BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Application of PacifiCorp (U 901 E) for Approval of its 2024 Energy Cost Adjustment Clause and Greenhouse Gas-Related Forecast and Reconciliation of Costs and Revenue	Application No. 23-09-___

APPLICATION OF PACIFICORP (U 901 E) FOR APPROVAL OF ITS 2024 ENERGY COST ADJUSTMENT CLAUSE AND GREENHOUSE GAS-RELATED FORECAST AND RECONCILIATION OF COSTS AND REVENUE

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Dated: September 15, 2023

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BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Application of PacifiCorp (U 901 E) for Approval of its 2024 Energy Cost Adjustment Clause and Greenhouse Gas-Related Forecast and Reconciliation of Costs and Revenue	Application No. 23-00-____ (Filed September 15, 2023)

APPLICATION OF PACIFICORP (U 901 E) FOR APPROVAL OF ITS 2024 ENERGY COST ADJUSTMENT CLAUSE AND GREENHOUSE GAS-RELATED FORECAST AND RECONCILIATION OF COSTS AND REVENUE

I. INTRODUCTION

PacifiCorp d/b/a Pacific Power (PacifiCorp or Company) respectfully requests the California Public Utilities Commission (Commission) approve the Company's 2024 Energy Cost Adjustment Clause (ECAC) and greenhouse gas related costs (Application). Specifically, PacifiCorp requests the Commission approve new rates and credits for: (1) the Company's Schedule ECAC-94 Energy Cost Adjustment Clause Tariff Rate Rider; (2) Schedule GHG-92 Surcharge to Recover Greenhouse Gas Carbon Pollution Permit Costs (GHG Surcharge); (3) Schedule GHG-93 California Climate Credit (California Climate Credit); and (4) continue allocations under Schedule No. NEMVS-139 Virtual Net Energy Metering for Solar Multifamily Affordable Housing Program (SOMAH). PacifiCorp also requests the Commission remove the requirement to provide additional coal cycling scenarios for future ECAC proceedings, and recommends the Commission amend the Company's ECAC Tariff to include one new cost category.

Taken together, PacifiCorp requests an overall rate increase of $30.3 million (25.0 percent) based on the combined ECAC and GHG Surcharge, for rates effective March 1, 2024. This includes: (1) a $29.97 per megawatt hour (MWh) ECAC Balancing Rate, resulting in a customer increase of approximately $23.4 million; (2) a $48.14 per MWh ECAC Offset Rate, resulting in a $12.6 million increase from the amount currently collected in rates; and (3) a decrease to the GHG Surcharge of approximately $5.6 million. If approved, these rates result in a California Climate Credit of $174.25 for small business and residential customers, and retains the Company's historical support for SOMAH programs.

Section II of this Application provides relevant background on the ECAC, GHG Surcharge, California Climate Credit, and SOMAH programs. Section III details the Company's proposed rate changes, the request to remove the requirement to provide additional coal cycling studies, and requested Tariff amendment. The combined effect of the proposed rates on PacifiCorp's California customer classes, not including the California Climate Credits or support for SOMAH Program, can be found in Table 1.

Table 1: Proposed Rate Changes by Customer Class

Customer Class	Proposed Rate Change	
Residential	$14,806,000	23.3%
Commercial/Industrial	$11,579,000	27.6%
Irrigation	$3,843,000	25.6%
Lighting	$110,000	13.5%
Overall	$30,338,000	25.0%

II. BACKGROUND

The ECAC provides dollar-for-dollar recovery of NPC and fuel stock carrying charges, and is trued-up monthly for actual NPC compared to forecasted NPC that are reflected in current ECAC rates. NPC generally includes the costs of fuel expenses, wholesale purchase power expenses and wheeling expenses, less wholesale sales revenue. Rates for NPC are unbundled from other rates and are collected through PacifiCorp's ECAC (Schedule ECAC-94). The ECAC provides PacifiCorp the opportunity to recover NPC in a timely and efficient manner, which allows PacifiCorp to continue to provide adequate, safe, and reliable service to its California customers.[1]

The Commission initially approved PacifiCorp's request for annual recovery of NPCs through the ECAC in the Company's 2005 general rate case.[2] The Commission reauthorized PacifiCorp to continue using the ECAC in PacifiCorp's 2019 general rate case,[3] and PacifiCorp has requested the Commission reauthorize the ECAC in the Company's pending 2023 general

[1] *In re PacifiCorp's 2005 Rate Case,* A.05-11-022, Joint Motion to Adopt Settlement Agreement, at 10.
[2] D.06-12-011.
[3] D.20-02-025.

rate case.[4] PacifiCorp generally files annual applications with the Commission on August 1 of each year to update the Company's ECAC rates.

In 2006 the California Legislature passed Assembly Bill (AB) 32, the Global Warming Solutions Act, that required California to develop regulations that will reduce GHG emissions to 1990 levels by 2020. Pursuant to this authority the California Air Resources Board (ARB) established a Cap-and-Trade Program that caps the GHG emissions that a facility is allowed to emit, and covered entities are required to procure GHG emissions allowances for all emissions that exceed the cap.[5] ARB allocated PacifiCorp and other California electric utilities GHG emissions allowances to mitigate compliance costs for retail customers.[6]

The Commission subsequently approved a methodology for utilities to account for Cap-and-Trade compliance costs and revenues.[7] Beginning in 2015, electric utilities were required to include Cap-and-Trade compliance costs within their respective energy supply cost recovery mechanisms.[8] Accordingly, PacifiCorp accounts for these costs in the Company's GHG Surcharge (Schedule GHG-92), which are collected from all of PacifiCorp's California customer classes, and included in annual ECAC applications. Revenue from the sale of GHG allowances are then credited to residential and small business customers (less necessary revenue for administrative and outreach costs) through PacifiCorp's California Climate Credit.[9] The California Climate Credit is distributed to customers twice a year in April and October.[10]

GHG allowance revenue also supports clean energy and energy efficiency programs under PacifiCorp's SOMAH Tariff, as required by the Multifamily Affordable Housing Solar Roofs Program.[11] The Commission directed electric utilities, including PacifiCorp, to set aside

[4] A.22.05.006
[5] *In re Cap-and-Trade 2010 Rulemaking,* California Air Resources Board, Resolution 11-32 (Oct. 20, 2011) (codified at 17 CCR §§ 95801-96022); 17 CCR § 95801.
[6] 17 CCR § 95892.
[7] D.12-12-033.
[8] D.14-10-033, at 30.
[9] D.13-12-002.
[10] D.21-08-026.
[11] Assembly Bill No. 693 – The Multifamily Affordable Housing Solar Roofs Program (2015 Cal. Stat. Ch. 582) (codified at Cal Pub. Util. Code § 2870).

five percent of 2016 GHG allowance proceeds, and ten percent of annual proceeds through June 30, 2026.[12]

III. DESCRIPTION OF PACIFICORP'S REQUEST

The Company requests the Commission approve new rates for PacifiCorp's ECAC mechanism that accounts for annual California-allocated net power costs (NPC), the GHG Surcharge that accounts for costs and revenues to comply with California's Cap-and-Trade Program, new customer credits for the California Climate Credit that offsets Cap-and-Trade compliance costs for small business and residential customers, and continues PacifiCorp's support for SOMAH program. The Commission has issued a decision on PacifiCorp's 2023 ECAC application, and the requested ECAC rates reflect the Commission's 2023 decision.[13]

The Company also requests the Commission remove the requirement to provide additional coal cycling studies for future ECAC proceedings, and amend certain language in the Company's ECAC Tariff to include one new cost category. These issues are discussed below.

A. ECAC Balancing and Offset Rate Adjustments

PacifiCorp respectfully requests the Commission authorize a Balancing Rate of $29.97 per MWh and an Offset Rate of $ $48.14 per MWh, for rates effective March 1, 2024. Both rates include PacifiCorp's billing factors.[14] The proposed Balancing Rate results in a rate increase to customers of approximately $23.4 million, and the proposed Offset Rate in an increase of approximately $12.6 million. The combined impact to customers from the ECAC, not including the GHG Surcharge, is an overall approximate $36.0 million increase from the amount presently in rates.

