculations unless there is a triggering event indicating Sierra Pacific is reasonably certain to exercise the option. Sierra Pacific's accounting policy is to not recognize right-of-use assets and lease obligations for leases with contract terms of one year or less and not separate lease components from non-lease components and instead account for each separate lease component and the non-lease components associated with a lease as a single lease component. Right-of-use assets are evaluated for impairment in line with Accounting Standards Codification ("ASC") Topic 360, "Property, Plant and Equipment" when a triggering event has occurred that might affect the value and use of the assets being leased.

Sierra Pacific's leases of generating facilities generally are for the long-term purchase of electric energy, also known as power purchase agreements ("PPA"). PPAs are generally signed before or during the early stages of project construction and can yield a lease that has not yet commenced. These agreements are primarily for renewable energy and the payments are considered variable lease payments as they are based on the amount of output.

Sierra Pacific's operating and finance right-of-use assets are recorded in other assets and the operating and current finance lease liabilities are recorded in current and long-term other liabilities accordingly.

Revenue Recognition

Sierra Pacific uses a single five-step model to identify and recognize revenue from contracts with customers ("Customer Revenue") upon transfer of control of promised goods or services in an amount that reflects the consideration to which Sierra Pacific expects to be entitled in exchange for those goods or services. Sierra Pacific records sales, franchise and excise taxes collected directly from customers and remitted directly to the taxing authorities on a net basis on the Consolidated Statements of Operations.

Substantially all of Sierra Pacific's Customer Revenue is derived from tariff-based sales arrangements approved by various regulatory commissions. These tariff-based revenues are mainly comprised of energy, transmission, distribution and natural gas and have performance obligations to deliver energy products and services to customers which are satisfied over time as energy is delivered or services are provided. Other revenue consists primarily of revenue recognized in accordance with ASC 842, "Leases" and amounts not considered Customer Revenue within ASC 606, "Revenue from Contracts with Customers."

Revenue recognized is equal to what Sierra Pacific has the right to invoice as it corresponds directly with the value to the customer of Sierra Pacific's performance to date and includes billed and unbilled amounts. As of December 31, 2025 and 2024, trade receivables, net on the Consolidated Balance Sheets relate substantially to Customer Revenue, including unbilled revenue of $75 million and $84 million, respectively. Payments for amounts billed are generally due from the customer within 30 days of billing. Rates charged for energy products and services are established by regulators or contractual arrangements that establish the transaction price as well as the allocation of price amongst the separate performance obligations. When preliminary regulated rates are permitted to be billed prior to final approval by the applicable regulator, certain revenue collected may be subject to refund and a liability for estimated refunds is accrued.

Unamortized Debt Premiums, Discounts and Issuance Costs

Premiums, discounts and financing costs incurred for the issuance of long-term debt are amortized over the term of the related financing using the effective interest method.

Income Taxes

Berkshire Hathaway includes Sierra Pacific in its consolidated U.S. federal income tax return. Consistent with established regulatory practice, Sierra Pacific's provision for income taxes has been computed on a stand-alone basis.

Deferred income tax assets and liabilities are based on differences between the financial statement and income tax basis of assets and liabilities using enacted income tax rates expected to be in effect for the year in which the differences are expected to reverse. Changes in deferred income tax assets and liabilities associated with components of other comprehensive income ("OCI") are charged or credited directly to OCI. Changes in deferred income tax assets and liabilities associated with certain property-related basis differences and other various differences that Sierra Pacific deems probable to be passed on to its customers are charged or credited directly to a regulatory asset or liability and will be included in regulated rates when the temporary differences reverse. Other changes in deferred income tax assets and liabilities are included as a component of income tax expense. Changes in deferred income tax assets and liabilities attributable to changes in enacted income tax rates are charged or credited to income tax expense or a regulatory asset or liability in the period of enactment. Valuation allowances are established when necessary to reduce deferred income tax assets to the amount that is more-likely-than-not to be realized.

Investment tax credits are deferred and amortized over the estimated useful lives of the related properties.

Sierra Pacific recognizes the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the Consolidated Financial Statements from such a position are measured based on the largest benefit that is more-likely-than-not to be realized upon ultimate settlement. Sierra Pacific's unrecognized tax benefits are primarily included in other long-term liabilities on the Consolidated Balance Sheets. Estimated interest and penalties, if any, related to uncertain tax positions are included as a component of income tax expense (benefit) on the Consolidated Statements of Operations.

New Accounting Pronouncements

In December 2023, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2023-09, Income Taxes Topic 740, "Income Tax—Improvements to Income Tax Disclosures" which requires enhanced disclosures, including specific categories and disaggregation of information in the effective tax rate reconciliation, disaggregated information related to income taxes paid, income or loss from continuing operations before income tax expense or benefit, and income tax expense or benefit from continuing operations. This guidance is effective for annual reporting periods beginning after December 15, 2024. Early adoption is permitted and should be applied on a prospective basis, however retrospective application is permitted. Sierra Pacific adopted this guidance for the fiscal year beginning January 1, 2025, under the retrospective method. The adoption did not have a material impact on Sierra Pacific's Consolidated Financial Statements, but did expand the disclosures included within Notes to Consolidated Financial Statements. Refer to Note 9 for expanded rate reconciliation disclosures and disaggregation of income taxes paid.

In November 2024, the FASB issued ASU No. 2024-03, Income Statement—Reporting Comprehensive Income—Expense Disaggregation Disclosures Subtopic 220-40, "Disaggregation of Income Statement Expenses" which addresses requests from investors for more detailed information about certain expenses and requires disclosure of the amounts of purchases of inventory, employee compensation, depreciation and intangible asset amortization included in each relevant expense caption presented on the income statement. This guidance, as clarified in ASU 2025-01, is effective for annual reporting periods beginning after December 15, 2026 and interim reporting periods beginning after December 15, 2027. Early adoption is permitted and should be applied on a prospective basis, however retrospective application is permitted. Sierra Pacific is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

In December 2025, the FASB issued ASU No. 2025-10, Government Grants Topic 832, "Accounting for Government Grants Received by Business Entities" which establishes accounting for government grants received by an entity, including guidance for a grant related to an asset and a grant related to income. This guidance also requires, consistent with current disclosure requirements, that an entity provide disclosures including the nature of the government grant received, the accounting policies used to account for the grant, and significant terms and conditions of the grant. This guidance is effective for interim and annual reporting periods beginning after December 15, 2028. Early adoption is permitted and can be applied using either a modified prospective approach, a modified retrospective approach or a retrospective approach. Sierra Pacific is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

(3) Property, Plant and Equipment, Net

Property, plant and equipment, net consists of the following as of December 31 (in millions):

	Depreciable Life	2025	2024
Utility plant:			
Generation	25 - 70 years	$ 1,413	$ 1,339
Transmission	50 - 76 years	1,321	1,071
Electric distribution	20 - 76 years	2,298	2,224
Electric intangible plant and other	5 - 65 years	189	254
Natural gas distribution	35 - 70 years	591	563
Natural gas intangible plant and other	5 - 65 years	19	18
Common other	5 - 65 years	461	377
Utility plant		6,292	5,846
Accumulated depreciation and amortization		(2,296)	(2,208)
		3,996	3,638
Construction work-in-progress		2,060	801
Property, plant and equipment, net		$ 6,056	$ 4,439

All of Sierra Pacific's plant is subject to the ratemaking jurisdiction of the PUCN and the FERC. Sierra Pacific's depreciation and amortization expense, as authorized by the PUCN, stated as a percentage of the depreciable property balances as of December 31, 2025, 2024 and 2023 was 2.7%, 3.1% and 3.3%, respectively. Sierra Pacific is required to file a utility plant depreciation study every six years as a companion filing with the triennial general rate review filings. The most recent study was filed in 2022 and the approved rates were effective January 1, 2023.

Construction work-in-progress is primarily related to the construction of regulated assets mainly related to the costs associated with the 400-MW solar photovoltaic facility with additional 400-MW of co-located battery storage being developed in Churchill County, Nevada and the Greenlink Nevada transmission expansion project that is being developed in western and northern Nevada.

(4) Jointly Owned Utility Facilities

Under joint facility ownership agreements, Sierra Pacific, as tenants in common, has undivided interests in jointly owned generation and transmission facilities. Sierra Pacific accounts for its proportionate share of each facility and each joint owner has provided financing for its share of each facility. Operating costs of each facility are assigned to joint owners based on their percentage of ownership or energy production, depending on the nature of the cost. Operating costs and expenses on the Consolidated Statements of Operations include Sierra Pacific's share of the expenses of these facilities.

The amounts shown in the table below represent Sierra Pacific's share in each jointly owned facility included in property, plant and equipment, net as of December 31, 2025 (dollars in millions):

	Sierra Pacific's Share	Utility Plant	Accumulated Depreciation	Construction Work-in-Progress
Valmy Nos. 1 and 2	50 %	$ 448	$ 373	$ 21
ON Line Transmission Line	6	40	13	30
Valmy Transmission	50	2	2	—
Total		$ 490	$ 388	$ 51

(5) Leases

The following table summarizes Sierra Pacific's leases recorded on the Consolidated Balance Sheet as of December 31 (in millions):

	2025	2024
Right-of-use assets:		
Operating leases	$ 16	$ 15
Finance leases	98	99
Total right-of-use assets	$ 114	$ 114
Lease liabilities:		
Operating leases	$ 16	$ 15
Finance leases	99	102
Total lease liabilities	$ 115	$ 117

The following table summarizes Sierra Pacific's lease costs for the years ended December 31 (in millions):

	2025	2024	2023
Variable	$ 97	$ 100	$ 99
Operating	2	2	2
Finance:			
Amortization	5	5	5
Interest	7	8	8
Total lease costs	$ 111	$ 115	$ 114
Weighted-average remaining lease term (years):			
Operating leases	21.1	23.8	24.6
Finance leases	24.2	26.2	27.6
Weighted-average discount rate:			
Operating leases	5.0 %	5.0 %	5.0 %
Finance leases	8.3 %	8.4 %	8.4 %

The following table summarizes Sierra Pacific's supplemental cash flow information relating to leases for the years ended December 31 (in millions):

	2025	2024	2023
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows from operating leases	$ (2)	$ (2)	$ (2)
Operating cash flows from finance leases	(8)	(8)	(8)
Financing cash flows from finance leases	(9)	(8)	(7)
Right-of-use assets obtained in exchange for lease liabilities:			
Operating leases	$ 2	$ 1	1
Finance leases	3	5	3

Sierra Pacific has the following remaining lease commitments as of December 31, 2025 (in millions):

	Operating	Finance	Total
2026	$ 1	$ 17	$ 18
2027	1	15	16
2028	1	15	16
2029	2	10	12
2030	1	10	11
Thereafter	21	115	136
Total undiscounted lease payments	27	182	209
Less - amounts representing interest	(11)	(83)	(94)
Lease liabilities	$ 16	$ 99	$ 115

Operating and Finance Lease Obligations

Sierra Pacific's operating and finance lease obligations consist mainly of ON Line and Truckee-Carson Irrigation District ("TCID"). ON Line was placed in-service on December 31, 2013. Sierra Pacific and Nevada Power, collectively the ("Nevada Utilities"), entered into a long-term transmission use agreement, in which the Nevada Utilities have a 25% interest and Great Basin Transmission South, LLC has a 75% interest. The Nevada Utilities' share of the long-term transmission use agreement and ownership interest is split at 75% for Nevada Power and 25% for Sierra Pacific. The term of the lease is 41 years with the agreement ending December 31, 2054. In 1999, Sierra Pacific entered into a 50-year agreement with TCID to lease electric distribution facilities. Total finance lease obligations of $109 million and $114 million were included on the Consolidated Balance Sheets as of December 31, 2025 and 2024, respectively, for these leases. See Note 2 for further discussion of Sierra Pacific's remaining lease obligations.

(6) Regulatory Matters

Regulatory Assets

Regulatory assets represent costs that are expected to be recovered in future rates. Sierra Pacific's regulatory assets reflected on the Consolidated Balance Sheets consist of the following as of December 31 (in millions):

	Weighted Average Remaining Life	2025	2024
Natural disaster protection plan	1 year	$ 65	$ 90
Merger costs from 1999 merger	20 years	54	57
Employee benefit plans [1]	7 years	37	45
Deferred operating costs	2 years	13	16
Other	Various	105	84
Total regulatory assets		$ 274	$ 292
Reflected as:			
Current assets		$ 56	$ 90
Noncurrent assets		218	202
Total regulatory assets		$ 274	$ 292

(1) Represents amounts not yet recognized as a component of net periodic benefit cost that are expected to be included in regulated rates when recognized.

Sierra Pacific had regulatory assets not earning a return on investment of $149 million and $131 million as of December 31, 2025 and 2024, respectively. The regulatory assets not earning a return on investment primarily consist of merger costs from the 1999 merger, a portion of the employee benefit plans, unrealized losses on regulated derivative contracts, AROs and losses on reacquired debt.

Regulatory Liabilities

Regulatory liabilities represent amounts that are expected to be returned to customers in future periods. Sierra Pacific's regulatory liabilities reflected on the Consolidated Balance Sheets consist of the following as of December 31 (in millions):

	Weighted Average Remaining Life	2025	2024
Cost of removal[1]	30 years	$ 207	$ 216
Deferred income taxes[2]	Various	173	193
Deferred energy costs	1 year	44	86
Other	Various	39	27
Total regulatory liabilities		$ 463	$ 522
Reflected as:			
Current liabilities		$ 72	$ 106
Noncurrent liabilities		391	416
Total regulatory liabilities		$ 463	$ 522

(1) Amounts represent estimated costs, as accrued through depreciation rates and exclusive of ARO liabilities, of removing regulated property, plant and equipment in accordance with accepted regulatory practices.

(2) Amounts primarily represent income tax liabilities related to the federal tax rate change from 35% to 21% that are probable to be passed on to customers, offset by income tax benefits related to accelerated tax depreciation and certain property-related basis differences and other various differences that were previously passed on to customers and will be included in regulated rates when the temporary differences reverse.

Deferred Energy

Nevada statutes permit regulated utilities to adopt deferred energy accounting procedures. The intent of these procedures is to ease the effect on customers of fluctuations in the cost of purchased natural gas, fuel and electricity and are subject to annual prudency review by the PUCN. Under deferred energy accounting, to the extent actual fuel and purchased power costs exceed fuel and purchased power costs recoverable through current rates that excess is not recorded as a current expense on the Consolidated Statements of Operations but rather is deferred and recorded as a regulatory asset on the Consolidated Balance Sheets and would be included in the regulatory assets table above as deferred energy costs. Conversely, a regulatory liability is recorded to the extent fuel and purchased power costs recoverable through current rates exceed actual fuel and purchased power costs and is included in the regulatory liabilities table above as deferred energy costs. These excess amounts are reflected in quarterly adjustments to rates and recorded as cost of fuel, energy and capacity in future time periods.

Regulatory Rate Review

In February 2024, Sierra Pacific filed electric and gas regulatory rate reviews with the PUCN that requested annual revenue increases of $95 million, or 8.8% and $11 million, or 4.9%, respectively. Sierra Pacific filed the certification filing that updated the electric and gas filings to requested annual revenue increases of $96 million, or 9.5% and $12 million, or 6.4%, respectively. Hearings in the cost of capital phase were held in June 2024 and the hearings for the revenue requirement phase were held in July 2024. The hearings in the rate design phase were held in August 2024. In September 2024, the PUCN issued an order approving an increase in base rates for electric of $40 million and for gas of $8 million. In October 2024, Sierra Pacific filed a petition for reconsideration and clarification of the order. In November 2024, the PUCN issued a final order approving in part and denying in part the petition for reconsideration.

Wildfire Self-Insurance Policy Filing

In January 2025, Sierra Pacific filed an application for approval of the establishment and associated cost recovery of a Wildfire Self-Insurance Policy. In the application, Sierra Pacific request that the PUCN issue an order determining that it is reasonable and prudent for the Nevada Utilities to establish a $500 million wildfire self-insurance policy (the "Policy") in order to have additional wildfire liability insurance in place in the event that a catastrophic wildfire in Nevada is alleged to be caused or exacerbated by utility equipment. The Policy would provide $500 million in additional coverage for the Nevada Utilities for third-party claims, and it would be in excess to the commercial wildfire liability insurance that the Nevada Utilities possess. In addition, the application requests approval to collect the costs for the Policy in rates over a ten-year period. Hearings before the Commission concluded in June 2025. In July 2025, the PUCN issued an order that approved the application in part and denied the application in part. The PUCN found that $1.0-$1.5 billion in insurance coverage is a prudent range for the Nevada Utilities based on its wildfire risk profile and that the Nevada Utilities sufficiently supported its initial request for an additional $500 million of excess insurance. However, the PUCN also determined that additional information is necessary to assess whether the self-insurance policy proposed by the Nevada Utilities is prudent under the circumstances and reasonable considering other options, if any. The Nevada Utilities filed the additional information requested by the PUCN in October 2025. The PUCN has set a hearing in April 2026 to assess the prudency of self-insurance.

(7) Short-term Debt and Credit Facilities

Sierra Pacific has a $400 million secured credit facility expiring in June 2028 with an unlimited number of maturity extension options, subject to lender consent. The credit facility, which is for general corporate purposes and provides for the issuance of letters of credit, has a variable interest rate based on the Secured Overnight Financing Rate or a base rate, at Sierra Pacific's option, plus a spread that varies based on Sierra Pacific's credit ratings for its senior secured long-term debt securities. As of December 31, 2025 and 2024, Sierra Pacific had no borrowings outstanding under the credit facility. Amounts due under Sierra Pacific's credit facility are collateralized by Sierra Pacific's general and refunding mortgage bonds. The credit facility requires Sierra Pacific's ratio of debt, including current maturities, to total capitalization not exceed 0.65 to 1.0 as of the last day of each quarter.

As of both December 31, 2025 and 2024, Sierra Pacific had $50 million of letter of credit capacity under its $400 million secured credit facility, of which no amount was outstanding.

(8) Long-term Debt

Sierra Pacific's long-term debt consists of the following, including unamortized premiums, discounts and debt issuance costs, as of December 31 (dollars in millions):

	Par Value	2025	2024
General and refunding mortgage securities:			
2.60% Series U, due 2026	$ 400	$ 400	$ 399
6.75% Series P, due 2037	252	253	254
4.71% Series W, due 2052	250	248	248
5.90% Series 2023A, due 2054	400	394	394
Tax-exempt refunding revenue bond obligations:			
Fixed-rate series:			
3.55% Pollution Control Series 2016A, due 2029	20	20	20
3.55% Pollution Control Series 2016B, due 2029 (1)	30	29	29
3.625% Gas and Water Series 2016B, due 2036 (2)	60	59	59
4.125% Water Facilities Series 2016C, due 2036 (2)	30	29	30
4.125% Water Facilities Series 2016F, due 2036 (2)	75	74	74
3.625% Water Facilities Series 2016G, due 2036 (2)	20	20	20
Total long-term debt	$ 1,537	$ 1,526	$ 1,527
Reflected as:			
Current portion of long-term debt		$ 410	$ —
Long-term debt		1,116	1,527
Total long-term debt		$ 1,526	$ 1,527

(1) Subject to mandatory sinking fund redemption by Sierra Pacific in the principal amount of $10 million in April 2026.

(2) Subject to mandatory purchase by Sierra Pacific in October 2029 at which date the interest rate may be adjusted.

Junior Subordinated Debt

Sierra Pacific's junior subordinated debt consists of the following, as of December 31 (dollars in millions):

	Par Value	2025	2024
6.20% JSN Series 2025A, due 2055(1)	$ 450	$ 446	$ —
Total junior subordinated debt - non current	$ 450	446	—

(1) Sierra Pacific will pay interest on the junior subordinated notes at a rate of 6.20% through December 2030, subject to a reset every five years.

Annual Repayments of Long-Term Debt

The annual repayments of long-term debt for the years beginning January 1, 2026 and thereafter, are as follows (in millions):

2026	$ 410
2027	—
2028	—
2029	40
2031 and thereafter	1,537
Total	1,987
Unamortized premium, discount and debt issuance cost	(15)
Total	$ 1,972

The issuance of General and Refunding Mortgage Securities by Sierra Pacific is subject to PUCN approval and is limited by available property and other provisions of the mortgage indentures. As of December 31, 2025, approximately $5.6 billion (based on original cost) of Sierra Pacific's property was subject to the liens of the mortgages.

(9) Income Taxes

Berkshire Hathaway includes BHE and its subsidiaries in its U.S. federal income tax return and BHE includes its subsidiaries in certain state income tax returns. Consistent with established regulatory practice, Sierra Pacific's provision for federal and state income tax has been computed on a stand-alone basis, and substantially all of its currently payable or receivable income tax is remitted to or received from BHE pursuant to a tax allocation agreement. Income before income tax expense as reported on the Consolidated Statement of Operations, is all domestic.

Income tax expense consists of the following for the years ended December 31 (in millions):

	2025	2024	2023
Current:			
Federal	$ 18	$ 59	$ 71
State	—	—	1
Total	18	59	72
Deferred:			
Federal	1	(49)	(57)
Total	1	(49)	(57)
Investment tax credits	—	—	1
Total income tax expense	$ 19	$ 10	$ 16

The following table presents income taxes paid, net of refunds, for the years ended December 31 (in millions):

	2025	2024	2023
Jurisdiction:			
Federal	$ 18	$ 66	$ 55
State	—	—	1
Total[(1)]	$ 18	$ 66	$ 56

(1) Substantially all income taxes paid or (received) by Sierra Pacific are pursuant to a tax allocation agreement.

A reconciliation of the federal statutory income rate to the effective income tax rate applicable to income before income tax expense is as follows for the years ended December 31:

	2025		2024		2023	
	Amount	Percent	Amount	Percent	Amount	Percent
U.S federal statutory income tax rate	$ 35	21.0 %	$ 20	21.0 %	$ 28	21.0 %
Other adjustments:						
Effects of ratemaking	(16)	(9.3)	(11)	(10.8)	(12)	(8.8)
Other	—	—	1	1.0	—	—
Effective income tax rate	$ 19	11.7 %	$ 10	11.2 %	$ 16	12.2 %

Effects of ratemaking is primarily attributable to the recognition of excess deferred income taxes related to the federal tax rate change from 35% to 21% pursuant to an order issued by the PUCN effective January 1, 2020.

The net deferred income tax liability consists of the following as of December 31 (in millions):

	2025	2024
Deferred income tax assets:		
Regulatory liabilities	$ 65	$ 60
Customer advances	37	24
Operating and finance leases	24	24
Unamortized contract value	3	3
Other	6	7
Total deferred income tax assets	135	118
Deferred income tax liabilities:		
Property-related items	(394)	(379)
Regulatory assets	(90)	(68)
Operating and finance leases	(24)	(24)
Other	(17)	(16)
Total deferred income tax liabilities	(525)	(487)
Net deferred income tax liability	$ (390)	$ (369)

The U.S. Internal Revenue Service has closed or effectively settled its examination of Sierra Pacific's income tax return through the short year ended December 31, 2014. The closure of examinations, or the expiration of the statute of limitations, may not preclude the U.S. Internal Revenue Service from adjusting the federal net operating loss carryforward utilized in a year for which the statute of limitations is not closed.

(10) Employee Benefit Plans

Sierra Pacific is a participant in benefit plans sponsored by NV Energy. The NV Energy Retirement Plan includes a qualified pension plan ("Qualified Pension Plan") and a supplemental executive retirement plan and a restoration plan (collectively, "Non-Qualified Pension Plans") that provide pension benefits for eligible employees. The NV Energy Comprehensive Welfare Benefit and Cafeteria Plan provides certain postretirement health care and life insurance benefits for eligible retirees ("Other Postretirement Plans") on behalf of Sierra Pacific. Sierra Pacific did not make any contributions to the Qualified Pension Plan for the years ended December 31, 2025, 2024 and 2023. Sierra Pacific contributed $1 million to the Non-Qualified Pension Plans for the years ended December 31, 2025, 2024 and 2023. Sierra Pacific contributed $— million, $3 million and $3 million to the Other Post Retirement Plans for the years ended December 31, 2025, 2024 and 2023, respectively. Amounts attributable to Sierra Pacific were allocated from NV Energy based upon the current, or in the case of retirees, previous, employment location. Offsetting regulatory assets and liabilities have been recorded related to the amounts not yet recognized as a component of net periodic benefit costs that will be included in regulated rates. Net periodic benefit costs not included in regulated rates are included in accumulated other comprehensive loss, net.

Amounts receivable from (payable to) NV Energy are included on the Consolidated Balance Sheets and consist of the following as of December 31 (in millions):

	2025	2024
Qualified Pension Plan -		
Other noncurrent assets	$ 72	$ 59
Non-Qualified Pension Plans:		
Other current liabilities	(1)	(1)
Other long-term liabilities	(5)	(5)
Other Postretirement Plans:		
Other noncurrent assets	2	5

(11) Asset Retirement Obligations

Sierra Pacific estimates its ARO liabilities based upon detailed engineering calculations of the amount and timing of the future cash spending for a third party to perform the required work. Spending estimates are escalated for inflation and then discounted at a credit-adjusted, risk-free rate. Changes in estimates could occur for a number of reasons, including changes in laws and regulations, plan revisions, inflation and changes in the amount and timing of the expected work.

Sierra Pacific does not recognize liabilities for AROs for which the fair value cannot be reasonably estimated. Due to the indeterminate removal date, the fair value of the associated liabilities on certain generation, transmission, distribution and other assets cannot currently be estimated, and no amounts are recognized on the Consolidated Financial Statements other than those included in the cost of removal regulatory liability established via approved depreciation rates in accordance with accepted regulatory practices. These accruals totaled $207 million and $216 million as of December 31, 2025 and 2024, respectively.

The following table presents Sierra Pacific's ARO liabilities by asset type as of December 31 (in millions):

	2025	2024
Asbestos	$ 5	$ 5
Evaporative ponds and dry ash landfills	2	2
Solar-powered generating facilities	1	1
Other	3	3
Total asset retirement obligations	$ 11	$ 11

The following table reconciles the beginning and ending balances of Sierra Pacific's ARO liabilities for the years ended December 31 (in millions):

	2025	2024
Beginning balance	$ 11	$ 12
Change in estimated costs	(1)	(2)
Accretion	1	1
Ending balance	$ 11	$ 11
Reflected as -		
Other long-term liabilities	$ 11	$ 11

Certain of Sierra Pacific's decommissioning and reclamation obligations relate to jointly-owned facilities. Sierra Pacific is committed to pay a proportionate share of the decommissioning or reclamation costs. In the event of a default by any of the other joint participants, the respective subsidiary may be obligated to absorb, directly or by paying additional sums to the entity, a proportionate share of the defaulting party's liability. Sierra Pacific's estimated share of the decommissioning and reclamation obligations are primarily recorded as ARO liabilities in other long-term liabilities on the Consolidated Balance Sheets.

In May 2024, the United States Environmental Protection Agency published its final rule on legacy coal combustion residuals ("CCR") surface impoundments and CCR management units ("CCRMUs") in the Federal Register. CCRMUs include CCR surface impoundments and landfills closed before October 19, 2015 and inactive CCR landfills. The final rule contains three main components: (1) a definition for legacy CCR surface impoundments, which are inactive surface impoundments at inactive generating facilities that must adhere to the same regulations as inactive CCR impoundments at active generating facilities, barring location restrictions and liner design criteria, with customized compliance deadlines; (2) groundwater monitoring, corrective action, closure, and post closure care requirements for CCRMUs, which may be located at active generating facilities and inactive generating facilities with a legacy CCR surface impoundment; and (3) the owners and operators of inactive generating facilities must identify the presence of legacy CCR surface impoundments and comply with all rule requirements for surface impoundments; and the owners and operators of active generating facilities and inactive generating facilities with a legacy CCR surface impoundment must prepare Facility Evaluation Reports ("FERs") that identify and describe the CCRMUs and determine whether closure is required. In February 2026, the EPA extended certain compliance deadlines with CCRMUs. Accordingly, and in a manner consistent with existing CCR rules, owners and operators must publish FERs on their CCR websites in two parts, within 12 months (Part 1) and 24 months (Part 2) of the final rule's effective date in February 2026. Sierra Pacific is currently evaluating the final rule and does not anticipate identifying any legacy surface impoundments, but does anticipate that it may identify CCRMUs subject to the rule. Due to the number of site investigations warranted by this rule and the nature of engineering and other studies required at each site, Sierra Pacific is unable to reasonably estimate the potential impact, which may be material, to its asset retirement obligations.

(12) Risk Management and Hedging Activities

Sierra Pacific is exposed to the impact of market fluctuations in commodity prices and interest rates. Sierra Pacific is principally exposed to electricity, natural gas and coal market fluctuations primarily through Sierra Pacific's obligation to serve retail customer load in its regulated service territory. Sierra Pacific's load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity and wholesale electricity that is purchased and sold. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, generating facility availability, customer usage, storage, and transmission and transportation constraints. The actual cost of fuel and purchased power is recoverable through the deferred energy mechanism. Interest rate risk exists on variable-rate debt and future debt issuances. Sierra Pacific does not engage in proprietary trading activities.

Sierra Pacific has established a risk management process that is designed to identify, assess, manage and report on each of the various types of risk involved in its business. To mitigate a portion of its commodity price risk, Sierra Pacific uses commodity derivative contracts, which may include forwards, futures, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. Sierra Pacific manages its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. Additionally, Sierra Pacific may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, to mitigate Sierra Pacific's exposure to interest rate risk. Sierra Pacific does not hedge all of its commodity price and interest rate risks, thereby exposing the unhedged portion to changes in market prices.

There have been no significant changes in Sierra Pacific's accounting policies related to derivatives. Refer to Notes 2 and 13 for additional information on derivative contracts.

The following table, which excludes contracts that have been designated as normal under the normal purchases and normal sales exception afforded by GAAP, summarizes the fair value of Sierra Pacific's derivative contracts, on a gross basis, and reconciles those amounts presented on a net basis on the Consolidated Balance Sheets (in millions):

	Other Long-Term Assets	Other Current Liabilities	Other Long-term Liabilities	Total
As of December 31, 2025:				
Not designated as hedging contracts [1]:				
Commodity assets	$ 1	$ —	$ —	$ 1
Commodity liabilities	—	(8)	(4)	(12)
Total derivative - net basis	$ 1	$ (8)	$ (4)	$ (11)
As of December 31, 2024:				
Not designated as hedging contracts [1] -				
Commodity assets	$ 1	$ —	$ —	$ 1
Commodity liabilities	—	(14)	—	(14)
Total derivative - net basis	$ 1	$ (14)	$ —	$ (13)

(1) Sierra Pacific's commodity derivatives not designated as hedging contracts are included in regulated rates. As of December 31, 2025 and 2024, a regulatory asset of $11 million and $13 million, respectively, was recorded related to the net derivative liability of $11 million and $13 million, respectively.

Derivative Contract Volumes

The following table summarizes the net notional amounts of outstanding commodity derivative contracts with fixed price terms that comprise the mark-to-market values as of December 31 (in millions):

	Unit of Measure	2025	2024
Electricity purchases	Megawatt hours	1	1
Natural gas purchases	Decatherms	75	57

Credit Risk

Sierra Pacific is exposed to counterparty credit risk associated with wholesale energy supply and marketing activities with other utilities, energy marketing companies, financial institutions and other market participants. Credit risk may be concentrated to the extent Sierra Pacific's counterparties have similar economic, industry or other characteristics and due to direct and indirect relationships among the counterparties. Before entering into a transaction, Sierra Pacific analyzes the financial condition of each significant wholesale counterparty, establishes limits on the amount of unsecured credit to be extended to each counterparty and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate wholesale counterparty credit risk, Sierra Pacific enters into netting and collateral arrangements that may include margining and cross-product netting agreements and obtain third-party guarantees, letters of credit and cash deposits. If required, Sierra Pacific exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

Collateral and Contingent Features

In accordance with industry practice, certain wholesale agreements, including derivative contracts, contain credit support provisions that in part base certain collateral requirements on credit ratings for senior unsecured debt as reported by one or more of the recognized credit rating agencies. These agreements may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance" if there is a material adverse change in Sierra Pacific's creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2025, Sierra Pacific's credit ratings for its senior secured debt and its issuer credit ratings for subordinated debt from the recognized credit rating agencies were investment grade.

The aggregate fair value of Sierra Pacific's derivative contracts in liability positions with specific credit-risk-related contingent features totaled $1 million and $— million as of December 31, 2025 and 2024, respectively, which represents the amount of collateral to be posted if all credit risk related contingent features for derivative contracts in liability positions had been triggered. Sierra Pacific's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation or other factors.

(13) Fair Value Measurements

The carrying value of Sierra Pacific's cash, certain cash equivalents, receivables, payables, accrued liabilities and short-term borrowings approximates fair value because of the short-term maturity of these instruments. Sierra Pacific has various financial assets and liabilities that are measured at fair value on the Consolidated Balance Sheets using inputs from the three levels of the fair value hierarchy. A financial asset or liability classification within the hierarchy is determined based on the lowest level input that is significant to the fair value measurement. The three levels are as follows:

- Level 1 - Inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Sierra Pacific has the ability to access at the measurement date.
- Level 2 - Inputs include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means (market corroborated inputs).
- Level 3 - Unobservable inputs reflect Sierra Pacific's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. Sierra Pacific develops these inputs based on the best information available, including its own data.

The following table presents Sierra Pacific's financial assets and liabilities recognized on the Consolidated Balance Sheets and measured at fair value on a recurring basis (in millions):

	Input Levels for Fair Value Measurements			
	Level 1	Level 2	Level 3	Total
As of December 31, 2025:				
Assets:				
Commodity derivatives	$ —	$ —	$ 1	$ 1
Money market mutual funds	14	—	—	14
Investment funds	1	—	—	1
	$ 15	$ —	$ 1	$ 16
Liabilities - commodity derivatives	$ —	$ —	$ (12)	$ (12)
As of December 31, 2024:				
Assets:				
Commodity derivatives	$ —	$ —	$ 1	$ 1
Money market mutual funds	12	—	—	12
Investment funds	1	—	—	1
	$ 13	$ —	$ 1	$ 14
Liabilities - commodity derivatives	$ —	$ —	$ (14)	$ (14)

Sierra Pacific's investments in money market mutual funds and investment funds are accounted for as available-for-sale securities and are stated at fair value. When available, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value.

Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. When available, the fair value of derivative contracts is estimated using unadjusted quoted prices for identical contracts in the market in which Sierra Pacific transacts. When quoted prices for identical contracts are not available, Sierra Pacific uses forward price curves. Forward price curves represent Sierra Pacific's estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates. Sierra Pacific bases its forward price curves upon internally developed models, with internal and external fundamental data inputs. Market price quotations for certain electricity and natural gas trading hubs are not as readily obtainable due to markets that are not active. Given that limited market data exists for these contracts, Sierra Pacific uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs that are based on unobservable inputs. The model incorporates a mid-market pricing convention (the mid-point price between bid and ask prices) as a practical expedient for valuing its assets and liabilities measured and reported at fair value. The determination of the fair value for derivative contracts not only includes counterparty risk, but also the impact of Sierra Pacific's nonperformance risk on its liabilities, which as of December 31, 2025, had an immaterial impact to the fair value of its derivative contracts. As such, Sierra Pacific considers its derivative contracts to be valued using Level 3 inputs.

The following table reconciles the beginning and ending balances of Sierra Pacific's net commodity derivative assets or liabilities measured at fair value on a recurring basis using significant Level 3 inputs for the years ended December 31 (in millions):

	2025	2024	2023
Beginning balance	$ (13)	$ (16)	$ (13)
Changes in fair value recognized in regulatory assets or liabilities	(24)	(27)	(50)
Settlements	26	30	47
Ending balance	$ (11)	$ (13)	$ (16)

Sierra Pacific's long-term debt is carried at cost on the Consolidated Balance Sheets. The fair value of Sierra Pacific's long-term debt is a Level 2 fair value measurement and has been estimated based upon quoted market prices, where available, or at the present value of future cash flows discounted at rates consistent with comparable maturities with similar credit risks. The following table presents the carrying value and estimated fair value of Sierra Pacific's long-term debt as of December 31 (in millions):

	2025		2024	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 1,972	$ 1,967	$ 1,527	$ 1,506

(14) Commitments and Contingencies

Commitments

Sierra Pacific has the following firm commitments that are not reflected on the Consolidated Balance Sheet. Minimum payments as of December 31, 2025 are as follows (in millions):

Contract type:	2026	2027	2028	2029	2030	2031 and Thereafter	Total
Purchased electricity and Energy Storage contracts - commercially operable	$ 9	$ 9	$ 9	$ 9	$ 10	$ 52	$ 98
Fuel contracts	73	58	45	44	36	445	701
Construction commitments	816	347	91	8	—	—	1,262
Transmission	11	24	—	—	11	4	50
Easements	2	2	2	2	2	29	39
Maintenance, service and other contracts	8	17	13	1	1	2	42
Total commitments	$ 919	$ 457	$ 160	$ 64	$ 60	$ 532	$ 2,192

Purchased Electricity Contracts - Commercially Operable

Sierra Pacific has several contracts for long-term purchase of electric energy which have been approved by the PUCN. The expiration of these contracts range from 2026 to 2053. Sierra Pacific has many long-term PPAs primarily with solar-powered and geothermal generating facilities that are not included in the table above due to there being no minimum payments generally due to being dependent on solar and geothermal conditions. These PPAs generally range from 15 to 25 years in duration. Future payments associated with these PPAs are expected to be material. Certain PPAs qualify as leases as described in Note 2 and are also excluded from the table above. Refer to Note 5 for variable lease costs associated with these lease commitments.