The change in the proposed Offset Rate exceeds the five percent threshold from the Company's currently effective ECAC rates approved in A.22-08-001. The Offset Rate and Balancing Rate for 2022, 2023 and proposed 2024 tracking periods are found in Table 2.

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[12] *See, e.g.,* D.17-12-022 (initially authorizing SOMAH funding levels); D.20.04.012 (continuing authorization of SOMAH funds through June 30, 2026); D.17-12-022 (approving PacifiCorp's SOMAH funding levels).
[13] Decision 23-08-030 (Sept. 1, 2023).
[14] Schedule ECAC-94, Revised Cal. P.U.C. Sheet No. 5041-E (defining PacifiCorp's ECAC billing factor).

Table 2: Comparison of Balancing and Offset Rates

	2022 ECAC (Approved)	2023 ECAC (Approved)	2024 ECAC (Proposed)
Balancing Rate	$4.25/MWh	($1.34)/MWh	$29.97/MWh
Offset Rate	$25.15/MWh	$31.33/MWh	$48.14/MWh

PacifiCorp's ECAC applies to all electric sales under all of PacifiCorp's California tariffs, and includes all NPC and other Commission-approved costs.[15] The ECAC includes two primary billing determinants, the Balancing Rate and the Offset Rate.[16]

The Balancing Rate either returns to, or recovers from, customers the difference between the actual NPC and the forecasted NPC reflected in PacifiCorp's ECAC balancing account from the previous tracking period.[17] It represents the balancing period's "California allocated share of the difference between prior ECACs' Projected NPC and Adjusted Actual/Projected NPC plus Other Costs for Recovery all adjusted by California actual sales, divided by California projected sales and adjusted for the ECAC Billing Factor."[18] Other Costs for Recovery are costs other than NPC,[19] and include, on a California allocated basis as necessary, any payments or bill credits for: (1) net surplus compensation expense from Schedule NEM-35; (2) renewable energy production tax credits; (3) California Air Resources Board (CARB) implementation and reporting verification fees and costs; (4) fuel stock carrying charges; (5) purchases of renewable energy certifications for RPS compliance; (6) start-up fuel costs and mandatory reporting; (7) Energy Imbalance Market body of state regulator fees; and (8) Western Power Pool Western Resource Adequacy Program costs.[20]

The Offset Rate accounts for forecasted NPC and fuel stock carrying charges that are anticipated for the upcoming tracking period, and can be updated annually if it varies by five percent or more from current rates.[21] It "is an unbundled rate established during the most recent

[15] Schedule ECAC-94, Revised Cal. P.U.C. Sheet No. 5041-E (describing purpose and application of tariff).
[16] *Id.*
[17] D.06-12-011.
[18] Exhibit PAC/702.
[19] Benefits from PacifiCorp's participation in the California Independent System Operator Energy Imbalance Market are included in actual NPC (Exhibit PAC/200).
[20] Schedule ECAC-94, Revised Cal. P.U.C. Sheet No. 5041-E (defining "Other Costs for Recovery").
[21] *In re PacifiCorp's 2005 Rate Case,* A.05-11-022, Joint Motion to Adopt Settlement Agreement, at 4-11.

California general rate case or between general rate cases if the new ECAC Offset Rate changes by more than 5 percent and is equal to the Offset Period's California allocated Projected NPC plus Other Costs for Recovery, all divided by California projected sales and adjusted for the ECAC Billing Factor."[22]

The Offset Rate typically includes the same cost components as the Balancing Rate,[23] however the Offset Rate relies on forecasted data for the upcoming tracking period compared to actual costs, revenues, and credits from the previous tracking period.[24] Projected NPC is the "sum of net power cost components during the Intermediate Period and the Offset Period calculated either between or during general rate cases by the Company's production cost model."[25] PacifiCorp's Projected NPC includes various inputs, such as: (1) forward price curves for electricity and natural gas products; (2) new wholesale electricity and natural transactions (physical and financial); (3) wheeling contracts and updated transmission paths and capacity; (4) updated wholesale electricity and natural gas contracts and wheeling expenses; (5) new and updated coal supply and transportation contracts; (6) updates to Company-owned generation resource capabilities and renewable generation integration costs; and (7) updated load forecasts, among others.

An overview of the Company's ECAC, modeling parameters that are necessary to determine Projected NPC, and Commission-ordered analyses and information on the Company's coal units,[26] are discussed in the supporting testimony, exhibits, and workpapers of Company witness Ramon Mitchell (Exhibits PAC/100 through 106). The Balancing Rate and Offset Rate are detailed in the supporting testimony and exhibits of Company witness Jack Painter (Exhibits PAC/200 through 204). Company witness James Owen details the relevant terms, conditions, and prudency of several coal supply agreements that the Company has executed since the previous ECAC Application, discusses recent coal market conditions, and provides the most recent Jim Bridger Long-Term Fuel Supply Plan (Exhibits PAC/300 to 308).[27] The impacts to

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[22] Schedule ECAC-94, Revised Cal. P.U.C. Sheet No. 4483-E (defining "ECAC Offset Rate").
[23] However certain cost categories may be incurred in certain years, though not in others. In these circumstances, a discrete cost category could appear in the Balancing Rate, though not in the Offset Rate, or vice versa.
[24] Schedule ECAC-94 (defining "ECAC Offset Rate").
[25] *Id.* (defining "Projected NPC").
[26] D.22-11-008, Ordering Paragraphs 4, 5, 6, and 8.
[27] *Id.* ¶ 7.

customer rates, as well as the Company's proposed amendments to the language in the ECAC Tariff, are included in the testimony and exhibits of Company witness Judith M. Ridenour (Exhibits PAC/700 to 708).

B. GHG Surcharge, California Climate Credit, and SOMAH Adjustments

PacifiCorp respectfully requests the Commission authorize an overall decrease to the GHG Surcharge of $5.6 million.

PacifiCorp's GHG Surcharge accounts for costs and revenues to comply with California's Cap-and-Trade program.[28] The GHG Surcharge "applies to all electric sales rendered under all tariff schedules authorized by the Commission, with the exception of interdepartmental sales or transfers and sales to electric public utilities."[29] The GHG Surcharge reconciles forecasted and actual Cap-and-Trade costs, and accounts for program outreach and administrative costs. Specifically, the GHG Surcharge includes: (1) a true-up related to actual GHG allowance revenue and related interest through May 31, 2023; (2) a forecast of 2024 GHG allowance revenue; (3) a true-up of actual customer outreach and administrative costs through May 31, 2023; and (4) a forecast of customer outreach and administrative costs for 2024.

The GHG Surcharge true-up, forecast, and reconciliation process are discussed in the direct testimony and supporting exhibits of Company witness Zepure Shahumyan (Exhibits PAC/400 to 409). Customer outreach costs are discussed in the direct testimony and supporting exhibits of Company witness Selyna Bermudez (Exhibits PAC/500 through 504). Administrative costs are discussed in the direct testimony and supporting exhibits of Company witness Anthony B. Worthington (Exhibits PAC/600 through 603). The impacts to the GHG Surcharge are reflected in the direct testimony and supporting exhibits of Company Witness Judith M. Ridenour (Exhibits PAC/700 through 708).

Consistent with Schedule GHG-93, PacifiCorp requests the Commission authorize a $174.25 semi-annual California Climate Credit for both small business and residential customers.[30] The Company forecasts that it will distribute approximately $15.4 million in California Climate Credits to customers in 2024. Consistent with Schedule NEMVS-139,

[28] Schedule GHG-92, Revised Cal. P.U.C. Sheet No. 4874-E (describing purpose of GHG Surcharge).
[29] *Id.* (defining applicability).
[30] D.21-08-026 (reauthorizing the small business and residential California Customer Credit).

PacifiCorp requests the Commission continue to direct PacifiCorp to allocate ten percent of GHG allowance costs to support SOMAH programs and related true-up amounts.[31] Both the proposed California Climate Credits and the SOMAH allocation are described in the direct testimony and supporting exhibits of Company witness Judith Ridenour (Exhibits PAC/700 through 708).

C. Tariff Amendment

The Company requests the Commission amend the definition of Adjusted Actual NPC to incorporate recent amendments to FERC Uniform System of Accounts. On June 29, 2023, FERC issued a final rule that amended the Uniform System of Accounts.[32] Relevant here, the FERC created sub-account 509.1 to account and report for allowances associated with monthly emissions.[33] This rule is effective January 1, 2025.[34] This final rule affects the costs associated with greenhouse gas and environmental allowances that have been booked to FERC account 555 and historically included in the ECAC. Because the Company's ECAC does not currently allow for recovery of costs in FERC Account 509, the Company requests the Commission approve recovery of costs in this account.

However the Company is not requesting recovery of any amounts in Account 509 with this Application. Rather, because the FERC's decision is not effective until January 1, 2025, the Company is proactively requesting the Commission add this new cost category to the Company's ECAC mechanism. This would allow the Company to request recovery of, and the Commission will have the discretion to review and approve, actual Account 509 costs in subsequent ECAC proceedings. These FERC amendments are discussed in the supporting testimony of Company witness Jack Painter (Exhibit PAC/200), and reflected in the amended tariff language in the supporting exhibit of Company witness Judith Ridenour (Exhibit PAC/702).

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[31] *See, e.g.,* D.17-12-022 (initially authorizing SOMAH funding levels); D.20.04.012 (continuing authorization of SOMAH funds through June 30, 2026).
[32] Final Rule, 183 FERC ¶ 61,205, Docket No. RM21-11-000 (Jun. 29, 2023).
[33] *Id.* ¶ 77, 87–98.
[34] *Id.* ¶ 3.

D. Request to Remove the Requirement for Supplemental Coal Cycling Scenarios

In 2022 the Commission directed PacifiCorp to provide information on three issues for future ECAC applications: (1) the assumed marginal fuel costs for the Company's coal plants, and indicate specific coal plants where adjustments were made to align forecasted generation with minimum take provisions, and the magnitude of adjustments made; (2) an Aurora model run that depicts NPC when average fuel costs are utilized to forecast unit dispatch; and (3) analyses that investigate various economic cycling scenarios of the Company's coal units.[35] This information and analyses are included in Ramon Mitchell's testimony.

The Company requests the Commission remove this third requirement for future ECAC proceedings. Consistent with D.22-11-008, the Company met with the parties from the service lists of A.21-08-004 and A.22-08-001 to receive input on coal unit cycling scenarios, and filed supplemental testimony in A.22-08-001 that incorporated this input. These scenarios analyzed the benefits of economic cycling, including limiting cycling to particular coal units, times of year, and variable lengths of time that units could be offline.[36] These analyses indicated the economic cycling of the Company's coal units would materially increase NPC for our California customers.[37]

The Company solicited input from the same parties to inform the current Application, and also requested parties to represent whether any objected to the Company requesting the Commission waive this requirement for future ECAC proceedings. No parties had any input on potential coal cycling scenarios, or requested any additional scenarios, and none objected to the Company seeking a waiver of this requirement. The Company's coal cycling analyses can be found in the testimony, exhibits, and workpapers of witness Ramon Mitchell (Exhibits PAC/100 through 106). Similar to the Company's studies from the previous ECAC Application, these subsequent studies continue to indicate that coal cycling strategies, if pursued, would materially increase NPC for our California customers.

For this reason, PacifiCorp requests the Commission remove this requirement for future ECAC proceedings. The Company strives to pursue least-cost, least-risk strategies for all of its

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[35] D.22-11-008, Ordering ¶ 4–6, 9.
[36] *See, e.g.,* A.22-08-001, Supplemental Application, Exhibits PAC/800-C Direct Testimony of Eshwar Rao (Feb. 2, 2023).
[37] *Id.* at 2–16.

generation, transmission, and distribution activities, including the Company's baseload coal generation units. These supplemental coal cycling studies confirm that the Company's current operational and procurement decisions are in the public interest, because pursuing any of the alternative strategies would significantly increase NPC. While there are benefits to these studies because they provide further support for the Company's ECAC applications, the Company represents that the time and resources that are necessary to complete each outweighs their utility. In future ECAC proceedings, the Commission could always require the Company to provide similar supplemental studies. However economic cycling of the Company's coal facilities is not currently reasonable, and given that no parties provided input on alternative cycling studies for the current Application, and none objected to removing this requirement for future applications, this issue does not warrant additional investigation at this time.

Accordingly, the Company requests the Commission remove the requirement to provide supplemental coal-cycling analyses from D.22-11-008, ¶¶ 4–6, for future ECAC proceedings.

IV. STATUTORY AND REGULATORY REQUIREMENTS

A. Applicant, Correspondence, and Statutory and Procedural Authorities (Rules 2.1(a)–(b))

This Application is filed pursuant to California Public Utilities Code §§ 451, 454, and 701; Rules 2.1 and 3.2, and this Commission's prior decisions, orders, and resolutions. The relief sought is summarized in Sections I-IV, and an officer of PacifiCorp has verified this Application as required by Rules 1.11 and 2.1.

PacifiCorp is a public utility organized and existing under the laws of the state of Oregon. PacifiCorp engages in the business of generating, transmitting, and distributing electric energy in portions of northern California, Idaho, Oregon, Utah, Washington, and Wyoming. PacifiCorp's principal place of business is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. Communications regarding this application should be addressed to:

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B. Proposed Categorization, Need for Hearing, Issues to be Considered, Relevant Safety Considerations, and Proposed Schedule (Rule 2.1(c))

i. Proposed Category of Proceeding

PacifiCorp proposes that this Application be categorized as a ratesetting proceeding, because the Company has requested adjustments to its ECAC, GHG Surcharge, California Climate Credit, and SOMAH programs.

ii. Need for Hearing

PacifiCorp does not believe that approval of this Application will require hearings. If no party objects to the Company's proposed rates, a hearing is not necessary.[38] In that event, PacifiCorp's Application and supporting appendices, testimony, and exhibits constitute a sufficient record for the Commission to rule on PacifiCorp's ECAC without the need for a hearing.

[38] *Citizens for Allegany County, Inc. v. FPC,* 414 F.2d 1125, 1128 (D.C. Cir. 1968) ("The precedents establish, for example, that no evidentiary hearing is required when there is no dispute on the facts and the agency proceeding involves only a question of law.").

iii. Issues to be Considered and Relevant Safety Considerations

The issues to be considered are described in this Application, accompanying testimony, and attached appendices.

Additionally, the Commission recently amended Rule 2.1(c) to require that utilities clearly state any "relevant safety considerations" raised by respective applications.[39] The Company is committed to promoting the health, safety, comfort and convenience of customers and the public at large. Safety for PacifiCorp employees, customers, and stakeholders is one of PacifiCorp's six core principles. PacifiCorp has developed and implemented various programs to help customers, employees, and stakeholders understand their own personal safety. In 2012 PacifiCorp received Prestigious Member Recognition from the National Safety Council for holding safety as a core value and making safety a priority in business. In 2013, 2015, and 2016 PacifiCorp received the Occupational Excellence Achievement Award from the National Safety Council for working to reduce on the job injuries. PacifiCorp was recognized for its safety achievement by the Edison Electric Institute by being in the top 1 percent of the safest electrical utilities in America for 2015. PacifiCorp also holds its contractors to a high standard of safety by requiring its contractors to register with a third-party evaluator of the contractor's safety performance.

The Company complies with all applicable safety codes, including, but not limited to, the National Electric Safety Code, the Occupational Health and Safety Act, and any applicable state health and safety act requirements, at all of its generation facilities. Certain safety codes may also be applicable to the operation of the Company's transmission and distribution facilities. PacifiCorp has developed standards that meet or exceed the National Electrical Safety Code. Employees are trained in work practice regulations along with Company construction standards to the highest standards and consistency.

The Company also works to develop teamwork to mitigate safety risks and has developed and implemented programs to continue improvement in safety. The Company continuously communicates safety goals in order to stay consistently on message across the organization. These programs include training and communicating from the top down, consistently delivering the same safety message and programs to all locations, and auditing the communications and

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[39] D.16-01-017.

programs. The Company sends daily emails to all of its employees noting accident reports and containing general reminders about safety. Other examples of the Company's commitment to safety include periodic emails with general safety tips for workplace and personal safety, safety committees for each floor of its corporate offices and field offices, annual safety training requirements which are linked to each employee's performance review, daily hazard assessment meetings for field offices, and annual evacuation drills.