Purchased Electricity Contracts - Non-Commercially Operable

Sierra Pacific has several contracts for long-term purchase of electric energy in which the facility remains under development. Amounts represent the estimated payments under renewable energy power purchase contracts, which have been approved by the PUCN and are contingent upon the developers obtaining commercial operation and their ability to deliver power.

Fuel Contracts

Sierra Pacific has a long-term contract for the transport of coal that expires in 2026. Additionally, gas transportation contracts expire from 2026 to 2046.

Construction Commitments

Sierra Pacific's construction commitments included in the table above relate to firm commitments and include costs associated with a 400-MW solar photovoltaic facility with an additional 400-MWs of co-located battery storage that is being developed in Churchill County, Nevada, with ownership share approved by the PUCN of 90% Sierra Pacific and 10% Nevada Power, the repower project at the Valmy generating station to convert existing coal-fired combustion to natural gas-fire combustion, a hydrogen-capable natural gas simple cycle combustion turbine peakers project at the Valmy generating station, the Greenlink Nevada transmission expansion project that is being developed in western and northern Nevada and certain other generation plant projects.

Transmission

Sierra Pacific has contracts for the right to transmit electricity over other entities' transmission lines to facilitate delivery to Sierra Pacific's customers.

Easements

Sierra Pacific has non-cancelable easements for land. Operating and maintenance expense on non-cancelable easements totaled $2 million for the years ended December 31, 2025, 2024 and 2023.

Maintenance, Service and Other Contracts

Sierra Pacific has long-term service agreements for the performance of maintenance on generation units. Obligation amounts are based on estimated usage. The estimated expiration of these service agreements range from 2026 to 2029.

Environmental Laws and Regulations

Sierra Pacific is subject to federal, state and local laws and regulations regarding air quality, climate change, emissions performance standards, water quality, coal ash disposal and other environmental matters that have the potential to impact its current and future operations. Sierra Pacific believes it is in material compliance with all applicable laws and regulations.

Accrual for Customer Refund

In 2025, Sierra Pacific recorded an accrual totaling $14 million in connection with a potential customer refund arising from an ongoing regulatory proceeding. The estimated accrual is based on currently available information to date and Sierra Pacific believes it is probable that losses will be incurred associated with the ongoing regulatory proceeding which reflects Sierra Pacific's commitment to transparency and regulatory compliance. Sierra Pacific filed an Offer of Compromise with the PUCN in January 2026 to settle the regulatory proceeding, inclusive of the amount accrued in 2025, that was accepted by the PUCN in February 2026.

Legal Matters

Sierra Pacific is party to a variety of legal actions arising out of the normal course of business. Sierra Pacific does not believe that such normal and routine litigation will have a material impact on its consolidated financial results.

(15) Revenues from Contracts with Customers

The following table summarizes Sierra Pacific's Customer Revenue by customer class, including a reconciliation to Sierra Pacific's reportable segment information included in Note 18, for the years ended December 31 (in millions):

	2025			2024			2023		
	Electric	Natural Gas	Total	Electric	Natural Gas	Total	Electric	Natural Gas	Total
Customer Revenue:									
Retail:									
Residential	$ 343	$ 80	$ 423	$ 388	$ 114	$ 502	$ 421	$ 143	$ 564
Commercial	316	30	346	349	47	396	385	64	449
Industrial	226	9	235	264	19	283	299	27	326
Other	4	2	6	4	1	5	5	1	6
Total fully bundled	889	121	1,010	1,005	181	1,186	1,110	235	1,345
Distribution only service	9	—	9	6	—	6	5	—	5
Total retail	898	121	1,019	1,011	181	1,192	1,115	235	1,350
Wholesale, transmission and other	64	3	67	68	—	68	78	—	78
Total Customer Revenue	962	124	1,086	1,079	181	1,260	1,193	235	1,428
Other revenue	2	—	2	1	1	2	1	2	3
Total operating revenue	$ 964	$ 124	$ 1,088	$ 1,080	$ 182	$ 1,262	$ 1,194	$ 237	$ 1,431

(16) Supplemental Cash Flow Disclosures

The summary of supplemental cash flow disclosures as of and for the years ended December 31 is as follows (in millions):

	2025	2024	2023
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	$ 85	$ 72	$ 49
Supplemental disclosure of non-cash investing and financing transactions:			
Accruals related to property, plant and equipment additions	$ 74	$ 133	$ 51

(17) Related Party Transactions

Sierra Pacific has an intercompany administrative services agreement with BHE and its subsidiaries. Amounts charged to Sierra Pacific under this agreement, either directly or through NV Energy, totaled $13 million, $45 million and $27 million for the years ended December 31, 2025, 2024 and 2023, respectively. Amounts charged to Sierra Pacific in 2025 and 2024 primarily relate to information technology projects billed at a consolidated level and passed through to affiliates.

Sierra Pacific provided electricity to Nevada Power of $35 million, $29 million and $70 million for the years ended December 31, 2025, 2024 and 2023, respectively. Receivables associated with these transactions were $2 million and $1 million as of December 31, 2025 and 2024, respectively. Sierra Pacific purchased electricity from Nevada Power of $199 million, $188 million and $230 million for the years ended December 31, 2025, 2024 and 2023, respectively. Payables associated with these transactions were $15 million and $7 million as of December 31, 2025 and 2024, respectively.

Sierra Pacific incurs intercompany administrative and shared facility costs with NV Energy and Nevada Power. These transactions are governed by an intercompany service agreement and are priced at cost. NV Energy provided services to Sierra Pacific of $8 million, $5 million, and $5 million for the years ending December 31, 2025, 2024 and 2023, respectively. Sierra Pacific provided services to Nevada Power of $60 million, $19 million, and $19 million for the years ended December 31, 2025, 2024 and 2023, respectively. Nevada Power provided services to Sierra Pacific of $63 million, $31 million, and $28 million for the years ended December 31, 2025, 2024 and 2023, respectively. Sierra Pacific provided services to NV Energy of $6 million, $3 million, and $1 million for the years ended December 31, 2025, 2024 and 2023, respectively. As of December 31, 2025 and 2024, Sierra Pacific's Consolidated Balance Sheets included amounts due to NV Energy of $195 million and $54 million, respectively. There were $169 million and $— million receivables due from NV Energy as of December 31, 2025 and 2024, respectively. As of December 31, 2025 and 2024, Sierra Pacific's Consolidated Balance Sheets included no payables due to Nevada Power. There were $26 million and $65 million receivables due from Nevada Power as of December 31, 2025 and 2024, respectively.

Sierra Pacific is party to a tax allocation agreement and is part of the Berkshire Hathaway consolidated U.S. federal income tax return and certain BHE consolidated state income tax returns. Federal income taxes payable to BHE were $2 million and $3 million as of December 31, 2025 and 2024, respectively. Sierra Pacific made cash payments for federal income taxes to BHE of $17 million, $65 million, and $55 million for the years ended December 31, 2025, 2024 and 2023, respectively.

Certain disbursements for accounts payable and payroll are made by NV Energy on behalf of Sierra Pacific and reimbursed automatically when settled by the bank. These amounts are recorded as accounts payable at the time of disbursement.

(18) Segment Information

Sierra Pacific's chief operating decision maker ("CODM") is its President and Chief Executive Officer. Net income for each reportable segment is considered by the CODM in allocating resources and capital. The CODM generally considers actual results versus historical results, budgets or forecasts, and state regulatory ratemaking results as well as unique risks and opportunities, when making decisions about the allocation of resources and capital to each reportable segment.

Sierra Pacific has identified two reportable operating segments: regulated electric and regulated natural gas. The regulated electric segment derives most of its revenue from regulated retail sales of electricity to residential, commercial, and industrial customers and from wholesale sales. The regulated natural gas segment derives most of its revenue from regulated retail sales of natural gas to residential, commercial, and industrial customers and also obtains revenue by transporting natural gas owned by others through its distribution system. Pricing for regulated electric and regulated natural gas sales are established separately by the PUCN; therefore, management also reviews each segment separately to make decisions regarding allocation of resources and in evaluating performance.

The following tables provide information on a reportable segment basis (in millions):

	2025		
	Regulated Electric	Regulated Natural Gas	Total
Operating revenue	$ 964	$ 124	$ 1,088
Cost of sales	435	58	493
Operations and maintenance	218	23	241
Depreciation and amortization	143	18	161
Interest expense	92	9	101
Interest and dividend income	11	—	11
Income tax expense	17	2	19
Other segment items [1]	65	(3)	62
Net income	$ 135	$ 11	$ 146
Capital expenditures	$ 1,548	$ 102	$ 1,650

	2024		
	Regulated Electric	Regulated Natural Gas	Total
Operating revenue	$ 1,080	$ 182	$ 1,262
Cost of sales	561	121	682
Operations and maintenance	213	32	245
Depreciation and amortization	162	19	181
Interest expense	79	7	86
Interest and dividend income	12	—	12
Income tax expense (benefit)	12	(2)	10
Other segment items [1]	17	(2)	15
Net Income	$ 82	$ 3	$ 85
Capital expenditures	$ 643	$ 31	$ 674

	2023		
	Regulated Electric	Regulated Natural Gas	Total
Operating revenue	$ 1,194	$ 237	$ 1,431
Cost of sales	689	176	865
Operations and maintenance	182	22	204
Depreciation and amortization	168	17	185
Interest expense	62	4	66
Interest and dividend income	20	2	22
Income tax expense	14	2	16
Other segment items [1]	(1)	1	—
Net Income	$ 98	$ 19	$ 117
Capital expenditures	$ 350	$ 38	$ 388

	As of December 31,		
	2025	2024	2023
Assets			
Regulated electric	$ 6,541	$ 4,767	$ 4,251
Regulated natural gas	485	518	454
Regulated common assets[2]	19	42	67
Total assets	$ 7,045	$ 5,327	$ 4,772

(1) Consists principally of property and other taxes, allowance for borrowed and equity funds and other income (expense).

(2) Consists principally of cash and cash equivalents not included in either the regulated electric or regulated natural gas segments

Eastern Energy Gas Holdings, LLC and its subsidiaries
Consolidated Financial Section

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following is management's discussion and analysis of certain significant factors that have affected the consolidated financial condition and results of operations of Eastern Energy Gas during the periods included herein. This discussion should be read in conjunction with Eastern Energy Gas' historical Consolidated Financial Statements and Notes to Consolidated Financial Statements in Item 8 of this Form 10-K. Eastern Energy Gas' actual results in the future could differ significantly from the historical results.

Results of Operations

Overview

Net income attributable to Eastern Energy Gas for the year ended December 31, 2025 was $579 million, a decrease of $12 million, or 2%, compared to 2024, primarily due to an increase in interest expense, partially offset by higher margin from regulated gas transmission and storage operations of $37 million and higher earnings from Cove Point of $23 million, largely due to an increase in variable revenue.

Net income attributable to Eastern Energy Gas for the year ended December 31, 2024 was $591 million, an increase of $117 million, or 25%, compared to 2023, primarily due to higher earnings from Cove Point of $151 million, largely due to the acquisition of an additional 50% limited partner interest in Cove Point, partially offset by one-time favorable income tax adjustments recorded in 2023 as a result of the acquisition of an additional 50% limited partner interest in Cove Point.

Year Ended December 31, 2025 Compared to Year Ended December 31, 2024

Operating revenue increased $81 million, or 4%, for 2025 compared to 2024, primarily due to an increase in Cove Point LNG variable revenue of $55 million, an increase in EGTS' regulated gas transmission and storage services revenues of $22 million primarily due to additional capacity contracts, an increase in CGT's regulated gas transmission service revenues primarily due to additional capacity contracts of $10 million and the settlement of its general rate case of $8 million and an increase in services provided to affiliates of $6 million, partially offset by a decrease in Cove Point's storage-related service revenues of $7 million, a decrease in variable revenue related to park and loan activity of $5 million and a decrease in regulated gas sales for operational and system balancing purposes primarily due to decreased volumes of $5 million.

Cost of gas decreased $6 million, or 86%, for 2025 compared to 2024, primarily due to a decrease in volumes sold.

Operations and maintenance increased $7 million, or 1%, for 2025 compared to 2024, primarily due to an increase in charges from affiliates of $12 million and an increase in services provided to affiliates of $6 million, partially offset by a gain from the sale of a compressor unit to Northern Natural Gas of $5 million and lower salary and benefit expenses of $3 million.

Depreciation and amortization increased $14 million, or 4%, for 2025 compared to 2024, primarily due to higher plant placed in-service of $11 million and the settlement of depreciation rates in CGT's general rate case of $3 million.

Interest expense increased $80 million, or 57%, for 2025 compared to 2024, primarily due to the issuances of $1.2 billion of long-term debt in the first quarter of 2025 of $69 million and timing impacts and higher interest rates on $1.0 billion of long-term debt refinanced during 2024 of $18 million, partially offset by lower lending activity under BHE GT&S' intercompany revolving credit agreement of $8 million.

Interest and dividend income increased $8 million, or 57%, for 2025 compared to 2024, primarily due to higher lending activity under BHE GT&S' intercompany revolving credit agreement of $12 million, partially offset by a decrease in income from money market mutual fund investments of $4 million.

Income tax expense decreased $28 million, or 14%, for 2025 compared to 2024. The effective tax rate was 21% and 24% for 2025 and 2024, respectively. The $28 million decrease was primarily due to favorable state income tax adjustments and lower equity earnings.

Equity income decreased $22 million, or 31%, for 2025 compared to 2024, primarily due to lower variable revenues at Iroquois, largely from unfavorable pricing.

Net income attributable to noncontrolling interests increased $9 million, or 7%, for 2025 compared to 2024, primarily due to higher net income attributable to Cove Point.

Year Ended December 31, 2024 Compared to Year Ended December 31, 2023

Operating revenue decreased $48 million, or 2%, for 2024 compared to 2023, primarily due to a decrease in Cove Point's storage-related revenues of $22 million, a decrease in EGTS' variable revenue related to park and loan activity of $18 million, a decrease in regulated gas sales for operational and system balancing purposes due to decreased prices and volumes of $15 million, a decrease in Cove Point LNG variable revenue of $7 million, a decrease in Cove Point's regulated gas transmission service revenues due to decreased prices and volumes of $5 million and a decrease in services provided to affiliates of $5 million, partially offset by an increase in EGTS' regulated gas transmission and storage services revenues of $17 million primarily due to additional capacity contracts and an increase in CGT's regulated gas transmission service revenues of $12 million primarily due to the settlement of its general rate case.

Cost of gas decreased $31 million, or 82%, for 2024 compared to 2023, primarily due to the unfavorable revaluation of volumes retained in 2023.

Operations and maintenance decreased $17 million, or 3%, for 2024 compared to 2023, primarily due to lower technology and related charges of $19 million, lower outside services of $9 million due to the termination of Dominion Energy Inc.'s transition services agreement and a decrease in services provided to affiliates of $5 million, partially offset by a gain in 2023 from an agreement to convey development rights underneath one of its natural gas storage fields of $8 million and an increase in salary and benefit expenses of $4 million.

Depreciation and amortization increased $14 million, or 4%, for 2024 compared to 2023, primarily due to higher plant placed in-service of $9 million and the settlement of depreciation rates in CGT's general rate case of $5 million.

Interest expense decreased $5 million, or 3%, for 2024 compared to 2023, primarily due to the repayments of $650 million of long-term debt during 2023 of $17 million, partially offset by timing impacts and higher interest rates on $1.0 billion of long-term debt re-financed during 2024 of $8 million and higher lending activity under BHE GT&S' intercompany revolving credit agreement of $4 million.

Interest and dividend income decreased $16 million, or 53%, for 2024 compared to 2023, primarily due to lower lending activity under BHE GT&S' intercompany revolving credit agreement.

Income tax expense increased $90 million, or 82%, for 2024 compared to 2023. The effective tax rate was 24% and 13% for 2024 and 2023, respectively. The $90 million increase was primarily due to less benefit from non-controlling interest from the ownership of 75% of the limited partner interests in Cove Point for the full year 2024 and a one-time favorable state adjustments of $26 million recorded in 2023, both as a result of the acquisition of an additional 50% limited partner interest in Cove Point on September 1, 2023.

Net income attributable to noncontrolling interests decreased $226 million, or 63%, for 2024 compared to 2023, primarily due to the acquisition of an additional 50% limited partner interest in Cove Point.

Liquidity and Capital Resources

As of December 31, 2025, Eastern Energy Gas' total net liquidity was as follows (in millions):

Cash and cash equivalents	$	80
Intercompany revolving credit agreement		400
Total net liquidity	$	480
Intercompany revolving credit agreement:		
Maturity date		2027

Refer to Note 19 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for further discussion regarding Eastern Energy Gas' intercompany revolving credit agreement.

Eastern Energy Gas' future financial performance and capital expenditures related to certain projects may be affected by the combined effects of ongoing macroeconomic and geopolitical conditions, including changes in international trade policies and tariff regimes. The pace of change in these areas accelerated during 2025, and uncertainty persists regarding the scope and duration of these external factors. However, Eastern Energy Gas currently does not believe these items and any resulting changes to future capital project allocations will significantly impact its business in the near term.

Operating Activities

Net cash flows from operating activities for the years ended December 31, 2025 and 2024 were $1.2 billion and $1.3 billion, respectively. The change was primarily due to lower distributions from Iroquois and higher cash paid for interest, partially offset by other working capital adjustments.

Net cash flows from operating activities for the years ended December 31, 2024 and 2023 were $1.3 billion and $1.2 billion, respectively. The change was primarily due to the repayment of EGTS rate refunds to customers in 2023, the settlement of contract liabilities in 2023 and other changes in working capital, partially offset by unfavorable operating results.

Investing Activities

Net cash flows from investing activities for the years ended December 31, 2025 and 2024 were $(866) million and $(372) million, respectively. The change was primarily due to a decrease in repayments of notes by its parent under an intercompany revolving credit agreement of $288 million and an increase in notes issued to its parent under an intercompany revolving credit agreement of $225 million, partially offset by an increase in proceeds from sales of marketable securities of $8 million and a decrease in capital expenditures of $6 million.

Net cash flows from investing activities for the years ended December 31, 2024 and 2023 were $(372) million and $177 million, respectively. The change was primarily due to a decrease in repayments of notes by its parent under an intercompany revolving credit agreement of $429 million, an increase in notes issued to its parent under an intercompany revolving credit agreement of $107 million, an increase in capital expenditures of $11 million and proceeds from the assignment of shale development rights in 2023 of $8 million.

Financing Activities

Net cash flows from financing activities for the year ended December 31, 2025 were $(299) million. Sources of cash totaled $1.2 billion and consisted of proceeds from the issuance of long-term debt. Uses of cash totaled $1.5 billion and consisted of distributions to its indirect parent, BHE, of $1.3 billion and distributions to noncontrolling interests from Cove Point of $167 million.

Net cash flows from financing activities for the year ended December 31, 2024 were $(925) million. Sources of cash totaled $1.0 billion and consisted of proceeds from the issuance of long-term debt. Uses of cash totaled $2.0 billion and consisted of repayments of long-term debt of $1.1 billion, net repayment of notes payable to affiliates of $400 million, distributions to its indirect parent, BHE, of $361 million and distributions to noncontrolling interests from Cove Point of $155 million.

Net cash flows from financing activities for the year ended December 31, 2023 were $(1.4) billion. Sources of cash totaled $3.3 billion and consisted of proceeds from equity contributions to fund the purchase of Cove Point noncontrolling interest of $2.9 billion and net issuance of notes payable to affiliates of $400 million. Uses of cash totaled $4.7 billion and consisted of $3.3 billion for the purchase of Cove Point noncontrolling interest, repayment of long-term debt of $650 million, distributions to noncontrolling interests from Cove Point of $388 million and distributions to its indirect parent, BHE, of $332 million.

Long-term Debt

Eastern Energy Gas currently has an effective shelf registration statement filed with the SEC to issue an additional $400 million of long-term debt securities through January 2027.

Future Uses of Cash

Capital Expenditures

Capital expenditure needs are reviewed regularly by management and may change significantly as a result of these reviews, which may consider, among other factors, new growth projects and the timing of growth projects; changes in environmental and other rules and regulations; impacts to customers' rates; outcomes of regulatory proceedings; changes in income tax laws; general business conditions; system reliability standards; the cost and efficiency of construction labor, equipment and materials; commodity prices; and the cost and availability of capital.

Eastern Energy Gas' historical and forecasted capital expenditures, each of which exclude amounts for non-cash equity AFUDC and other non-cash items, for the years ending December 31 are as follows (in millions):

	Historical			Forecast		
	2023	**2024**	**2025**	**2026**	**2027**	**2028**
Natural gas transmission and storage	$ 23	$ 64	$ 62	$ 115	$ 258	$ 605
Other	342	312	308	420	240	276
Total	$ 365	$ 376	$ 370	$ 535	$ 498	$ 881

Eastern Energy Gas' natural gas transmission and storage capital expenditures primarily include growth capital expenditures related to planned regulated projects. Eastern Energy Gas' other capital expenditures consist primarily of nonregulated and routine capital expenditures for natural gas transmission, storage and LNG terminalling infrastructure needed to serve existing and expected demand.

Off-Balance Sheet Arrangements

Eastern Energy Gas has certain investments that are accounted for under the equity method in accordance with GAAP. Accordingly, an amount is recorded on Eastern Energy Gas' Consolidated Balance Sheets as an equity investment and is increased or decreased for Eastern Energy Gas' pro-rata share of earnings or losses, respectively, less any dividends from such investments.

As of December 31, 2025, Eastern Energy Gas' investments that are accounted for under the equity method had short- and long-term debt of $295 million and an unused revolving credit facility of $10 million. As of December 31, 2025, Eastern Energy Gas' pro-rata share of such short- and long-term debt was $148 million and unused revolving credit facility was $5 million. The entire amount of Eastern Energy Gas' pro-rata share of the outstanding short- and long-term debt and unused revolving credit facility is non-recourse to Eastern Energy Gas. Although Eastern Energy Gas is generally not required to support debt service obligations of its equity investees, default with respect to this non-recourse short- and long-term debt could result in a loss of invested equity.

Material Cash Requirements

The following table summarizes Eastern Energy Gas' material cash requirements as of December 31, 2025 (in millions):

	Payments Due by Periods				
	2026	2027-2028	2029-2030	2031 and thereafter	Total
Interest payments on long-term debt[(1)]	$ 217	$ 415	$ 397	$ 2,990	$ 4,019
Natural gas supply and transmission[(1)]	46	92	92	46	276
Total cash requirements	$ 263	$ 507	$ 489	$ 3,036	$ 4,295

(1) Not reflected on the Consolidated Balance Sheets.

In addition, Eastern Energy Gas also has cash requirements that may affect its consolidated financial condition that arise from long-term debt (refer to Note 8), construction and other development costs (refer to Liquidity and Capital Resources included within this Item 7), uncertain tax positions (refer to Note 9) and AROs (refer to Note 11). Refer, where applicable, to the respective referenced note in Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

Regulatory Matters

Eastern Energy Gas is subject to comprehensive regulation. Refer to the discussion contained in Item 1 of this Form 10-K for further information regarding Eastern Energy Gas' general regulatory framework and current regulatory matters.

Environmental Laws and Regulations

Eastern Energy Gas is subject to federal, state and local laws and regulations regarding air quality, climate change, emissions performance standards, water quality and other environmental matters that have the potential to impact its current and future operations. In addition to imposing continuing compliance obligations, these laws and regulations provide regulators with the authority to levy substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. These laws and regulations are administered by various federal, state and local agencies. Eastern Energy Gas believes it is in material compliance with all applicable laws and regulations, although many are subject to interpretation that may ultimately be resolved by the courts. Environmental laws and regulations continue to evolve, and Eastern Energy Gas is unable to predict the impact of the changing laws and regulations on its operations and consolidated financial results.

Refer to "Environmental Laws and Regulations" in Item 1 of this Form 10-K for further discussion regarding environmental laws and regulations.

Collateral and Contingent Features

Debt of Eastern Energy Gas is rated by credit rating agencies. Assigned credit ratings are based on each rating agency's assessment of Eastern Energy Gas' ability to, in general, meet the obligations of its issued debt. The credit ratings are not a recommendation to buy, sell or hold securities, and there is no assurance that a particular credit rating will continue for any given period of time.

Eastern Energy Gas has no credit rating downgrade triggers that would accelerate the maturity dates of outstanding debt, and a change in ratings is not an event of default under the applicable debt instruments.

Inflation

Historically, overall inflation and changing prices in the economies where Eastern Energy Gas operates have not had a significant impact on Eastern Energy Gas' consolidated financial results. Eastern Energy Gas and its subsidiaries primarily operate under cost-of-service based rate-setting structures administered by the FERC. Under these rate-setting structures, Eastern Energy Gas is allowed to include prudent costs in its rates, including the impact of inflation. Eastern Energy Gas attempts to minimize the potential impact of inflation on its operations by employing prudent risk management and hedging strategies and by considering, among other areas, its impact on purchases of energy, operating expenses, materials and equipment costs, contract negotiations, future capital spending programs and long-term debt issuances. There can be no assurance that such actions will be successful.

New Accounting Pronouncements

For a discussion of new accounting pronouncements affecting Eastern Energy Gas, refer to Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Critical Accounting Estimates

Certain accounting measurements require management to make estimates and judgments concerning transactions that will be settled several years in the future. Amounts recognized on the Consolidated Financial Statements based on such estimates involve numerous assumptions subject to varying and potentially significant degrees of judgment and uncertainty and will likely change in the future as additional information becomes available. The following critical accounting estimates are impacted significantly by Eastern Energy Gas' methods, judgments and assumptions used in the preparation of the Consolidated Financial Statements and should be read in conjunction with Eastern Energy Gas' Summary of Significant Accounting Policies included in Eastern Energy Gas' Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Accounting for the Effects of Certain Types of Regulation

Eastern Energy Gas prepares its Consolidated Financial Statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, Eastern Energy Gas defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur.

Eastern Energy Gas continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future regulated rates by considering factors such as a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation, other regulatory actions or the impact of competition that could limit Eastern Energy Gas' ability to recover its costs. Eastern Energy Gas believes its application of the guidance for regulated operations is appropriate and its existing regulatory assets and liabilities are probable of inclusion in future regulated rates. The evaluation reflects the current political and regulatory climate at the federal level. If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the related regulatory assets and liabilities will be recognized in net income, returned to customers or re-established as AOCI. Total regulatory assets were $74 million and total regulatory liabilities were $666 million as of December 31, 2025. Refer to Eastern Energy Gas' Note 6 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding Eastern Energy Gas' regulatory assets and liabilities.

Impairment of Goodwill and Long-Lived Assets

Eastern Energy Gas' Consolidated Balance Sheet as of December 31, 2025 includes goodwill of acquired businesses of $1.3 billion. Eastern Energy Gas evaluates goodwill for impairment at least annually and completed its annual review as of October 31, 2025. Additionally, no indicators of impairment were identified as of December 31, 2025. Significant judgment is required in estimating the fair value of the reporting unit and performing goodwill impairment tests. Eastern Energy Gas uses a variety of methods to estimate a reporting unit's fair value, principally discounted projected future net cash flows. Key assumptions used include, but are not limited to, the use of estimated future cash flows; multiples of earnings; and an appropriate discount rate. Estimated future cash flows are impacted by, among other factors, growth rates, changes in regulations and rates, ability to renew contracts and estimates of future commodity prices. In estimating future cash flows, Eastern Energy Gas incorporates current market information, as well as historical factors.

Eastern Energy Gas evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or when the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Consolidated Statements of Operations. As a majority of all property, plant and equipment is used in regulated businesses, the impacts of regulation are considered when evaluating the carrying value of regulated assets.

The estimate of cash flows arising from the future use of an asset, for the purposes of impairment analysis, requires the exercise of judgment. Circumstances that could significantly alter the calculation of fair value or the recoverable amount of an asset may include significant changes in the regulatory environment, the business climate, management's plans, legal factors, market price of the asset, the use of the asset, the physical condition of the asset, future market prices, competition and many other factors over the life of the asset. Any resulting impairment loss is highly dependent on the underlying assumptions and could significantly affect Eastern Energy Gas' results of operations.

Income Taxes

In determining Eastern Energy Gas' income taxes, management is required to interpret complex income tax laws and regulations, which includes consideration of regulatory implications imposed by the FERC. Eastern Energy Gas' income tax returns are subject to continuous examinations by federal, state and local income tax authorities that may give rise to different interpretations of these complex laws and regulations. Due to the nature of the examination process, it generally takes years before these examinations are completed and these matters are resolved. Eastern Energy Gas recognizes the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the Consolidated Financial Statements from such a position are measured based on the largest benefit that is more-likely-than-not to be realized upon ultimate settlement. Although the ultimate resolution of Eastern Energy Gas' federal, state and local income tax examinations is uncertain, Eastern Energy Gas believes it has made adequate provisions for these income tax positions. The aggregate amount of any additional income tax liabilities that may result from these examinations is not expected to have a material impact on Eastern Energy Gas' consolidated financial results. Refer to Eastern Energy Gas' Note 9 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding Eastern Energy Gas' income taxes.

It is probable that Eastern Energy Gas will pass income tax benefit and expense related to the federal tax rate change from 35% to 21%, certain property-related basis differences and other various differences on to their customers. As of December 31, 2025, these amounts were recognized as a net regulatory liability of $404 million and will be included in regulated rates when the temporary differences reverse.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Eastern Energy Gas' Consolidated Balance Sheets include assets and liabilities with fair values that are subject to market risks. Eastern Energy Gas' significant market risks are primarily associated with interest rates, foreign currency and the extension of credit to counterparties with which Eastern Energy Gas transacts. The following discussion addresses the significant market risks associated with Eastern Energy Gas' business activities. Eastern Energy Gas has established guidelines for credit risk management. Refer to Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding Eastern Energy Gas' contracts accounted for as derivatives.

Interest Rate Risk

Eastern Energy Gas is exposed to interest rate risk on its outstanding variable-rate short- and long-term debt and future debt issuances. Eastern Energy Gas manages its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. As a result of the fixed interest rates, Eastern Energy Gas' fixed-rate long-term debt does not expose Eastern Energy Gas to the risk of loss due to changes in market interest rates. Additionally, because fixed-rate long-term debt is not carried at fair value on the Consolidated Balance Sheets, changes in fair value would impact earnings and cash flows only if Eastern Energy Gas were to reacquire all or a portion of these instruments prior to their maturity. The nature and amount of Eastern Energy Gas' short- and long-term debt can be expected to vary from period to period as a result of future business requirements, market conditions and other factors. Refer to Note 8 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional discussion of Eastern Energy Gas' long-term debt.

As of December 31, 2025 and 2024, Eastern Energy Gas had no short- and long-term variable-rate obligations that expose Eastern Energy Gas to the risk of increased interest expense in the event of increases in short-term interest rates.

Eastern Energy Gas holds foreign currency swaps with the purpose of hedging the foreign currency exchange risk associated with Euro denominated debt. As of December 31, 2025 and 2024, Eastern Energy Gas had €250 million in aggregate notional amounts of these foreign currency swaps outstanding. A hypothetical 10% decrease in market interest rates would not have resulted in a material decrease in fair value of Eastern Energy Gas' foreign currency swaps as of December 31, 2025 and 2024.

The impact of a change in interest rates on the Eastern Energy Gas' interest rate-based financial derivative instruments at a point in time is not necessarily representative of the results that will be realized when the contracts are ultimately settled. Net gains and/or losses from interest rate derivative instruments used for hedging purposes, to the extent realized, will generally be offset by recognition of the hedged transaction.

Credit Risk

Eastern Energy Gas is exposed to counterparty credit risk associated with natural gas transmission and storage service contracts with utilities, natural gas producers, power generators, industrials, energy marketing companies, financial institutions and other market participants. Credit risk may be concentrated to the extent Eastern Energy Gas' counterparties have similar economic, industry or other characteristics and due to direct and indirect relationships among the counterparties. Before entering into a transaction, Eastern Energy Gas analyzes the financial condition of each wholesale counterparty, establishes limits on the amount of unsecured credit to be extended to each counterparty and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate counterparty credit risk, Eastern Energy Gas obtains third-party guarantees, letters of credit, financial guarantee bonds and cash deposits. If required, Eastern Energy Gas exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

Eastern Energy Gas' gross credit exposure for each counterparty is calculated as outstanding receivables plus any unrealized on- or off-balance sheet exposure, taking into account contractual netting rights. Gross credit exposure is calculated prior to the application of collateral. As of December 31, 2025, Eastern Energy Gas' credit exposure totaled $35 million. Of this amount, investment grade counterparties, including those internally rated, represented 100%, and no single counterparty exceeded $10 million of the credit exposure.

Item 8. Financial Statements and Supplementary Data

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Eastern Energy Gas Holdings, LLC

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Eastern Energy Gas Holdings, LLC and subsidiaries ("Eastern Energy Gas") as of December 31, 2025 and 2024, the related consolidated statements of operations, comprehensive income, changes in equity, and cash flows, for each of the three years in the period ended December 31, 2025, 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 Eastern Energy Gas as of December 31, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of Eastern Energy Gas' management. Our responsibility is to express an opinion on Eastern Energy Gas' financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to Eastern Energy Gas 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. Eastern Energy Gas is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of Eastern Energy Gas' internal control over financial reporting. Accordingly, we express no such opinion.

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 Board of Directors 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 — Effects of Rate Regulation on the Financial Statements — Refer to Notes 2 and 6 to the Financial Statements

Critical Audit Matter Description

Eastern Energy Gas, through its subsidiaries, is subject to rate regulation by the Federal Energy Regulatory Commission (the "FERC"), which has jurisdiction with respect to the rates of interstate natural gas transmission companies in the respective service territories where Eastern Energy Gas operates. Management has determined its regulated operations meet the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. Accounting for the economic effects of rate regulation has a pervasive effect on the financial statements.

Revenue provided by the Eastern Energy Gas interstate natural gas transmission operations is based primarily on rates approved by the FERC. Eastern Energy Gas defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur. Eastern Energy Gas continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future rates by considering factors such as a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation, other regulatory actions or the impact of competition that could limit Eastern Energy Gas' ability to recover its costs. The evaluation reflects the current political and regulatory climate. If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the regulatory assets and liabilities will be recognized in net income, returned to customers, or re-established as accumulated other comprehensive income (loss).

We identified the effects of rate regulation on the financial statements 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 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) a refund to customers. Given that management's accounting judgments are based on assumptions about the outcome of decisions by the FERC, 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 decisions by the FERC included the following, among others:

- We evaluated Eastern Energy Gas' disclosures related to the effects of rate regulation by testing recorded balances and evaluating regulatory developments.

- We read relevant regulatory orders issued by the FERC, regulatory statutes, filings made by Eastern Energy Gas and other external information. We evaluated relevant external information and compared it to certain recorded regulatory asset and liability balances for completeness.

- For certain regulatory matters, we inspected Eastern Energy Gas' filings with the FERC, and the filings with the FERC by intervenors to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedents of the FERC's treatment of similar costs under similar circumstances.

/s/ Deloitte & Touche LLP

Richmond, Virginia
February 27, 2026

We have served as Eastern Energy Gas' auditor since 2012.

EASTERN ENERGY GAS HOLDINGS, LLC AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2025	**2024**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 80	$ 34
Trade receivables, net	191	189
Receivables from affiliates	20	33
Notes receivable from affiliates	513	—
Inventories	155	143
Prepayments and other deferred charges	78	85
Natural gas imbalances	66	71
Other current assets	92	52
Total current assets	1,195	607
Property, plant and equipment, net	10,363	10,338
Goodwill	1,286	1,286
Investments	255	261
Other assets	98	85
Total assets	$ 13,197	$ 12,577

The accompanying notes are an integral part of these consolidated financial statements.