The Company prioritizes safety for all resources and to the benefit of all employees, customers, and stakeholders. Consistent with prior CPUC decisions on previous PacifiCorp ECAC applications,[40] the Company has not identified any safety issues that are presented with this Application.

iv. Proposed Schedule

PacifiCorp proposes the following schedule, which allows for expedited Commission resolution:

Application Filed	September 15, 2023
Protest/Responses to Application	30 days after notice of Application published in Daily Calendar
Prehearing Conference	October 25, 2023
Scoping Memo	November 29, 2023
Proposed Decision	December 21, 2023
Final Commission Decision	January 21, 2024
Rates Effective	March 1, 2024

C. Organization and Qualification to Transact Business (Rule 2.2)

The Commission acknowledged a certified copy of PacifiCorp's current Articles of Incorporation in 1997, and are incorporated by reference under Rule 2.2.[41]

[40] *In re PacifiCorp's 2022 ECAC,* Scoping Ruling, at 4 (Nov. 22, 2021); *In re PacifiCorp's 2021 ECAC Application,* Scoping Ruling, at 3 (Oct. 14, 2020).
[41] D.97-12-093.

D. Authority to Increase Rates (Rule 3.2(a)(1), (2), (3), and (5))

PacifiCorp's: quarterly financial statements filed with Securities and Exchange Commission's Form 10-Q, for the period ending March 31, 2023, are included in Appendix A; present and proposed rates are included in Appendix B; and earnings on a California-specific basis are included in Appendix C of the Company's original Application.

E. List of Appendices, Testimony, and Exhibits

PacifiCorp's submissions to support its Application include the following:

Appendix A	PacifiCorp Form 10-Q for the period ending March 31, 2023
Appendix B	Statement of Present and Proposed Rates
Appendix C	Summary of PacifiCorp's Earnings ending December 31, 2022
Exhibits PAC/100	Direct Testimony of Ramon Mitchell (Confidential)
PAC/101	Net Power Cost Analysis—Projected 2024 Net Power Costs
PAC/102	Net Power Cost Analysis—Prior ECAC Projected 2023 Net Power Costs
PAC/103	Net Power Cost Analysis—Projected NPC Comparison to Prior ECAC (Confidential)
PAC/104	2024 California-allocated Net Power Costs
PAC/105	Coal Cycling Scenarios (Confidential)
PAC/106	Coal Volumes
Workpaper #1	ECAC Avg Cost 2024 NPC CONF (Confidential)
Workpaper #2	Coal Expense Calculations HiCONF (Confidential)
Exhibits PAC/200	Direct Testimony of Jack Painter
PAC/201	California ECAC Offset/Balancing Rate Calculation
PAC/202	Net Power Cost Analysis—Adjusted Actual 2022 Net Power Costs
PAC/203	Net Power Cost Analysis—Adjusted Actual/Projected 2023 Net Power Costs
PAC/204	ARB Administrative Costs (Confidential)
Exhibits PAC/300	Direct Testimony of James Owen (Confidential)
PAC/301	Wyodak CSA Analysis (Highly Confidential)
PAC/302	Dave Johnston CSA Analysis (Highly Confidential)
PAC/303	Hunter/Gentry CSA Analysis (Highly Confidential)
PAC/304	Hunter/Gentry CSA First Amendment Analysis (Highly Confidential)
PAC/305	Hunter/Gentry Spot Agreement Analysis (Highly Confidential)
PAC/306	Hunter/Bronco CSA Second Amendment Analysis (Highly Confidential)
PAC/307	Hunger/Bronco CSA Third Amendment Analysis (Highly Confidential
PAC/308	Hunter/Wolverine CSA Analysis (Highly Confidential)

PAC/309	Jim Bridger/Peabody CSA Analysis (Highly Confidential)
PAC/310	Jim Bridger Long-Term Fuel Plan (Highly Confidential)
Exhibits PAC/400	Direct Testimony of Zepure Shahumyan (Confidential)
PAC/401	Commission Template C – Weighted Average Cost of Compliance Instruments (Confidential)
PAC/402	Commission Template D-2 – Annual GHG Emissions and Associated Compliance Obligation (Confidential)
PAC/403	Summary of the GHG Allowance Costs Sub-Balancing Account (Confidential)
PAC/404	2024 Forecast Compliance Obligation and GHG Allowance Costs (Confidential)
PAC/405	Commission Template C-2 – GHG Balancing Account Table for Direct GHG Costs in 2022 (Confidential)
PAC/406	2022 Recorded GHG Allowance Revenue (Confidential)
PAC/407	2023 Recorded/Forecast GHG Allowance Revenue (Confidential)
PAC/408	Summary of the GHG Allowance Revenue Balancing Account (Confidential)
PAC/409	2024 Forecast GHG Allowance Revenue (Confidential)
Exhibits PAC/500	Direct Testimony of Selyna Bermudez
PAC/501	2013 – 2023 Recorded/Forecast Customer Outreach Costs
PAC/502	2023 Customer Outreach Activities and Estimated Costs
PAC/503	2024 Forecast Customer Outreach Costs
PAC/504	Commission Template D-3 – Detail of Outreach Costs
Exhibits PAC/600	Direct Testimony of Anthony B. Worthington
PAC/601	2013 – 2023 Recorded/Forecast Administrative Costs
PAC/602	2024 Forecast Administrative Costs
PAC/603	Commission Template D-3 – Detail of Administrative Costs
Exhibits PAC/700	Direct Testimony of Judith M. Ridenour
PAC/701	Calculation of Proposed ECAC Adjustment Rates
PAC/702	Proposed ECAC-94 Tariff Change
PAC/703	GHG Allowance Costs to be Recovered in Rates (Confidential)
PAC/704	GHG Allowance Revenue to be Distributed Through the California Climate Credit
PAC/705	Calculation of Proposed GHG Allowance Costs Surcharge and California Climate Credit Rates
PAC/706	Commission Template D-1 – Annual Allowance Revenue Receipts and Customer Returns (Confidential)
PAC/707	Effects of Proposed Rate Change Distributed by Rate Schedule
PAC/708	Essential Usage and Average Usage Bills, Affordability Ratios and Hours at Minimum Wage by Climate Zone

F. Public Notice (Rule 3.2(b), (c) and (d))

Certain California cities and counties will be affected by PacifiCorp's requested rate changes in this application. This includes the cities and towns of Yreka, Crescent City, Alturas, Mount Shasta, Weed, Dunsmuir, Fort Jones, Dorris, and Tulelake, and the counties of Siskiyou, Del Norte, Modoc, and Shasta. PacifiCorp will notify customers consistent with Rule 3.2(b), (c) and (d), and notice of the application will be: (1) served on the Attorney General and the Department of General Services when the state is a customer or subscriber whose rates would be affected by the proposed change; (2) served on the County Counsel (or District Attorney if the county has no County Counsel) and County Clerk, and the City Attorney and City Clerk, listed in the current roster published by the Secretary of State in each county and city in which the proposed change in rates is to be made effective; (3) published in a newspaper of general circulation in each county in PacifiCorp's service territory within which the rate changes would be effective; (4) included with regular bills mailed to all customers affected by the proposed changes or by electronically linking to notice of this application for customers that receive their bills electronically; and (5) served on any other persons whom PacifiCorp deems appropriate or as required by the Commission.

Customer bill inserts are required to include the application number assigned to this Application. Unless PacifiCorp receives the assigned application number for the Application within four days of filing, it may not be able to meet the deadline for completing the bill insert cycle within 45-days of filing the Application. Accordingly, PacifiCorp requests either: (a) expeditious assignment of an application number so that it can timely complete the bill inserts, or (b) a seven-day extension to complete this requirement.

G. Type of Rate Change Requested (Rule 3.2(a)(10))

The Company's ECAC is a pass-through mechanism that recovers from customers the annual increase or decrease costs that the Company has incurred to provide electric services. The GHG Surcharge, California Climate Credit, and SOMAH allocations return funds to customers, and are not rate increases. passes through electric procurement costs and

H. Commission Templates

PacifiCorp's Application includes the following Commission templates:

- Commission Template C: Weighted Average Cost of Compliance Instruments provided as Confidential Exhibit PAC/401 to the direct testimony of Zepure Shahumyan.

- Commission Template C-2: GHG Balancing Account Table for Direct GHG Costs in 2021 provided as Confidential Exhibit PAC/405 to the direct testimony of Zepure Shahumyan.

- Commission Template D-1: Annual Allowance Revenue Receipts and Customer Returns provided as Confidential Exhibit PAC/706 to the direct testimony of Judith M. Ridenour

- Commission Template D-2: Annual GHG Emissions and Associated Compliance Obligation provided as Confidential Exhibit PAC/402 to the direct testimony of Zepure Shahumyan.

- Commission Template D-3: Detail of Outreach and Administrative Expenses. The template provided by the Commission included outreach and administrative costs in the same table. The table has been split into two tables, one for outreach and one for administrative costs so that each table may be included as an exhibit for the appropriate Company witness. Refer to Exhibit PAC/504 to the direct testimony of Selyna Bermudez for the detail of outreach costs. Refer to Exhibit PAC/603 to the direct testimony of Anthony B. Worthington for detail of administrative costs.

V. CONCLUSION

PacifiCorp respectfully requests the Commission approve the Company's proposed 2024 ECAC rates, GHG surcharge, California Climate Credit, and amendments to the language in the ECAC Tariff as set forth in this Amended Application, and grant the Company's request to remove the requirement to provide supplemental coal cycling studies for future ECAC applications.

Respectfully submitted this September 15, 2023, at San Francisco, California.

/s/ Zachary Rogala
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/s/ Megan Somogyi
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Attorneys for PacifiCorp

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Application of PacifiCorp (U 901 E) for Approval of its 2024 Energy Cost Adjustment Clause and Greenhouse Gas-Related Forecast and Reconciliation of Costs and Revenue	Application No. 23-09-___

OFFICER VERIFICATION

I am an officer of PacifiCorp and am authorized to make this verification on its behalf. The statements in the foregoing document are true on my own knowledge, except as to matters which are stated therein on information or belief, and as to those matters, I believe them to be true. I declare under penalty of perjury that the foregoing is true and correct.

Executed on September 15, 2023, at Portland, Oregon.

Matt McVee
Vice President, Regulatory Policy and Operations

APPENDIX A

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

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, 2022

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)** **666 Grand Avenue** **Des Moines, Iowa 50309-2580** **515-242-4300**	**94-2213782**
001-05152	**PACIFICORP** **(An Oregon Corporation)** **825 N.E. Multnomah Street, Suite 1900** **Portland, Oregon 97232** **888-221-7070**	**93-0246090**
333-90553	**MIDAMERICAN FUNDING, LLC** **(An Iowa Limited Liability Company)** **666 Grand Avenue** **Des Moines, Iowa 50309-2580** **515-242-4300**	**47-0819200**
333-15387	**MIDAMERICAN ENERGY COMPANY** **(An Iowa Corporation)** **666 Grand Avenue** **Des Moines, Iowa 50309-2580** **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)** **6603 West Broad Street** **Richmond, Virginia 23230** **804-613-5100**	**46-3639580**
333-266049	**EASTERN GAS TRANSMISSION AND STORAGE, INC.** **(A Delaware Corporation)** **6603 West Broad Street** **Richmond, Virginia 23230** **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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

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 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 privately held by a limited group of investors. As of January 31, 2023, 75,627,913 shares of common stock, no par value, were outstanding.

All shares of outstanding common stock of PacifiCorp are indirectly owned by Berkshire Hathaway Energy Company. As of January 31, 2023, 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, 2023.

All shares of outstanding common stock of MidAmerican Energy Company are owned by its parent company, MHC Inc., which is a direct, wholly owned subsidiary of MidAmerican Funding, LLC. As of January 31, 2023, 70,980,203 shares of common stock, no par value, were outstanding.

All shares of outstanding common stock of Nevada Power Company are owned by its parent company, NV Energy, Inc., which is an indirect, wholly owned subsidiary of Berkshire Hathaway Energy Company. As of January 31, 2023, 1,000 shares of common stock, $1.00 stated value, were outstanding.

All shares of outstanding common stock of Sierra Pacific Power Company are owned by its parent company, NV Energy, Inc. As of January 31, 2023, 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, 2023.

All shares of outstanding common stock of Eastern Gas Transmission and Storage, Inc. are owned 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, 2023, 60,101 shares of common stock, $10,000 par value, were outstanding.

Berkshire Hathaway Energy Company, 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.

TABLE OF CONTENTS

PART I

PART II

PART III

PART IV

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
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
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
GT&S Transaction	The acquisition of substantially all of the natural gas transmission and storage business of Dominion Energy, Inc. and Dominion Energy Questar Corporation, exclusive of Dominion Energy Questar Pipeline, LLC and related entities on November 1, 2020
DEI	Dominion Energy, Inc.
Dominion Questar	Dominion Energy Questar Corporation
Questar Pipeline Group	Dominion Energy Questar Pipeline, LLC and related entities
Liquefaction Facility	A natural gas export/liquefaction facility
Atlantic Coast Pipeline	Atlantic Coast Pipeline, LLC

Certain Industry Terms

2017 Tax Reform	The Tax Cuts and Jobs Act enacted on December 22, 2017, effective January 1, 2018
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
COVID-19	Coronavirus Disease 2019
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
IUB	Iowa Utilities Board
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
PTAM	Post Test-year Adjustment Mechanism
PTC	Production Tax Credit
PUCN	Public Utilities Commission of Nevada
RCRA	Resource Conservation and Recovery Act
RAC	Renewable Adjustment Clause
REC	Renewable Energy Credit
RFP	Request for Proposals
RPS	Renewable Portfolio Standards
RRA	Renewable Energy Credit and Sulfur Dioxide Revenue Adjustment Mechanism
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
VIE	Variable Interest Entity
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, 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 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 that could, among other items, increase operating and capital costs, reduce facility output, accelerate 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;
- 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, an electromagnetic pulse, mining incidents, costly litigation, wars (including, for example, Russia's invasion of Ukraine in February 2022), 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 for which the cause has yet to be determined; 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 outcome of any legal proceedings initiated against the respective Registrant; the risk that the respective Registrant is not able to recover costs from insurance or through rates; and the effect on the respective Registrant's reputation of such wildfires, investigations and proceedings;
- the respective Registrant's ability to reduce wildfire threats and improve safety, including the ability to comply with the targets and metrics set forth in its wildfire mitigation plans; to retain or contract for the workforce necessary to execute its wildfire mitigation 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;
- changes in the respective Registrant's credit ratings;
- 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 and regulations that could affect brokerage, mortgage and franchising transactions;
- 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 in applicable geographic regions and demand for natural gas 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 is a holding company that owns a highly diversified portfolio of locally managed and operated businesses principally engaged in the energy industry and is a consolidated subsidiary of Berkshire Hathaway. As of January 31, 2023, Berkshire Hathaway and family members and related or affiliated entities of the late Mr. Walter Scott, Jr., a former member of BHE's Board of Directors, owned 92% and 8%, respectively, of BHE's voting common stock.

Berkshire Hathaway Energy'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, owns 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 residential real estate brokerage franchise networks in the U.S.