EASTERN ENERGY GAS HOLDINGS, LLC AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (continued)
(Amounts in millions)

	As of December 31,	
	2025	**2024**
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 87	$ 86
Accounts payable to affiliates	27	33
Accrued interest	58	25
Accrued property, income and other taxes	141	291
Regulatory liabilities	46	29
Current portion of long-term debt	293	—
Other current liabilities	81	83
Total current liabilities	733	547
Long-term debt	4,161	3,231
Regulatory liabilities	620	627
Deferred income taxes	621	498
Other long-term liabilities	115	139
Total liabilities	6,250	5,042
Commitments and contingencies (Note 14)		
Equity:		
Members' equity:		
Membership interests	5,736	6,300
Accumulated other comprehensive loss, net	(31)	(35)
Total members' equity	5,705	6,265
Noncontrolling interests	1,242	1,270
Total equity	6,947	7,535
Total liabilities and equity	$ 13,197	$ 12,577

The accompanying notes are an integral part of these consolidated financial statements.

EASTERN ENERGY GAS HOLDINGS, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2025	**2024**	**2023**
Operating revenue	$ 2,092	$ 2,011	$ 2,059
Operating expenses:			
Cost of gas	1	7	38
Operations and maintenance	580	573	590
Depreciation and amortization	350	336	322
Property and other taxes	141	133	134
Total operating expenses	1,072	1,049	1,084
Operating income	1,020	962	975
Other income (expense):			
Interest expense	(221)	(141)	(146)
Allowance for borrowed funds	3	4	2
Allowance for equity funds	12	9	8
Interest and dividend income	22	14	30
Other, net	4	1	(3)
Total other income (expense)	(180)	(113)	(109)
Income before income tax expense (benefit) and equity income (loss)	840	849	866
Income tax expense (benefit)	172	200	110
Equity income (loss)	50	72	74
Net income	718	721	830
Net income attributable to noncontrolling interests	139	130	356
Net income attributable to Eastern Energy Gas	$ 579	$ 591	$ 474

The accompanying notes are an integral part of these consolidated financial statements.

EASTERN ENERGY GAS HOLDINGS, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Amounts in millions)

	Years Ended December 31,		
	2025	**2024**	**2023**
Net income	$ 718	$ 721	$ 830
Other comprehensive income, net of tax:			
Unrecognized amounts on retirement benefits, net of tax of $—, $— and $(1)	1	1	(2)
Unrealized gains on cash flow hedges, net of tax of $1, $1 and $3	3	4	5
Total other comprehensive income, net of tax	4	5	3
Comprehensive income	722	726	833
Comprehensive income attributable to noncontrolling interests	139	130	356
Comprehensive income attributable to Eastern Energy Gas	$ 583	$ 596	$ 477

The accompanying notes are an integral part of these consolidated financial statements.

EASTERN ENERGY GAS HOLDINGS, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(Amounts in millions)

	Membership Interests	Accumulated Other Comprehensive Loss, Net	Noncontrolling Interests	Total Equity
Balance, December 31, 2022	$ 3,983	$ (42)	$ 3,947	$ 7,888
Net income	474	—	356	830
Other comprehensive income	—	3	—	3
Distributions	(556)	—	(388)	(944)
Contributions	2,931	—	—	2,931
Purchase of Cove Point noncontrolling interest (Note 3)	(559)	(1)	(2,620)	(3,180)
Balance, December 31, 2023	6,273	(40)	1,295	7,528
Net income	591	—	130	721
Other comprehensive income	—	5	—	5
Distributions	(683)	—	(155)	(838)
Contributions	119	—	—	119
Balance, December 31, 2024	6,300	(35)	1,270	7,535
Net income	579	—	139	718
Other comprehensive income	—	4	—	4
Distributions	(1,373)	—	(167)	(1,540)
Contributions	230	—	—	230
Balance, December 31, 2025	$ 5,736	$ (31)	$ 1,242	$ 6,947

The accompanying notes are an integral part of these consolidated financial statements.

EASTERN ENERGY GAS HOLDINGS, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Amounts in millions)

	Years Ended December 31,		
	2025	**2024**	**2023**
Cash flows from operating activities:			
Net income	$ 718	$ 721	$ 830
Adjustments to reconcile net income to net cash flows from operating activities:			
Losses (gains) on other items, net	2	5	(3)
Depreciation and amortization	350	336	322
Allowance for equity funds	(12)	(9)	(8)
Equity (income) loss, net of distributions	(3)	20	(1)
Changes in regulatory assets and liabilities	(23)	1	(91)
Deferred income taxes	119	126	353
Other, net	2	3	(5)
Changes in other operating assets and liabilities:			
Trade receivables and other assets	25	29	(9)
Receivables from affiliates	(14)	(8)	3
Gas balancing activities	13	8	22
Derivative collateral, net	—	—	1
Accrued property, income and other taxes	13	35	(232)
Accounts payable to affiliates	(6)	(12)	35
Accounts payable and other liabilities	33	10	(19)
Net cash flows from operating activities	1,217	1,265	1,198
Cash flows from investing activities:			
Capital expenditures	(370)	(376)	(365)
Proceeds from assignment of shale development rights	—	—	8
Proceeds from sales of marketable securities	11	3	—
Issuance of notes receivable to affiliates	(530)	(305)	(198)
Repayment of notes receivable by affiliates	17	305	734
Other, net	6	1	(2)
Net cash flows from investing activities	(866)	(372)	177
Cash flows from financing activities:			
Proceeds from long-term debt	1,187	1,041	—
Repayments of long-term debt	—	(1,050)	(650)
(Repayment) issuance of notes payable to affiliates, net	—	(400)	400
Proceeds from equity contributions	—	—	2,893
Purchase of Cove Point noncontrolling interest	—	—	(3,300)
Distributions to noncontrolling interests	(167)	(155)	(388)
Distributions to parent	(1,319)	(361)	(332)
Net cash flows from financing activities	(299)	(925)	(1,377)
Net change in cash and cash equivalents and restricted cash and cash equivalents	52	(32)	(2)
Cash and cash equivalents and restricted cash and cash equivalents at beginning of period	61	93	95
Cash and cash equivalents and restricted cash and cash equivalents at end of period	$ 113	$ 61	$ 93

The accompanying notes are an integral part of these consolidated financial statements.

(1) Organization and Operations

Eastern Energy Gas Holdings, LLC is a holding company, and together with its subsidiaries ("Eastern Energy Gas") conducts business activities consisting of Federal Energy Regulatory Commission ("FERC")-regulated interstate natural gas transmission systems and underground storage operations in the eastern region of the U.S. and operates Cove Point LNG, LP ("Cove Point"), a liquefied natural gas ("LNG") export, import and storage facility. Eastern Energy Gas holds 100% of the general partner interest and 75% of the limited partner interests of Cove Point. In addition, Eastern Energy Gas holds a 50% noncontrolling interest in Iroquois Gas Transmission System, L.P. ("Iroquois"), a 414-mile FERC-regulated interstate natural gas transmission system. Eastern Energy Gas is an indirect wholly owned subsidiary of Berkshire Hathaway Energy Company ("BHE"). BHE is a holding company based in Des Moines, Iowa that has investments in subsidiaries principally engaged in energy businesses. BHE is a wholly owned subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

(2) Summary of Significant Accounting Policies

Basis of Consolidation and Presentation

The Consolidated Financial Statements include the accounts of Eastern Energy Gas and its subsidiaries in which it holds a controlling financial interest as of the financial statement date. Eastern Energy Gas consolidates variable interest entities ("VIE") in which it possesses both (i) the power to direct the activities that most significantly impact the entity's economic performance and (ii) the obligation to absorb losses or receive benefits from the entity that could potentially be significant to the VIE. Intercompany accounts and transactions have been eliminated.

Use of Estimates in Preparation of Financial Statements

The preparation of the Consolidated Financial Statements in conformity with accounting principles generally accepted in the United States of America ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the period. These estimates include, but are not limited to, the effects of regulation; impairment of goodwill; recovery of long-lived assets; certain assumptions made in accounting for pension and other postretirement benefits; asset retirement obligations ("AROs"); income taxes; unbilled revenue; valuation of certain financial assets and liabilities, including derivative contracts; and accounting for contingencies. Actual results may differ from the estimates used in preparing the Consolidated Financial Statements.

Accounting for the Effects of Certain Types of Regulation

Eastern Energy Gas prepares its Consolidated Financial Statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, Eastern Energy Gas defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur.

If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the related regulatory assets and liabilities will be recognized in net income, returned to customers or re-established as accumulated other comprehensive income (loss) ("AOCI").

Fair Value Measurements

As defined under GAAP, fair value is the price that would be received to sell an asset or paid to transfer a liability between market participants in the principal market or in the most advantageous market when no principal market exists. Adjustments to transaction prices or quoted market prices may be required in illiquid or disorderly markets in order to estimate fair value. Alternative valuation techniques may be appropriate under the circumstances to determine the value that would be received to sell an asset or paid to transfer a liability in an orderly transaction. Market participants are assumed to be independent, knowledgeable, able and willing to transact an exchange and not under duress. Nonperformance or credit risk is considered when determining fair value. Considerable judgment may be required in interpreting market data used to develop the estimates of fair value. Accordingly, estimates of fair value presented herein are not necessarily indicative of the amounts that could be realized in a current or future market exchange.

Cash and Cash Equivalents and Restricted Cash and Cash Equivalents

Cash equivalents consist of funds invested in money market mutual funds, U.S. Treasury Bills and other investments with a maturity of three months or less when purchased. Cash and cash equivalents exclude amounts where availability is restricted by legal requirements, loan agreements or other contractual provisions. Restricted cash and cash equivalents consist of customer deposits as allowed under the FERC gas tariffs. A reconciliation of cash and cash equivalents and restricted cash and cash equivalents as of December 31, 2025 and 2024, as presented on the Consolidated Statements of Cash Flows is outlined below and disaggregated by the line items in which they appear on the Consolidated Balance Sheets (in millions):

	As of December 31,	
	2025	**2024**
Cash and cash equivalents	$ 80	$ 34
Restricted cash and cash equivalents included in other current assets	33	27
Total cash and cash equivalents and restricted cash and cash equivalents	$ 113	$ 61

Investments

Trading securities are carried at fair value with realized and unrealized gains and losses recognized in earnings.

Equity Method Investments

Eastern Energy Gas utilizes the equity method of accounting with respect to investments when it possesses the ability to exercise significant influence, but not control, over the operating and financial policies of the investee. The ability to exercise significant influence is presumed when the investor possesses more than 20% of the voting interests of the investee. This presumption may be overcome based on specific facts and circumstances that demonstrate that the ability to exercise significant influence is restricted. In applying the equity method, Eastern Energy Gas records the investment at cost and subsequently increases or decreases the carrying value of the investment by Eastern Energy Gas' share of the net earnings or losses and other comprehensive income ("OCI") of the investee. Eastern Energy Gas records dividends or other equity distributions as reductions in the carrying value of the investment.

Allowance for Credit Losses

Trade receivables are primarily short-term in nature with stated collection terms of less than one year from the date of origination and are stated at the outstanding principal amount, net of an estimated allowance for credit losses. The allowance for credit losses is based on Eastern Energy Gas' assessment of the collectability of amounts owed to Eastern Energy Gas by its customers. This assessment requires judgment regarding the ability of customers to pay or the outcome of any pending disputes. In measuring the allowance for credit losses for trade receivables, Eastern Energy Gas primarily utilizes credit loss history. However, Eastern Energy Gas may adjust the allowance for credit losses to reflect current conditions and reasonable and supportable forecasts that deviate from historical experience. As of December 31, 2025 and 2024, the allowance for credit losses was insignificant and is included in trade receivables, net on the Consolidated Balance Sheets.

Derivatives

Eastern Energy Gas employs a number of different derivative contracts, which may include forwards, futures, options, swaps and other agreements, to manage its commodity price, interest rate and foreign currency exchange rate risks. Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. Derivative balances reflect offsetting permitted under master netting agreements with counterparties and cash collateral paid or received under such agreements. Cash collateral received from or paid to counterparties to secure derivative contract assets or liabilities in excess of amounts offset is included in other current assets or other current liabilities on the Consolidated Balance Sheets.

Commodity derivatives used in normal business operations that are settled by physical delivery, among other criteria, are eligible for and may be designated as normal purchases or normal sales. Normal purchases or normal sales contracts are not marked-to-market and settled amounts are recognized as operating revenue or cost of gas on the Consolidated Statements of Operations.

For Eastern Energy Gas' derivatives not designated as hedging contracts, unrealized gains and losses are recognized on the Consolidated Statements of Operations as operating revenue for derivatives related to natural gas sales contracts.

For Eastern Energy Gas' derivatives designated as hedging contracts, Eastern Energy Gas formally assesses, at inception and thereafter, whether the hedging contract is highly effective in offsetting changes in the hedged item. Eastern Energy Gas formally documents hedging activity by transaction type and risk management strategy. For derivative instruments that are accounted for as cash flow hedges or fair value hedges, the cash flows from the derivatives and from the related hedged items are classified in operating cash flows.

Changes in the estimated fair value of a derivative contract designated and qualified as a cash flow hedge, to the extent effective, are included on the Consolidated Statements of Changes in Equity as AOCI, net of tax, until the contract settles and the hedged item is recognized in earnings. Eastern Energy Gas discontinues hedge accounting prospectively when it has determined that a derivative contract no longer qualifies as an effective hedge, or when it is no longer probable that the hedged forecasted transaction will occur. When hedge accounting is discontinued because the derivative contract no longer qualifies as an effective hedge, future changes in the estimated fair value of the derivative contract are charged to earnings. Gains and losses related to discontinued hedges that were previously recorded in AOCI will remain in AOCI until the contract settles and the hedged item is recognized in earnings, unless it becomes probable that the hedged forecasted transaction will not occur at which time associated deferred amounts in AOCI are immediately recognized in earnings.

Inventories

Inventories consist mainly of materials and supplies and are determined using the average cost method.

Natural Gas Imbalances

Natural gas imbalances occur when the physical amount of natural gas delivered from, or received by, a pipeline system or storage facility differs from the contractual amount of natural gas delivered or received. Eastern Energy Gas values these imbalances due to, or from, shippers and operators at an appropriate index price at period end, subject to the terms of its tariff for regulated entities. Imbalances are primarily settled in-kind. Imbalances due to Eastern Energy Gas from other parties are reported in natural gas imbalances and imbalances that Eastern Energy Gas owes to other parties are reported in other current liabilities on the Consolidated Balance Sheets.

Property, Plant and Equipment, Net

General

Additions to property, plant and equipment are recorded at cost. Eastern Energy Gas capitalizes all construction-related materials, direct labor and contract services, as well as indirect construction costs. Indirect construction costs include capitalized interest, including debt allowance for funds used during construction ("AFUDC"), and equity AFUDC, as applicable. The cost of additions and betterments are capitalized, while costs incurred that do not improve or extend the useful lives of the related assets are generally expensed.

Depreciation and amortization are generally computed by applying the composite or straight-line method based on estimated useful lives. Depreciation studies are completed by Eastern Energy Gas for its regulated property, plant and equipment to determine the appropriate group lives, net salvage and group depreciation rates. These studies are reviewed and rates are ultimately approved by the FERC. Net salvage includes the estimated future residual values of the assets and any estimated removal costs recovered through approved depreciation rates. Estimated removal costs are recorded as either a cost of removal regulatory liability or an ARO liability on the Consolidated Balance Sheets, depending on whether the obligation meets the requirements of an ARO. As actual removal costs are incurred, the associated liability is reduced.

Generally when Eastern Energy Gas retires or sells a component of regulated property, plant and equipment, it charges the original cost, net of any proceeds from the disposition, to accumulated depreciation. Any gain or loss on disposals of all other assets is recorded through earnings.

Debt and equity AFUDC, which represent the estimated costs of debt and equity funds necessary to finance the construction of regulated facilities, is capitalized by Eastern Energy Gas as a component of property, plant and equipment, with offsetting credits to the Consolidated Statements of Operations. AFUDC is computed based on guidelines set forth by the FERC. After construction is completed, Eastern Energy Gas is permitted to earn a return on these costs as a component of the related assets, as well as recover these costs through depreciation expense over the useful lives of the related assets.

Asset Retirement Obligations

Eastern Energy Gas recognizes AROs when it has a legal obligation to perform decommissioning, reclamation or removal activities upon retirement of an asset. Eastern Energy Gas' AROs are primarily related to the obligations associated with its interstate natural gas transmission and storage well assets. The fair value of an ARO liability is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made, and is added to the carrying amount of the associated asset, which is then depreciated over the remaining useful life of the asset. Subsequent to the initial recognition, the ARO liability is adjusted for any revisions to the original estimate of undiscounted cash flows (with corresponding adjustments to property, plant and equipment, net) and for accretion of the ARO liability due to the passage of time. For Eastern Energy Gas, the difference between the ARO liability, the corresponding ARO asset included in property, plant and equipment, net and amounts recovered in rates to satisfy such liabilities is recorded as a regulatory asset or liability.

Impairment

Eastern Energy Gas evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or when the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Consolidated Statements of Operations. As a majority of all property, plant and equipment is used in regulated businesses, the impacts of regulation are considered when evaluating the carrying value of regulated assets.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of identifiable net assets acquired in business combinations. Eastern Energy Gas evaluates goodwill for impairment at least annually and completed its annual review as of October 31, 2025. When evaluating goodwill for impairment, Eastern Energy Gas estimates the fair value of its reporting unit. If the carrying amount of a reporting unit, including goodwill, exceeds the estimated fair value, then the excess is charged to earnings as an impairment loss. Significant judgment is required in estimating the fair value of the reporting unit and performing goodwill impairment tests. The determination of fair value incorporates significant unobservable inputs. During 2025, 2024 and 2023, Eastern Energy Gas did not record any goodwill impairments.

Eastern Energy Gas records goodwill adjustments for changes to the purchase price allocation prior to the end of the measurement period, which is not to exceed one year from the acquisition date.

Revenue Recognition

Eastern Energy Gas uses a single five-step model to identify and recognize revenue from contracts with customers ("Customer Revenue") upon transfer of control of promised goods or services in an amount that reflects the consideration to which Eastern Energy Gas expects to be entitled in exchange for those goods or services. Eastern Energy Gas records sales and excise taxes collected directly from customers and remitted directly to the taxing authorities on a net basis on the Consolidated Statements of Operations.

A majority of Eastern Energy Gas' Customer Revenue is derived from tariff-based sales arrangements approved by the FERC. These tariff-based revenues are mainly comprised of natural gas transmission and storage services and have performance obligations which are satisfied over time as services are provided. Eastern Energy Gas' revenue that is nonregulated primarily relates to LNG terminalling services and have performance obligations which are satisfied over time as services are provided.

Revenue recognized is equal to the value to the customer of Eastern Energy Gas' performance to date and includes billed and unbilled amounts. As of December 31, 2025 and 2024, trade receivables, net on the Consolidated Balance Sheets relate substantially to Customer Revenue, including unbilled revenue of $13 million and $12 million, respectively. Payments for amounts billed are generally due from the customer within 30 days of billing. Rates charged for energy products and services are established by regulators or contractual arrangements that establish the transaction price as well as the allocation of price amongst the separate performance obligations. When preliminary regulated rates are permitted to be billed prior to final approval by the applicable regulator, certain revenue collected may be subject to refund and a liability for estimated refunds is accrued. In the event one of the parties to a contract has performed before the other, Eastern Energy Gas would recognize a contract asset or contract liability depending on the relationship between Eastern Energy Gas' performance and the customer's payment. Eastern Energy Gas has recognized contract assets of $6 million and $7 million as of December 31, 2025 and 2024, respectively, and $43 million and $40 million of contract liabilities as of December 31, 2025 and 2024, respectively, due to Eastern Energy Gas' performance on certain contracts. Eastern Energy Gas recognizes revenue as it fulfills its obligations to provide services to its customers. For each of the years ended December 31, 2025 and 2024, Eastern Energy Gas recognized revenue of $13 million from the beginning contract liability balances.

Unamortized Debt Premiums, Discounts and Debt Issuance Costs

Premiums, discounts and debt issuance costs incurred for the issuance of long-term debt are amortized over the term of the related financing using the effective interest method.

Income Taxes

Berkshire Hathaway includes Eastern Energy Gas in its consolidated U.S. federal income tax return. Consistent with established regulatory practice, Eastern Energy Gas' provision for income taxes has been computed on a stand-alone basis.

Deferred income tax assets and liabilities are based on differences between the financial statement and income tax basis of assets and liabilities using enacted income tax rates expected to be in effect for the year in which the differences are expected to reverse. Changes in deferred income tax assets and liabilities associated with components of OCI are charged or credited directly to OCI. Changes in deferred income tax assets and liabilities associated with certain property-related basis differences and other various differences that Eastern Energy Gas' regulated businesses deems probable to be passed on to its customers are charged or credited directly to a regulatory asset or liability and will be included in regulated rates when the temporary differences reverse. Other changes in deferred income tax assets and liabilities are included as a component of income tax expense. Changes in deferred income tax assets and liabilities attributable to changes in enacted income tax rates are charged or credited to income tax expense or a regulatory asset or liability in the period of enactment. Valuation allowances are established when necessary to reduce deferred income tax assets to the amount that is more-likely-than-not to be realized.

Eastern Energy Gas recognizes the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the Consolidated Financial Statements from such a position are measured based on the largest benefit that is more-likely-than-not to be realized upon ultimate settlement. Estimated interest and penalties, if any, related to uncertain tax positions are included as a component of income tax expense (benefit) on the Consolidated Statements of Operations.

Segment Information

Eastern Energy Gas currently has one reportable segment, which includes its natural gas transmission, storage and LNG operations. Eastern Energy Gas' chief operating decision maker ("CODM") is the BHE Pipeline Group (which consists primarily of BHE GT&S, LLC and its subsidiaries ("BHE GT&S"), Northern Natural Gas Company and Kern River Gas Transmission Company) President and Chief Executive Officer. The CODM uses net income attributable to Eastern Energy Gas, as reported on the Consolidated Statements of Operations, and generally considers actual results versus historical results, budgets or forecast, as well as unique risks and opportunities, when making decisions about the allocation of resources and capital. The segment expenses regularly provided to the CODM align with the captions presented on the Consolidated Statements of Operations. The measure of segment assets is reported on the Consolidated Balance Sheets as total assets.

New Accounting Pronouncements

In December 2023, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2023-09, Income Taxes Topic 740, "Income Tax—Improvements to Income Tax Disclosures" which requires enhanced disclosures, including specific categories and disaggregation of information in the effective tax rate reconciliation, disaggregated information related to income taxes paid, income or loss from continuing operations before income tax expense or benefit, and income tax expense or benefit from continuing operations. This guidance is effective for annual reporting periods beginning after December 15, 2024. Early adoption is permitted and should be applied on a prospective basis, however retrospective application is permitted. Eastern Energy Gas adopted this guidance for the fiscal year beginning January 1, 2025, under the retrospective method. The adoption did not have a material impact on Eastern Energy Gas' Consolidated Financial Statements, but did expand the disclosures included within Notes to Consolidated Financial Statements. Refer to Note 9 for expanded rate reconciliation disclosures and disaggregation of income taxes paid.

In November 2024, the FASB issued ASU No. 2024-03, Income Statement—Reporting Comprehensive Income—Expense Disaggregation Disclosures Subtopic 220-40, "Disaggregation of Income Statement Expenses" which addresses requests from investors for more detailed information about certain expenses and requires disclosure of the amounts of purchases of inventory, employee compensation, depreciation and intangible asset amortization included in each relevant expense caption presented on the income statement. This guidance, as clarified in ASU 2025-01, is effective for annual reporting periods beginning after December 15, 2026 and interim reporting periods beginning after December 15, 2027. Early adoption is permitted and should be applied on a prospective basis, however retrospective application is permitted. Eastern Energy Gas is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

(3) Business Acquisitions

On September 1, 2023, BHE and Eastern MLP Holding Company II, LLC ("the Buyer"), a wholly owned subsidiary of Eastern Energy Gas, completed the acquisition of DECP Holdings, Inc.'s, an indirect wholly owned subsidiary of Dominion Energy, Inc., 50% limited partner interests in Cove Point ("The Transaction"). Under the terms of the Purchase and Sale Agreement, dated July 9, 2023, the Buyer paid $3.3 billion in cash, plus the pro rata portion of the quarterly distribution made by Cove Point for the third fiscal quarter of 2023. Eastern Energy Gas funded the Transaction through cash provided by BHE GT&S, which included an equity contribution of $2.9 billion and the repayment of affiliated notes of $474 million. The Buyer now holds 75% of the limited partner interests, and its affiliate, Cove Point GP Holding Company, LLC, continues to hold 100% of the general partner interest, of Cove Point. Prior to the Transaction, Eastern Energy Gas held 100% of the general partner interest and 25% of the limited partner interests in Cove Point. Eastern Energy Gas previously determined it has the power to direct the activities that most significantly impact Cove Point's economic performance as well as the obligation to absorb losses and benefits which could be significant to it and accordingly, consolidated Cove Point. Because Eastern Energy Gas controls Cove Point both before and after the Transaction, the changes in Eastern Energy Gas' interest in Cove Point were accounted for as an equity transaction and no gain or loss was recognized. In connection with the Transaction, Eastern Energy Gas recognized $120 million of income taxes in equity primarily attributable to the step up in tax basis of the investment in Cove Point of $144 million, partially offset by establishing additional regulatory liabilities related to excess deferred income taxes of $24 million.

(4) Property, Plant and Equipment, Net

Property, plant and equipment, net consists of the following as of December 31 (in millions):

	Depreciable Life	2025	2024
Utility Plant:			
Interstate natural gas transmission assets	34 - 51 years	$ 6,599	$ 6,461
Storage assets	47 - 79 years	2,856	2,767
Intangible plant and other assets	4 - 53 years	514	482
Utility plant in-service		9,969	9,710
Accumulated depreciation and amortization		(3,555)	(3,381)
Utility plant in-service, net		6,414	6,329
Nonutility Plant:			
LNG facility	40 years	4,585	4,565
Accumulated depreciation and amortization		(901)	(779)
Nonutility plant, net		3,684	3,786
		10,098	10,115
Construction work- in-progress		265	223
Property, plant and equipment, net		$ 10,363	$ 10,338

Construction work-in-progress includes $255 million and $213 million as of December 31, 2025 and 2024, respectively, related to the construction of utility plant.

Assignment of Shale Development Rights

In September 2025, Eastern Gas Transmission and Storage, Inc. ("EGTS") signed an agreement to convey development rights over time to a natural gas producer for approximately 23,000 acres of Utica Shale and Point Pleasant Formation underneath one of its natural gas storage fields. The agreement provides for payments to EGTS of approximately $49 million over a period of three years, and an overriding royalty interest in gas produced from the acreage. In January 2026, EGTS conveyed approximately 7,600 acres and received proceeds of $16 million from the initial conveyance. This transaction resulted in a $16 million ($12 million after-tax) gain recorded in operations and maintenance expense in January 2026.

In June 2023, EGTS conveyed development rights to a natural gas producer for approximately 6,500 acres of Utica Shale and Point Pleasant Formation underneath one of its natural gas storage fields and received proceeds of $8 million and an overriding royalty interest in gas produced from the acreage. This transaction resulted in an $8 million ($6 million after-tax) gain, included in operations and maintenance expense in its Consolidated Statements of Operations.

(5) Jointly Owned Utility Facilities

Under joint facility ownership agreements with other utilities, Eastern Energy Gas, as a tenant in common, has undivided interests in jointly owned transmission and storage facilities. Eastern Energy Gas accounts for its proportionate share of each facility, and each joint owner has provided financing for its share of each facility. Operating costs of each facility are assigned to joint owners primarily based on their percentage of ownership. Operating costs and expenses on the Consolidated Statements of Operations include Eastern Energy Gas' share of the expenses of these facilities.

The amounts shown in the table below represent Eastern Energy Gas' share in each jointly owned facility included in property, plant and equipment, net as of December 31, 2025 (dollars in millions):

	Eastern Energy Gas' Share	Facility in Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
Ellisburg Pool	39 %	$ 35	$ 13	$ —
Ellisburg Station	50	34	10	3
Harrison	50	62	22	2
Leidy	50	160	55	3
Oakford	50	219	78	—
Total		$ 510	$ 178	$ 8

(6) Regulatory Matters

Regulatory Assets

Regulatory assets represent costs that are expected to be recovered in future regulated rates. Eastern Energy Gas' regulatory assets reflected on the Consolidated Balance Sheets consist of the following as of December 31 (in millions):

	Weighted Average Remaining Life	2025	2024
Employee benefit plans[1]	10 years	$ 24	$ 24
Gas costs[2]	1 year	25	5
Electric power cost adjustment[3]	2 years	12	4
Other	Various	13	8
Total regulatory assets		$ 74	$ 41
Reflected as:			
Other current assets		$ 30	$ 11
Other assets		44	30
Total regulatory assets		$ 74	$ 41

(1) Represents costs expected to be recovered through future rates generally over the expected remaining service period of plan participants by certain rate-regulated subsidiaries.

(2) Reflects unrecovered gas costs, which are recovered through filings with the FERC.

(3) Reflects unrecovered electric power costs, which are recovered through filings with the FERC.

Eastern Energy Gas had regulatory assets not earning a return on investment of $65 million and $37 million as of December 31, 2025 and 2024, respectively.

Regulatory Liabilities

Regulatory liabilities represent income to be recognized or amounts expected to be returned to customers in future periods. Eastern Energy Gas' regulatory liabilities reflected on the Consolidated Balance Sheets consist of the following as of December 31 (in millions):

	Weighted Average Remaining Life	2025	2024
Deferred income taxes[1]	Various	$ 404	$ 416
Other postretirement benefit costs[2]	Various	128	129
Cost of removal[3]	46 years	96	92
Other	Various	38	19
Total regulatory liabilities		$ 666	$ 656
Reflected as:			
Current liabilities		$ 46	$ 29
Noncurrent liabilities		620	627
Total regulatory liabilities		$ 666	$ 656

(1) Amounts primarily represent income tax liabilities related to the federal tax rate change from 35% to 21% that are probable to be passed on to customers, offset by income tax benefits related to certain property-related basis differences and other various differences that were previously passed on to customers and will be included in regulated rates when the temporary differences reverse.

(2) Reflects a regulatory liability for the collection of postretirement benefit costs allowed in rates in excess of expense incurred.

(3) Amounts represent estimated costs, as accrued through depreciation rates and exclusive of ARO liabilities, of removing regulated property, plant and equipment in accordance with accepted regulatory practices. Refer to Note 11 for more information.

(7) Investments and Restricted Cash and Cash Equivalents

Investments and restricted cash and cash equivalents consists of the following as of December 31 (in millions):

	2025	2024
Investments:		
Investment funds	$ 8	$ 18
Equity method investments:		
Iroquois	247	243
Total investments	255	261
Restricted cash and cash equivalents:		
Customer deposits	33	27
Total restricted cash and cash equivalents	33	27
Total investments and restricted cash and cash equivalents	$ 288	$ 288
Reflected as:		
Other current assets	$ 33	$ 27
Noncurrent assets	255	261
Total investments and restricted cash and cash equivalents	$ 288	$ 288

Equity Method Investments

Eastern Energy Gas, through subsidiaries, holds 50% of Iroquois, which owns and operates an interstate natural gas transmission system located in the states of New York and Connecticut.

As of December 31, 2025 and 2024, the carrying amount of Eastern Energy Gas' investments exceeded its share of underlying equity in net assets by $130 million. The difference reflects equity method goodwill and is not being amortized. Eastern Energy Gas received distributions from its investments of $47 million, $92 million and $73 million for the years ended December 31, 2025, 2024 and 2023, respectively.

(8) Long-term Debt

Eastern Energy Gas' long-term debt consists of the following, including unamortized premiums, discounts and debt issuance costs, as of December 31 (dollars and euros in millions):

	Par Value	2025	2024
Eastern Energy Gas:			
3.317% Senior Notes, due 2026 (€250)[1]	$ 293	$ 293	$ 259
3.00% Senior Notes, due 2029	174	173	173
3.80% Senior Notes, due 2031	150	150	150
5.80% Senior Notes, due 2035	700	694	—
4.80% Senior Notes, due 2043	54	53	53
4.60% Senior Notes, due 2044	56	56	56
3.90% Senior Notes, due 2049	27	26	26
5.65% Senior Notes, due 2054	900	892	892
6.20% Senior Notes, due 2055	500	494	—
EGTS:			
3.00% Senior Notes, due 2029	426	423	423
5.02% Senior Notes, due 2034	150	149	149
4.80% Senior Notes, due 2043	346	342	342
4.60% Senior Notes, due 2044	444	438	437
3.90% Senior Notes, due 2049	273	271	271
Total long-term debt	$ 4,493	$ 4,454	$ 3,231
Reflected as:			
Current portion of long-term debt		$ 293	$ —
Long-term debt		4,161	3,231
Total long-term debt		$ 4,454	$ 3,231

(1) The senior notes are denominated in Euros with an outstanding principal balance of €250 million and a fixed interest rate of 1.45%. Eastern Energy Gas has entered into cross currency swaps that fix USD payments for 100% of the notes. The fixed USD outstanding principal when combined with the swaps is $280 million, with fixed interest rates as of December 31, 2025 and 2024 that averaged 3.317%.

Eastern Energy Gas currently has an effective shelf registration statement filed with the U.S. Securities and Exchange Commission to issue an additional $400 million of long-term debt securities through January 2027.

Annual Payment on Long-Term Debt

The annual repayments of long-term debt for the years beginning January 1, 2026 and thereafter, are as follows (in millions):

2026	$ 293
2027	—
2028	—
2029	600
2030	—
2031 and thereafter	3,600
Total	4,493
Unamortized premium, discount and debt issuance cost	(39)
Total	$ 4,454

(9) Income Taxes

Berkshire Hathaway includes BHE and its subsidiaries in its U.S. federal income tax return and BHE includes its subsidiaries in certain state income tax returns. Consistent with established regulatory practice, Eastern Energy Gas' provision for federal and state income tax has been computed on a stand-alone basis, and substantially all of its currently payable or receivable income tax is remitted to or received from BHE pursuant to a tax allocation agreement. Income before income tax expense (benefit) and equity income (loss) as reported on the Consolidated Statements of Operations, is all domestic.

Income tax expense (benefit) consists of the following for the years ended December 31 (in millions):

	2025	2024	2023
Current:			
Federal	$ 51	$ 44	$ (236)
State	2	29	(7)
	53	73	(243)
Deferred:			
Federal	96	112	357
State	23	15	(4)
	119	127	353
Total	$ 172	$ 200	$ 110

The following table presents income taxes paid (received), net of refunds, for the years ended December 31 (in millions):

	2025	2024	2023
Jurisdiction:			
Federal	$ 201	$ (215)	$ (180)
State	4	3	—
Total[(1)]	$ 205	$ (212)	$ (180)

(1) Pursuant to a tax allocation agreement, BHE GT&S makes cash payments for income taxes, net of refunds, on behalf of Eastern Energy Gas for federal income taxes and certain state income taxes. For the years ended December 31, 2025, 2024 and 2023, Eastern Energy Gas made cash payments of $2 million, $— million and $5 million, respectively, to tax authorities, with the remaining amounts settled through non-cash equity distributions and contributions with BHE GT&S.

A reconciliation of the federal statutory income tax rate to the effective income tax rate applicable to income before income tax expense (benefit) is as follows for the years ended December 31 (amounts in millions):

	2025		2024		2023	
	Amount	Percent	Amount	Percent	Amount	Percent
U.S. federal statutory income tax rate	$ 176	21.0 %	$ 178	21.0 %	$ 182	21.0 %
State and local income taxes, net of federal income tax	20	2.4	34	4.0	(9)	(1.0)
Nontaxable or nondeductible items:						
Equity earnings	10	1.2	15	1.8	15	1.7
Non-controlling interest	(29)	(3.5)	(27)	(3.2)	(76)	(8.8)
Other, net	(1)	(0.1)	2	0.2	(1)	(0.1)
Other adjustments	(4)	(0.5)	(2)	(0.2)	(1)	(0.1)
Effective income tax rate	$ 172	20.5 %	$ 200	23.6 %	$ 110	12.7 %

The net deferred income tax liability consists of the following as of December 31 (in millions):

	2025	2024
Deferred income tax assets:		
State carryforwards	$ 25	$ 27
Employee benefits	22	25
Intangibles and goodwill	66	84
Derivatives and hedges	11	11
Deferred state income taxes	20	22
Regulatory liabilities	8	10
Other	3	2
Total deferred income tax assets	155	181
Deferred income tax liabilities:		
Property-related items	(485)	(410)
Partnership investments	(241)	(211)
Debt exchange	(44)	(47)
Regulatory assets	(6)	(6)
Other	—	(4)
Total deferred income tax liabilities	(776)	(678)
Net deferred income tax liability[(1)]	$ (621)	$ (497)

(1) As of December 31, 2024, net federal deferred income tax liability is presented in noncurrent liabilities and a $1 million net state deferred income tax asset is presented in other assets in the Consolidated Balance Sheets.