BHE owns a highly diversified portfolio of primarily regulated businesses that 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 Berkshire Hathaway Energy's consolidated adjusted earnings on common shares during 2022 was generated from rate-regulated businesses.
- The Utilities serve 5.2 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, 2022, the Company owns approximately 35,500 MWs of generation capacity in operation and under construction:
  - Approximately 29,500 MWs of generation capacity is owned by its regulated electric utility businesses;
  - Approximately 6,000 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 41% wind and solar, 31% natural gas, 23% coal, 4% hydroelectric and geothermal and 1% nuclear and other; and,
  - Cumulative investments in (i) owned wind, solar and geothermal generation facilities of $31.6 billion and (ii) wind projects sponsored by third parties, commonly referred to as tax equity investments, of $5.8 billion.
- The Company owns approximately 36,300 miles of electric transmission lines, a 50% interest in ETT that has approximately 1,900 miles of electric transmission lines, approximately 174,700 miles of electric distribution lines and approximately 2,800 substations.
- The BHE Pipeline Group operates approximately 21,200 miles of pipeline with a design capacity of approximately 21.1 Bcf of natural gas per day, transported approximately 15% of the total natural gas consumed in the U.S. during 2022 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 over $168.3 billion of home sales in 2022 and has brokerage, mortgage and franchise services in all 50 states. HomeServices' franchise business has approximately 300 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, 2022, BHE had approximately 24,000 employees, consisting of approximately 13,600 (57%) electric and natural gas operations employees, approximately 6,800 (28%) real estate services employees and approximately 3,600 (15%) corporate services employees. HomeServices has approximately 45,000 real estate agents who are independent contractors. As of December 31, 2022, approximately 8,600 BHE 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 best-in-class 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 one-year period. The recordable incident rates for each of the Registrants are included below:

	Year Ended December 31, 2022
Recordable Incident Rate:	
PacifiCorp	0.81
MidAmerican Energy	0.52
Nevada Power	0.36
Sierra Pacific	0.79
Eastern Energy Gas	0.19
EGTS	0.15
BHE Overall	0.38

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 666 Grand Avenue, Des Moines, Iowa 50309-2580, 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 2.0 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 the franchise agreements is approximately 22 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 and its principal executive offices are located at 825 N.E. Multnomah Street, Suite 1900 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 owned by BHE. PacifiCorp also has shares of preferred stock outstanding that are subject to voting rights in certain limited circumstances.

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:

	2022		2021		2020	
Utah	26,110	46 %	25,657	46 %	24,851	46 %
Oregon	13,701	24	13,510	24	12,993	24
Wyoming	8,666	15	8,557	15	8,358	15
Washington	4,181	7	4,199	8	4,065	7
Idaho	3,707	7	3,553	6	3,534	7
California	799	1	798	1	759	1
Total	57,164	100 %	56,274	100 %	54,560	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:

	2022		2021		2020	
GWhs sold:						
Residential	18,425	30 %	17,905	29 %	17,150	29 %
Commercial	19,570	32	18,839	31	17,727	29
Industrial	17,622	28	17,909	29	18,039	30
Other	1,547	2	1,621	3	1,644	3
Total retail	57,164	92	56,274	92	54,560	91
Wholesale	4,836	8	5,113	8	5,249	9
Total GWhs sold	62,000	100 %	61,387	100 %	59,809	100 %
Average number of retail customers (in thousands):						
Residential	1,775	87 %	1,745	87 %	1,713	87 %
Commercial	225	11	222	11	217	11
Industrial	9	1	9	1	9	1
Other	28	1	27	1	28	1
Total	2,037	100 %	2,003	100 %	1,967	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 of generating power.

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. Peak demand in the winter occurs due to heating requirements. During 2022, PacifiCorp's peak demand was 11,017 MWs in the summer and 9,026 MWs in the winter.

Generating Facilities and Fuel Supply

PacifiCorp has ownership interest in a diverse portfolio of generating facilities. The following table presents certain information regarding PacifiCorp's owned generating facilities as of December 31, 2022:

Generating Facility	Location	Energy Source	Installed / Repowered(1)	Facility Net Capacity (MWs)(2)	Net Owned Capacity (MWs)(2)
COAL:					
Jim Bridger Nos. 1, 2, 3 and 4 (3)	Rock Springs, WY	Coal	1974-1979	2,119	1,413
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
Naughton Nos. 1 and 2	Kemmerer, WY	Coal	1963-1968	357	357
Wyodak No. 1	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
				8,583	5,234
NATURAL GAS:					
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 (4)	Kemmerer, WY	Natural gas	1971	247	247
Gadsby Steam	Salt Lake City, UT	Natural gas	1951-1955	238	238
Hermiston	Hermiston, OR	Natural gas/steam	1996	461	231

Generating Facility	Location	Energy Source	Installed / Repowered(1)	Facility Net Capacity (MWs)(2)	Net Owned Capacity (MWs)(2)
Gadsby Peakers	Salt Lake City, UT	Natural gas	2002	119	119
				3,243	3,013
WIND:					
TB Flats	Medicine Bow, WY	Wind	2020-2021	500	500
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
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
Foote Creek	Arlington, WY	Wind	1999 / 2021	41	41
McFadden Ridge	McFadden, WY	Wind	2009 / 2019	28	28
				2,254	2,254
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
Minor hydroelectric facilities (5)	Various	Hydroelectric	1895-1986	32	32
				971	971
OTHER:					
Blundell	Milford, UT	Geothermal	1984, 2007	32	32
				32	32
Total Available Generating Capacity				15,083	11,504
PROJECTS UNDER CONSTRUCTION:					
Various projects				93	93
				15,176	11,597

(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 at rates that depend upon the date on which construction begins.

(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 PacifiCorp's ownership of Facility Net Capacity.

(3) Jim Bridger Units 1 and 2 are currently operating under a consent decree as described in "Environmental Laws and Regulations" in Item 1 of this Form 10-K.

(4) Naughton No. 3 was converted from a coal-fueled to a natural gas-fueled generating facility in 2020.

(5) In November 2022, the FERC issued a license surrender order for the four mainstem Klamath hydroelectric dams. The remaining three hydroelectric facilities owned by PacifiCorp on the Klamath River are now included in minor hydroelectric facilities. Refer to Note 16 of the Notes to Consolidated Financial Statements of Berkshire Hathaway Energy in Item 8 of this Form 10-K and Note 14 of the Notes to Consolidated Financial Statements of PacifiCorp in Item 8 of this Form 10-K for further discussion.

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

	2022	2021	2020
Coal	43 %	48 %	48 %
Natural gas	21	20	19
Wind[(1)]	11	10	6
Hydroelectric and other[(1)]	5	5	5
Total energy generated	80	83	78
Energy purchased - long-term contracts (renewable)[(1)]	15	15	12
Energy purchased - short-term contracts and other	5	2	10
	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 transportation costs, weather, legislative considerations, transmission constraints and wholesale market prices of electricity. PacifiCorp evaluates these factors continuously in order to facilitate economic 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. The Bridger underground mine ceased coal production in November 2021. These mines supplied 21%, 21% and 16% of PacifiCorp's total coal requirements during the years ended December 31, 2022, 2021 and 2020, respectively. The remaining coal requirements for PacifiCorp's coal-fueled generating facilities are acquired through long- and short-term third-party contracts.

Most of PacifiCorp's coal reserves are held through agreements with the federal Bureau of Land Management and from 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%. To meet applicable standards, PacifiCorp blends its coal with contracted coal and utilizes emissions reduction technologies for controlling SO_2 and other emissions. For fuel needs at PacifiCorp's coal-fueled generating facilities in excess of coal reserves available, PacifiCorp believes it will be able to purchase coal under both long- and short-term contracts to supply its 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. PacifiCorp also utilizes financial swap contracts to mitigate price risk associated with its forecasted fuel requirements.

Wind

PacifiCorp has pursued renewable resources as a viable, economical and environmentally prudent means of supplying electricity and complying with laws and regulations. Renewable resources have low to no emissions and require little or no fossil fuel. The generation from PacifiCorp's wind-powered generating fleet, comprised of newly constructed and recently repowered wind-powered generating facilities, qualifies for 100% of the federal PTCs available for 10 years from the date the equipment is placed in-service. In addition to the discussion contained herein regarding repowering activities, refer to "Regulatory Matters" in Item 1 of this Form 10-K.

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. For discussion of PacifiCorp's hydroelectric relicensing activities, including updated information regarding the Klamath River hydroelectric system, refer to Note 16 of the Notes to Consolidated Financial Statements of Berkshire Hathaway Energy in Item 8 of this Form 10-K and Note 14 of the Notes to Consolidated Financial Statements of PacifiCorp in Item 8 of this Form 10-K.

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 electricity price volatility.

Energy Imbalance Market

PacifiCorp and the California ISO implemented an EIM in November 2014, 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. Outside the EIM footprint, utilities in the western U.S. do not utilize comparable technology and are largely limited to transactions within the borders of their balancing authority area to balance supply and demand intra-hour using a combination of manual and automated dispatch. 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 resource diversity. In December 2022, PacifiCorp announced its intention to join the California ISO Extended Day-Ahead Market in 2024.

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 17,100 miles of transmission lines in 10 states, 65,300 miles of distribution lines and 900 substations as of December 31, 2022.

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.

PacifiCorp's Energy Gateway Transmission Expansion Program represents plans to build over 2,000 miles of new high-voltage transmission lines, with an estimated cost of approximately $11 billion, primarily in Wyoming, Utah, Idaho and Oregon. The approximately $11 billion estimated cost includes: (a) the 135-mile, 345-kV transmission line between the Terminal substation near the Salt Lake City Airport and the Populus substation in Downey, Idaho, placed in-service in 2010; (b) the 100-mile, 345/500-kV transmission line between the Mona substation in central Utah and the Oquirrh substation in the Salt Lake Valley, placed in-service in 2013; (c) the 170-mile, 345-kV transmission line between the Sigurd substation in central Utah and the Red Butte substation in southwest Utah, placed in-service in 2015; (d) the 140-mile, 500-kV transmission line between the Aeolus substation near Medicine Bow, Wyoming and the Jim Bridger generating facility, placed in-service in 2020; (e) the 416-mile, 500-kV high-voltage transmission line between the Aeolus substation and the Clover substation near Mona, Utah, expected to be placed in-service in 2024; (f) the 59-mile, 230-kV high-voltage transmission line between the Windstar substation near Glenrock, Wyoming and the Aeolus substation, expected to be placed in-service in 2024; (g) the 290-mile, 500-kV high-voltage transmission line from the Longhorn substation near Boardman, Oregon to the Hemingway substation near Boise, Idaho (a joint project), expected to be placed in-service in 2026; (h) the 14-mile, 345-kV high-voltage transmission line between the Oquirrh substation and the Terminal substation, expected to be placed in-service in 2024; and (i) remaining segments that are expected to be placed in-service in future years, depending on load growth, economic analysis, IRP results, siting, permitting and construction schedules. The transmission line segments are intended to: (a) address customer load growth; (b) improve system reliability; (c) reduce transmission system constraints; (d) provide access to diverse generation resources, including renewable and zero carbon resources; and (e) improve the flow of electricity throughout PacifiCorp's six-state service area. Proposed transmission line segments are evaluated to ensure optimal benefits and timing before committing to move forward with permitting and construction. Through December 31, 2022, $3.8 billion had been spent and $2.3 billion, including AFUDC, had been placed in-service.

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 September 2021, PacifiCorp filed its 2021 IRP with its state commissions and subsequently filed its 2021 IRP Update in March and April 2022. In March 2022, the OPUC acknowledged PacifiCorp's 2021 IRP and its preferred portfolio. In June 2022, the UPSC issued an order declining to acknowledge the 2021 IRP due to its determination that PacifiCorp did not meet the commission's IRP guidelines by excluding new natural gas-fueled resources in its modeling of the 2021 IRP's preferred portfolio, as well as the commission's view that PacifiCorp did not provide ample time for public input and information exchange during the development of the IRP. The UPSC did approve the 2022 All Source RFP ("2022AS RFP") to procure resources identified in the 2021 IRP. In August 2022, the IPUC acknowledged PacifiCorp's 2021 IRP and its preferred portfolio. Reviews of the 2021 IRP by the WPSC and the WUTC are ongoing.

The 2021 IRP includes investments in new renewable energy resources, new battery storage resources, expanded transmission investments and advanced nuclear resources. New renewable energy resources in the IRP include more than 1,800 MWs of new wind-powered generation, over 2,100 MWs of new solar-powered generation and nearly 700 MWs of new battery storage capacity by 2025. The IRP also outlines PacifiCorp's plan to retire or convert to natural gas all coal-fueled resources by 2042.

Requests for Proposals

PacifiCorp issues individual RFPs, each of which typically focuses on a specific category of generation resources consistent with the IRP or other customer-driven demands. 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.

A draft of PacifiCorp's 2022AS RFP was approved by the WUTC in March 2022 and by the UPSC and the OPUC in April 2022. The 2022AS RFP was issued to market in April 2022. PacifiCorp-owned bids were due late November 2022 and market bids are due February 2023. PacifiCorp expects to provide a recommended final shortlist for state commission and independent evaluator consideration by late June 2023.

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 seasonal peak 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 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. During 2022, PacifiCorp spent $167 million on these DSM programs, resulting in an estimated 514,928 MWhs of first-year energy savings and an estimated 432 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 372 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. The corresponding recovery of costs was approved by the respective state commissions or through PacifiCorp's general rate case process.

Human Capital

Employees

As of December 31, 2022, PacifiCorp had approximately 4,800 employees, of which approximately 57% 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 owns all of the outstanding common stock of MHC Inc. ("MHC"), which is a holding company owning 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 the ownership of MHC. MHC conducts no business other than the ownership of 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 and its principal executive offices are located at 666 Grand Avenue, Des Moines, Iowa 50309-2580 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 or two 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 and operating income derived from the following business activities for the years ended December 31 were as follows (dollars in millions):

	2022		2021		2020	
Operating revenue:						
Regulated electric	$ 2,988	74 %	$ 2,529	71 %	$ 2,139	79 %
Regulated gas	1,030	26	1,003	28	573	21
Other	7	—	15	1	8	—
Total operating revenue	$ 4,025	100 %	$ 3,547	100 %	$ 2,720	100 %
Operating income:						
Regulated electric	$ 372	85 %	$ 358	86 %	$ 384	86 %
Regulated gas	66	15	58	14	64	14
Total operating income	$ 438	100 %	$ 416	100 %	$ 448	100 %

MidAmerican Energy was incorporated under the laws of the state of Iowa in 1995 and its principal executive offices are located at 666 Grand Avenue, Des Moines, Iowa 50309-2580, 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:

	2022		2021		2020	
Iowa	27,024	92 %	25,909	92 %	24,425	92 %
Illinois	1,970	7	1,895	7	1,847	7
South Dakota	296	1	270	1	251	1
	29,290	100 %	28,074	100 %	26,523	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:

	2022		2021		2020	
GWhs sold:						
Residential	7,006	15 %	6,718	15 %	6,687	18 %
Commercial	4,017	9	3,841	9	3,707	10
Industrial	16,646	35	15,944	36	14,645	39
Other	1,621	3	1,571	4	1,484	4
Total retail	29,290	62	28,074	64	26,523	71
Wholesale	17,964	38	16,011	36	11,219	29
Total GWhs sold	47,254	100 %	44,085	100 %	37,742	100 %
Average number of retail customers (in thousands):						
Residential	697	86 %	690	86 %	682	86 %
Commercial	99	12	98	12	97	12
Industrial	2	—	2	—	2	—
Other	15	2	14	2	14	2
Total	813	100 %	804	100 %	795	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, July, August and 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 25%, 24% and 23% of total retail electric sales in 2022, 2021 and 2020, respectively. Sales to electronic data storage customers included in the 10 largest customers comprised 18%, 16% and 16% of total retail electric sales in 2022, 2021 and 2020, 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. On August 2, 2022, retail customer usage of electricity caused a new record hourly peak demand of 5,386 MWs on MidAmerican Energy's electric distribution system, which is 150 MWs greater than the previous record hourly peak demand of 5,236 MWs set June 17, 2021.