The following table provides Eastern Energy Gas' net operating loss carryforwards and expiration dates as of December 31, 2025 (in millions):

	State
Net operating loss carryforwards	$ 461
Deferred income taxes on net operating loss carryforwards	$ 25
Expiration dates	2036 - indefinite

The U.S. Internal Revenue Service has not closed or effectively settled an examination of Eastern Energy Gas' income tax returns for any tax years beginning on or after November 1, 2020. The statute of limitations for Eastern Energy Gas' states remains open for periods beginning on or after November 1, 2020. The closure of examinations, or the expiration of the statute of limitations, for state filings may not preclude the state from adjusting the state net operating loss carryforward utilized in a year for which the statute of limitations is not closed.

(10) Employee Benefit Plans

Defined Benefit Plans

Eastern Energy Gas is a participant in benefit plans sponsored by MidAmerican Energy Company ("MidAmerican Energy"), an affiliate. The MidAmerican Energy Company Retirement Plan includes a qualified pension plan ("Qualified Pension Plan") that provides pension benefits for eligible employees. The MidAmerican Energy Company Welfare Benefit Plan provides certain postretirement health care and life insurance benefits for eligible retirees ("Other Postretirement Plans") on behalf of Eastern Energy Gas. Eastern Energy Gas made $6 million, $7 million and $8 million of contributions to the MidAmerican Energy Company Retirement Plan for the years ended December 31, 2025, 2024 and 2023, respectively. Eastern Energy Gas made $1 million, $2 million and $2 million of contributions to the MidAmerican Energy Company Welfare Benefit Plan for the years ended December 31, 2025, 2024 and 2023, respectively. Contributions related to these plans are reflected as net periodic benefit cost in operations and maintenance expense in the Consolidated Statements of Operations. Amounts attributable to Eastern Energy Gas were allocated from MidAmerican Energy in accordance with the intercompany administrative service agreement. Offsetting regulatory assets and liabilities have been recorded related to the amounts not yet recognized as a component of net periodic benefit costs that will be included in regulated rates. Net periodic benefit costs not included in regulated rates are included in accumulated other comprehensive loss, net.

Defined Contribution Plan

Eastern Energy Gas participates in the MidAmerican Energy defined contribution plan. Eastern Energy Gas' matching contributions are based on each participant's level of contribution. Contributions cannot exceed the maximum allowable for tax purposes. Certain participants now receive enhanced benefits in the defined contribution plan and no longer accrue benefits in the noncontributory defined benefit pension plans. Eastern Energy Gas' contributions to the plans were $16 million, $14 million and $12 million for the years ended December 31, 2025, 2024 and 2023, respectively.

(11) Asset Retirement Obligations

Eastern Energy Gas estimates its ARO liabilities based upon detailed engineering calculations of the amount and timing of the future cash spending for a third party to perform the required work. Spending estimates are escalated for inflation and then discounted at a credit-adjusted, risk-free rate. Changes in estimates could occur for a number of reasons, including changes in laws and regulations, plan revisions, inflation and changes in the amount and timing of the expected work.

Eastern Energy Gas does not recognize liabilities for AROs for which the fair value cannot be reasonably estimated. Due to the indeterminate removal date, the fair value of the associated liabilities on the Cove Point LNG facility, interim removal of natural gas pipelines and certain storage wells in EGTS' underground natural gas storage network cannot currently be estimated, and no amounts are recognized on the Consolidated Financial Statements other than those included in the cost of removal regulatory liability established via approved depreciation rates in accordance with accepted regulatory practices. These accruals totaled $96 million and $92 million as of December 31, 2025 and 2024, respectively.

The following table reconciles the beginning and ending balances of Eastern Energy Gas' ARO liabilities for the years ended December 31 (in millions):

	2025	2024
Beginning balance	$ 28	$ 30
Change in estimated costs	2	—
Retirements	(5)	(3)
Accretion	1	1
Ending balance	$ 26	$ 28
Reflected as:		
Other current liabilities	$ 2	$ 3
Other long-term liabilities	24	25
Total ARO liability	$ 26	$ 28

(12) Risk Management and Hedging Activities

Eastern Energy Gas is exposed to the impact of market fluctuations in commodity prices, interest rates, and foreign currency exchange rates. Eastern Energy Gas is principally exposed to natural gas market fluctuations primarily through fuel retained and used during the operation of the pipeline system, to interest rate risk on its outstanding variable-rate short-term debt and future debt issuances, and to foreign currency exchange risk associated with Euro denominated debt. Eastern Energy Gas has established a risk management process that is designed to identify, assess, manage and report on each of the various types of risk involved in its business. To mitigate a portion of its commodity price risk, Eastern Energy Gas uses commodity derivative contracts, which may include forwards, futures, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. Eastern Energy Gas also uses interest rate swaps to hedge its exposure to variable interest rates on long-term debt as well as foreign currency swaps to hedge its exposure to principal and interest payments denominated in Euros. Eastern Energy Gas does not hedge all of its commodity price and interest rate risks, thereby exposing the unhedged portion to changes in market prices.

There have been no significant changes in Eastern Energy Gas' accounting policies related to derivatives. Refer to Notes 2 and 13 for additional information on derivative contracts.

Derivative Contract Volumes

The following table summarizes the combined absolute value of long and short positions of outstanding commodity and foreign currency derivative contracts with fixed price terms that comprise the mark-to-market values as of December 31 (in millions):

	Unit of Measure	2025	2024
Foreign currency	Euro €	250	250

Credit Risk

Eastern Energy Gas is exposed to counterparty credit risk associated with wholesale energy supply and marketing activities with other utilities, energy marketing companies, financial institutions and other market participants. Credit risk may be concentrated to the extent Eastern Energy Gas' counterparties have similar economic, industry or other characteristics and due to direct or indirect relationships among the counterparties. Before entering into a transaction, Eastern Energy Gas analyzes the financial condition of each significant wholesale counterparty, establishes limits on the amount of unsecured credit to be extended to each counterparty and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate wholesale counterparty credit risk, Eastern Energy Gas enters into netting and collateral arrangements that may include margining and cross-product netting agreements and obtains third-party guarantees, letters of credit and cash deposits. If required, Eastern Energy Gas exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

The majority of Cove Point's revenue and earnings are from annual reservation payments under certain terminalling, storage and transmission contracts with ST Cove Point, LLC, a joint venture of Sumitomo Corporation and Tokyo Gas Co., LTD., and GAIL Global (USA) LNG, LLC (the "Export Customers"). If such agreements were terminated and Cove Point was unable to replace such agreements on comparable terms, there could be a material impact on results of operations, financial condition and/or cash flows.

The Export Customers comprised approximately 39% of Eastern Energy Gas' operating revenues for the years ended December 31, 2025 and 2024, with Eastern Energy Gas' largest customer representing approximately 21% and 20% of such amounts, respectively.

For the year ended December 31, 2025, EGTS provided operational service to 250 customers with approximately 95% of its storage and transmission revenue being provided through firm services. The 10 largest customers provided approximately 40% of EGTS' total storage and transmission revenue and the thirty largest provided approximately 71% of EGTS' total storage and transmission revenue.

(13) Fair Value Measurements

The carrying value of Eastern Energy Gas' cash, certain cash equivalents, receivables, payables, accrued liabilities and short-term borrowings approximates fair value because of the short-term maturity of these instruments. Eastern Energy Gas has various financial assets and liabilities that are measured at fair value on the Consolidated Financial Statements using inputs from the three levels of the fair value hierarchy. A financial asset or liability classification within the hierarchy is determined based on the lowest level input that is significant to the fair value measurement. The three levels are as follows:

- Level 1 - Inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Eastern Energy Gas has the ability to access at the measurement date.
- Level 2 - Inputs include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means (market corroborated inputs).
- Level 3 - Unobservable inputs reflect Eastern Energy Gas' judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. Eastern Energy Gas develops these inputs based on the best information available, including its own data.

The following table presents Eastern Energy Gas' financial assets and liabilities recognized on the Consolidated Balance Sheets and measured at fair value on a recurring basis (in millions):

	Input Levels for Fair Value Measurements			
	Level 1	Level 2	Level 3	Total
As of December 31, 2025				
Assets:				
Foreign currency exchange rate derivatives	$ —	$ 11	$ —	$ 11
Money market mutual funds	80	—	—	80
Equity securities:				
Investment funds	8	—	—	8
	$ 88	$ 11	$ —	$ 99
As of December 31, 2024				
Assets:				
Money market mutual funds	$ 34	$ —	$ —	$ 34
Equity securities:				
Investment funds	18	—	—	18
	$ 52	$ —	$ —	$ 52
Liabilities:				
Foreign currency exchange rate derivatives	$ —	$ (23)	$ —	$ (23)
	$ —	$ (23)	$ —	$ (23)

Eastern Energy Gas' investments in money market mutual funds and investment funds are stated at fair value. When available, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value.

Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchase or normal sales and qualify for the exception afforded by GAAP. When available, the fair value of derivative contracts is estimated using unadjusted quoted prices for identical contracts in the market in which Eastern Energy Gas transacts. When quoted prices for identical contracts are not available, Eastern Energy Gas uses forward price curves. Forward price curves represent Eastern Energy Gas' estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates. Eastern Energy Gas bases its forward price curves upon market price quotations, when available, or internally developed and commercial models, with internal and external fundamental data

inputs. Market price quotations are obtained from independent brokers, exchanges, direct communication with market participants and actual transactions executed by Eastern Energy Gas. Market price quotations are generally readily obtainable for the applicable term of Eastern Energy Gas' outstanding derivative contracts; therefore, Eastern Energy Gas' forward price curves reflect observable market quotes. Market price quotations for certain natural gas trading hubs are not as readily obtainable due to the length of the contracts. Given that limited market data exists for these contracts, as well as for those contracts that are not actively traded, Eastern Energy Gas uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs that are based on unobservable inputs. The estimated fair value of these derivative contracts is a function of underlying forward commodity prices, interest rates, currency rates, related volatility, counterparty creditworthiness and duration of contracts.

Eastern Energy Gas' long-term debt is carried at cost, including unamortized premiums, discounts and debt issuance costs as applicable, on the Consolidated Financial Statements. The fair value of Eastern Energy Gas' long-term debt is a Level 2 fair value measurement and has been estimated based upon quoted market prices, where available, or at the present value of future cash flows discounted at rates consistent with comparable maturities with similar credit risks. The following table presents the carrying value and estimated fair value of Eastern Energy Gas' long-term debt as of December 31 (in millions):

	2025		2024	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 4,454	$ 4,276	$ 3,231	$ 2,919

(14) Commitments and Contingencies

Environmental Laws and Regulations

Eastern Energy Gas is subject to federal, state and local laws and regulations regarding air quality, climate change, emissions performance standards, water quality and other environmental matters that have the potential to impact its current and future operations. Eastern Energy Gas believes it is in material compliance with all applicable laws and regulations.

Legal Matters

Eastern Energy Gas is party to a variety of legal actions arising out of the normal course of business. Eastern Energy Gas does not believe that such normal and routine litigation will have a material impact on its consolidated financial results.

Surety Bonds

As of December 31, 2025, Eastern Energy Gas had purchased $17 million of surety bonds. Under the terms of the surety bonds, Eastern Energy Gas is obligated to indemnify the respective surety bond company for any amounts paid.

(15) Revenue from Contracts with Customers

The following table summarizes Eastern Energy Gas' Customer Revenue by regulated and nonregulated, with further disaggregation of regulated by line of business, for the years ended December 31 (in millions):

	2025	2024	2023
Customer Revenue:			
Regulated:			
Gas transmission and storage	$ 1,222	$ 1,197	$ 1,210
Wholesale	2	7	22
Other	—	1	5
Total regulated	1,224	1,205	1,237
Nonregulated	865	802	818
Total Customer Revenue	2,089	2,007	2,055
Other revenue[(1)]	3	4	4
Total operating revenue	$ 2,092	$ 2,011	$ 2,059

(1) Other revenue consists primarily of revenue recognized in accordance with Accounting Standards Codification ("ASC") 815, "Derivative and Hedging" which includes unrealized gains and losses for derivatives not designated as hedges related to natural gas sales contracts, contingent fees from certain farmout agreements recognized in accordance with ASC 450, "Contingencies" and the royalties from the conveyance of mineral rights accounted for under ASC 932 "Extractive Activities – Oil and Gas".

Remaining Performance Obligations

The following table summarizes Eastern Energy Gas' revenue it expects to recognize in future periods related to significant unsatisfied remaining performance obligations for fixed contracts with expected durations in excess of one year as of December 31, 2025 (in millions):

	Performance obligations expected to be satisfied		
	Less than 12 months	More than 12 months	Total
Eastern Energy Gas	$ 1,780	$ 13,049	$ 14,829

(16) Components of Accumulated Other Comprehensive Loss, Net

The following table shows the change in accumulated other comprehensive loss by each component of other comprehensive income (loss), net of applicable income taxes, for the year ended December 31 (in millions):

	Unrecognized Amounts On Retirement Benefits	Unrealized Losses On Cash Flow Hedges	Noncontrolling Interests	Accumulated Other Comprehensive Loss, Net
Balance, December 31, 2022	$ (1)	$ (43)	$ 2	$ (42)
Other comprehensive (loss) income	(2)	5	—	3
Purchase of noncontrolling interest	—	—	(1)	(1)
Balance, December 31, 2023	(3)	(38)	1	(40)
Other comprehensive income	1	4	—	5
Balance, December 31, 2024	(2)	(34)	1	(35)
Other comprehensive income	1	3	—	4
Balance, December 31, 2025	$ (1)	$ (31)	$ 1	$ (31)

The following table shows the reclassifications from AOCI to net income for the year ended December 31 (in millions):

	Amounts Reclassified From AOCI	Affected Line Item In The Consolidated Statements of Operations
2025		
Deferred (gains) and losses on derivatives-hedging activities:		
Interest rate contracts	$ 4	Interest expense
Foreign currency contracts	(35)	Other, net
Total	(31)	
Tax	8	Income tax expense (benefit)
Total, net of tax	$ (23)	
2024		
Deferred (gains) and losses on derivatives-hedging activities:		
Interest rate contracts	$ 3	Interest expense
Foreign currency contracts	17	Other, net
Total	20	
Tax	(5)	Income tax expense (benefit)
Total, net of tax	$ 15	
2023		
Deferred (gains) and losses on derivatives-hedging activities:		
Interest rate contracts	$ 3	Interest expense
Foreign currency contracts	(8)	Other, net
Total	(5)	
Tax	1	Income tax expense (benefit)
Total, net of tax	$ (4)	

The following table presents selected information related to losses on cash flow hedges included in AOCI in Eastern Energy Gas' Consolidated Balance Sheet as of December 31, 2025 (in millions):

	AOCI After-Tax	Amounts Expected to be Reclassified to Earnings During the Next 12 Months After-Tax	Maximum Term
Interest rate	$ (29)	$ (3)	228 months
Foreign currency	(2)	(2)	6 months
Total	$ (31)	$ (5)	

The amounts that will be reclassified from AOCI to earnings will generally be offset by the recognition of the hedged transactions (e.g., interest payments) in earnings, thereby achieving the realization of prices contemplated by the underlying risk management strategies and will vary from the expected amounts presented above as a result of changes in interest rates and foreign currency exchange rates.

(17) Variable Interest Entities and Noncontrolling Interests

The primary beneficiary of a VIE is required to consolidate the VIE and to disclose certain information about its significant variable interests in the VIE. The primary beneficiary of a VIE is the entity that has both (i) the power to direct the activities that most significantly impact the entity's economic performance and (ii) the obligation to absorb losses or receive benefits from the entity that could potentially be significant to the VIE.

As of December 31, 2025, Eastern Energy Gas holds 75% of the limited partner interest and holds 100% of the general partner interest of Cove Point. Eastern Energy Gas concluded that Cove Point is a VIE due to the limited partner lacking the characteristics of a controlling financial interest. Eastern Energy Gas is the primary beneficiary of Cove Point as it has the power to direct the activities that most significantly impact its economic performance as well as the obligation to absorb losses and benefits which could be significant to it.

Eastern Energy Gas purchased shared services from Carolina Gas Services, Inc. ("Carolina Gas Services") an affiliated VIE, of $3 million for the year ended December 31, 2023. Effective April 2023, Carolina Gas Services no longer provides services to Eastern Energy Gas. Eastern Energy Gas determined that neither it nor any of its consolidated entities was the primary beneficiary of Carolina Gas Services as neither it nor any of its consolidated entities had both the power to direct the activities that most significantly impacted its economic performance as well as the obligation to absorb losses and benefits which could be significant to them. Carolina Gas Services provided marketing and operational services. Neither Eastern Energy Gas nor any of its consolidated entities had any obligation to absorb more than its allocated share of Carolina Gas Services costs.

Included in noncontrolling interests in the Consolidated Financial Statements are Dominion Energy Inc.'s 50% interest in Cove Point (through August 2023) and Brookfield Super-Core Infrastructure Partner's 25% interest in Cove Point.

(18) Supplemental Cash Flow Disclosures

The summary of supplemental cash flow disclosures as of and for the years ended December 31 is as follows (in millions):

	2025	2024	2023
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	$ 184	$ 130	$ 144
Supplemental disclosure of non-cash investing and financing transactions:			
Accruals related to property, plant and equipment additions	$ 44	$ 10	$ 18
Equity distributions[(1)]	$ (54)	$ (322)	$ (224)
Equity contributions[(1)]	$ 230	$ 119	$ 38

(1) Amounts primarily represent the settlement of affiliated receivables/payables.

(19) Related Party Transactions

Eastern Energy Gas is party to a tax allocation agreement and is part of the Berkshire Hathaway consolidated U.S. federal income tax return and certain BHE consolidated state income tax returns. For current federal and state income taxes, Eastern Energy Gas had a payable to BHE of $39 million and $188 million as of December 31, 2025 and 2024, respectively.

In December 2025, EGTS completed the sale of a compressor unit to Northern Natural Gas Company, an affiliate. This transaction resulted in a $5 million ($4 million after-tax) gain, included in operations and maintenance expense in its Consolidated Statements of Operations.

Presented below are Eastern Energy Gas' significant transactions with affiliated and related parties for the years ended December 31 (in millions):

	2025	2024	2023
Sales of natural gas and transmission and storage services	$ 6	$ 4	$ 5
Services provided by related parties[(1)]	46	58	99
Services provided to related parties	36	30	35

(1) Includes capitalized expenditures.

Eastern Energy Gas participates in certain MidAmerican Energy benefit plans as described in Note 10. As of December 31, 2025 and 2024, Eastern Energy Gas' amount due to MidAmerican Energy associated with these plans and reflected in other long-term liabilities on the Consolidated Balance Sheets was $39 million.

Borrowings with BHE GT&S

Eastern Energy Gas has a $400 million intercompany revolving credit agreement from its parent, BHE GT&S, expiring in March 2027. The credit agreement, which is for general corporate purposes and provides for the issuance of letters of credit, has a variable interest rate based on the Secured Overnight Financing Rate ("SOFR") plus a fixed spread. There were no amounts outstanding under the credit agreement as of December 31, 2025 and 2024. Interest expense related to the credit agreement totaled $8 million and $4 million for the years ended December 31, 2024 and 2023, respectively.

BHE GT&S has a $650 million intercompany revolving credit agreement from Eastern Energy Gas expiring in November 2026. The credit agreement has a variable interest rate based on SOFR plus a fixed spread. Net outstanding borrowings totaled $513 million as of December 31, 2025. There were no amounts outstanding under the credit agreement as of December 31, 2024. Interest income related to the credit agreement totaled $14 million, $2 million and $20 million for the years ended December 31, 2025, 2024 and 2023, respectively.

Eastern Gas Transmission and Storage, Inc. and its subsidiaries
Consolidated Financial Section

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following is management's discussion and analysis of certain significant factors that have affected the consolidated financial condition and results of operations of EGTS during the periods included herein. This discussion should be read in conjunction with EGTS' historical Consolidated Financial Statements and Notes to Consolidated Financial Statements in Item 8 of this Form 10-K. EGTS' actual results in the future could differ significantly from the historical results.

Results of Operations

Overview

Net income for the year ended December 31, 2025 was $266 million, an increase of $10 million, or 4%, compared to 2024, primarily due to higher margin from regulated gas transmission and storage operations of $19 million and an increase in interest income from higher lending activity under Eastern Energy Gas' intercompany revolving credit agreement, partially offset by increases in depreciation and amortization, property and other taxes and operations and maintenance expenses.

Net income for the year ended December 31, 2024 was $256 million, an increase of $18 million, or 8%, compared to 2023, primarily due to lower technology and related charges, lower outside services due to the termination of Dominion Energy, Inc.'s transition services agreement and higher margin from regulated gas transmission and storage operations of $4 million, partially offset by a gain in 2023 from an agreement to convey development rights underneath one of its natural gas storage fields.

Year Ended December 31, 2025 Compared to Year Ended December 31, 2024

Operating revenue increased $13 million, or 1%, for 2025 compared to 2024, primarily due to an increase in regulated gas transmission and storage services revenues of $22 million primarily due to additional capacity contracts, partially offset by a decrease in variable revenue related to park and loan activity of $5 million and a decrease in regulated gas sales for operational and system balancing purposes primarily due to decreased volumes of $5 million.

Cost of gas decreased $6 million, or 86%, for 2025 compared to 2024, primarily due a decrease in volumes sold.

Operations and maintenance increased $4 million, or 1%, for 2025 compared to 2024, primarily due to an increase in charges from affiliates of $11 million, partially offset by a gain from the sale of a compressor unit to Northern Natural Gas of $5 million.

Depreciation and amortization increased $6 million, or 4%, for 2025 compared to 2024, primarily due to higher plant placed in-service.

Property and other taxes increased $5 million, or 9%, for 2025 compared to 2024, primarily due to higher tax assessments.

Other, net increased $6 million for 2025 compared to 2024, primarily due to an increase in interest income from higher lending activity under Eastern Energy Gas' intercompany revolving credit agreement.

Income tax expense was flat for 2025 compared to 2024 and the effective tax rate was 25% in 2025 and 2024.

Year Ended December 31, 2024 Compared to Year Ended December 31, 2023

*Operating revenu*e decreased $27 million, or 3%, for 2024 compared to 2023, primarily due to a decrease in variable revenue related to park and loan activity of $18 million, a decrease in regulated gas sales for operational and system balancing purposes due to decreased prices and volumes of $15 million and a decrease in services provided to affiliates of $7 million, partially offset by an increase in regulated gas transmission and storage services revenues of $17 million primarily due to additional capacity contracts.

Cost of gas decreased $31 million, or 82%, for 2024 compared to 2023, primarily due to the unfavorable revaluation of volumes retained in 2023.

Operations and maintenance decreased $20 million, or 5%, for 2024 compared to 2023, primarily due to lower technology and related charges of $14 million, lower outside services of $7 million due to the termination of Dominion Energy Inc.'s transition services agreement and a decrease in services provided to affiliates of $7 million, partially offset by a gain in 2023 from an agreement to convey development rights underneath one of its natural gas storage fields of $8 million.

Other, net increased $4 million for 2024 compared to 2023, largely due to ARO settlement gains resulting from the FERC order in late 2023 finalizing the remediation activities for the Supply Header Project.

Income tax expense increased $8 million, or 10%, for 2024 compared to 2023 and the effective tax rate was 25% in 2024 and 2023. The $8 million increase was primarily due to higher pre-tax income.

Liquidity and Capital Resources

As of December 31, 2025, EGTS' total net liquidity was as follows (in millions):

Cash and cash equivalents	$	10
Intercompany revolving credit agreement		400
Total net liquidity	$	410
Intercompany revolving credit agreement:		
Maturity date		2027

Refer to Note 17 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for further discussion regarding EGTS' intercompany revolving credit agreement.

EGTS' future financial performance and capital expenditures related to certain projects may be affected by the combined effects of ongoing macroeconomic and geopolitical conditions, including changes in international trade policies and tariff regimes. The pace of change in these areas accelerated during 2025, and uncertainty persists regarding the scope and duration of these external factors. However, EGTS currently does not believe these items and any resulting changes to future capital project allocations will significantly impact its business in the near term.

Operating Activities

Net cash flows from operating activities for the years ended December 31, 2025 and 2024 were $462 million and $497 million, respectively. The change was primarily due to lower collections from customers and the timing of payments for operating costs, partially offset by favorable operating results and other working capital adjustments.

Net cash flows from operating activities for the years ended December 31, 2024 and 2023 were $497 million and $418 million, respectively. The change was primarily due to the repayment of EGTS rate refunds to customers in 2023 and other changes in working capital.

Investing Activities

Net cash flows from investing activities for the years ended December 31, 2025 and 2024 were $(399) million and $(251) million, respectively. The change was primarily due to an increase in notes issued to Eastern Energy Gas under an intercompany revolving credit agreement of $128 million, an increase in capital expenditures of $30 million and a decrease in repayments of notes by Eastern Energy Gas under an intercompany revolving credit agreement of $3 million, partially offset by an increase in proceeds from sales of marketable securities of $8 million.

Net cash flows from investing activities for the years ended December 31, 2024 and 2023 were $(251) million and $(237) million, respectively. The change was primarily due to an increase in notes issued to Eastern Energy Gas under an intercompany revolving credit agreement of $25 million, an increase in capital expenditures of $14 million and proceeds from the assignment of shale development rights in 2023 of $8 million, partially offset by an increase in repayments of notes by Eastern Energy Gas under an intercompany revolving credit agreement of $25 million, an increase in proceeds from sales of marketable securities of $3 million a decrease in purchases of marketable securities of $3 million.

Financing Activities

Net cash flows from financing activities for the year ended December 31, 2025 were $(56) million and consisted of dividends paid to Eastern Energy Gas.

Net cash flows from financing activities for the year ended December 31, 2024 were $(248) million. Sources of cash totaled $162 million and consisted of proceeds from the issuance of long-term debt of $149 million and proceeds from equity contributions from Eastern Energy Gas of $13 million. Uses of cash totaled $410 million and consisted of dividends paid to Eastern Energy Gas of $297 million, repayment of long-term debt of $111 million and net repayment of notes payable to Eastern Energy Gas of $2 million.

Net cash flows from financing activities for the year ended December 31, 2023 were $(192) million and consisted of dividends paid to Eastern Energy Gas of $158 million and net repayment of notes payable to Eastern Energy Gas of $34 million.

Future Uses of Cash

Capital Expenditures

Capital expenditure needs are reviewed regularly by management and may change significantly as a result of these reviews, which may consider, among other factors, new growth projects and the timing of growth projects; changes in environmental and other rules and regulations; impacts to customers' rates; outcomes of regulatory proceedings; changes in income tax laws; general business conditions; system reliability standards; the cost and efficiency of construction labor, equipment and materials; commodity prices; and the cost and availability of capital.

EGTS' historical and forecasted capital expenditures, each of which exclude amounts for non-cash equity AFUDC and other non-cash items, for the years ending December 31 are as follows (in millions):

	Historical			Forecast		
	2023	2024	2025	2026	2027	2028
Natural gas transmission and storage	$ 16	$ 34	$ 54	$ 114	$ 258	$ 605
Other	225	221	231	350	177	179
Total	$ 241	$ 255	$ 285	$ 464	$ 435	$ 784

EGTS' natural gas transmission and storage capital expenditures primarily include growth capital expenditures related to planned regulated projects. EGTS' other capital expenditures consist primarily of pipeline integrity work, automation and controls upgrades, underground storage, corrosion control, unit exchanges, compressor modifications and projects related to Pipeline Hazardous Materials Safety Administration natural gas storage rules. The amounts also include EGTS' asset modernization program, which includes projects for vintage pipeline replacement, compression replacement, pipeline assessment and underground storage integrity.

Material Cash Requirements

The following table summarizes EGTS' material cash requirements as of December 31, 2025 (in millions):

	Payments Due by Periods				
	2026	2027-2028	2029-2030	2031 and thereafter	Total
Interest payments on long-term debt[(1)]	$ 68	$ 136	$ 123	$ 735	$ 1,062
Natural gas supply and transmission[(1)]	46	92	92	46	276
Total cash requirements	$ 114	$ 228	$ 215	$ 781	$ 1,338

(1) Not reflected on the Consolidated Balance Sheets.

In addition, EGTS also has cash requirements that may affect its consolidated financial condition that arise from operating leases (refer to Note 5), long-term debt (refer to Note 8), construction and other development costs (refer to Liquidity and Capital Resources included within this Item 7), uncertain tax positions (refer to Note 9) and AROs (refer to Note 11). Refer, where applicable, to the respective referenced note in Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

Regulatory Matters

EGTS is subject to comprehensive regulation. Refer to the discussion contained in Item 1 of this Form 10-K for further information regarding EGTS' general regulatory framework and current regulatory matters.

Environmental Laws and Regulations

EGTS is subject to federal, state and local laws and regulations regarding air quality, climate change, emissions performance standards, water quality and other environmental matters that have the potential to impact its current and future operations. In addition to imposing continuing compliance obligations and capital expenditure requirements, these laws and regulations provide regulators with the authority to levy substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. These laws and regulations are administered by various federal, state and local agencies. EGTS believes it is in material compliance with all applicable laws and regulations, although many laws and regulations are subject to interpretation that may ultimately be resolved by the courts. Environmental laws and regulations continue to evolve, and EGTS is unable to predict the impact of the changing laws and regulations on its operations and consolidated financial results.

Refer to "Environmental Laws and Regulations" in Item 1 of this Form 10-K for further discussion regarding environmental laws and regulations.

Collateral and Contingent Features

Debt of EGTS is rated by credit rating agencies. Assigned credit ratings are based on each rating agency's assessment of EGTS' ability to, in general, meet the obligations of its issued debt. The credit ratings are not a recommendation to buy, sell or hold securities, and there is no assurance that a particular credit rating will continue for any given period of time.

EGTS has no credit rating downgrade triggers that would accelerate the maturity dates of outstanding debt, and a change in ratings is not an event of default under the applicable debt instruments.

Inflation

Historically, overall inflation and changing prices in the economies where EGTS operates have not had a significant impact on EGTS' consolidated financial results. EGTS operates under cost-of-service based rate-setting structures administered by the FERC. Under these rate-setting structures, EGTS is allowed to include prudent costs in its rates, including the impact of inflation. EGTS attempts to minimize the potential impact of inflation on its operations by employing prudent risk management and hedging strategies and by considering, among other areas, its impact on purchases of energy, operating expenses, materials and equipment costs, contract negotiations, future capital spending programs and long-term debt issuances. There can be no assurance that such actions will be successful.

New Accounting Pronouncements

For a discussion of new accounting pronouncements affecting EGTS, refer to Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Critical Accounting Estimates

Certain accounting measurements require management to make estimates and judgments concerning transactions that will be settled several years in the future. Amounts recognized on the Consolidated Financial Statements based on such estimates involve numerous assumptions subject to varying and potentially significant degrees of judgment and uncertainty and will likely change in the future as additional information becomes available. The following critical accounting estimates are impacted significantly by EGTS' methods, judgments and assumptions used in the preparation of the Consolidated Financial Statements and should be read in conjunction with EGTS' Summary of Significant Accounting Policies included in EGTS' Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Accounting for the Effects of Certain Types of Regulation

EGTS prepares its Consolidated Financial Statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, EGTS defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates.

Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur.

EGTS continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future regulated rates by considering factors such as a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation, other regulatory actions or the impact of competition that could limit EGTS' ability to recover its costs. EGTS believes its application of the guidance for regulated operations is appropriate and its existing regulatory assets and liabilities are probable of inclusion in future regulated rates. The evaluation reflects the current political and regulatory climate at the federal level. If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the related regulatory assets and liabilities will be recognized in net income, returned to customers or re-established as AOCI. Total regulatory assets were $45 million and total regulatory liabilities were $533 million as of December 31, 2025. Refer to EGTS' Note 6 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding EGTS' regulatory assets and liabilities.

Impairment of Long-Lived Assets

EGTS evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or when the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Consolidated Statements of Operations. As substantially all property, plant and equipment supports EGTS' regulated businesses, the impacts of regulation are considered when evaluating the carrying value of regulated assets.

The estimate of cash flows arising from the future use of an asset, for the purposes of impairment analysis, requires the exercise of judgment. Circumstances that could significantly alter the calculation of fair value or the recoverable amount of an asset may include significant changes in the regulatory environment, the business climate, management's plans, legal factors, market price of the asset, the use of the asset, the physical condition of the asset, future market prices, competition and many other factors over the life of the asset. Any resulting impairment loss is highly dependent on the underlying assumptions and could significantly affect EGTS' results of operations.

Income Taxes

In determining EGTS' income taxes, management is required to interpret complex income tax laws and regulations, which includes consideration of regulatory implications imposed by the FERC. EGTS' income tax returns are subject to continuous examinations by federal, state and local income tax authorities that may give rise to different interpretations of these complex laws and regulations. Due to the nature of the examination process, it generally takes years before these examinations are completed and these matters are resolved. EGTS recognizes the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the Consolidated Financial Statements from such a position are measured based on the largest benefit that is more-likely-than-not to be realized upon ultimate settlement. Although the ultimate resolution of EGTS' federal, state and local income tax examinations is uncertain, EGTS believes it has made adequate provisions for these income tax positions. The aggregate amount of any additional income tax liabilities that may result from these examinations is not expected to have a material impact on EGTS' consolidated financial results. Refer to EGTS' Note 9 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding EGTS' income taxes.

It is probable that EGTS will pass income tax benefit and expense related to the federal tax rate change from 35% to 21%, certain property-related basis differences and other various differences on to their customers. As of December 31, 2025, these amounts were recognized as a net regulatory liability of $360 million and will be included in regulated rates when the temporary differences reverse.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

EGTS' Consolidated Balance Sheets include assets and liabilities with fair values that are subject to market risks. EGTS' significant market risks are primarily associated with interest rates and the extension of credit to counterparties with which EGTS transacts. The following discussion addresses the significant market risks associated with EGTS' business activities. EGTS has established guidelines for credit risk management. Refer to Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding EGTS' contracts accounted for as derivatives.

Interest Rate Risk

EGTS is exposed to interest rate risk on its outstanding variable-rate short- and long-term debt and future debt issuances. EGTS manages its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. As a result of the fixed interest rates, EGTS' fixed-rate long-term debt does not expose EGTS to the risk of loss due to changes in market interest rates. Additionally, because fixed-rate long-term debt is not carried at fair value on the Consolidated Balance Sheets, changes in fair value would impact earnings and cash flows only if EGTS were to reacquire all or a portion of these instruments prior to their maturity. The nature and amount of EGTS' short- and long-term debt can be expected to vary from period to period as a result of future business requirements, market conditions and other factors. Refer to Note 8 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional discussion of EGTS' long-term debt.

As of December 31, 2025 and 2024, EGTS had no short- and long-term variable-rate obligations that expose EGTS to the risk of increased interest expense in the event of increases in short-term interest rates.

Credit Risk

EGTS is exposed to counterparty credit risk associated with natural gas transmission and storage service contracts with utilities, natural gas producers, power generators, industrials, energy marketing companies, financial institutions and other market participants. Credit risk may be concentrated to the extent EGTS' counterparties have similar economic, industry or other characteristics and due to direct and indirect relationships among the counterparties. Before entering into a transaction, EGTS analyzes the financial condition of each wholesale counterparty, establishes limits on the amount of unsecured credit to be extended to each counterparty and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate counterparty credit risk, EGTS obtains third-party guarantees, letters of credit, financial guarantee bonds and cash deposits. If required, EGTS exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

EGTS' gross credit exposure for each counterparty is calculated as outstanding receivables plus any unrealized on- or off-balance sheet exposure, taking into account contractual netting rights. Gross credit exposure is calculated prior to the application of collateral. As of December 31, 2025, EGTS' credit exposure totaled $35 million. Of this amount, investment grade counterparties, including those internally rated, represented 100%, and no single counterparty exceeded $10 million of the credit exposure.

Item 8. Financial Statements and Supplementary Data

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Eastern Gas Transmission and Storage, Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Eastern Gas Transmission and Storage, Inc., and subsidiaries ("EGTS") as of December 31, 2025 and 2024, the related consolidated statements of operations, comprehensive income, changes in shareholder's equity, and cash flows, for each of the three years in the period ended December 31, 2025, 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 EGTS as of December 31, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of EGTS' management. Our responsibility is to express an opinion on EGTS' financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to EGTS 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. EGTS is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of EGTS' internal control over financial reporting. Accordingly, we express no such opinion.

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 Board of Directors 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 — Effects of Rate Regulation on the Financial Statements — Refer to Notes 2 and 6 to the Financial Statements

Critical Audit Matter Description

EGTS is subject to rate regulation by the Federal Energy Regulatory Commission (the "FERC"), which has jurisdiction with respect to the rates of interstate natural gas transmission companies in the respective service territories where EGTS operates. Management has determined its regulated operations meet the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. Accounting for the economic effects of rate regulation has a pervasive effect on the financial statements.

Revenue provided by EGTS' interstate natural gas transmission operations is based primarily on rates approved by the FERC. EGTS defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur. EGTS continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future rates by considering factors such as a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation, other regulatory actions or the impact of competition that could limit EGTS' ability to recover its costs. The evaluation reflects the current political and regulatory climate. If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the regulatory assets and liabilities will be recognized in net income, returned to customers, or re-established as accumulated other comprehensive income (loss).

We identified the effects of rate regulation on the financial statements 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 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) a refund to customers. Given that management's accounting judgments are based on assumptions about the outcome of decisions by the FERC, 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 decisions by the FERC included the following, among others:

- We evaluated EGTS' disclosures related to the effects of rate regulation by testing recorded balances and evaluating regulatory developments.

- We read relevant regulatory orders issued by the FERC, regulatory statutes, filings made by EGTS and other external information. We evaluated relevant external information and compared it to certain recorded regulatory asset and liability balances for completeness.

- For certain regulatory matters, we inspected EGTS' filings with the FERC, and the filings with the FERC by intervenors to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedents of the FERC's treatment of similar costs under similar circumstances.

/s/ Deloitte & Touche LLP

Richmond, Virginia
February 27, 2026

We have served as EGTS' auditor since 2000.

EASTERN GAS TRANSMISSION AND STORAGE, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2025	**2024**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 10	$ 8
Restricted cash and cash equivalents	29	24
Trade receivables, net	97	93
Receivables from affiliates	5	17
Notes receivable from affiliates	131	—
Inventories	58	55
Prepayments and other deferred charges	30	28
Natural gas imbalances	73	72
Other current assets	24	10
Total current assets	457	307
Property, plant and equipment, net	4,909	4,771
Other assets	61	73
Total assets	$ 5,427	$ 5,151

The accompanying notes are an integral part of these consolidated financial statements.

EASTERN GAS TRANSMISSION AND STORAGE, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (continued)
(Amounts in millions, except share data)

	As of December 31,	
	2025	**2024**
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Accounts payable	$ 57	$ 55
Accounts payable to affiliates	20	27
Accrued property, income and other taxes	75	68
Accrued employee expenses	19	18
Regulatory liabilities	19	13
Customer and security deposits	29	24
Other current liabilities	33	25
Total current liabilities	252	230
Long-term debt	1,623	1,622
Regulatory liabilities	514	527
Deferred income taxes	167	85
Other long-term liabilities	77	81
Total liabilities	2,633	2,545
Commitments and contingencies (Note 14)		
Shareholder's equity:		
Common stock - 75,000 shares authorized, $10,000 par value, 60,101 issued and outstanding	609	609
Additional paid-in capital	1,380	1,352
Retained earnings	829	671
Accumulated other comprehensive loss, net	(24)	(26)
Total shareholder's equity	2,794	2,606
Total liabilities and shareholder's equity	$ 5,427	$ 5,151

The accompanying notes are an integral part of these consolidated financial statements.

EASTERN GAS TRANSMISSION AND STORAGE, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2025	**2024**	**2023**
Operating revenue	$ 1,010	$ 997	$ 1,024
Operating expenses:			
Cost of gas	1	7	38
Operations and maintenance	388	384	404
Depreciation and amortization	161	155	151
Property and other taxes	58	53	50
Total operating expenses	608	599	643
Operating income	402	398	381
Other income (expense):			
Interest expense	(72)	(69)	(71)
Allowance for borrowed funds	2	2	1
Allowance for equity funds	10	7	5
Other, net	11	5	1
Total other income (expense)	(49)	(55)	(64)
Income before income tax expense (benefit)	353	343	317
Income tax expense (benefit)	87	87	79
Net income	$ 266	$ 256	$ 238

The accompanying notes are an integral part of these consolidated financial statements.

EASTERN GAS TRANSMISSION AND STORAGE, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Amounts in millions)

	Years Ended December 31,		
	2025	**2024**	**2023**
Net income	$ 266	$ 256	$ 238
Other comprehensive income, net of tax:			
Unrealized gains on cash flow hedges, net of tax of $1, $1 and $1	2	2	2
Total other comprehensive income, net of tax	2	2	2
Comprehensive income	$ 268	$ 258	$ 240

The accompanying notes are an integral part of these consolidated financial statements.

EASTERN GAS TRANSMISSION AND STORAGE, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY
(Amounts in millions, except shares)

	Common Stock		Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss, Net	Total Shareholder's Equity
	Shares	Amount				
Balance, December 31, 2022	60,101	$ 609	$ 1,275	$ 746	$ (30)	$ 2,600
Net income	—	—	—	238	—	238
Other comprehensive income	—	—	—	—	2	2
Dividends declared	—	—	—	(181)	—	(181)
Contributions	—	—	29	—	—	29
Balance, December 31, 2023	60,101	609	1,304	803	(28)	2,688
Net income	—	—	—	256	—	256
Other comprehensive income	—	—	—	—	2	2
Dividends declared	—	—	—	(388)	—	(388)
Contributions	—	—	48	—	—	48
Balance, December 31, 2024	60,101	609	1,352	671	(26)	2,606
Net income	—	—	—	266	—	266
Other comprehensive income	—	—	—	—	2	2
Dividends declared	—	—	—	(108)	—	(108)
Contributions	—	—	28	—	—	28
Balance, December 31, 2025	60,101	$ 609	$ 1,380	$ 829	$ (24)	$ 2,794

The accompanying notes are an integral part of these consolidated financial statements.

EASTERN GAS TRANSMISSION AND STORAGE, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Amounts in millions)

	Years Ended December 31,		
	2025	2024	2023
Cash flows from operating activities:			
Net income	$ 266	$ 256	$ 238
Adjustments to reconcile net income to net cash flows from operating activities:			
Gains on other items, net	(6)	(1)	(8)
Depreciation and amortization	161	155	151
Allowance for equity funds	(10)	(7)	(5)
Changes in regulatory assets and liabilities	(19)	(18)	(76)
Deferred income taxes	80	67	119
Other, net	(1)	(1)	(8)
Changes in other operating assets and liabilities:			
Trade receivables and other assets	17	39	15
Receivables from affiliates	(15)	(8)	4
Gas balancing activities	16	9	27
Accrued property, income and other taxes	(16)	(2)	(57)
Accounts payable to affiliates	(7)	(2)	24
Accounts payable and other liabilities	(4)	10	(6)
Net cash flows from operating activities	462	497	418
Cash flows from investing activities:			
Capital expenditures	(285)	(255)	(241)
Proceeds from assignment of shale development rights	—	—	8
Proceeds from sales of marketable securities	11	3	—
Issuance of notes receivable to affiliates	(153)	(25)	—
Repayment of notes receivable by affiliates	22	25	—
Other, net	6	1	(4)
Net cash flows from investing activities	(399)	(251)	(237)
Cash flows from financing activities:			
Proceeds from long-term debt	—	149	—
Repayments of long-term debt	—	(111)	—
Repayment of notes payable to affiliates, net	—	(2)	(34)
Proceeds from equity contributions	—	13	—
Dividends paid	(56)	(297)	(158)
Net cash flows from financing activities	(56)	(248)	(192)
Net change in cash and cash equivalents and restricted cash and cash equivalents	7	(2)	(11)
Cash and cash equivalents and restricted cash and cash equivalents at beginning of period	32	34	45
Cash and cash equivalents and restricted cash and cash equivalents at end of period	$ 39	$ 32	$ 34

The accompanying notes are an integral part of these consolidated financial statements.

EASTERN GAS TRANSMISSION AND STORAGE, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Organization and Operations

Eastern Gas Transmission and Storage, Inc. and its subsidiaries ("EGTS") conduct business activities consisting of Federal Energy Regulatory Commission ("FERC")-regulated interstate natural gas transmission systems and underground storage. EGTS' operations include transmission assets located in Maryland, New York, Ohio, Pennsylvania, Virginia and West Virginia. EGTS also operates one of the nation's largest underground natural gas storage systems located in New York, Pennsylvania and West Virginia. EGTS is a wholly owned subsidiary of Eastern Energy Gas Holdings, LLC ("Eastern Energy Gas"), which is an indirect wholly owned subsidiary of Berkshire Hathaway Energy Company ("BHE"). BHE is a holding company based in Des Moines, Iowa that has investments in subsidiaries principally engaged in energy businesses. BHE is a wholly owned subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

(2) Summary of Significant Accounting Policies

Basis of Consolidation and Presentation

The Consolidated Financial Statements include the accounts of EGTS and its subsidiaries in which it holds a controlling financial interest as of the financial statement date. Intercompany accounts and transactions have been eliminated.

Use of Estimates in Preparation of Financial Statements

The preparation of the Consolidated Financial Statements in conformity with accounting principles generally accepted in the United States of America ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the period. These estimates include, but are not limited to, the effects of regulation; recovery of long-lived assets; certain assumptions made in accounting for pension and other postretirement benefits; asset retirement obligations ("AROs"); income taxes; unbilled revenue; valuation of certain financial assets and liabilities, including derivative contracts; and accounting for contingencies. Actual results may differ from the estimates used in preparing the Consolidated Financial Statements.

Accounting for the Effects of Certain Types of Regulation

EGTS prepares its Consolidated Financial Statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, EGTS defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur.

If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the related regulatory assets and liabilities will be recognized in net income, returned to customers or re-established as accumulated other comprehensive income (loss) ("AOCI").

Fair Value Measurements

As defined under GAAP, fair value is the price that would be received to sell an asset or paid to transfer a liability between market participants in the principal market or in the most advantageous market when no principal market exists. Adjustments to transaction prices or quoted market prices may be required in illiquid or disorderly markets in order to estimate fair value. Alternative valuation techniques may be appropriate under the circumstances to determine the value that would be received to sell an asset or paid to transfer a liability in an orderly transaction. Market participants are assumed to be independent, knowledgeable, able and willing to transact an exchange and not under duress. Nonperformance or credit risk is considered when determining fair value. Considerable judgment may be required in interpreting market data used to develop the estimates of fair value. Accordingly, estimates of fair value presented herein are not necessarily indicative of the amounts that could be realized in a current or future market exchange.

Cash and Cash Equivalents and Restricted Cash and Cash Equivalents

Cash equivalents consist of funds invested in money market mutual funds, U.S. Treasury Bills and other investments with a maturity of three months or less when purchased. Cash and cash equivalents exclude amounts where availability is restricted by legal requirements, loan agreements or other contractual provisions. Restricted cash and cash equivalents consist of customer deposits as allowed under the FERC gas tariff. A reconciliation of cash and cash equivalents and restricted cash and cash equivalents as of December 31, 2025 and 2024, as presented on the Consolidated Statements of Cash Flows is outlined below and disaggregated by the line items in which they appear on the Consolidated Balance Sheets (in millions):

	As of December 31,	
	2025	2024
Cash and cash equivalents	$ 10	$ 8
Restricted cash and cash equivalents	29	24
Total cash and cash equivalents and restricted cash and cash equivalents	$ 39	$ 32

Investments

Trading securities are carried at fair value with realized and unrealized gains and losses recognized in earnings.

Allowance for Credit Losses

Trade receivables are primarily short-term in nature with stated collection terms of less than one year from the date of origination and are stated at the outstanding principal amount, net of an estimated allowance for credit losses. The allowance for credit losses is based on EGTS' assessment of the collectability of amounts owed to EGTS by its customers. This assessment requires judgment regarding the ability of customers to pay or the outcome of any pending disputes. In measuring the allowance for credit losses for trade receivables, EGTS primarily utilizes credit loss history. However, EGTS may adjust the allowance for credit losses to reflect current conditions and reasonable and supportable forecasts that deviate from historical experience. As of December 31, 2025 and 2024, the allowance for credit losses was insignificant and is included in trade receivables, net on the Consolidated Balance Sheets.

Derivatives

EGTS employs a number of different derivative contracts, which may include forwards, futures, options, swaps and other agreements, to manage its commodity price and interest rate risks. Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. Derivative balances reflect offsetting permitted under master netting agreements with counterparties and cash collateral paid or received under such agreements. Cash collateral received from or paid to counterparties to secure derivative contract assets or liabilities in excess of amounts offset is included in other current assets or other current liabilities on the Consolidated Balance Sheets.

Commodity derivatives used in normal business operations that are settled by physical delivery, among other criteria, are eligible for and may be designated as normal purchases or normal sales. Normal purchases or normal sales contracts are not marked-to-market and settled amounts are recognized as operating revenue or cost of gas on the Consolidated Statements of Operations.

For EGTS' derivatives not designated as hedging contracts, unrealized gains and losses are recognized on the Consolidated Statements of Operations as operating revenue for derivatives related to natural gas sales contracts.

For EGTS' derivatives designated as hedging contracts, EGTS formally assesses, at inception and thereafter, whether the hedging contract is highly effective in offsetting changes in the hedged item. EGTS formally documents hedging activity by transaction type and risk management strategy. For derivative instruments that are accounted for as cash flow hedges or fair value hedges, the cash flows from the derivatives and from the related hedged items are classified in operating cash flows.

Changes in the estimated fair value of a derivative contract designated and qualified as a cash flow hedge, to the extent effective, are included on the Consolidated Statements of Changes in Equity as AOCI, net of tax, until the contract settles and the hedged item is recognized in earnings. EGTS discontinues hedge accounting prospectively when it has determined that a derivative contract no longer qualifies as an effective hedge, or when it is no longer probable that the hedged forecasted transaction will occur. When hedge accounting is discontinued because the derivative contract no longer qualifies as an effective hedge, future changes in the estimated fair value of the derivative contract are charged to earnings. Gains and losses related to discontinued hedges that were previously recorded in AOCI will remain in AOCI until the contract settles and the hedged item is recognized in earnings, unless it becomes probable that the hedged forecasted transaction will not occur at which time associated deferred amounts in AOCI are immediately recognized in earnings.

Inventories

Inventories consist mainly of materials and supplies and are determined using the average cost method.

Natural Gas Imbalances

Natural gas imbalances occur when the physical amount of natural gas delivered from, or received by, a pipeline system or storage facility differs from the contractual amount of natural gas delivered or received. EGTS values these imbalances due to, or from, shippers and operators at an appropriate index price at period end, subject to the terms of its tariff for regulated entities. Imbalances are primarily settled in-kind. Imbalances due to EGTS from other parties are reported in natural gas imbalances and imbalances that EGTS owes to other parties are reported in other current liabilities on the Consolidated Balance Sheets.

Property, Plant and Equipment, Net

General

Additions to property, plant and equipment are recorded at cost. EGTS capitalizes all construction-related materials, direct labor and contract services, as well as indirect construction costs. Indirect construction costs include debt and equity allowance for funds used during construction ("AFUDC"), as applicable. The cost of additions and betterments are capitalized, while costs incurred that do not improve or extend the useful lives of the related assets are generally expensed.

Depreciation and amortization are generally computed by applying the composite or straight-line method based on estimated useful lives. Depreciation studies are completed by EGTS to determine the appropriate group lives, net salvage and group depreciation rates. These studies are reviewed and rates are ultimately approved by the FERC. Net salvage includes the estimated future residual values of the assets and any estimated removal costs recovered through approved depreciation rates. Estimated removal costs are recorded as either a cost of removal regulatory liability or an ARO liability on the Consolidated Balance Sheets, depending on whether the obligation meets the requirements of an ARO. As actual removal costs are incurred, the associated liability is reduced.

Generally when EGTS retires or sells a component of regulated property, plant and equipment, it charges the original cost, net of any proceeds from the disposition, to accumulated depreciation. Any gain or loss on disposals of all other assets is recorded through earnings.

Debt and equity AFUDC, which represent the estimated costs of debt and equity funds necessary to finance the construction of regulated facilities, is capitalized by EGTS as a component of property, plant and equipment, with offsetting credits to the Consolidated Statements of Operations. AFUDC is computed based on guidelines set forth by the FERC. After construction is completed, EGTS is permitted to earn a return on these costs as a component of the related assets, as well as recover these costs through depreciation expense over the useful lives of the related assets.

Asset Retirement Obligations

EGTS recognizes AROs when it has a legal obligation to perform decommissioning, reclamation or removal activities upon retirement of an asset. EGTS' AROs are primarily related to the obligations associated with its interstate natural gas transmission and storage well assets. The fair value of an ARO liability is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made, and is added to the carrying amount of the associated asset, which is then depreciated over the remaining useful life of the asset. Subsequent to the initial recognition, the ARO liability is adjusted for any revisions to the original estimate of undiscounted cash flows (with corresponding adjustments to property, plant and equipment, net) and for accretion of the ARO liability due to the passage of time. For EGTS, the difference between the ARO liability, the corresponding ARO asset included in property, plant and equipment, net and amounts recovered in rates to satisfy such liabilities is recorded as a regulatory asset or liability.

Impairment

EGTS evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or when the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Consolidated Statements of Operations. As substantially all property, plant and equipment supports EGTS' regulated businesses, the impacts of regulation are considered when evaluating the carrying value of regulated assets.

Leases

EGTS has non-cancelable operating leases primarily for office space, office equipment and land. These leases generally require EGTS to pay for insurance, taxes and maintenance applicable to the leased property. Given the capital-intensive nature of the utility industry, it is common for a portion of lease costs to be capitalized when used during construction or maintenance of assets, in which the associated costs will be capitalized with the corresponding asset and depreciated over the remaining life of that asset. Certain leases contain renewal options for varying periods and escalation clauses for adjusting rent to reflect changes in price indices. EGTS does not include options in its lease calculations unless there is a triggering event indicating EGTS is reasonably certain to exercise the option. EGTS' accounting policy is to not recognize right-of-use assets and lease obligations for leases with contract terms of one year or less and not separate lease components from non-lease components and instead account for each separate lease component and the non-lease components associated with a lease as a single lease component. Right-of-use assets are evaluated for impairment in line with Accounting Standards Codification 360, "Property, Plant and Equipment" when a triggering event has occurred that might affect the value and use of the assets being leased.

EGTS' operating right-of-use assets are recorded in other assets and the operating lease liabilities are recorded in current and long-term other liabilities accordingly.

Revenue Recognition

EGTS uses a single five-step model to identify and recognize revenue from contracts with customers ("Customer Revenue") upon transfer of control of promised goods or services in an amount that reflects the consideration to which EGTS expects to be entitled in exchange for those goods or services. EGTS records sales and excise taxes collected directly from customers and remitted directly to the taxing authorities on a net basis on the Consolidated Statements of Operations.

A majority of EGTS' Customer Revenue is derived from tariff-based sales arrangements approved by the FERC. These tariff-based revenues are mainly comprised of natural gas transmission and storage services and have performance obligations which are satisfied over time as services are provided.

Revenue recognized is equal to what EGTS has the right to invoice as it corresponds directly with the value to the customer of EGTS' performance to date and includes billed and unbilled amounts. Trade receivables, net on the Consolidated Balance Sheets relate substantially to Customer Revenue. Payments for amounts billed are generally due from the customer within 30 days of billing. Rates charged for energy products and services are established by regulators or contractual arrangements that establish the transaction price as well as the allocation of price amongst the separate performance obligations. When preliminary regulated rates are permitted to be billed prior to final approval by the applicable regulator, certain revenue collected may be subject to refund and a liability for estimated refunds is accrued. In the event one of the parties to a contract has performed before the other, EGTS would recognize a contract asset or contract liability depending on the relationship between EGTS' performance and the customer's payment. EGTS has recognized contract assets of $6 million and $7 million as of December 31, 2025 and 2024, respectively, and $7 million and $3 million of contract liabilities as of December 31, 2025 and 2024, respectively, due to EGTS' performance on certain contracts.

Unamortized Debt Premiums, Discounts and Debt Issuance Costs

Premiums, discounts and debt issuance costs incurred for the issuance of long-term debt are amortized over the term of the related financing using the effective interest method.

Income Taxes

Berkshire Hathaway includes EGTS in its consolidated U.S. federal income tax return. Consistent with established regulatory practice, EGTS' provision for income taxes has been computed on a stand-alone basis.

Deferred income tax assets and liabilities are based on differences between the financial statement and income tax basis of assets and liabilities using enacted income tax rates expected to be in effect for the year in which the differences are expected to reverse. Changes in deferred income tax assets and liabilities associated with components of OCI are charged or credited directly to OCI. Changes in deferred income tax assets and liabilities associated with certain property-related basis differences and other various differences that EGTS' regulated businesses deems probable to be passed on to its customers are charged or credited directly to a regulatory asset or liability and will be included in regulated rates when the temporary differences reverse. Other changes in deferred income tax assets and liabilities are included as a component of income tax expense. Changes in deferred income tax assets and liabilities attributable to changes in enacted income tax rates are charged or credited to income tax expense or a regulatory asset or liability in the period of enactment. Valuation allowances are established when necessary to reduce deferred income tax assets to the amount that is more-likely-than-not to be realized.

EGTS recognizes the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the Consolidated Financial Statements from such a position are measured based on the largest benefit that is more-likely-than-not to be realized upon ultimate settlement. Estimated interest and penalties, if any, related to uncertain tax positions are included as a component of income tax expense (benefit) on the Consolidated Statements of Operations.

Segment Information

EGTS currently has one reportable segment, which includes its natural gas transmission and storage operations. EGTS' chief operating decision maker ("CODM") is the BHE Pipeline Group (which consists primarily of BHE GT&S, LLC and its subsidiaries ("BHE GT&S"), Northern Natural Gas Company and Kern River Gas Transmission Company) President and Chief Executive Officer. The CODM uses net income, as reported on the Consolidated Statements of Operations, and generally considers actual results versus historical results, budgets or forecast, as well as unique risks and opportunities, when making decisions about the allocation of resources and capital. The segment expenses regularly provided to the CODM align with the captions presented on the Consolidated Statements of Operations. The measure of segment assets is reported on the Consolidated Balance Sheets as total assets.

New Accounting Pronouncements

In December 2023, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2023-09, Income Taxes Topic 740, "Income Tax—Improvements to Income Tax Disclosures" which requires enhanced disclosures, including specific categories and disaggregation of information in the effective tax rate reconciliation, disaggregated information related to income taxes paid, income or loss from continuing operations before income tax expense or benefit, and income tax expense or benefit from continuing operations. This guidance is effective for annual reporting periods beginning after December 15, 2024. Early adoption is permitted and should be applied on a prospective basis, however retrospective application is permitted. EGTS adopted this guidance for the fiscal year beginning January 1, 2025, under the retrospective method. The adoption did not have a material impact on EGTS' Consolidated Financial Statements, but did expand the disclosures included within Notes to Consolidated Financial Statements. Refer to Note 9 for expanded rate reconciliation disclosures and disaggregation of income taxes paid.

In November 2024, the FASB issued ASU No. 2024-03, Income Statement—Reporting Comprehensive Income—Expense Disaggregation Disclosures Subtopic 220-40, "Disaggregation of Income Statement Expenses" which addresses requests from investors for more detailed information about certain expenses and requires disclosure of the amounts of purchases of inventory, employee compensation, depreciation and intangible asset amortization included in each relevant expense caption presented on the income statement. This guidance, as clarified in ASU 2025-01, is effective for annual reporting periods beginning after December 15, 2026 and interim reporting periods beginning after December 15, 2027. Early adoption is permitted and should be applied on a prospective basis, however retrospective application is permitted. EGTS is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

(3) Property, Plant and Equipment, Net

Property, plant and equipment, net consists of the following as of December 31 (in millions):

	Depreciable Life	2025	2024
Interstate natural gas transmission assets	47 - 51 years	$ 5,213	$ 5,093
Storage assets	47 - 51 years	1,884	1,803
Intangible plant and other assets	12 - 53 years	408	386
Plant in-service		7,505	7,282
Accumulated depreciation and amortization		(2,824)	(2,699)
		4,681	4,583
Construction work-in-progress		228	188
Property, plant and equipment, net		$ 4,909	$ 4,771

Assignment of Shale Development Rights

In September 2025, EGTS signed an agreement to convey development rights over time to a natural gas producer for approximately 23,000 acres of Utica Shale and Point Pleasant Formation underneath one of its natural gas storage fields. The agreement provides for payments to EGTS of approximately $49 million over a period of three years, and an overriding royalty interest in gas produced from the acreage. In January 2026, EGTS conveyed approximately 7,600 acres and received proceeds of $16 million from the initial conveyance. This transaction resulted in a $16 million ($12 million after-tax) gain recorded in operations and maintenance expense in January 2026.

In June 2023, EGTS conveyed development rights to a natural gas producer for approximately 6,500 acres of Utica Shale and Point Pleasant Formation underneath one of its natural gas storage fields and received proceeds of $8 million and an overriding royalty interest in gas produced from the acreage. This transaction resulted in an $8 million ($6 million after-tax) gain, included in operations and maintenance expense in its Consolidated Statements of Operations.

(4) Jointly Owned Utility Facilities

Under joint facility ownership agreements with other utilities, EGTS, as a tenant in common, has undivided interests in jointly owned transmission and storage facilities. EGTS accounts for its proportionate share of each facility, and each joint owner has provided financing for its share of each facility. Operating costs of each facility are assigned to joint owners primarily based on their percentage of ownership. Operating costs and expenses on the Consolidated Statements of Operations include EGTS' share of the expenses of these facilities.

The amounts shown in the table below represent EGTS' share in each jointly owned facility included in property, plant and equipment, net as of December 31, 2025 (dollars in millions):

	EGTS' Share	Facility in Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
Ellisburg Pool	39 %	$ 35	$ 13	$ —
Ellisburg Station	50	34	10	3
Harrison	50	62	22	2
Leidy	50	160	55	3
Oakford	50	219	78	—
Total		$ 510	$ 178	$ 8

(5) Leases

The following table summarizes EGTS' leases recorded on the Consolidated Balance Sheets as of December 31 (in millions):

	2025	2024
Right-of-use assets:		
Operating leases	$ 16	$ 17
Total right-of-use assets	$ 16	$ 17
Lease liabilities:		
Operating leases	$ 15	$ 16
Total lease liabilities	$ 15	$ 16

The following table summarizes EGTS' operating lease costs for the years ended December 31 (in millions):

	2025	2024	2023
Total operating lease costs	$ 2	$ 2	$ 2
Weighted-average remaining operating lease term (years)	10.6	11.7	12.7
Weighted-average operating lease discount rate	4.3 %	4.3 %	4.3 %

The following table summarizes EGTS' supplemental cash flow information relating to leases for the years ended December 31 (in millions):

	2025	2024	2023
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows from operating leases	$ 2	$ 2	$ 2

EGTS has the following remaining operating lease commitments as of December 31, 2025 (in millions):

2026	$ 2
2027	2
2028	2
2029	2
2030	1
Thereafter	10
Total undiscounted lease payments	19
Less - amounts representing interest	(4)
Lease liabilities	$ 15

(6) Regulatory Matters

Regulatory Assets

Regulatory assets represent costs that are expected to be recovered in future regulated rates. EGTS' regulatory assets reflected on the Consolidated Balance Sheets consist of the following as of December 31 (in millions):

	Weighted Average Remaining Life	2025	2024
Employee benefit plans[1]	10 years	$ 23	$ 23
Gas costs[2]	1 year	19	3
Other	Various	3	5
Total regulatory assets		$ 45	$ 31
Reflected as:			
Other current assets		$ 22	$ 7
Other assets		23	24
Total regulatory assets		$ 45	$ 31

(1) Represents costs expected to be recovered through future rates generally over the expected remaining service period of plan participants.

(2) Reflects unrecovered gas costs, which are recovered through filings with the FERC.

EGTS had regulatory assets not earning a return on investment of $45 million and $31 million as of December 31, 2025 and 2024, respectively.

Regulatory Liabilities

Regulatory liabilities represent income to be recognized or amounts expected to be returned to customers in future periods. EGTS' regulatory liabilities reflected on the Consolidated Balance Sheets consist of the following as of December 31 (in millions):

	Weighted Average Remaining Life	2025	2024
Deferred income taxes[1]	Various	$ 360	$ 371
Other postretirement benefit costs[2]	Various	128	129
Cost of removal[3]	48 years	34	34
Other	Various	11	6
Total regulatory liabilities		$ 533	$ 540
Reflected as:			
Current liabilities		$ 19	$ 13
Noncurrent liabilities		514	527
Total regulatory liabilities		$ 533	$ 540

(1) Amounts primarily represent income tax liabilities related to the federal tax rate change from 35% to 21% that are probable to be passed on to customers, offset by income tax benefits related to certain property-related basis differences and other various differences that were previously passed on to customers and will be included in regulated rates when the temporary differences reverse.

(2) Reflects a regulatory liability for the collection of postretirement benefit costs allowed in rates in excess of expense incurred.

(3) Amounts represent estimated costs, as accrued through depreciation rates and exclusive of ARO liabilities, of removing regulated property, plant and equipment in accordance with accepted regulatory practices. Refer to Note 11 for more information.

(7) Investments and Restricted Cash and Cash Equivalents

Investments and restricted cash and cash equivalents consists of the following as of December 31 (in millions):

	2025	2024
Investments:		
Investment funds	$ 8	$ 18
Restricted cash and cash equivalents:		
Customer deposits	29	24
Total restricted cash and cash equivalents	29	24
Total investments and restricted cash and cash equivalents	$ 37	$ 42
Reflected as:		
Current assets	$ 29	$ 24
Other assets	8	18
Total investments and restricted cash and cash equivalents	$ 37	$ 42

(8) Long-term Debt

EGTS' long-term debt consists of the following, including unamortized premiums, discounts and debt issuance costs, as of December 31 (dollars in millions):

	Par Value	2025	2024
3.00% Senior Notes, due 2029	$ 426	$ 423	$ 423
5.02% Senior Notes, due 2034	150	149	149
4.80% Senior Notes, due 2043	346	342	342
4.60% Senior Notes, due 2044	444	438	437
3.90% Senior Notes, due 2049	273	271	271
Total long-term debt	$ 1,639	$ 1,623	$ 1,622
Reflected as:			
Total long-term debt		$ 1,623	$ 1,622

Annual Payment on Long-Term Debt

The annual repayments of long-term debt for the years beginning January 1, 2026 and thereafter, are as follows (in millions):

2026	$ —
2027	—
2028	—
2029	426
2030	—
2031 and thereafter	1,213
Total	1,639
Unamortized discounts and debt issuance costs	(16)
Total	$ 1,623

AOCI

The following table presents selected information related to losses on interest rate cash flow hedges included in AOCI in EGTS' Consolidated Balance Sheets as of December 31, 2025 (in millions):

	AOCI After-Tax	Amounts Expected to be Reclassified to Earnings During the Next 12 Months After-Tax	Maximum Term
Interest rate	$ (24)	$ (3)	228 months

EGTS reclassified $3 million from AOCI to interest expense for each of the years ended December 31, 2025, 2024 and 2023.

(9) Income Taxes

Berkshire Hathaway includes BHE and its subsidiaries in its U.S. federal income tax return and BHE includes its subsidiaries in certain state income tax returns. Consistent with established regulatory practice, EGTS' provision for federal and state income tax has been computed on a stand-alone basis, and substantially all of its currently payable or receivable income tax is remitted to or received from BHE pursuant to a tax allocation agreement. Income before income tax expense (benefit) as reported on the Consolidated Statements of Operations, is all domestic.

Income tax expense (benefit) consists of the following for the years ended December 31 (in millions):

	2025	2024	2023
Current:			
Federal	$ 5	$ 8	$ (28)
State	2	12	(12)
	7	20	(40)
Deferred:			
Federal	65	58	91
State	15	9	28
	80	67	119
Total	$ 87	$ 87	$ 79

The following table presents income taxes paid (received), net of refunds, for the years ended December 31 (in millions):

	2025	2024	2023
Jurisdiction:			
Federal	$ 1	$ (48)	$ —
State	1	(1)	10
Total[1]	$ 2	$ (49)	$ 10

(1) Pursuant to a tax allocation agreement, BHE GT&S makes cash payments for income taxes, net of refunds, on behalf of EGTS for federal income taxes and certain state income taxes. For the years ended December 31, 2025, 2024 and 2023, EGTS made cash payments of $— million, $— million and $5 million, respectively, to tax authorities, with the remaining amounts settled through non-cash equity distributions and contributions with Eastern Energy Gas.

Income taxes paid, net of refunds exceeded five percent of total income taxes paid in the following states (in millions):

	2025	2024	2023
State:			
New York[1]	$ 1	$ *	$ 1
Pennsylvania[2]	$ *	$ *	$ 4
Virginia[2]	$ *	$ *	$ 1
West Virginia[1]	$ *	$ *	$ 4

(1) Amounts are pursuant to a tax allocation agreement and were settled through non-cash equity distributions and contributions with Eastern Energy Gas.

(2) Cash payments made pursuant to a tax allocation agreement.

* Jurisdiction below the threshold for the period presented

A reconciliation of the federal statutory income tax rate to the effective income tax rate applicable to income before income tax expense (benefit) is as follows for the years ended December 31 (amounts in millions):

	2025		2024		2023	
	Amount	Percent	Amount	Percent	Amount	Percent
U.S. federal statutory income tax rate	$ 74	21.0 %	$ 72	21.0 %	$ 67	21.0 %
State and local income taxes, net of federal income tax	13	3.6	16	4.7	13	4.1
Nontaxable or nondeductible items:						
Other, net	—	—	(2)	(0.6)	—	—
Other adjustments	—	—	1	0.3	(1)	(0.2)
Effective income tax rate	$ 87	24.6 %	$ 87	25.4 %	$ 79	24.9 %

The net deferred income tax liability consists of the following as of December 31 (in millions):

	2025	2024
Deferred income tax assets:		
State carryforwards	$ 10	$ 10
Employee benefits	20	23
Intangibles and goodwill	228	240
Derivatives and hedges	8	9
Other	7	5
Total deferred income tax assets	273	287
Deferred income tax liabilities:		
Property-related items	(396)	(325)
Debt exchange	(44)	(47)
Total deferred income tax liabilities	(440)	(372)
Net deferred income tax liability	$ (167)	$ (85)

The following table provides EGTS' net operating loss carryforwards and expiration dates as of December 31, 2025 (in millions):

	State
Net operating loss carryforwards	$ 173
Deferred income taxes on net operating loss carryforwards	$ 10
Expiration dates	2036 - indefinite

The U.S. Internal Revenue Service has not closed or effectively settled an examination of EGTS' income tax returns for any tax years beginning on or after November 1, 2020. The statute of limitations for EGTS' states remains open for periods beginning on or after November 1, 2020. The closure of examinations, or the expiration of the statute of limitations, for state filings may not preclude the state from adjusting the state net operating loss carryforward utilized in a year for which the statute of limitations is not closed.

(10) Employee Benefit Plans

Defined Benefit Plans

EGTS is a participant in benefit plans sponsored by MidAmerican Energy Company ("MidAmerican Energy"), an affiliate. The MidAmerican Energy Company Retirement Plan includes a qualified pension plan that provides pension benefits for eligible employees. The MidAmerican Energy Company Welfare Benefit Plan provides certain postretirement health care and life insurance benefits for eligible retirees on behalf of EGTS. EGTS made $5 million, $7 million and $7 million of contributions to the MidAmerican Energy Company Retirement Plan for the years ended December 31, 2025, 2024 and 2023, respectively. EGTS made $1 million, $2 million, and $2 million of contributions to the MidAmerican Energy Company Welfare Benefit Plan for the years ended December 31, 2025, 2024 and 2023, respectively. Contributions related to these plans are reflected as net periodic benefit cost in operations and maintenance expense in the Consolidated Statements of Operations. Amounts attributable to EGTS were allocated from MidAmerican Energy in accordance with the intercompany administrative service agreement. Offsetting regulatory assets and liabilities have been recorded related to the amounts not yet recognized as a component of net periodic benefit costs that will be included in regulated rates.

Defined Contribution Plan

EGTS participates in the MidAmerican Energy defined contribution plan. EGTS' matching contributions are based on each participant's level of contribution. Contributions cannot exceed the maximum allowable for tax purposes. Certain participants now receive enhanced benefits in the defined contribution plan and no longer accrue benefits in the noncontributory defined benefit pension plans. EGTS' contributions to the plans were $12 million, $10 million and $9 million for the years ended December 31, 2025, 2024 and 2023, respectively.

(11) Asset Retirement Obligations

EGTS estimates its ARO liabilities based upon detailed engineering calculations of the amount and timing of the future cash spending for a third party to perform the required work. Spending estimates are escalated for inflation and then discounted at a credit-adjusted, risk-free rate. Changes in estimates could occur for a number of reasons, including changes in laws and regulations, plan revisions, inflation and changes in the amount and timing of the expected work.

EGTS does not recognize liabilities for AROs for which the fair value cannot be reasonably estimated. Due to the indeterminate removal date, the fair value of the interim removal of natural gas pipelines and certain storage wells in EGTS' underground natural gas storage network cannot currently be estimated, and no amounts are recognized on the Consolidated Financial Statements other than those included in the cost of removal regulatory liability established via approved depreciation rates in accordance with accepted regulatory practices. These accruals totaled $34 million as of December 31, 2025 and 2024.

The following table reconciles the beginning and ending balances of EGTS' ARO liabilities for the years ended December 31 (in millions):

	2025	2024
Beginning balance	$ 28	$ 30
Change in estimated costs	2	—
Retirements	(5)	(3)
Accretion	1	1
Ending balance	$ 26	$ 28
Reflected as:		
Other current liabilities	$ 2	$ 3
Other long-term liabilities	24	25
Total ARO liability	$ 26	$ 28

(12) Risk Management and Hedging Activities

EGTS is exposed to the impact of market fluctuations in commodity prices, principally, to natural gas market fluctuations primarily related to fuel retained and used during the operation of the pipeline system. EGTS has established a risk management process that is designed to identify, assess, manage, mitigate, monitor and report, each of the various types of risk involved in its business. To mitigate a portion of its commodity price risk, EGTS uses commodity derivative contracts, which may include forwards, futures, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. EGTS does not hedge all of its commodity price risk, thereby exposing the unhedged portion to changes in market prices. See Note 13 for further information about fair value measurements and associated valuation methods for derivatives.

There have been no significant changes in EGTS' accounting policies related to derivatives. Refer to Notes 2 and 13 for additional information on derivative contracts.

Credit Risk

EGTS is exposed to counterparty credit risk associated with wholesale energy supply and marketing activities with other utilities, energy marketing companies, financial institutions and other market participants. Credit risk may be concentrated to the extent EGTS' counterparties have similar economic, industry or other characteristics and due to direct or indirect relationships among the counterparties. For the year ended December 31, 2025, the 10 largest customers provided 40% of the total storage and transmission revenues. Before entering into a transaction, EGTS analyzes the financial condition of each significant wholesale counterparty, establishes limits on the amount of unsecured credit to be extended to each counterparty and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate wholesale counterparty credit risk, EGTS enters into netting and collateral arrangements that may include margining and cross-product netting agreements and obtains third-party guarantees, letters of credit and cash deposits. If required, EGTS exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

(13) Fair Value Measurements

The carrying value of EGTS' cash, certain cash equivalents, receivables, payables, accrued liabilities and short-term borrowings approximates fair value because of the short-term maturity of these instruments. EGTS has various financial assets and liabilities that are measured at fair value on the Consolidated Financial Statements using inputs from the three levels of the fair value hierarchy. A financial asset or liability classification within the hierarchy is determined based on the lowest level input that is significant to the fair value measurement. The three levels are as follows:

- Level 1 - Inputs are unadjusted quoted prices in active markets for identical assets or liabilities that EGTS has the ability to access at the measurement date.
- Level 2 - Inputs include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means (market corroborated inputs).
- Level 3 - Unobservable inputs reflect EGTS' judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. EGTS develops these inputs based on the best information available, including its own data.

The following table presents EGTS' financial assets and liabilities recognized on the Consolidated Balance Sheets and measured at fair value on a recurring basis (in millions):

	Input Levels for Fair Value Measurements			
	Level 1	Level 2	Level 3	Total
As of December 31, 2025				
Assets:				
Money market mutual funds	$ 10	$ —	$ —	$ 10
Equity securities:				
Investment funds	8	—	—	8
	$ 18	$ —	$ —	$ 18
As of December 31, 2024				
Assets:				
Money market mutual funds	$ 8	$ —	$ —	$ 8
Equity securities:				
Investment funds	18	—	—	18
	$ 26	$ —	$ —	$ 26

EGTS' investments in money market mutual funds and investment funds are stated at fair value. When available, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value.

Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchase or normal sales and qualify for the exception afforded by GAAP. When available, the fair value of derivative contracts is estimated using unadjusted quoted prices for identical contracts in the market in which EGTS transacts. When quoted prices for identical contracts are not available, EGTS uses forward price curves. Forward price curves represent EGTS' estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates. EGTS bases its forward price curves upon market price quotations, when available, or internally developed and commercial models, with internal and external fundamental data inputs. Market price quotations are obtained from independent brokers, exchanges, direct communication with market participants and actual transactions executed by EGTS. Market price quotations are generally readily obtainable for the applicable term of EGTS' outstanding derivative contracts; therefore, EGTS' forward price curves reflect observable market quotes. Market price quotations for certain natural gas trading hubs are not as readily obtainable due to the length of the contracts. Given that limited market data exists for these contracts, as well as for those contracts that are not actively traded, EGTS uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs that are based on unobservable inputs. The estimated fair value of these derivative contracts is a function of underlying forward commodity prices, related volatility, counterparty creditworthiness and duration of contracts.

EGTS' long-term debt is carried at cost, including unamortized premiums, discounts and debt issuance costs as applicable, on the Consolidated Financial Statements. The fair value of EGTS' long-term debt is a Level 2 fair value measurement and has been estimated based upon quoted market prices, where available, or at the present value of future cash flows discounted at rates consistent with comparable maturities with similar credit risks. The following table presents the carrying value and estimated fair value of EGTS' long-term debt as of December 31 (in millions):

	2025		2024	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 1,623	$ 1,442	$ 1,622	$ 1,409

(14) Commitments and Contingencies

Environmental Laws and Regulations

EGTS is subject to federal, state and local laws and regulations regarding air quality, climate change, emissions performance standards, water quality and other environmental matters that have the potential to impact its current and future operations. EGTS believes it is in material compliance with all applicable laws and regulations.

Legal Matters

EGTS is party to a variety of legal actions arising out of the normal course of business. EGTS does not believe that such normal and routine litigation will have a material impact on its consolidated financial results.

Surety Bonds

As of December 31, 2025, EGTS had purchased $14 million of surety bonds. Under the terms of the surety bonds, Eastern Energy Gas is obligated to indemnify the respective surety bond company for any amounts paid.

(15) Revenue from Contracts with Customers

The following table summarizes EGTS' Customer Revenue by regulated and other, with further disaggregation of regulated by line of business, for the years ended December 31 (in millions):

	2025	2024	2023
Customer Revenue:			
Regulated:			
Gas transmission	$ 664	$ 650	$ 656
Gas storage	282	279	274
Wholesale	2	7	22
Other	—	1	2
Total regulated	948	937	954
Management services and other revenues	59	56	66
Total Customer Revenue	1,007	993	1,020
Other revenue[1]	3	4	4
Total operating revenue	$ 1,010	$ 997	$ 1,024

(1) Other revenue consists primarily of revenue recognized in accordance with Accounting Standards Codification ("ASC") 815, "Derivative and Hedging" which includes unrealized gains and losses for derivatives not designated as hedges related to natural gas sales contracts, contingent fees from certain farmout agreements recognized in accordance with ASC 450, "Contingencies" and the royalties from the conveyance of mineral rights accounted for under ASC 932 "Extractive Activities – Oil and Gas".

Remaining Performance Obligations

The following table summarizes EGTS' revenue it expects to recognize in future periods related to significant unsatisfied remaining performance obligations for fixed contracts with expected durations in excess of one year as of December 31, 2025 (in millions):

	Performance obligations expected to be satisfied		
	Less than 12 months	More than 12 months	Total
EGTS	$ 826	$ 3,019	$ 3,845

(16) Supplemental Cash Flow Disclosures

The summary of supplemental cash flow disclosures as of and for the years ended December 31 is as follows (in millions):

	2025	2024	2023
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	$ 71	$ 66	$ 69
Supplemental disclosure of non-cash investing and financing transactions:			
Accruals related to property, plant and equipment additions	$ 35	$ 7	$ 9
Equity dividends[1]	$ (52)	$ (91)	$ (23)
Equity contributions	$ 28	$ 35	$ 29

(1) Equity dividends represents the settlement of affiliated receivables.

(17) Related Party Transactions

EGTS is party to a tax allocation agreement and is part of the Berkshire Hathaway consolidated U.S. federal income tax return and certain BHE consolidated state income tax returns. For current federal and state income taxes, EGTS had a payable to BHE of $11 million and $7 million as of December 31, 2025 and 2024, respectively.

As of December 31, 2025, EGTS had $11 million of natural gas imbalances payable to affiliates, presented in other current liabilities on the Consolidated Balance Sheets.

EGTS participates in certain MidAmerican Energy benefit plans as described in Note 10. As of December 31, 2025 and 2024, EGTS' amount due to MidAmerican Energy associated with these plans and reflected in other long-term liabilities on the Consolidated Balance Sheets was $35 million.

In December 2025, EGTS completed the sale of a compressor unit to Northern Natural Gas Company, an affiliate. This transaction resulted in a $5 million ($4 million after-tax) gain, included in operations and maintenance expense in its Consolidated Statements of Operations.

Presented below are EGTS' significant transactions with related parties for the years ended December 31 (in millions):

	2025	2024	2023
Sales of natural gas and transmission and storage services	$ 6	$ 4	$ 4
Services provided by related parties[1]	36	37	58
Services provided to related parties	53	52	59

(1) Includes capitalized expenditures.

Borrowings With Eastern Energy Gas

EGTS has a $400 million intercompany revolving credit agreement from its parent, Eastern Energy Gas, expiring in March 2027. The credit agreement, which is for general corporate purposes, has a variable interest rate based on the Secured Overnight Financing Rate ("SOFR") plus a fixed spread. There were no amounts outstanding under the credit agreement as of December 31, 2025 and 2024. Interest expense related to the credit agreement totaled $1 million for the year ended December 31, 2023.

Eastern Energy Gas has a $400 million intercompany revolving credit agreement from EGTS expiring in March 2027. The credit agreement has a variable interest rate based on SOFR plus a fixed spread. Net outstanding borrowings totaled $131 million as of December 31, 2025. There were no amounts outstanding under the credit agreement as of December 31, 2024. Interest income related to the credit agreement totaled $5 million for the year ended December 31, 2025.

Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

At the end of the period covered by this Annual Report on Form 10-K, each of Berkshire Hathaway Energy Company, PacifiCorp, MidAmerican Funding, LLC, MidAmerican Energy Company, Nevada Power Company, Sierra Pacific Power Company, Eastern Energy Gas Holdings, LLC and Eastern Gas Transmission and Storage, Inc. carried out separate evaluations, under the supervision and with the participation of each such entity's management, including its Chief Executive Officer (principal executive officer) and its Chief Financial Officer (principal financial officer), or persons performing similar functions, of the effectiveness of the design and operation of its disclosure controls and procedures (as defined in Rule 13a-15(e) promulgated under the Securities and Exchange Act of 1934, as amended). Based upon these evaluations, management of each such entity, including its Chief Executive Officer (principal executive officer) and its Chief Financial Officer (principal financial officer), or persons performing similar functions, in each case, concluded that the disclosure controls and procedures for such entity were effective to ensure that information required to be disclosed by such entity in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the U.S. Securities and Exchange Commission's rules and forms, and is accumulated and communicated to its management, including its Chief Executive Officer (principal executive officer) and its Chief Financial Officer (principal financial officer), or persons performing similar functions, in each case, as appropriate to allow timely decisions regarding required disclosure by it. Each such entity hereby states that there has been no change in its internal control over financial reporting during the quarter ended December 31, 2025 that has materially affected, or is reasonably likely to materially affect, its internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting

Management of each of Berkshire Hathaway Energy Company, PacifiCorp, MidAmerican Funding, LLC, MidAmerican Energy Company, Nevada Power Company, Sierra Pacific Power Company, Eastern Energy Gas Holdings, LLC and Eastern Gas Transmission and Storage, Inc., respectively, is responsible for establishing and maintaining, for such entity, adequate internal control over financial reporting, as such term is defined in the Securities Exchange Act of 1934 Rule 13a-15(f). Under the supervision and with the participation of management for each such entity, including its Chief Executive Officer (principal executive officer) and its Chief Financial Officer (principal financial officer), or persons performing similar functions, in each case, such management conducted an evaluation for the relevant entity of the effectiveness of internal control over financial reporting as of December 31, 2025, as required by the Securities Exchange Act of 1934 Rule 13a-15(c). In making this assessment, management for each such respective entity used the criteria set forth in the framework in "Internal Control - Integrated Framework (2013)" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the evaluation conducted under the framework in "Internal Control - Integrated Framework (2013)," management for each such respective entity concluded that internal control over financial reporting for such entity was effective as of December 31, 2025.

Berkshire Hathaway Energy Company February 27, 2026	PacifiCorp February 27, 2026	MidAmerican Funding, LLC February 27, 2026
MidAmerican Energy Company February 27, 2026	Nevada Power Company February 27, 2026	Sierra Pacific Power Company February 27, 2026
Eastern Energy Gas Holdings, LLC February 27, 2026	Eastern Gas Transmission and Storage, Inc. February 27, 2026	

Item 9B. Other Information

None.

Item 9C. Disclosure Regarding Foreign Jurisdictions that Prevent Inspection

Not applicable.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

BERKSHIRE HATHAWAY ENERGY, PACIFICORP, MIDAMERICAN FUNDING, MIDAMERICAN ENERGY, NEVADA POWER, SIERRA PACIFIC, EASTERN ENERGY GAS AND EGTS

Information required by Item 10 is omitted pursuant to General Instruction I(2)(c) to Form 10-K.

Item 11. Executive Compensation

BERKSHIRE HATHAWAY ENERGY, PACIFICORP, MIDAMERICAN FUNDING, MIDAMERICAN ENERGY, NEVADA POWER, SIERRA PACIFIC, EASTERN ENERGY GAS AND EGTS

Information required by Item 11 is omitted pursuant to General Instruction I(2)(c) to Form 10-K.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

BERKSHIRE HATHAWAY ENERGY, PACIFICORP, MIDAMERICAN FUNDING, MIDAMERICAN ENERGY, NEVADA POWER, SIERRA PACIFIC, EASTERN ENERGY GAS AND EGTS

Information required by Item 12 is omitted pursuant to General Instruction I(2)(c) to Form 10-K.

Item 13. Certain Relationships and Related Transactions, and Director Independence

BERKSHIRE HATHAWAY ENERGY, PACIFICORP, MIDAMERICAN FUNDING, MIDAMERICAN ENERGY, NEVADA POWER, SIERRA PACIFIC, EASTERN ENERGY GAS AND EGTS

Information required by Item 13 is omitted pursuant to General Instruction I(2)(c) to Form 10-K.

Item 14. Principal Accountant Fees and Services

The following table shows the fees paid or accrued by each Registrant for audit and audit-related services and fees paid for tax and all other services rendered by Deloitte & Touche LLP (PCAOB ID No. 34), the member firms of Deloitte Touche Tohmatsu Limited, and their respective affiliates (collectively, the "Deloitte Entities") for each of the last two years (in millions):

	Berkshire Hathaway Energy[1]	PacifiCorp	MidAmerican Funding[1]	MidAmerican Energy	Nevada Power	Sierra Pacific	Eastern Energy Gas[1]	EGTS
2025								
Audit fees[2]	$ 13.1	$ 2.3	$ 1.5	$ 1.2	$ 1.1	$ 1.2	$ 1.5	$ 0.9
Audit-related fees[3]	1.9	—	1.4	1.4	—	—	0.2	—
Tax fees[4]	—	—	—	—	—	—	—	—
Other	0.3	—	—	—	—	—	—	—
Total	$ 15.3	$ 2.3	$ 2.9	$ 2.6	$ 1.1	$ 1.2	$ 1.7	$ 0.9
2024								
Audit fees[2]	$ 13.0	$ 2.3	$ 1.5	$ 1.3	$ 1.0	$ 1.0	$ 1.6	$ 0.9
Audit-related fees[3]	0.8	—	0.1	0.1	—	—	0.2	0.1
Tax fees[4]	0.1	—	—	—	—	—	—	—
Other	0.5	—	—	—	—	—	—	—
Total	$ 14.4	$ 2.3	$ 1.6	$ 1.4	$ 1.0	$ 1.0	$ 1.8	$ 1.0

(1) The reported fees for Berkshire Hathaway Energy include those fees reported for PacifiCorp, MidAmerican Funding, Nevada Power, Sierra Pacific and Eastern Energy Gas while the reported fees for MidAmerican Funding include those fees reported for MidAmerican Energy and the reported fees for Eastern Energy Gas include those fees reported for EGTS.

(2) Audit fees include fees for the audit of the consolidated financial statements and interim reviews of the quarterly financial statements for each Registrant, audit services provided in connection with required statutory audits of certain of BHE's subsidiaries and comfort letters, consents and other services related to SEC matters for each Registrant.

(3) Audit-related fees primarily include fees for assurance and related services for any other statutory or regulatory requirements, audits of certain employee benefit plans and consultations on various accounting and reporting matters.

(4) Tax fees include fees for services relating to tax compliance, tax planning and tax advice. These services include assistance regarding federal, state and international tax compliance, tax return preparation and tax audits.

Each Registrant is a wholly owned subsidiary of Berkshire Hathaway and does not have an audit committee. The Berkshire Hathaway audit committee has considered whether the non-audit services provided to the Registrants by the Deloitte Entities impaired the independence of the Deloitte Entities and concluded that they did not. All of the services performed by the Deloitte Entities were pre-approved in accordance with the pre-approval policy adopted by the Berkshire Hathaway audit committee. The policy provides guidelines for the audit, audit-related, tax and other non-audit services that may be provided by the Deloitte Entities to the Registrants. The policy (a) identifies the guiding principles that must be considered by the Berkshire Hathaway audit committee in approving services to ensure that the Deloitte Entities' independence is not impaired; (b) describes the audit, audit-related and tax services that may be provided and the non-audit services that are prohibited; and (c) sets forth pre-approval requirements for all permitted services.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) Financial Statements and Schedules

(1) Financial Statements

The financial statements of all Registrants are included in their respective Item 8 of this Form 10-K. 103

(2) Financial Statement Schedules

BHE Parent Company Only Condensed Financial Statements (Schedule I) 508
MidAmerican Funding, LLC Parent Company Only Condensed Financial Statements (Schedule I) 513

Schedules not listed above have been omitted because they are either not applicable, not required or the information required to be set forth therein is included on the Consolidated Financial Statements or notes thereto.

(3) Management contracts or compensatory plans are identified by an asterisk in the Exhibit Index filed as part of this Annual Report. 516

(b) Exhibits

The exhibits listed on the accompanying Exhibit Index are filed as part of this Annual Report. 516

Item 16. Form 10-K Summary

None.

Schedule I

BERKSHIRE HATHAWAY ENERGY COMPANY
PARENT COMPANY ONLY
CONDENSED BALANCE SHEETS
(Amounts in millions, except share amounts)

	As of December 31,	
	2025	**2024**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 145	$ 78
Accounts receivable - affiliate	1,637	1,415
Notes receivable - affiliate	7	13
Income tax receivable	43	1
Other current assets	8	7
Total current assets	1,840	1,514
Investments in subsidiaries	62,426	60,499
Other investments	300	277
Goodwill	1,221	1,221
Other assets	1,150	1,280
Total assets	$ 66,937	$ 64,791
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and other current liabilities	$ 364	$ 560
Notes payable - affiliate	602	502
Short-term debt	—	180
Current portion of BHE senior debt	—	1,650
Total current liabilities	966	2,892
BHE senior debt	11,461	11,457
Other long-term liabilities	445	433
Total liabilities	12,872	14,782
Equity:		
Preferred stock - 100,000,000 shares authorized, $0.01 par value, — and 481,000 shares issued and outstanding	—	481
Common stock - 100 shares authorized, no par value, 1 share issued and outstanding	—	—
Additional paid-in capital	5,558	5,558
Retained earnings	50,351	46,311
Accumulated other comprehensive loss, net	(1,844)	(2,341)
Total equity	54,065	50,009
Total liabilities and equity	$ 66,937	$ 64,791

The accompanying notes are an integral part of this financial statement schedule.

Schedule I

BERKSHIRE HATHAWAY ENERGY COMPANY
PARENT COMPANY ONLY
CONDENSED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2025	**2024**	**2023**
Operating expenses:			
General and administration	$ 86	$ 79	$ 77
Depreciation and amortization	5	7	7
Total operating expenses	91	86	84
Operating loss	(91)	(86)	(84)
Other income (expense):			
Interest expense	(604)	(669)	(702)
Other, net	48	57	49
Total other income (expense)	(556)	(612)	(653)
Loss before income tax expense (benefit) and equity income (loss)	(647)	(698)	(737)
Income tax expense (benefit)	(188)	(229)	(233)
Equity income (loss)	4,528	4,769	3,524
Net income attributable to BHE shareholders	4,069	4,300	3,020
Preferred dividends	3	—	34
Earnings on common shares	$ 4,066	$ 4,300	$ 2,986

The accompanying notes are an integral part of this financial statement schedule.

Schedule I

BERKSHIRE HATHAWAY ENERGY COMPANY
PARENT COMPANY ONLY
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME
(Amounts in millions)

	Years Ended December 31,		
	2025	**2024**	**2023**
Net income	$ 4,069	$ 4,300	$ 3,020
Other comprehensive income (loss), net of tax	497	(437)	246
Comprehensive income attributable to BHE shareholders	$ 4,566	$ 3,863	$ 3,266

The accompanying notes are an integral part of this financial statement schedule.

Schedule I

BERKSHIRE HATHAWAY ENERGY COMPANY
PARENT COMPANY ONLY
CONDENSED STATEMENTS OF CASH FLOWS
(In millions)

	Years Ended December 31,		
	2025	**2024**	**2023**
Cash flows from operating activities	$ 4,162	$ 5,375	$ 5,824
Cash flows from investing activities:			
Investments in subsidiaries	(1,875)	(1,053)	(4,995)
Purchases of marketable securities	(5)	(10)	(39)
Proceeds from sales of marketable securities	14	13	35
Notes receivable from affiliate, net	6	6	(571)
Other, net	(19)	4	(18)
Net cash flows from investing activities	(1,879)	(1,040)	(5,588)
Cash flows from financing activities:			
Preferred stock redemptions	(481)	—	(850)
Preferred dividends	(3)	—	(38)
Common stock purchases	—	(2,276)	—
Repayments of BHE senior debt	(1,650)	—	(900)
Repayments of BHE subordinated debt	—	(91)	—
Net (repayments of) proceeds from short-term debt	(180)	(1,755)	1,690
Notes payable to affiliate, net	100	300	—
Notes payable	—	(600)	—
Other, net	(2)	(1)	(4)
Net cash flows from financing activities	(2,216)	(4,423)	(102)
Net change in cash and cash equivalents	67	(88)	134
Cash and cash equivalents at beginning of year	78	166	32
Cash and cash equivalents at end of year	$ 145	$ 78	$ 166

The accompanying notes are an integral part of this financial statement schedule.

Schedule I

BERKSHIRE HATHAWAY ENERGY COMPANY
PARENT COMPANY ONLY
NOTES TO CONDENSED FINANCIAL STATEMENTS

Basis of Presentation - The condensed financial information of BHE investments in subsidiaries are presented under the equity method of accounting. Under this method, the assets and liabilities of subsidiaries are not consolidated. The investments in subsidiaries are recorded in the Condensed Balance Sheets. The income from operations of subsidiaries is reported on a net basis as equity income in the Condensed Statements of Operations.

Dividends and distributions from subsidiaries - Cash dividends paid to BHE by its subsidiaries for the years ended December 31, 2025, 2024 and 2023 were $5.0 billion, $6.8 billion and $6.8 billion, respectively. In January and February 2026, BHE received cash dividends from its subsidiaries totaling $86 million.

Guarantees and commitments - BHE has issued guarantees and letters of credit in respect of subsidiaries, equity method investments and other related parties aggregating $3.9 billion and commitments.

See the notes to the consolidated BHE financial statements in Part II, Item 8 for other disclosures regarding long-term obligations (Notes 9, 10 and 11) and shareholders' equity (Note 18).

Schedule I

MIDAMERICAN FUNDING, LLC
PARENT COMPANY ONLY
CONDENSED BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2025	**2024**
ASSETS		
Investments in and advances to subsidiaries	$ 12,090	$ 11,504
Total assets	$ 12,090	$ 11,504
LIABILITIES AND MEMBER'S EQUITY		
Current liabilities:		
Interest accrued and other current liabilities	$ 6	$ 6
Payable to affiliate	71	59
Long-term debt	240	240
Total liabilities	317	305
Member's equity:		
Paid-in capital	1,679	1,679
Retained earnings	10,094	9,520
Total member's equity	11,773	11,199
Total liabilities and member's equity	$ 12,090	$ 11,504

The accompanying notes are an integral part of this financial statement schedule.

MIDAMERICAN FUNDING, LLC
PARENT COMPANY ONLY
CONDENSED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2025	**2024**	**2023**
Other income (expense):			
Interest expense	$ (17)	$ (17)	$ (17)
Loss before income tax expense (benefit)	(17)	(17)	(17)
Income tax expense (benefit)	(5)	(5)	(5)
Equity in undistributed earnings of subsidiaries	1,060	1,003	992
Net income	$ 1,048	$ 991	$ 980

The accompanying notes are an integral part of this financial statement schedule.

Schedule I

MIDAMERICAN FUNDING, LLC
PARENT COMPANY ONLY
CONDENSED STATEMENTS OF CASH FLOWS
(In millions)

	Years Ended December 31,		
	2025	**2024**	**2023**
Net cash flows from operating activities	$ (12)	$ (11)	$ (12)
Net cash flows from investing activities:			
Dividends from subsidiary	474	425	1,025
Net cash flows from investing activities	474	425	1,025
Net cash flows from financing activities:			
Distributions to member	(474)	(425)	(1,025)
Net change in amounts payable to subsidiary	12	11	12
Net cash flows from financing activities	(462)	(414)	(1,013)
Net change in cash and cash equivalents	—	—	—
Cash and cash equivalents at beginning of year	—	—	—
Cash and cash equivalents at end of year	$ —	$ —	$ —

The accompanying notes are an integral part of this financial statement schedule.

Schedule I

MIDAMERICAN FUNDING, LLC
PARENT COMPANY ONLY
NOTES TO CONDENSED FINANCIAL STATEMENTS

Incorporated by reference are MidAmerican Funding, LLC and Subsidiaries Consolidated Statements of Changes in Member's Equity for the three years ended December 31, 2025, 2024 and 2023 in Part II, Item 8.

Basis of Presentation - The condensed financial information of MidAmerican Funding, LLC's ("MidAmerican Funding's") investments in subsidiaries is presented under the equity method of accounting. Under this method, the assets and liabilities of subsidiaries are not consolidated. The investments in and advances to subsidiaries are recorded on the Condensed Balance Sheets. The income from operations of the subsidiaries is reported on a net basis as equity in undistributed earnings of subsidiary companies on the Condensed Statements of Operations. The Condensed Statements of Comprehensive Income have been omitted as net income equals comprehensive income for the years ended December 31, 2025, 2024 and 2023.

Income Taxes - MidAmerican Funding is not subject to income tax and is disregarded by the taxing authorities. However, a portion of Berkshire Hathaway Inc.'s consolidated income tax expense has been allocated to MidAmerican Funding for presentation in its separate financial statements commensurate with computing MidAmerican Funding's provision on a stand-alone basis.

Payable to Affiliate - MHC, Inc. ("MHC") settles all obligations of MidAmerican Funding including interest costs on, and repayments of, MidAmerican Funding's long-term debt, income taxes and distributions to parent. MHC paid $486 million, $436 million and $1,037 million in 2025, 2024 and 2023, respectively, on behalf of MidAmerican Funding.

Distributions to Parent - In 2025, 2024 and 2023, MidAmerican Funding declared and paid, via MHC, cash dividends of $474 million, $425 million and $1,025 million, respectively.

See the notes to the consolidated MidAmerican Funding financial statements in Part II, Item 8 for other disclosures.

EXHIBIT INDEX

Exhibit No.	Description
BERKSHIRE HATHAWAY ENERGY	
3.1	Fourth Amended and Restated Articles of Incorporation of Berkshire Hathaway Energy Company, effective as of December 30, 2024 (incorporated by reference to Exhibit 3.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated December 31, 2024).
3.2	Amended and Restated Bylaws of Berkshire Hathaway Energy Company (incorporated by reference to Exhibit 3.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2025).
4.1	Indenture, dated as of October 4, 2002, by and between MidAmerican Energy Holdings Company and The Bank of New York, Trustee (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Registration Statement No. 333-101699 dated December 6, 2002).
4.2	Fourth Supplemental Indenture, dated as of March 24, 2006, by and between MidAmerican Energy Holdings Company and The Bank of New York Trust Company, N.A., Trustee, relating to the 6.125% Senior Bonds due 2036 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated March 28, 2006).
4.3	Fifth Supplemental Indenture, dated as of May 11, 2007, by and between MidAmerican Energy Holdings Company and The Bank of New York Trust Company, N.A., Trustee, relating to the 5.95% Senior Bonds due 2037 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated May 11, 2007).
4.4	Sixth Supplemental Indenture, dated as of August 28, 2007, by and between MidAmerican Energy Holdings Company and The Bank of New York Trust Company, N.A., Trustee, relating to the 6.50% Senior Bonds due 2037 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated August 28, 2007).
4.5	Ninth Supplemental Indenture, dated as of November 8, 2013, by and between MidAmerican Energy Holdings Company and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the 5.150% Senior Notes due 2043 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated November 8, 2013).
4.6	Tenth Supplemental Indenture, dated as December 4, 2014, by and between Berkshire Hathaway Energy Company and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the 4.50% Senior Notes due 2045 (incorporated by reference to Exhibit 4.8 to the Berkshire Hathaway Energy Company Registration Statement No. 333-200928 dated December 12, 2014).
4.7	Eleventh Supplemental Indenture, dated as of December 29, 2017, by and between Berkshire Hathaway Energy Company and The Bank of New York Mellon Trust Company, N.A., as trustee, relating to the 6.50% Senior Bonds due 2037 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated January 5, 2018).
4.8	Twelfth Supplemental Indenture, dated as of January 5, 2018, by and between Berkshire Hathaway Energy Company and The Bank of New York Mellon Trust Company, N.A., as trustee, relating to the 3.25% Senior Notes due 2028 and the 3.80% Senior Notes due 2048 (incorporated by reference to Exhibit 4.2 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated January 5, 2018).
4.9	Thirteenth Supplemental Indenture, dated as of July 25, 2018, by and between Berkshire Hathaway Energy Company and The Bank of New York Mellon Trust Company, N.A., as trustee, relating to the 4.45% Senior Notes due 2049 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2018).
4.10	Fifteenth Supplemental Indenture, dated as of March 27, 2020, by and between Berkshire Hathaway Energy Company and The Bank of New York Mellon Trust Company, N.A., as trustee, relating to the 3.70% Senior Notes due 2030 and the 4.25% Senior Notes due 2050 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated March 27, 2020).
4.11	Sixteenth Supplemental Indenture, dated as of October 29, 2020, by and between Berkshire Hathaway Energy Company and The Bank of New York Mellon Trust Company, N.A., as trustee, relating to the 1.650% Senior Notes due 2031 and the 2.850% Senior Notes due 2051 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated November 2, 2020).

Exhibit No.	Description
4.12	Seventeenth Supplemental Indenture, dated as of April 21, 2022, by and between Berkshire Hathaway Energy Company and The Bank of New York Mellon Trust Company, N.A., as trustee, relating to the 4.600% Senior Notes due 2053 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated April 25, 2022).
4.13	Indenture, dated as of October 15, 1997, by and between MidAmerican Energy Holdings Company and IBJ Schroder Bank & Trust Company, Trustee (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated October 23, 1997).
4.14	Form of Second Supplemental Indenture, dated as of September 22, 1998 by and between MidAmerican Energy Holdings Company and IBJ Schroder Bank & Trust Company, Trustee, relating to the 8.48% Senior Notes due 2028 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated September 17, 1998).
4.15	Trust Deed, dated as of February 4, 1998 among Yorkshire Power Finance Limited, Yorkshire Power Group Limited and Bankers Trustee Company Limited, Trustee, relating to the £200,000,000 in principal amount of the 7.25% Guaranteed Bonds due 2028 (incorporated by reference to Exhibit 10.74 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
4.16	First Supplemental Trust Deed, dated as of October 1, 2001, among Yorkshire Power Finance Limited, Yorkshire Power Group Limited and Bankers Trustee Company Limited, Trustee, relating to the £200,000,000 in principal amount of the 7.25% Guaranteed Bonds due 2028 (incorporated by reference to Exhibit 10.75 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
4.17	Trust Deed dated May 5, 2005 among Northern Electric Finance plc, Northern Electric Distribution Limited, Ambac Assurance UK Limited and HSBC Trustee (C.I.) Limited (incorporated by reference to Exhibit 99.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).
4.18	Reimbursement and Indemnity Agreement, dated May 5, 2005 among Northern Electric Finance plc, Northern Electric Distribution Limited and Ambac Assurance UK Limited (incorporated by reference to Exhibit 99.2 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).
4.19	Trust Deed, dated May 5, 2005 among Yorkshire Electricity Distribution plc, Ambac Assurance UK Limited and HSBC Trustee (C.I.) Limited (incorporated by reference to Exhibit 99.3 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).
4.20	Reimbursement and Indemnity Agreement, dated May 5, 2005 between Yorkshire Electricity Distribution plc and Ambac Assurance UK Limited (incorporated by reference to Exhibit 99.4 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).
4.21	Trust Deed, dated as of July 5, 2012, among Northern Powergrid (Yorkshire) plc and HSBC Corporate Trustee Company (UK) Limited, relating to the £150,000,000 in principal amount of the 4.375% Bonds due 2032 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2012).
4.22	Trust Deed, dated as of November 14, 2023, among Northern Powergrid (Yorkshire) plc and HSBC Corporate Trustee Company (UK) Limited, relating to the £250,000,000 in principal amount of the 5.625% Bonds due 2033 (incorporated by reference to Exhibit 4.26 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2023).
4.23	£120,000,000 Finance Contract, dated December 2, 2015, by and between Northern Powergrid (Northeast) Ltd and the European Investment Bank (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2016).
4.24	Guarantee and Indemnity Agreement, dated December 8, 2015, by and between Northern Powergrid Holdings Company and the European Investment Bank (incorporated by reference to Exhibit 4.2 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2016).
4.25	£130,000,000 Finance Contract, dated December 2, 2015, by and between Northern Powergrid (Yorkshire) plc and the European Investment Bank (incorporated by reference to Exhibit 4.3 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2016).
4.26	Guarantee and Indemnity Agreement, dated December 8, 2015, by and between Northern Powergrid Holdings Company and the European Investment Bank (incorporated by reference to Exhibit 4.4 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2016).

Exhibit No.	Description
4.27	Deed of Amendment and Consent, dated March 1, 2016, by and between Northern Powergrid Holdings Company, Northern Powergrid (Yorkshire) plc and the European Investment Bank (incorporated by reference to Exhibit 4.5 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2016).
4.28	Trust Deed, dated as of May 24, 2019, among Northern Electric Finance plc, Northern Powergrid (Northeast) Limited, and HSBC Corporate Trustee Company (UK) Limited, relating to the £150,000,000 in principal amount of the 2.75% Guaranteed Bonds due 2049 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2019).
4.29	Trust Deed, dated as of October 9, 2019, among Northern Powergrid (Yorkshire) plc and HSBC Corporate Trustee Company (UK) Limited, relating to the £300,000,000 in principal amount of the 2.25% Guaranteed Bonds due 2059 (incorporated by reference to Exhibit 4.3 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2019).
4.30	Trust Deed, dated as of June 16, 2020, by and between Northern Powergrid (Northeast) plc and HSBC Corporate Trustee Company (UK) Limited, Trustee, relating to the £300,000,000 in principal amount of 1.875% Green Bonds due 2062 (incorporated by reference to Exhibit 4.3 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2020).
4.31	Trust Deed, dated as of April 1, 2022, among Northern Powergrid (Northeast) plc and HSBC Corporate Trustee Company (UK) Limited, relating to the £350,000,000 in principal amount of the 3.250% Bonds due 2052 (incorporated by reference to Exhibit 4.2 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2022).
4.32	Trust Deed, dated as of March 21, 2025, among Northern Powergrid (Yorkshire) plc, Northern Powergrid (Northeast) plc and HSBC Corporate Trustee Company (UK) Limited, relating to the £1,000,000,000 Euro Medium Term Note Programme (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2025).
4.33	Subscription Agreement, dated as of March 28, 2025, among Northern Powergrid (Yorkshire) plc, Barclays Bank PLC, HSBC Bank plc, Lloyds Bank Corporate Markets plc and RBC Europe Limited, relating to the £250,000,000 in principal amount of the 6.125% Fixed Rate Notes due 2050 (incorporated by reference to Exhibit 4.2 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2025).
4.34	Subscription Agreement, dated as of October 31, 2025, among Northern Powergrid (Northeast) plc, Barclays Bank PLC, HSBC Bank plc, Lloyds Bank Corporate Markets plc and RBC Europe Limited, relating to the £250,000,000 in principal amount of the 5.375% Fixed Rate Notes due 2037.
4.35	Subscription Agreement, dated as of October 31, 2025, among Northern Powergrid (Yorkshire) plc, Barclays Bank PLC, HSBC Bank plc, Lloyds Bank Corporate Markets plc and RBC Europe Limited, relating to the £300,000,000 in principal amount of the 5.875% Fixed Rate Notes due 2055.
4.36	Fiscal Agency Agreement, dated February 12, 2007, by and between Northern Natural Gas Company and The Bank of New York Trust Company, N.A., Fiscal Agent, relating to the $150,000,000 in principal amount of the 5.80% Senior Bonds due 2037 (incorporated by reference to Exhibit 99.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated February 12, 2007).
4.37	Fiscal Agency Agreement, dated August 27, 2012, by and between Northern Natural Gas Company and The Bank of New York Mellon Trust Company, N.A., Fiscal Agent, relating to the $250,000,000 in principal amount of the 4.10% Senior Bonds due 2042 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2012).
4.38	Fiscal Agency Agreement, dated as of July 17, 2018, by and between Northern Natural Gas Company and The Bank of New York Mellon Trust Company, N.A., Fiscal Agent, relating to the $450,000,000 in principal amount of the 4.30% Senior Bonds due 2049 (incorporated by reference to Exhibit 4.2 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2018).
4.39	Amendment No. 1 to the Fiscal Agency Agreement, dated as of July 17, 2018, by and between Northern Natural Gas Company and The Bank of New York Mellon Trust Company, N.A., Fiscal Agent, relating to an additional $200,000,000 in principal amount of the 4.30% Senior Bonds due 2049 (incorporated by reference to Exhibit 4.2 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2019).

Exhibit No.	Description
4.40	Fiscal Agency Agreement, dated as of April 9, 2021, by and between Northern Natural Gas Company and The Bank of New York Mellon Trust Company, N.A., Fiscal Agent, relating to the $550,000,000 in principal amount of the 3.40% Senior Notes due 2051 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2021).
4.41	Fiscal Agency Agreement, dated as of January 31, 2024, by and between Northern Natural Gas Company and The Bank of New York Mellon Trust Company, N.A., Fiscal Agent, relating to the $500,000,000 in principal amount of the 5.625% Senior Notes due 2054 (incorporated by reference to Exhibit 4.41 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2023).
4.42	Amended and Restated Master Trust Indenture, dated April 28, 2003, by and between AltaLink, L.P., AltaLink Management Ltd. and BMO Trust Company (incorporated by reference to Exhibit 4.99 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.43	Seventh Supplemental Indenture, dated April 28, 2003, by and between AltaLink, L.P., AltaLink Management Ltd. and BMO Trust Company (incorporated by reference to Exhibit 4.100 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.44	Ninth Supplemental Indenture, dated May 9, 2006, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada related to the C$150,000,000 in principal amount of 5.249% Series 2006-1 Medium-Term Notes due 2036 (incorporated by reference to Exhibit 4.101 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.45	Tenth Supplemental Indenture, dated May 21, 2008, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada related to the C$125,000,000 in principal amount of 5.381% Series 2010-1 Medium-Term Notes due 2040 (incorporated by reference to Exhibit 4.102 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.46	Twelfth Supplemental Indenture, dated August 18, 2010, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada relating to the C$150,000,000 in principal amount of 4.872% Series 2010-2 Medium-Term Notes due 2040, C$275,000,000 in principal amount of 4.462% Series 2011-1 Medium-Term Notes due 2041 and C$525,000,000 in principal amount of 3.990% Series 2012-1 Medium-Term Notes due 2042 (incorporated by reference to Exhibit 4.103 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.47	Sixteenth Supplemental Indenture, dated November 15, 2012, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada, relating to the C$350,000,000 in principal amount of 4.922% Series 2013-3 Medium-Term Notes due 2043, C$295,000,000 in principal amount of 4.054% Series 2014-3 Medium-Term Notes due 2044, C$250,000,000 in principal amount of 4.446% Series 2013-1 Medium-Term Notes due 2053 and C$130,000,000 in principal amount of 4.274% Series 2014-2 Medium-Term Notes due 2064 (incorporated by reference to Exhibit 4.104 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.48	Eighteenth Supplemental Indenture, dated October 24, 2014, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.106 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.49	Nineteenth Supplemental Indenture, dated October 24, 2014, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.107 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.50	Twentieth Supplemental Indenture, dated June 30, 2015, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada, relating to the C$350,000,000 in principal amount of 2.747% Series 2016-1 Medium-Term Notes due 2026, C$350,000,000 in principal amount of 4.09% Series 2015-1 Medium-Term Notes due 2045 and C$450,000,000 in principal amount of 3.717% Series 2016-2 Medium-Term Notes due 2046 (incorporated by reference to Exhibit 4.5 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2015).
4.51	Twenty-First Supplemental Indenture, dated December 14, 2018, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.64 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2018).

Exhibit No.	Description
4.52	Twenty-Third Supplemental Indenture, dated as of September 11, 2020, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada, as trustee, relating to the C$225,000,000 in principal amount of the 1.509% Series 2020-1 Senior Secured Notes due 2030 (incorporated by reference to Exhibit 4.5 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2020).
4.53	Twenty-Fourth Supplemental Indenture, dated as of November 28, 2022, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada, as trustee, relating to the C$275,000,000 in principal amount of the 4.692% Series 2022-1 Senior Secured Notes due 2032 (incorporated by reference to Exhibit 4.54 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2022).
4.54	Twenty-Fifth Supplemental Indenture, dated as of October 11, 2023, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada, as trustee, relating to the C$500,000,000 in principal amount of the 5.463% Series 2023-1 Senior Secured Notes due 2055 (incorporated by reference to Exhibit 4.1 to Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2023).
4.55	Twenty-Sixth Supplemental Indenture, dated as of May 22, 2024, by and between AltaLink, L.P., AltaLink Management Ltd., and BNY Trust Company of Canada, as trustee, relating to the C$325,000,000 in principal amount of the 4.742% Series 2024-1 Senior Secured Notes due 2054 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2024).
4.56	Indenture, dated as of February 24, 2012, by and between Topaz Solar Farms LLC and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the $850,000,000 in principal amount of the 5.75% Series A Senior Secured Notes due 2039 (incorporated by reference to Exhibit 4.56 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2011).
4.57	First Supplemental Indenture, dated as of April 15, 2013, between Topaz Solar Farms LLC, as Issuer, and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the $250,000,000 in principal amount of the 4.875% Series B Senior Secured Notes due 2039 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2013).
4.58	Indenture, dated as of June 27, 2013, between Solar Star Funding, LLC, as Issuer, and Wells Fargo Bank, National Association, as Trustee, relating to the $1,000,000,000 in principal amount of the 5.375% Series A Senior Secured Notes due 2035 (incorporated by reference to Exhibit 4.2 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2013).
4.59	First Supplemental Indenture, dated as of March 12, 2015, between Solar Star Funding, LLC, as Issuer, and Wells Fargo Bank, National Association, as Trustee, relating to the $325,000,000 in principal amount of the 3.95% Series B Senior Secured Notes due 2035 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2015).
10.1	Third Amendment to the $3,500,000,000 Third Amended and Restated Credit Agreement, dated as of June 30, 2025, among Berkshire Hathaway Energy Company, as Borrower, the Banks, Financial Institutions and Other Institutional Lenders, as Lenders, MUFG Bank, LTD., as Administrative Agent and the LC Issuing Banks (incorporated by reference to Exhibit 10.3 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2025).
10.2	Amended and Restated £200,000,000 Facility Agreement, dated as of December 18, 2025, among Northern Powergrid Holdings Company, as Guarantor, Northern Powergrid (Yorkshire) plc and Northern Powergrid (Northeast) plc, as Borrowers, and Barclays Bank plc, HSBC UK Bank plc, Lloyds Bank plc and Royal Bank of Canada, as Original Lenders (redacted).
10.3	Sixth Amended and Restated Credit Agreement, dated as of March 22, 2024 among AltaLink Investments, L.P., as borrower, AltaLink Investment Management LTD., as general partner, Royal Bank of Canada, as administrative agent, and Lenders (redacted) (incorporated by reference to Exhibit 10.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2024).
10.4	Second Amending Agreement to the Sixth Amended and Restated Credit Agreement, dated as of December 15, 2025 among AltaLink Investments, L.P., as borrower, AltaLink Investment Management LTD., as general partner, Royal Bank of Canada, as administrative agent, and Lenders.
10.5	Fifth Amended and Restated Credit Agreement, dated as of December 15, 2023, among AltaLink L.P., as borrower, AltaLink Management Ltd., as general partner, The Bank of Nova Scotia, as administrative agent, and Lenders (redacted) (incorporated by reference to Exhibit 10.7 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2023).

Exhibit No.	Description
10.6	Second Amending Agreement to the Fifth Amended and Restated Credit Agreement, dated as of December 15, 2025, among AltaLink L.P., as borrower, AltaLink Management Ltd., as general partner, The Bank of Nova Scotia, as administrative agent, and Lenders.
10.7	Sixth Amended and Restated Credit Agreement, dated as of December 15, 2023, among AltaLink, L.P., as borrower, AltaLink Management Ltd., as general partner, The Bank of Nova Scotia, as administrative agent and Lenders (redacted) (incorporated by reference to Exhibit 10.8 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2023).
10.8	Second Amending Agreement to the Sixth Amended and Restated Credit Agreement, dated as of December 15, 2025, among AltaLink, L.P., as borrower, AltaLink Management Ltd., as general partner, The Bank of Nova Scotia, as administrative agent and Lenders.
10.9	Credit Agreement, dated as of December 22, 2023, among BHE Canada Holdings Corporation, as borrower, Bank of Montreal, as administrative agent, and Lenders (redacted) (incorporated by reference to Exhibit 10.12 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2023).
10.10	First Amending Agreement to the Credit Agreement, dated as of February 4, 2025, among BHE Canada Holdings Corporation, as borrower, Bank of Montreal, as administrative agent, and Lenders (incorporated by reference to Exhibit 10.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2025).
10.11	Second Amending Agreement to the Credit Agreement, dated as of December 15, 2025, among BHE Canada Holdings Corporation, as borrower, Bank of Montreal, as administrative agent, and Lenders.
10.12	Berkshire Hathaway Energy Company Executive Voluntary Deferred Compensation Plan as Amended and Restated January 1, 2026 (incorporated by reference to Exhibit 99.2 to the Berkshire Hathaway Energy Company Registration Statement No. 333-292645, dated January 9, 2026).
10.13	Berkshire Hathaway Energy Company Long-Term Incentive Partnership Plan as Amended and Restated December 1, 2024 (incorporated by reference to Exhibit 10.2 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2025).
14.1	Berkshire Hathaway Energy Company Code of Ethics For Chief Executive Officer, Chief Financial Officer and Other Covered Officers (incorporated by reference to Exhibit 14.1 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2015).
21.1	Subsidiaries of the Registrant.
23.1	Consent of Deloitte & Touche LLP.
31.1	Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
PACIFICORP	
3.3	Fourth Restated Article of Incorporation of PacifiCorp, as amended January 31, 2025 (incorporated by reference to Exhibit 3.3 to the PacifiCorp Annual Report on Form 10-K for the year ended December 31, 2024).
3.4	Bylaws of PacifiCorp, as amended December 16, 2024 (incorporated by reference to Exhibit 3.1 to the PacifiCorp Current Report on Form 8-K dated December 16, 2024).
14.2	Code of Ethics (incorporated by reference to Exhibit 14.1 to the PacifiCorp Transition Report on Form 10-K for the nine-month period ended December 31, 2006).
23.2	Consent of Deloitte & Touche LLP.
31.3	Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.4	Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.3	Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.4	Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Exhibit No.	Description

BERKSHIRE HATHAWAY ENERGY AND PACIFICORP

4.60 Mortgage and Deed of Trust dated as of January 9, 1989, between PacifiCorp and The Bank of New York Mellon Trust Company, N.A., as successor Trustee, incorporated by reference to Exhibit 4-E to the PacifiCorp Form 8-B, as supplemented and modified by the following Supplemental Indentures each incorporated by reference:

Exhibit Number	PacifiCorp File Type	File Date
(4)a	10-Q	Quarter ended June 30, 1994
99(a)	8-K	November 21, 2001
4.1	10-Q	Quarter ended June 30, 2003
4	8-K	August 26, 2004
4	8-K	June 14, 2005
4.2	8-K	August 14, 2006
4	8-K	March 14, 2007
4.1	8-K	October 3, 2007
4.1	8-K	July 17, 2008
4.1	8-K	January 8, 2009
4.1	8-K	January 6, 2012
4.1	8-K	June 19, 2015
4.1	8-K	July 13, 2018
4.1	8-K	March 1, 2019
4.1	8-K	April 8, 2020
4.1	8-K	July 9, 2021
4.1	8-K	December 1, 2022
4.1	8-K	May 17, 2023
4.1	8-K	January 5, 2024
4.1	8-K	February 6, 2026

4.61 Indenture, dated as of March 20, 2025, between PacifiCorp and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.1 to the PacifiCorp Current Report on Form 8-K dated March 20, 2025).

4.62 First Supplemental Indenture, dated as of March 20, 2025, between PacifiCorp and The Bank of New York Mellon Trust Company, N.A., as trustee, relating to the 7.375% Fixed-to-Fixed Reset Rate Junior Subordinated Notes due 2055 (including the form of the Notes) (incorporated by reference to Exhibit 4.2 to the PacifiCorp Current Report on Form 8-K dated March 20, 2025).

4.63 Second Supplemental Indenture, dated as of February 5, 2026, between PacifiCorp and The Bank of New York Mellon Trust Company, N.A., as trustee, relating to the 7.125% Fixed-to-Fixed Reset Rate Junior Subordinated Notes due 2056 (including the form of the Notes) (incorporated by reference to Exhibit 4.1 to the PacifiCorp Current Report on Form 8-K dated February 5, 2026).

10.14 Third Amendment to the $2,000,000,000 Third Amended and Restated Credit Agreement, dated as of June 30, 2025, among PacifiCorp, as Borrower, the Banks, Financial Institutions and Other Institutional Lenders, as Lenders, JPMorgan Chase Bank, N.A., as Administrative Agent and the LC Issuing Banks (incorporated by reference to Exhibit 10.4 to the PacifiCorp Quarterly Report on Form 10-Q for the quarter ended June 30, 2025).

10.15 First Amendment to the $900,000,000 364-Day Credit Agreement, dated as of June 27, 2025, among PacifiCorp, as Borrower, the Banks, Financial Institutions and Other Institutional Lenders, as Lenders, and JPMorgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.5 to the PacifiCorp Quarterly Report on Form 10-Q for the quarter ended June 30, 2025).

10.16 Master Purchase and Sale Agreement between PacifiCorp, as the Seller, and BHE B2H, LLC, as the Buyer, dated November 7, 2025 (incorporated by reference to Exhibit 10.1 to the PacifiCorp Current Report on Form 8-K dated November 14, 2025).

Exhibit No.	Description
10.17	Project Schedule No. 1 to Master Purchase and Sale Agreement dated November 7, 2025 (incorporated by reference to Exhibit 10.2 to the PacifiCorp Current Report on Form 8-K dated November 14, 2025).
10.18	Master Lease Agreement between BHE B2H, LLC, as Lessor, and PacifiCorp, as Lessee, dated November 7, 2025 (incorporated by reference to Exhibit 10.3 to the PacifiCorp Current Report on Form 8-K dated November 14, 2025).
10.19	Asset Purchase and Service Area Transfer Agreement, dated as of February 15, 2026, by and among PacifiCorp, Gem Sub LLC and, solely for purposes of Article XI, Portland General Electric Company (incorporated by reference to Exhibit 2.1 to the PacifiCorp Current Report on Form 8-K dated February 15, 2026).
10.20	Long-Form Settlement Agreement, dated February 20, 2026 (incorporated by reference to Exhibit 10.1 to the PacifiCorp Current Report on Form 8-K dated February 20, 2026).
95	Mine Safety Disclosures Required by the Dodd-Frank Wall Street Reform and Consumer Protection Act.
MIDAMERICAN ENERGY	
3.5	Restated Articles of Incorporation of MidAmerican Energy Company, as amended October 27, 1998. (incorporated by reference to Exhibit 3.3 to the MidAmerican Energy Company Quarterly Report on Form 10-Q for the quarter ended September 30, 1998).
3.6	Restated Bylaws of MidAmerican Energy Company, as amended July 24, 1996. (incorporated by reference to Exhibit 3.1 to the MidAmerican Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 1996).
14.3	Code of Ethics for Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer. (incorporated by reference to Exhibit 14.1 to the MidAmerican Energy Company Annual Report on Form 10-K for the year ended December 31, 2003).
23.3	Consent of Deloitte & Touche LLP.
31.5	Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.6	Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.5	Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.6	Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
MIDAMERICAN FUNDING	
3.7	Articles of Organization of MidAmerican Funding, LLC (incorporated by reference to Exhibit 3.1 to the MidAmerican Funding, LLC Registration Statement No. 333-90553 dated November 8, 1999).
3.8	Operating Agreement of MidAmerican Funding, LLC (incorporated by reference to Exhibit 3.2 to the MidAmerican Funding, LLC Registration Statement No. 333-90553 dated November 8, 1999).
3.9	Amendment No. 1 to the Operating Agreement of MidAmerican Funding, LLC dated as of February 9, 2010 (incorporated by reference to Exhibit 3.3 to the MidAmerican Funding, LLC Annual Report on Form 10-K for the year ended December 31, 2009).
14.4	Code of Ethics for Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer (incorporated by reference to Exhibit 14.2 to the MidAmerican Funding, LLC Annual Report on Form 10-K for the year ended December 31, 2003).
31.7	Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.8	Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.7	Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.8	Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
BERKSHIRE HATHAWAY ENERGY, MIDAMERICAN ENERGY AND MIDAMERICAN FUNDING	
4.64	Form of Indenture, by and between MidAmerican Energy Company and The Bank of New York, Trustee (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Registration Statement No. 333-59760 dated January 31, 2002).

Exhibit No.	Description
4.65	First Supplemental Indenture, dated as of February 8, 2002, by and between MidAmerican Energy Company and The Bank of New York, Trustee (incorporated by reference to Exhibit 4.3 to the MidAmerican Energy Company Annual Report on Form 10-K for the year ended December 31, 2004).
4.66	Fourth Supplemental Indenture, dated November 1, 2005, by and between MidAmerican Energy Company and The Bank of New York Trust Company, NA, Trustee (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Annual Report on Form 10-K for the year ended December 31, 2005).
4.67	Indenture, dated as of October 1, 2006, by and between MidAmerican Energy Company and The Bank of New York Trust Company, N.A., Trustee (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2006).
4.68	First Supplemental Indenture, dated as of October 6, 2006, by and between MidAmerican Energy Company and The Bank of New York Trust Company, N.A., Trustee relating to the 5.80% Notes due 2036 (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2006).
4.69	Indenture, dated as of September 9, 2013, between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Current Report on Form 8-K dated September 13, 2013).
4.70	First Supplemental Indenture, dated as of September 19, 2013, between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Current Report on Form 8-K dated September 19, 2013).
4.71	Specimen of 4.80% First Mortgage Bonds due 2043 (incorporated by reference to Exhibit 4.4 to the MidAmerican Energy Company Current Report on Form 8-K dated September 19, 2013).
4.72	Amendment No. 1 to the First Supplemental Indenture, dated as of April 3, 2014, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of September 9, 2013 (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Current Report on Form 8-K dated April 3, 2014).
4.73	Second Supplemental Indenture, dated as of April 3, 2014, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of September 9, 2013 (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Company Current Report on Form 8-K dated April 3, 2014).
4.74	Specimen of 4.40% First Mortgage Bonds due 2044 (incorporated by reference to Exhibit 4.5 to the MidAmerican Energy Company Current Report on Form 8-K dated April 3, 2014).
4.75	Amendment No. 1 to the Second Supplemental Indenture, dated as of October 15, 2015, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of September 9, 2013 (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Current Report on Form 8-K dated October 15, 2015).
4.76	Third Supplemental Indenture, dated as of October 15, 2015, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of September 9, 2013 (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Company Current Report on Form 8-K dated October 15, 2015).
4.77	Specimen of 4.25% First Mortgage Bonds due 2046 (incorporated by reference to Exhibit 4.4 to the MidAmerican Energy Company Current Report on Form 8-K dated October 15, 2015).
4.78	Fourth Supplemental Indenture, dated as of December 8, 2016, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of September 9, 2013 (incorporated by reference to Exhibit 4.96 to the MidAmerican Energy Company Annual Report on Form 10-K for the year ended December 31, 2016).
4.79	Fifth Supplemental Indenture, dated as of February 1, 2017, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of September 9, 2013 (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Current Report on Form 8-K dated February 1, 2017).
4.80	Specimen of 3.10% First Mortgage Bonds due 2027 (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Company Current Report on Form 8-K dated February 1, 2017).
4.81	Specimen of 3.95% First Mortgage Bonds due 2047 (incorporated by reference to Exhibit 4.3 to the MidAmerican Energy Company Current Report on Form 8-K dated February 1, 2017).

Exhibit No.	Description
4.82	Sixth Supplemental Indenture, dated as of December 14, 2017, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of September 9, 2013 (incorporated by reference to Exhibit 4.91 to the MidAmerican Energy Company Annual Report on Form 10-K for the year ended December 31, 2017).
4.83	Seventh Supplemental Indenture, dated as of February 1, 2018, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of September 9, 2013 (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Current Report on Form 8-K dated February 1, 2018).
4.84	Specimen of 3.65% First Mortgage Bonds due 2048 (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Company Current Report on Form 8-K dated February 1, 2018).
4.85	Eighth Supplemental Indenture, dated January 9, 2019, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of September 9, 2013 (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Current Report on Form 8-K dated January 9, 2019).
4.86	Specimen of 3.65% First Mortgage Bonds due 2029 (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Company Current Report on Form 8-K dated January 9, 2019).
4.87	Specimen of 4.25% First Mortgage Bonds due 2049 (incorporated by reference to Exhibit 4.3 to the MidAmerican Energy Company Current Report on Form 8-K dated January 9, 2019).
4.88	Amendment No. 1 to the Eighth Supplemental Indenture, dated as of October 15, 2019, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of September 9, 2013 (incorporated by reference to Exhibit 4.3 to the MidAmerican Energy Company Current Report on Form 8-K dated October 15, 2019).
4.89	Ninth Supplemental Indenture, dated as of October 15, 2019, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of September 9, 2013 (incorporated by reference to Exhibit 4.4 to the MidAmerican Energy Company Current Report on Form 8-K dated October 15, 2019).
4.90	Specimen of 3.15% First Mortgage Bond due 2050 (incorporated by reference to Exhibit 4.4 to the MidAmerican Energy Company Current Report on Form 8-K dated October 15, 2019).
4.91	Tenth Supplemental Indenture, dated as of July 22, 2021, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of September 9, 2013 (incorporated by reference to Exhibit 4.3 to the MidAmerican Energy Company Current Report on Form 8-K dated July 22, 2021).
4.92	Specimen of the 2.70% First Mortgage Bonds due 2052 (incorporated by reference to Exhibit 4.4 to the MidAmerican Energy Company Current Report on Form 8-K dated July 22, 2021).
4.93	Eleventh Supplemental Indenture, dated as of September 7, 2023, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of September 9, 2013 (incorporated by reference to Exhibit 4.3 to the MidAmerican Energy Company Current Report on Form 8-K dated September 7, 2023).
4.94	Specimen of the 5.350% First Mortgage Bonds due 2034 (incorporated by reference to Exhibit 4.4 to the MidAmerican Energy Company Current Report on Form 8-K dated September 7, 2023).
4.95	Specimen of the 5.850% First Mortgage Bonds due 2054 (incorporated by reference to Exhibit 4.5 to the MidAmerican Energy Company Current Report on Form 8-K dated September 7, 2023).
4.96	Twelfth Supplemental Indenture, dated January 24, 2024, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.3 to the MidAmerican Energy Company Current Report on Form 8-K dated January 24, 2024).
4.97	Specimen of the 5.300% First Mortgage Bonds due 2055 (incorporated by reference to Exhibit 4.4 to the MidAmerican Energy Company Current Report on Form 8-K dated January 24, 2024).
4.98	Thirteenth Supplemental Indenture, dated November 5, 2025, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.3 to the MidAmerican Energy Company Current Report on Form 8-K dated November 5, 2025).
4.99	Specimen of the 5.500% First Mortgage Bonds due 2056 (incorporated by reference to Exhibit 4.4 to the MidAmerican Energy Company Current Report on Form 8-K dated November 5, 2025).

Exhibit No.	Description
4.100	Mortgage, Security Agreement, Fixture Filing and Financing Statement, dated as of September 9, 2013, from MidAmerican Energy Company to The Bank of New York Mellon Trust Company, N.A., as collateral trustee (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Company Current Report on Form 8-K dated September 13, 2013).
4.101	Intercreditor and Collateral Trust Agreement, dated as of September 9, 2013, among MidAmerican Energy Company, The Bank of New York Mellon Trust Company, N.A., as trustee, and The Bank of New York Mellon Trust Company, N.A., as collateral trustee (incorporated by reference to Exhibit 4.3 to the MidAmerican Energy Company Current Report on Form 8-K dated September 13, 2013).
4.102	Form of Indenture, between MidAmerican Energy Company and the Trustee, (Senior Unsecured Debt Securities) (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Registration Statement No. 333-192077 dated November 4, 2013).
4.103	Form of Indenture, between MidAmerican Energy Company and the Trustee, (Subordinated Unsecured Debt Securities) (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Company Registration Statement No. 333-192077 dated November 4, 2013).
10.21	Third Amendment to the $1,500,000,000 Third Amended and Restated Credit Agreement, dated as of June 30, 2025, among MidAmerican Energy Company, as Borrower, the Banks, Financial Institutions and Other Institutional Lenders, as Lenders, Mizuho Bank, Ltd., as Administrative Agent and the LC Issuing Banks (incorporated by reference to Exhibit 10.6 to the MidAmerican Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2025).
BERKSHIRE HATHAWAY ENERGY AND MIDAMERICAN FUNDING	
4.104	Indenture and First Supplemental Indenture, dated March 11, 1999, by and between MidAmerican Funding, LLC and IBJ Whitehall Bank & Trust Company, Trustee, relating to the $325 million Senior Bonds (incorporated by reference to Exhibits 4.1 and 4.2 to the MidAmerican Funding, LLC Registration Statement No. 333-905333 dated November 8, 1999).
NEVADA POWER	
3.10	Restated Articles of Incorporation of Nevada Power Company, dated July 28, 1999 (incorporated by reference to Exhibit 3(B) to the Nevada Power Company Annual Report on Form 10-K for the year ended December 31, 1999).
3.11	Amended and Restated Bylaws of Nevada Power Company as amended December 21, 2017 (incorporated by reference to Exhibit 3.1 to the Nevada Power Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2018).
4.105	Financing Agreement dated May 1, 2017 between Clark County, Nevada and Nevada Power Company (relating to Clark County, Nevada's $39,500,000 Pollution Control Refunding Revenue Bonds) (Nevada Power Company Project) Series 2017) (incorporated by reference to Exhibit 4.1 to the Nevada Power Company Current Report on Form 8-K dated May 25, 2017).
4.106	Financing Agreement dated May 1, 2017 between the Coconino County, Arizona Pollution Control Corporation and Nevada Power Company (relating to the Coconino County, Arizona Pollution Control Corporation's $53,000,000 Pollution Control Refunding Revenue Bonds (Nevada Power Company Projects) Series 2017A and 2017B) (incorporated by reference to Exhibit 4.2 to the Nevada Power Company Current Report on Form 8-K dated May 25, 2017).
10.22	Transmission Use and Capacity Exchange Agreement between Nevada Power Company, Sierra Pacific Power Company and Great Basin Transmission, LLC dated August 20, 2010 (incorporated by reference to Exhibit 10.1 to the Nevada Power Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2010).
14.5	Code of Ethics for Chief Executive Officer, Chief Financial Officer and Other Covered Officers (incorporated by reference to Exhibit 14.1 to the Nevada Power Company Annual Report on Form 10-K for the year ended December 31, 2013).
23.4	Consent of Deloitte & Touche LLP.
31.9	Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.10	Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.9	Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.10	Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Exhibit No.	Description
BERKSHIRE HATHAWAY ENERGY AND NEVADA POWER	
4.107	General and Refunding Mortgage Indenture, dated May 1, 2001, between Nevada Power Company and The Bank of New York, as Trustee (incorporated by reference to Exhibit 4.1(a) to the Nevada Power Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2001).
4.108	Second Supplemental Indenture, dated as of October 1, 2001 (incorporated by reference to Exhibit 4(A) to the Nevada Power Company Annual Report on Form 10-K for the year ended December 31, 2001).
4.109	Officer's Certificate establishing the terms of Nevada Power Company's 6.65% General and Refunding Mortgage Notes, Series N, due 2036 (incorporated by reference to Exhibit 4.1 to the Nevada Power Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2006).
4.110	Officer's Certificate establishing the terms of Nevada Power Company's 6.75% General and Refunding Mortgage Notes, Series R, due 2037 (incorporated by reference to Exhibit 4.1 to the Nevada Power Company Current Report on Form 8-K dated June 27, 2007).
4.111	Officer's Certificate establishing the terms of Nevada Power Company 5.375% General and Refunding Mortgage Notes, Series X, due 2040 (incorporated by reference to Exhibit 4.1 to Nevada Power Company Current Report on Form 8-K dated September 10, 2010).
4.112	Officer's Certificate establishing the terms of Nevada Power Company 5.45% General and Refunding Mortgage Notes, Series Y, due 2041 (incorporated by reference to Exhibit 4.1 to the Nevada Power Company Current Report on Form 8-K dated May 10, 2011).
4.113	Officer's Certificate establishing the terms of Nevada Power Company's General and Refunding Mortgage Notes, Series AA (Nos. AA-1 and AA-2) (incorporated by reference to Exhibit 4.3 to the Nevada Power Company Current Report on Form 8-K dated May 25, 2017).
4.114	Officer's Certificate establishing the terms of Nevada Power Company's 3.70% General and Refunding Mortgage Notes, Series CC, due 2029 (incorporated by reference to Exhibit 4.1 to the Nevada Power Company Current Report on Form 8-K dated January 30, 2019).
4.115	Officer's Certificate establishing the terms of Nevada Power Company's 2.40% General and Refunding Mortgage Notes, Series DD, due 2030 (incorporated by reference to Exhibit 4.1 to the Nevada Power Company Current Report on Form 8-K dated January 30, 2020).
4.116	Officer's Certificate establishing the terms of Nevada Power Company's 3.125% General and Refunding Mortgage Notes, Series EE, due 2050 (incorporated by reference to Exhibit 4.2 to the Nevada Power Company Current Report on Form 8-K dated January 30, 2020).
4.117	Officer's Certificate establishing the terms of Nevada Power Company's 5.90% General and Refunding Mortgage Notes, Series GG, due 2053 (incorporated by reference to Exhibit 4.1 to the Nevada Power Company Current Report on Form 8-K dated October 20, 2022).
4.118	Officer's Certificate establishing the terms of Nevada Power Company's 6.000% General and Refunding Mortgage Notes, Series 2023A, due 2054 (incorporated by reference to Exhibit 4.1 to the Nevada Power Company Current Report on Form 8-K dated September 14, 2023).
4.119	Indenture, dated as of February 3, 2025, by and between Nevada Power Company and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.1 to the Nevada Power Company Current Report on Form 8-K dated February 5, 2025).
4.120	First Supplemental Indenture, dated as of February 3, 2025, by and between Nevada Power Company and The Bank of New York Mellon Trust Company, N.A., as trustee relating to the 6.250% Fixed-to-Fixed Reset Rate Junior Subordinated Notes due 2055 (incorporated by reference to Exhibit 4.2 to the Nevada Power Company Current Report on Form 8-K dated February 5, 2025).
10.23	Third Amendment to the $600,000,000 Fifth Amended and Restated Credit Agreement, dated as of June 30, 2025, among Nevada Power Company, as Borrower, the Banks, Financial Institutions and Other Institutional Lenders, as Lenders, Wells Fargo Bank, National Association, as Administrative Agent and the LC Issuing Banks (incorporated by reference to Exhibit 10.7 to the Nevada Power Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2025).
SIERRA PACIFIC	
3.12	Restated Articles of Incorporation of Sierra Pacific Power Company, dated January 23, 2019 (incorporated by reference to Exhibit 3.2 to the Sierra Pacific Power Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2023).

Exhibit No.	Description
3.13	Amended and Restated Bylaws of Sierra Pacific Power Company as amended December 21, 2017 (incorporated by reference to Exhibit 3.2 to the Sierra Pacific Power Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2018).
4.121	Financing Agreement dated May 1, 2016 between Washoe County, Nevada and Sierra Pacific Power Company (relating to Washoe County, Nevada's $80,000,000 Water Facilities Refunding Revenue Bonds (Sierra Pacific Power Company Project) Series 2016C, 2016D and 2016E) (incorporated by reference to Exhibit 4.1 to the Sierra Pacific Power Company Current Report on Form 8-K dated May 24, 2016).
4.122	Financing Agreement dated May 1, 2016 between Washoe County, Nevada and Sierra Pacific Power Company (relating to Washoe County, Nevada's $213,930,000 Gas Facilities Refunding Revenue Bonds, Gas and Water Facilities Refunding Revenue Bonds and Water Facilities Refunding Revenue Bonds (Sierra Pacific Power Company Projects) Series 2016A, 2016B, 2016F and 2016G (incorporated by reference to Exhibit 4.2 to the Sierra Pacific Power Company Current Report on Form 8-K dated May 24, 2016).
4.123	Financing Agreement dated May 1, 2016 between Humboldt County, Nevada and Sierra Pacific Power Company (relating to Humboldt County, Nevada's $49,750,000 Pollution Control Refunding Revenue Bonds (Sierra Pacific Power Company Project) Series 2016A and 2016B (incorporated by reference to Exhibit 4.3 to the Sierra Pacific Power Company Current Report on Form 8-K dated May 24, 2016).
10.24	Transmission Use and Capacity Exchange Agreement between Nevada Power Company, Sierra Pacific Power Company and Great Basin Transmission, LLC dated August 20, 2010 (incorporated by reference to Exhibit 10.1 to the Sierra Pacific Power Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2010).
10.25	$200,000,000 Demand Promissory Note, dated as of April 14, 2022, among Sierra Pacific Power Company, as the Maker, and NV Energy Inc., as the Holder (incorporated by reference to Exhibit 10.1 to the Sierra Pacific Power Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2022).
14.6	Code of Ethics for Chief Executive Officer, Chief Financial Officer and Other Covered Officers (incorporated by reference to Exhibit 14.1 to the Sierra Pacific Power Company Annual Report on Form 10-K for the year ended December 31, 2013).
23.5	Consent of Deloitte & Touche LLP.
31.11	Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.12	Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.11	Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.12	Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

BERKSHIRE HATHAWAY ENERGY AND SIERRA PACIFIC

4.124	General and Refunding Mortgage Indenture, dated as of May 1, 2001, between Sierra Pacific Power Company and The Bank of New York, as Trustee (incorporated by reference to Exhibit 4.2(a) to the Sierra Pacific Power Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2001).
4.125	Second Supplemental Indenture, dated as of October 30, 2006, to subject additional properties of Sierra Pacific Power Company located in the State of California to the lien of the General and Refunding Mortgage Indenture and to correct defects in the original Indenture (incorporated by reference to Exhibit 4(A) to the Sierra Pacific Power Company Annual Report on Form 10-K for the year ended December 31, 2006).
4.126	Third Supplemental Indenture, dated as of May 31, 2022, by and between Sierra Pacific Power Company and the Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.3 to the Sierra Pacific Power Company Current Report on Form 8-K dated September 18, 2023).
4.127	Officer's Certificate establishing the terms of Sierra Pacific Power Company's 6.75% General and Refunding Mortgage Notes, Series P, due 2037 (incorporated by reference to Exhibit 4.2 to the Sierra Pacific Power Company Current Report on Form 8-K dated June 27, 2007).
4.128	Officer's Certificate establishing the terms of Sierra Pacific Power Company's 2.60% General and Refunding Mortgage Notes, Series U, due 2026 (incorporated by reference to Exhibit 4.1 to the Sierra Pacific Power Company Current Report on Form 8-K dated April 15, 2016).
4.129	Officer's Certificate establishing the terms of Sierra Pacific Power Company's General and Refunding Mortgage Notes, Series V (Nos. V-1, V-2 and V-3) (incorporated by reference to Exhibit 4.4 to the Sierra Pacific Power Company Current Report on Form 8-K dated May 24, 2016).

Exhibit No.	Description
4.130	Officer's Certificate establishing the terms of Sierra Pacific Power Company's 4.71% General and Refunding Mortgage Bonds, Series W, due 2052 (incorporated by reference to Exhibit 4.3 to the Sierra Pacific Power Company Current Report on Form 8-K dated June 3, 2022).
4.131	Bond Purchase Agreement, dated as of May 31, 2022, by and among Sierra Pacific Power Company and the Purchasers, relating to the $250,000,000 in principal amount of the 4.71% General and Refunding Mortgage Bonds due 2052 (incorporated by reference to Exhibit 4.1 to the Sierra Pacific Power Company Current Report on Form 8-K dated June 3, 2022).
4.132	Officer's Certificate establishing the terms of Sierra Pacific Power Company's 5.900% General and Refunding Mortgage Bonds, Series 2023A, due 2054 (incorporated by reference to Exhibit 4.1 to the Sierra Pacific Power Company Current Report on Form 8-K dated September 18, 2023).
4.133	Indenture, dated as of September 8, 2025, by and between Sierra Pacific Power Company and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.5 to the Sierra Pacific Power Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2025).
4.134	First Supplemental Indenture, dated as of September 8, 2025, by and between Sierra Pacific Power Company and The Bank of New York Mellon Trust Company, N.A., as trustee, relating to the 6.200% Fixed-to-Fixed Reset Rate Junior Subordinated Notes due 2055 (incorporated by reference to Exhibit 4.6 to the Sierra Pacific Power Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2025).
10.26	Third Amendment to the $400,000,000 Fifth Amended and Restated Credit Agreement, dated as of June 30, 2025, among Sierra Pacific Power Company, as Borrower, the Banks, Financial Institutions and Other Institutional Lenders, as Lenders, Wells Fargo Bank, National Association, as Administrative Agent and the LC Issuing Banks (incorporated by reference to Exhibit 10.8 to the Sierra Pacific Power Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2025).
EASTERN ENERGY GAS	
3.14	Articles of Organization of Dominion Energy Gas Holdings, LLC (incorporated by reference to Exhibit 3.1 to the Dominion Energy Gas Holdings, LLC Form S-4 dated April 4, 2014).
3.15	Articles of Amendment to the Articles of Organization of Eastern Energy Gas Holdings, LLC (incorporated by reference to Exhibit 3.1 to the Eastern Energy Gas Holdings, LLC Current Report on Form 8-K dated November 2, 2020).
3.16	Operating Agreement of Eastern Energy Gas Holdings, LLC, as amended and restated, effective November 2, 2020 (incorporated by reference to Exhibit 3.2 to the Eastern Energy Gas Holdings, LLC Current Report on Form 8-K dated November 2, 2020).
10.27	Distribution and Assumption Agreement (incorporated by reference to Exhibit 10.1 to the Eastern Energy Gas Holdings, LLC Current Report on Form 8-K dated November 2, 2020).
10.28	Distribution, Contribution and Assumption Agreement (incorporated by reference to Exhibit 10.2 to the Eastern Energy Gas Holdings, LLC Current Report on Form 8-K dated November 2, 2020).
10.29	Amended and Restated $400,000,000 Inter-Company Credit Agreement, dated as of March 1, 2023, by and between BHE GT&S, LLC and Eastern Energy Gas Holdings, LLC (incorporated by reference to Exhibit 10.4 to the Eastern Energy Gas Holdings. LLC Quarterly Report on Form 10-Q for the quarter ended March 31, 2023).
10.30	Amended and Restated $650,000,000 Inter-Company Credit Agreement, dated as of November 15, 2022, by and between BHE GT&S, LLC and Eastern Energy Gas Holdings, LLC (incorporated by reference to Exhibit 10.37 to the Eastern Energy Gas Holdings, LLC Annual Report on Form 10-K for the year ended December 31, 2023).
23.6	Consent of Deloitte & Touche LLP.
31.13	Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.14	Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.13	Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.14	Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Exhibit No.	Description
BERKSHIRE HATHAWAY ENERGY AND EASTERN ENERGY GAS	
4.135	Indenture, dated as of October 1, 2013, by and between Dominion Energy Gas Holdings, LLC and Deutsche Bank Trust Company Americas, Trustee (incorporated by reference to Exhibit 4.1, Form S-4, File No. 333-195066 dated April 4, 2014).
4.136	Third Supplemental Indenture, dated as of October 1, 2013, by and between Dominion Energy Gas Holdings, LLC and Deutsche Bank Trust Company Americas, Trustee, relating to the 4.80% Senior Notes due 2043 (incorporated by reference to Exhibit 4.4, Form S-4, File No. 333-195066, dated April 4, 2014).
4.137	Sixth Supplemental Indenture, dated as of December 1, 2014, by and between Dominion Energy Gas Holdings, LLC and Deutsche Bank Trust Company Americas, Trustee, relating to the 4.60% Senior Notes due 2044 (incorporated by reference to Exhibit 4.4 to the Eastern Energy Gas Holdings, LLC Current Report on Form 8-K dated December 8, 2014).
4.138	Eighth Supplemental Indenture, dated as of May 1, 2016, by and between Dominion Energy Gas Holdings, LLC and Deutsche Bank Trust Company Americas, Trustee, relating to the 3.80% Senior Notes due 2031 (incorporated by reference to Exhibit 4.1.a to the Eastern Energy Gas Holdings, LLC Quarterly Report on Form 10-Q for the quarter ended June 30, 2016).
4.139	Ninth Supplemental Indenture, dated as of June 1, 2016, by and between Dominion Energy Gas Holdings, LLC and Deutsche Bank Trust Company Americas, Trustee, relating to the 1.45% Senior Notes due 2026 (incorporated by reference to Exhibit 4.1.b to the Eastern Energy Gas Holdings, LLC Quarterly Report on Form 10-Q for the quarter ended June 30, 2016).
4.140	Thirteenth Supplemental Indenture, dated November 1, 2019, by and between Dominion Energy Gas Holdings, LLC and Deutsche Bank Trust Company Americas, Trustee, relating to the 3.00% Senior Notes due 2029 (incorporated by reference to Exhibit 4.3 to the Eastern Energy Gas Holdings, LLC Current Report on Form 8-K dated November 21, 2019).
4.141	Fourteenth Supplemental Indenture, dated November 1, 2019, by and between Dominion Energy Gas Holdings, LLC and Deutsche Bank Trust Company Americas, Trustee, relating to the 3.90% Senior Notes due 2049 (incorporated by reference to Exhibit 4.4 to the Eastern Energy Gas Holdings, LLC Current Report on Form 8-K dated November 21, 2019).
4.142	Fifteenth Supplemental Indenture, dated as of June 30, 2021, by and between Eastern Energy Gas Holdings, LLC and Deutsche Bank Trust Company Americas, as trustee, to the Indenture dated as of October 1, 2013, by and between Eastern Energy Gas Holdings, LLC and Deutsche Bank Trust Company Americas (incorporated by reference to Exhibit 4.1 to the Eastern Energy Gas Holdings, LLC Current Report on Form 8-K dated July 1, 2021).
4.143	Sixteenth Supplemental Indenture, dated as of October 9, 2024, by and between Eastern Energy Gas Holdings, LLC and Deutsche Bank Trust Company Americas, as trustee, relating to the 5.65% Senior Notes due 2054 (incorporated by reference to Exhibit 4.2 to the Eastern Energy Gas Holdings, LLC Current Report on Form 8-K dated October 9, 2024).
4.144	Seventeenth Supplemental Indenture, dated January 15, 2025, by and between Eastern Energy Gas Holdings, LLC and Deutsche Bank Trust Company, LLC and Deutsche Bank Trust Company Americas, as trustee, relating to the 5.80% Senior Notes due 2035 (incorporated by reference to Exhibit 4.2 to the Eastern Energy Gas Holdings, LLC Current Report on Form 8-K dated January 15, 2025).
4.145	Eighteenth Supplemental Indenture, dated January 15, 2025, by and between Eastern Energy Gas Holdings, LLC and Deutsche Bank Trust Company, LLC and Deutsche Bank Trust Company Americas, as trustee, relating to the 6.20% Senior Notes due 2055 (incorporated by reference to Exhibit 4.3 to the Eastern Energy Gas Holdings, LLC Current Report on Form 8-K dated January 15, 2025).
4.146	Description of Dominion Energy Gas Holdings, LLC's 4.60% Series C Senior Notes due 2044 (incorporated by reference to Exhibit 4.21 to the Dominion Energy Gas Holdings, LLC Annual Report on Form 10-K for the year ended December 31, 2019).
EASTERN GAS TRANSMISSION AND STORAGE	
3.17	Certificate of Incorporation of Consolidated Gas Transmission Corporation (incorporated by reference to Exhibit 3.1, Form S-4, File No. 333-266049 dated July 25, 2022).
3.18	Bylaws of Dominion Energy Transmission, Inc. (incorporated by reference to Exhibit 3.2, Form S-4, File No. 333-266049 dated July 25, 2022).

Exhibit No.	Description
10.31	Amended and Restated $400,000,000 Inter-Company Credit Agreement, dated as of March 1, 2023, by and between Eastern Energy Gas Holdings, LLC and Eastern Gas Transmission and Storage, Inc. (incorporated by reference to Exhibit 10.5 to the Eastern Gas Transmission and Storage, Inc. Quarterly Report on Form 10-Q for the quarter ended March 31, 2023).
10.32	Amended and Restated $400,000,000 Inter-Company Credit Agreement, dated as of March 1, 2023, by and between Eastern Gas Transmission and Storage, Inc. and Eastern Energy Gas Holdings, LLC (incorporated by reference to Exhibit 10.6 to the Eastern Gas Transmission and Storage Inc. Quarterly Report on Form 10-Q for the quarter ended March 31, 2023).
31.15	Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.16	Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.15	Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.16	Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

BERKSHIRE HATHAWAY ENERGY AND EASTERN GAS TRANSMISSION AND STORAGE

4.147	Indenture, dated as of June 30, 2021, by and between Eastern Gas Transmission and Storage, Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.6 to the Eastern Energy Gas Holdings, LLC Quarterly Report on Form 10-Q for the quarter ended June 30, 2021).
4.148	First Supplemental Indenture, dated as of June 30, 2021, by and between Eastern Gas Transmission and Storage, Inc. and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of June 30, 2021, and relating to the 3.900% Senior Notes due 2049 (incorporated by reference to Exhibit 4.7 to the Eastern Energy Gas Holdings, LLC Quarterly Report on Form 10-Q for the quarter ended June 30, 2021).
4.149	Second Supplemental Indenture, dated as of June 30, 2021, by and between Eastern Gas Transmission and Storage, Inc. and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of June 30, 2021, and relating to the 4.600% Senior Notes due 2044 (incorporated by reference to Exhibit 4.8 to the Eastern Energy Gas Holdings, LLC Quarterly Report on Form 10-Q for the quarter ended June 30, 2021).
4.150	Third Supplemental Indenture, dated as of June 30, 2021, by and between Eastern Gas Transmission and Storage, Inc. and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of June 30, 2021, and relating to the 4.800% Senior Notes due 2043 (incorporated by reference to Exhibit 4.9 to the Eastern Energy Gas Holdings, LLC Quarterly Report on Form 10-Q for the quarter ended June 30, 2021).
4.151	Fourth Supplemental Indenture, dated as of June 30, 2021, by and between Eastern Gas Transmission and Storage, Inc. and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of June 30, 2021, and relating to the 3.000% Senior Notes due 2029 (incorporated by reference to Exhibit 4.10 to the Eastern Energy Gas Holdings, LLC Quarterly Report on Form 10-Q for the quarter ended June 30, 2021).
4.152	Sixth Supplemental Indenture, dated as of December 10, 2024, by and between Eastern Gas Transmission and Storage, Inc. and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of June 30, 2021, and relating to the 5.020% Senior Notes due 2034 (incorporated by reference to Exhibit 4.2 to the Eastern Gas Transmission and Storage, Inc. Current Report on Form 8-K dated December 10, 2024).

ALL REGISTRANTS

101	The following financial information from each respective Registrant's Annual Report on Form 10-K for the year ended December 31, 2025 is formatted in iXBRL (Inline eXtensible Business Reporting Language) and included herein: (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Operations, (iii) the Consolidated Statements of Comprehensive Income, (iv) the Consolidated Statements of Changes in Equity, (v) the Consolidated Statements of Cash Flows and (vi) the Notes to Consolidated Financial Statements, tagged in summary and detail.
104	Cover Page Interactive Data File formatted in iXBRL (Inline eXtensible Business Reporting Language) and contained in Exhibit 101.

(a) Not available electronically on the SEC website as it was filed in paper previous to the electronic system currently in place.

Pursuant to Item 601(b)(4)(iii)(A) of Regulation S-K, each Registrant has not filed as an exhibit to this Form 10-K certain instruments with respect to long-term debt not registered in which the total amount of securities authorized thereunder does not exceed 10% of the total assets of the respective Registrant. Each Registrant hereby agrees to furnish a copy of any such instrument to the Commission upon request.

SIGNATURES

BERKSHIRE HATHAWAY ENERGY COMPANY

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 on this 27th day of February 2026.

BERKSHIRE HATHAWAY ENERGY COMPANY

/s/ Mark A. Hewett
Mark A. Hewett
Director, President and Chief Executive Officer
(principal 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/ Mark A. Hewett Mark A. Hewett	Director, President and Chief Executive Officer (principal executive officer)	February 27, 2026
/s/ Charles C. Chang Charles C. Chang	Director, Senior Vice President and Chief Financial Officer (principal financial and accounting officer)	February 27, 2026
/s/ Scott W. Thon Scott W. Thon	Director	February 27, 2026
/s/ Natalie L. Hocken Natalie L. Hocken	Director	February 27, 2026

SIGNATURES

PACIFICORP

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 on this 27th day of February 2026.

PACIFICORP

/s/ M. Ryan Weems
M. Ryan Weems
Director, Senior Vice President, Chief Financial Officer and Treasurer
(principal financial and accounting 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/ Darin M. Carroll Darin M. Carroll	Director, Chief Executive Officer (principal executive officer)	February 27, 2026
/s/ M. Ryan Weems M. Ryan Weems	Director, Senior Vice President, Chief Financial Officer and Treasurer (principal financial and accounting officer)	February 27, 2026
/s/ Cindy A. Crane Cindy A. Crane	Chair of the Board of Directors	February 27, 2026
/s/ Charles C. Chang Charles C. Chang	Director	February 27, 2026
/s/ Natalie L. Hocken Natalie L. Hocken	Director	February 27, 2026
/s/ Ryan L. Flynn Ryan L. Flynn	Director	February 27, 2026
/s/ Richard J. Garlish Richard J. Garlish	Director	February 27, 2026

SIGNATURES

MIDAMERICAN ENERGY COMPANY

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 on this 27th day of February 2026.

MIDAMERICAN ENERGY COMPANY

/s/ Kelcey A. Brown
Kelcey A. Brown
Director, President and Chief Executive Officer
(principal 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 date indicated:

Signature	Title	Date
/s/ Kelcey A. Brown Kelcey A. Brown	Director, President and Chief Executive Officer (principal executive officer)	February 27, 2026
/s/ Blake M. Groen Blake M. Groen	Director, Vice President and Chief Financial Officer (principal financial and accounting officer)	February 27, 2026

SIGNATURES

MIDAMERICAN FUNDING, LLC

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 on this 27th day of February 2026.

MIDAMERICAN FUNDING, LLC

/s/ Kelcey A. Brown
Kelcey A. Brown
Manager and President
(principal 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 date indicated:

Signature	Title	Date
/s/ Kelcey A. Brown Kelcey A. Brown	Manager and President (principal executive officer)	February 27, 2026
/s/ Blake M. Groen Blake M. Groen	Vice President and Controller (principal financial and accounting officer)	February 27, 2026
/s/ Daniel S. Fick Daniel S. Fick	Manager	February 27, 2026
/s/ Calvin D. Haack Calvin D. Haack	Manager	February 27, 2026
/s/ Natalie L. Hocken Natalie L. Hocken	Manager	February 27, 2026

SIGNATURES

NEVADA POWER COMPANY

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 on this 27th day of February 2026.

NEVADA POWER COMPANY

/s/ Brandon M. Barkhuff
Brandon M. Barkhuff
Director, President and Chief Executive Officer
(principal 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 date indicated:

Signature	Title	Date
/s/ Brandon M. Barkhuff Brandon M. Barkhuff	Director, President and Chief Executive Officer (principal executive officer)	February 27, 2026
/s/ Michael J. Behrens Michael J. Behrens	Director, Vice President and Chief Financial Officer (principal financial and accounting officer)	February 27, 2026
/s/ Jennifer L. Oswald Jennifer L. Oswald	Director	February 27, 2026
/s/ Anthony F. Sanchez, III Anthony F. Sanchez, III	Director	February 27, 2026
/s/ Shawn M. Elicegui Shawn Elicegui	Director	February 27, 2026

SIGNATURES

SIERRA PACIFIC POWER COMPANY

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 on this 27th day of February 2026.

SIERRA PACIFIC POWER COMPANY

/s/ Brandon M. Barkhuff
Brandon M. Barkhuff
Director, President and Chief Executive Officer
(principal 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 date indicated:

Signature	Title	Date
/s/ Brandon M. Barkhuff Brandon M. Barkhuff	Director, President and Chief Executive Officer (principal executive officer)	February 27, 2026
/s/ Michael J. Behrens Michael J. Behrens	Vice President and Chief Financial Officer (principal financial and accounting officer)	February 27, 2026
/s/ Jesse E. Murray Jesse E. Murray	Director	February 27, 2026
/s/ Jennifer L. Oswald Jennifer L. Oswald	Director	February 27, 2026
/s/ Anthony F. Sanchez, III Anthony F. Sanchez, III	Director	February 27, 2026
/s/ Ryan L. Bellows Ryan Bellows	Director	February 27, 2026

SIGNATURES

EASTERN ENERGY GAS HOLDINGS, LLC

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 on this 27th day of February 2026.

EASTERN ENERGY GAS HOLDINGS, LLC

/s/ Paul E. Ruppert

Paul E. Ruppert

President and Chief Executive Officer

(principal 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 date indicated:

Signature	Title	Date
/s/ Paul E. Ruppert Paul E. Ruppert	President and Chief Executive Officer (principal executive officer)	February 27, 2026
/s/ Scott C. Miller Scott C. Miller	Vice President, Chief Financial Officer and Treasurer (principal financial and accounting officer)	February 27, 2026
/s/ Laura K. Demman Laura K. Demman	Manager	February 27, 2026

SIGNATURES

EASTERN GAS TRANSMISSION AND STORAGE, INC.

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 on this 27th day of February 2026.

EASTERN GAS TRANSMISSION AND STORAGE, INC.

/s/ Paul E. Ruppert

Paul E. Ruppert

Chair of the Board of Directors and President

(principal 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 date indicated:

Signature	Title	Date
/s/ Paul E. Ruppert Paul E. Ruppert	Chair of the Board of Directors and President (principal executive officer)	February 27, 2026
/s/ Scott C. Miller Scott C. Miller	Director, Vice President, Chief Financial Officer and Treasurer (principal financial and accounting officer)	February 27, 2026

SUPPLEMENTAL INFORMATION TO BE FURNISHED WITH REPORTS FILED PURSUANT TO SECTION 15(D) OF THE ACT BY REGISTRANTS WHICH HAVE NOT REGISTERED SECURITIES PURSUANT TO SECTION 12 OF THE ACT

No annual report to security holders covering each respective Registrant's last fiscal year or proxy material has been sent to security holders.

EXHIBIT 21.1

BERKSHIRE HATHAWAY ENERGY COMPANY
SUBSIDIARIES AND JOINT VENTURES

Pursuant to Item 601(b)(21)(ii) of Regulation S-K, we have omitted certain subsidiaries (all of which, when considered in the aggregate as a single subsidiary, would not constitute a significant subsidiary as of the end of our last fiscal year).

PPW Holdings LLC	Delaware
PacifiCorp	Oregon
MidAmerican Funding, LLC	Iowa
MHC Inc.	Iowa
MidAmerican Energy Company	Iowa
NVE Holdings, LLC	Delaware
NV Energy, Inc.	Nevada
Nevada Power Company	Nevada
Sierra Pacific Power Company	Nevada
Northern Powergrid Holdings Company	United Kingdom
Northern Powergrid UK Holdings	United Kingdom
BHE Pipeline Group, LLC	Delaware
BHE GT&S, LLC	Delaware
Eastern Energy Gas Holdings, LLC	Virginia
Eastern MLP Holding Company II, LLC	Virginia
Cove Point GP Holding Company, LLC	Delaware
Cove Point LNG, LP	Delaware
Eastern Gas Transmission and Storage, Inc.	Delaware
NNGC Acquisition, LLC	Delaware
Northern Natural Gas Company	Delaware
BHE Canada Holdings Corporation	Canada
BHE U.S. Transmission, LLC	Delaware
BHE Renewables, LLC	Delaware
HomeServices of America, Inc.	Delaware

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-292645 on Form S-8 of our report dated February 27, 2026, relating to the financial statements and financial statement schedule of Berkshire Hathaway Energy Company appearing in this Annual Report on Form 10-K for the year ended December 31, 2025.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
February 27, 2026

EXHIBIT 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-281019 on Form S-3 of our report dated February 27, 2026, relating to the financial statements of PacifiCorp appearing in this Annual Report on Form 10-K for the year ended December 31, 2025.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 27, 2026

EXHIBIT 23.3

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-291012 on Form S-3 of our report dated February 27, 2026, relating to the financial statements of MidAmerican Energy Company appearing in this Annual Report on Form 10-K for the year ended December 31, 2025.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
February 27, 2026

EXHIBIT 23.4

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-283731 on Form S-3 of our report dated February 27, 2026, relating to the financial statements of Nevada Power Company appearing in this Annual Report on Form 10-K for the year ended December 31, 2025.

/s/ Deloitte & Touche LLP

Las Vegas, Nevada
February 27, 2026

EXHIBIT 23.5

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-285816 on Form S-3 of our report dated February 27, 2026, relating to the financial statements of Sierra Pacific Power Company appearing in this Annual Report on Form 10-K for the year ended December 31, 2025.

/s/ Deloitte & Touche LLP

Las Vegas, Nevada
February 27, 2026

EXHIBIT 23.6

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-276072 on Form S-3 of our report dated February 27, 2026, relating to the financial statements of Eastern Energy Gas Holdings, LLC appearing in this Annual Report on Form 10-K for the year ended December 31, 2025.

/s/ Deloitte & Touche LLP

Richmond, Virginia
February 27, 2026

EXHIBIT 31.1

CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002

I, Mark A. Hewett, certify that:

1. I have reviewed this Annual Report on Form 10-K of Berkshire Hathaway Energy Company;

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(s) 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(s) 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 27, 2026

/s/ Mark A. Hewett
Mark A. Hewett
President and Chief Executive Officer
(principal executive officer)

EXHIBIT 31.2

CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002

I, Charles C. Chang, certify that:

1. I have reviewed this Annual Report on Form 10-K of Berkshire Hathaway Energy Company;

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(s) 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(s) 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 27, 2026

/s/ Charles C. Chang
Charles C. Chang
Senior Vice President and Chief Financial Officer
(principal financial officer)

EXHIBIT 31.3

CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002

I, Darin M. Carroll, certify that:

1. I have reviewed this Annual Report on Form 10-K of PacifiCorp;

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(s) 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(s) 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 27, 2026

/s/ Darin M. Carroll
Darin M. Carroll
Chief Executive Officer
(principal executive officer)

EXHIBIT 31.4

CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002

I, M. Ryan Weems, certify that:

1. I have reviewed this Annual Report on Form 10-K of PacifiCorp;

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(s) 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(s) 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 27, 2026

/s/ M. Ryan Weems
M. Ryan Weems
Director, Senior Vice President, Chief Financial
Officer and Treasurer
(principal financial officer)

EXHIBIT 31.5

CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002

I, Kelcey A. Brown, certify that:

1. I have reviewed this Annual Report on Form 10-K of MidAmerican Energy Company;

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(s) 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(s) 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 27, 2026

/s/ Kelcey A. Brown
Kelcey A. Brown
President and Chief Executive Officer
(principal executive officer)

EXHIBIT 31.6

CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002

I, Blake M. Groen, certify that:

1. I have reviewed this Annual Report on Form 10-K of MidAmerican Energy Company;

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(s) 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(s) 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 27, 2026

/s/ Blake M. Groen
Blake M. Groen
Vice President and Chief Financial Officer
(principal financial officer)

EXHIBIT 31.7

CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002

I, Kelcey A. Brown, certify that:

1. I have reviewed this Annual Report on Form 10-K of MidAmerican Funding, LLC;

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(s) 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(s) 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 27, 2026

/s/ Kelcey A. Brown
Kelcey A. Brown
President
(principal executive officer)

EXHIBIT 31.8

CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002

I, Blake M. Groen, certify that:

1. I have reviewed this Annual Report on Form 10-K of MidAmerican Funding, LLC;

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(s) 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(s) 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 27, 2026

/s/ Blake M. Groen
Blake M. Groen
Vice President and Controller
(principal financial officer)

EXHIBIT 31.9

CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002

I, Brandon M. Barkhuff, certify that:

1. I have reviewed this Annual Report on Form 10-K of Nevada Power Company and its subsidiaries (dba NV Energy);

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(s) 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(s) 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 27, 2026

/s/ Brandon M. Barkhuff
Brandon M. Barkhuff
President and Chief Executive Officer
(principal executive officer)

EXHIBIT 31.10

CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002

I, Michael J. Behrens, certify that:

1. I have reviewed this Annual Report on Form 10-K of Nevada Power Company and its subsidiaries (dba NV Energy);

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(s) 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(s) 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 27, 2026

/s/ Michael J. Behrens
Michael J. Behrens
Vice President and Chief Financial Officer
(principal financial officer)

EXHIBIT 31.11

CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002

I, Brandon M. Barkhuff, certify that:

1. I have reviewed this Annual Report on Form 10-K of Sierra Pacific Power Company and its subsidiaries (dba NV Energy);

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(s) 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(s) 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 27, 2026

/s/ Brandon M. Barkhuff
Brandon M. Barkhuff
President and Chief Executive Officer
(principal executive officer)

EXHIBIT 31.12

CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002

I, Michael J. Behrens, certify that:

1. I have reviewed this Annual Report on Form 10-K of Sierra Pacific Power Company and its subsidiaries (dba NV Energy);

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(s) 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(s) 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 27, 2026

/s/ Michael J. Behrens
Michael J. Behrens
Vice President and Chief Financial Officer
(principal financial officer)

EXHIBIT 31.13

CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002

I, Paul E. Ruppert, certify that:

1. I have reviewed this Annual Report on Form 10-K of Eastern Energy Gas Holdings, LLC;

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 27, 2026

/s/ Paul E. Ruppert
Paul E. Ruppert
President and Chief Executive Officer
(principal executive officer)

EXHIBIT 31.14

CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002

I, Scott C. Miller, certify that:

1. I have reviewed this Annual Report on Form 10-K of Eastern Energy Gas Holdings, LLC;

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 27, 2026

/s/ Scott C. Miller
Scott C. Miller
Vice President, Chief Financial Officer and Treasurer
(principal financial officer)

EXHIBIT 31.15

CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002

I, Paul E. Ruppert, certify that:

1. I have reviewed this Annual Report on Form 10-K of Eastern Gas Transmission and Storage, Inc.;

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) [Reserved];

   (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 27, 2026

/s/ Paul E. Ruppert
Paul E. Ruppert
Chair of the Board of Directors and President
(principal executive officer)

EXHIBIT 31.16

CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002

I, Scott C. Miller, certify that:

1. I have reviewed this Annual Report on Form 10-K of Eastern Gas Transmission and Storage, Inc.;

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) [Reserved];

   (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 27, 2026

/s/ Scott C. Miller
Scott C. Miller
Director, Vice President, Chief Financial Officer and Treasurer
(principal financial officer)

EXHIBIT 32.1

CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

I, Mark A. Hewett, President and Chief Executive Officer of Berkshire Hathaway Energy Company (the "Company"), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of the Company for the annual period ended December 31, 2025 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 27, 2026

/s/ Mark A. Hewett
Mark A. Hewett
President and Chief Executive Officer
(principal executive officer)

EXHIBIT 32.2

CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

I, Charles C. Chang, Senior Vice President and Chief Financial Officer of Berkshire Hathaway Energy Company (the "Company"), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of the Company for the annual period ended December 31, 2025 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 27, 2026

/s/ Charles C. Chang
Charles C. Chang
Senior Vice President and Chief Financial Officer
(principal financial officer)

EXHIBIT 32.3

CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

I, Darin M. Carroll, Chief Executive Officer of PacifiCorp, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of PacifiCorp for the annual period ended December 31, 2025 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PacifiCorp.

Date: February 27, 2026

/s/ Darin M. Carroll
Darin M. Carroll
Chief Executive Officer
(principal executive officer)

EXHIBIT 32.4

CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

I, M. Ryan Weems, Senior Vice President, Chief Financial Officer of PacifiCorp, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of PacifiCorp for the annual period ended December 31, 2025 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PacifiCorp.

Date: February 27, 2026

/s/ M. Ryan Weems
M. Ryan Weems
Director, Senior Vice President, Chief Financial
Officer and Treasurer
(principal financial officer)

EXHIBIT 32.5

CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

I, Kelcey A. Brown, President and Chief Executive Officer of MidAmerican Energy Company , certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of MidAmerican Energy Company for the annual period ended December 31, 2025 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of MidAmerican Energy Company.

Date: February 27, 2026

/s/ Kelcey A. Brown
Kelcey A. Brown
President and Chief Executive Officer
(principal executive officer)

EXHIBIT 32.6

CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

I, Blake M. Groen, Vice President and Chief Financial Officer of MidAmerican Energy Company, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of MidAmerican Energy Company for the annual period ended December 31, 2025 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of MidAmerican Energy Company.

Date: February 27, 2026

/s/ Blake M. Groen
Blake M. Groen
Vice President and Chief Financial Officer
(principal financial officer)

EXHIBIT 32.7

CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

I, Kelcey A. Brown, President of MidAmerican Funding, LLC, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of MidAmerican Funding, LLC for the annual period ended December 31, 2025 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of MidAmerican Funding, LLC.

Date: February 27, 2026

/s/ Kelcey A. Brown
Kelcey A. Brown
President
(principal executive officer)

EXHIBIT 32.8

CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

I, Blake M. Groen, Vice President and Controller of MidAmerican Funding, LLC, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of MidAmerican Funding, LLC for the annual period ended December 31, 2025 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of MidAmerican Funding, LLC.

Date: February 27, 2026

/s/ Blake M. Groen
Blake M. Groen
Vice President and Controller
(principal financial officer)

EXHIBIT 32.9

CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

I, Brandon M. Barkhuff, President and Chief Executive Officer of Nevada Power Company and its subsidiaries (dba NV Energy), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of Nevada Power Company and its subsidiaries for the annual period ended December 31, 2025 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Nevada Power Company and its subsidiaries.

Date: February 27, 2026

/s/ Brandon M. Barkhuff
Brandon M. Barkhuff
President and Chief Executive Officer
(principal executive officer)

EXHIBIT 32.10

CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

I, Michael J. Behrens, Vice President and Chief Financial Officer of Nevada Power Company and its subsidiaries (dba NV Energy), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of Nevada Power Company and its subsidiaries for the annual period ended December 31, 2025 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Nevada Power Company and its subsidiaries.

Date: February 27, 2026

/s/ Michael J. Behrens
Michael J. Behrens
Vice President and Chief Financial Officer
(principal financial officer)

EXHIBIT 32.11

CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

I, Brandon M. Barkhuff, President and Chief Executive Officer of Sierra Pacific Power Company and its subsidiaries (dba NV Energy), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of Sierra Pacific Power Company and its subsidiaries for the annual period ended December 31, 2025 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Sierra Pacific Power Company and its subsidiaries.

Date: February 27, 2026

/s/ Brandon M. Barkhuff
Brandon M. Barkhuff
President and Chief Executive Officer
(principal executive officer)

EXHIBIT 32.12

CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

I, Michael J. Behrens, Vice President and Chief Financial Officer of Sierra Pacific Power Company and its subsidiaries (dba NV Energy), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of Sierra Pacific Power Company and its subsidiaries for the annual period ended December 31, 2025 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Sierra Pacific Power Company and its subsidiaries.

Date: February 27, 2026

/s/ Michael J. Behrens
Michael J. Behrens
Vice President and Chief Financial Officer
(principal financial officer)

EXHIBIT 32.13

CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

I, Paul E. Ruppert, President and Chief Executive Officer of Eastern Energy Gas Holdings, LLC, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of Eastern Energy Gas Holdings, LLC for the annual period ended December 31, 2022 (the "Report") fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of Eastern Energy Gas Holdings, LLC.

Date: February 27, 2026

/s/ Paul E. Ruppert

Paul E. Ruppert
President and Chief Executive Officer
(principal executive officer)

EXHIBIT 32.14

CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

I, Scott C. Miller, Vice President, Chief Financial Officer and Treasurer of Eastern Energy Gas Holdings, LLC, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of Eastern Energy Gas Holdings, LLC for the annual period ended December 31, 2022 (the "Report") fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of Eastern Energy Gas Holdings, LLC.

Date: February 27, 2026

/s/ Scott C. Miller
Scott C. Miller
Vice President, Chief Financial Officer and Treasurer
(principal financial officer)

EXHIBIT 32.15

CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

I, Paul E. Ruppert, Chair of the Board of Directors and President of Eastern Gas Transmission and Storage, Inc., certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of Eastern Gas Transmission and Storage, Inc. for the annual period ended December 31, 2022 (the "Report") fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of Eastern Gas Transmission and Storage, Inc..

Date: February 27, 2026

/s/ Paul E. Ruppert

Paul E. Ruppert
Chair of the Board of Directors and President
(principal executive officer)

EXHIBIT 32.16

CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

I, Scott C. Miller, Vice President, Chief Financial Officer and Treasurer of Eastern Gas Transmission and Storage, Inc., certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of Eastern Gas Transmission and Storage, Inc. for the annual period ended December 31, 2022 (the "Report") fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of Eastern Gas Transmission and Storage, Inc..

Date: February 27, 2026

/s/ Scott C. Miller
Scott C. Miller
Director, Vice President, Chief Financial Officer and Treasurer
(principal financial officer)

EXHIBIT 95

MINE SAFETY VIOLATIONS AND OTHER LEGAL MATTER DISCLOSURES PURSUANT TO SECTION 1503(a) OF THE DODD-FRANK WALL STREET REFORM AND CONSUMER PROTECTION ACT

PacifiCorp and its subsidiaries operate certain coal mines and coal processing facilities (collectively, the "mining facilities") that are regulated by the Federal Mine Safety and Health Administration ("MSHA") under the Federal Mine Safety and Health Act of 1977 (the "Mine Safety Act"). MSHA inspects PacifiCorp's mining facilities on a regular basis. The total number of reportable Mine Safety Act citations, orders, assessments and legal actions for the year ended December 31, 2025 are summarized in the table below and are subject to contest and appeal. The severity and assessment of penalties may be reduced or, in some cases, dismissed through the contest and appeal process. Amounts are reported regardless of whether PacifiCorp has challenged or appealed the matter. Mines that are closed or idled that had no reportable events occurring at those locations during the year ended December 31, 2025 are not included in the information below. There were no mining-related fatalities during the year ended December 31, 2025. PacifiCorp has not received any notice of a pattern, or notice of the potential to have a pattern, of violations of mandatory health or safety standards that are of such nature as could have significantly and substantially contributed to the cause and effect of coal or other mine health or safety hazards under Section 104(e) of the Mine Safety Act during the year ended December 31, 2025.

	Mine Safety Act						Legal Actions		
Mining Facilities	Section 104 Significant and Substantial Citations[1]	Section 104(b) Orders[2]	Section 104(d) Citations/ Orders[3]	Section 110(b)(2) Violations[4]	Section 107(a) Imminent Danger Orders[5]	Total Value of Proposed MSHA Assessments (in thousands)	Pending as of Last Day of Period[6]	Instituted During Period	Resolved During Period
Bridger (surface)	1	—	—	—	—	$ —	—	—	—
Wyodak Coal Crushing Facility	—	—	—	—	—	—	—	—	—

(1) Citations for alleged violations of mandatory health and safety standards that could significantly or substantially contribute to the cause and effect of a safety or health hazard under Section 104 of the Mine Safety Act.

(2) For alleged failure to totally abate the subject matter of a Mine Safety Act Section 104(a) citation within the period specified in the citation.

(3) For alleged unwarrantable failure (i.e., aggravated conduct constituting more than ordinary negligence) to comply with a mandatory health or safety standard.

(4) For alleged flagrant violations (i.e., reckless or repeated failure to make reasonable efforts to eliminate a known violation of a mandatory health or safety standard that substantially and proximately caused, or reasonably could have been expected to cause, death or serious bodily injury).

(5) For the existence of any condition or practice in a coal or other mine which could reasonably be expected to cause death or serious physical harm before such condition or practice can be abated.

(6) For the existence of any proposed penalties under Subparts B-H of the Federal Mine Safety and Health Review Commission's procedural rules. The pending legal actions are not exclusive to citations, notices, orders and penalties assessed by the MSHA during the reporting period.