Generating Facilities and Fuel Supply

MidAmerican Energy has ownership interest in a diverse portfolio of generating facilities. The following table presents certain information regarding MidAmerican Energy's owned generating facilities as of December 31, 2022:

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	475	475
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
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	250	250
O'Brien	Primghar, IA	Wind	2016	250	250
Southern Hills	Orient, IA	Wind	2020-2021	250	250
Century	Blairsburg, IA	Wind	2005-2008 / 2017-2018	200	200
Eclipse	Adair, IA	Wind	2012 / 2022	200	200
Plymouth	Remsen, IA	Wind	2021	200	200
Intrepid	Schaller, IA	Wind	2004-2005 / 2017	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	150	150
Adams	Lennox, IA	Wind	2015	150	150
Wellsburg	Wellsburg, IA	Wind	2014	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	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
				7,192	7,192
COAL:					
Louisa	Muscatine, IA	Coal	1983	747	657
Walter Scott, Jr. Unit No. 3	Council Bluffs, IA	Coal	1978	702	555
Walter Scott, Jr. Unit No. 4	Council Bluffs, IA	Coal	2007	806	481
Ottumwa	Ottumwa, IA	Coal	1981	706	367
George Neal Unit No. 3	Sergeant Bluff, IA	Coal	1975	504	363
George Neal Unit No. 4	Salix, IA	Coal	1979	640	260
				4,105	2,683
NATURAL GAS AND OTHER:					
Greater Des Moines	Pleasant Hill, IA	Gas	2003-2004	511	511
Electrifarm	Waterloo, IA	Gas or Oil	1975-1978	178	178
Pleasant Hill	Pleasant Hill, IA	Gas or Oil	1990-1994	155	155
Sycamore	Johnston, IA	Gas or Oil	1974	149	149

Generating Facility	Location	Energy Source	Year Installed / Repowered(1)	Facility Net Capacity (MWs)(2)	Net Owned Capacity (MWs)(2)
River Hills	Des Moines, IA	Gas	1966-1967	118	118
Coralville	Coralville, IA	Gas	1970	62	62
Moline	Moline, IL	Gas	1970	60	60
27 portable power modules	Various	Oil	2000	54	54
Parr	Charles City, IA	Gas	1969	33	33
				1,320	1,320
NUCLEAR:					
Quad Cities Unit Nos. 1 and 2	Cordova, IL	Uranium	1972	1,822	455
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				14,584	11,795

(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 at rates that depend upon the date on which construction begins.

(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.

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

	2022	2021	2020
Wind and other renewable(1)	58 %	52 %	54 %
Coal	21	27	19
Nuclear	8	9	10
Natural gas	3	3	2
Total energy generated	90	91	85
Energy purchased - short-term contracts and other	9	8	14
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 transportation costs, weather, environmental considerations, transmission constraints, and wholesale market prices of electricity. MidAmerican Energy evaluates these factors continuously in order to facilitate economic 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 IUB, facilities accounting for 92% of MidAmerican Energy's wind-powered generating capacity in-service at December 31, 2022, are authorized to earn over their regulatory lives a fixed rate of return on equity ranging from 11.0% to 12.2% 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 from 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 2032. Since 2014, MidAmerican Energy has repowered, or plans to repower, 2,204 MWs of wind-powered generating facilities for which PTCs had expired by the end of 2022.

Of the 7,414 MWs (nameplate capacity) of wind-powered generating facilities in-service as of December 31, 2022, 7,249 MWs were generating PTCs, including 2,310 MWs of repowered facilities. PTCs earned by MidAmerican Energy's wind-powered generating facilities placed in-service prior to 2013, except for repowered facilities, were included in MidAmerican Energy's Iowa EAC, through which MidAmerican Energy is allowed to recover fluctuations in its electric retail energy costs. All of the eligibility of those facilities to earn PTCs had expired by the end of 2022. MidAmerican Energy earned PTCs totaling $710 million, $574 million and $510 million in 2022, 2021 and 2020, respectively, of which 4%, 12% and 15%, respectively, were included in the Iowa EAC.

Coal

All of the coal-fueled generating facilities operated by MidAmerican Energy are fueled by low-sulfur, western 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 2027. MidAmerican Energy believes supplies from these sources are presently adequate and available to meet MidAmerican Energy's needs. MidAmerican Energy's coal supply portfolio has substantially all of its expected 2023 and a majority of 2024 requirements 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 all of the MidAmerican Energy-operated coal-fueled generating facilities other than the George Neal Energy Center. Under this agreement, BNSF delivers coal directly to MidAmerican Energy's Walter Scott, Jr. Energy Center and to an interchange point with Canadian Pacific Railway Company for short-haul delivery 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 does not anticipate it will have difficulty in obtaining the necessary uranium concentrates or conversion, enrichment or 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 June 1, 2027.

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. markets and can contract with several other utilities in the region. MidAmerican Energy utilizes financial swaps and physical fixed-price electricity sales and purchases contracts to reduce its exposure to electricity price volatility.

MidAmerican Energy's decisions regarding additions to or reductions of its generation portfolio may be impacted by the MISO's minimum reserve margin requirement. The MISO requires each member to maintain a minimum reserve margin of its accredited generating capacity over its peak demand obligation based on the member's load forecast filed with the MISO each year. The MISO's reserve requirement was 8.7% for the summer of 2022. MidAmerican Energy's owned and contracted capacity accredited for the 2022-2023 MISO capacity auction was 5,591 MWs compared to a peak demand obligation of 5,078 MWs, or a reserve margin of 10.1%. Beginning with the 2023-2024 planning year, the MISO will implement a seasonal construct requiring 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. The reserve requirements for the 2023-2024 planning year will be 7.4% for summer 2023, 14.9% for fall 2023, 25.5% for winter 2023-2024 and 24.5% for spring 2024. 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.

Transmission and Distribution

MidAmerican Energy's transmission and distribution systems included 4,600 circuit miles of transmission lines in four states, 25,400 circuit miles of distribution lines and 345 substations as of December 31, 2022. 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 economic 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 2022, 54% 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 24,600 miles of natural gas main and service lines as of December 31, 2022.

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:

	2022	2021	2020
Iowa	76 %	76 %	76 %
South Dakota	14	13	13
Illinois	9	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:

	2022	2021	2020
Residential	47 %	44 %	45 %
Commercial(1)	22	20	20
Industrial(1)	5	5	5
Total retail	74	69	70
Wholesale(2)	26	31	30
	100 %	100 %	100 %
Total Dths of natural gas sold (in thousands)	119,508	111,916	114,399
Total Dths of transportation service (in thousands)	102,827	112,631	110,263
Total average number of retail customers (in thousands)	789	781	774

(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.

On January 29, 2019, MidAmerican Energy recorded its all-time highest peak-day delivery through its distribution system of 1,319,361 Dths. This peak-day delivery consisted of 68% traditional retail sales service and 32% transportation service. MidAmerican Energy's 2022/2023 winter heating season preliminary peak-day delivery as of February 2, 2023, was 1,311,920 Dths, reached on December 22, 2022. This preliminary peak-day delivery consisted of 71% traditional retail sales service and 29% 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 IUB 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 2022/2023 winter heating season preliminary peak-day of December 22, 2022, supply sources used to meet deliveries to traditional retail sales service customers included 54% from purchases delivered on interstate pipelines, 35% from interstate pipeline storage services and 11% 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. IUB 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 demand- and energy-reduction 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 2022, $43 million was expensed for MidAmerican Energy's energy efficiency programs, which resulted in estimated first-year energy savings of 133,000 MWhs of electricity and 174,000 Dths of natural gas and an estimated peak load reduction of 384 MWs of electricity and 2,444 Dths per day of natural gas.

Human Capital

Employees

All of MidAmerican Funding's employees are employed by MidAmerican Energy. As of December 31, 2022, MidAmerican Energy had approximately 3,400 employees, of which approximately 1,400 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 1.0 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 20- to 25-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 2022, 78% 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 and operating income derived from the following business activities for the years ended December 31 were as follows (dollars in millions):

	2022		2021		2020	
Operating revenue:						
Electric	$ 1,025	86 %	$ 848	88 %	$ 738	86 %
Gas	168	14	117	12	116	14
Total operating revenue	$ 1,193	100 %	$ 965	100 %	$ 854	100 %
Operating income:						
Electric	$ 146	88 %	$ 148	89 %	$ 147	89 %
Gas	19	12	19	11	18	11
Total operating income	$ 165	100 %	$ 167	100 %	$ 165	100 %

Nevada Power was incorporated under the laws of the state of Nevada in 1929 and 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 and 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

<u>Customers</u>

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:

	2022		2021		2020	
Nevada Power:						
GWhs sold:						
Residential	10,299	42 %	10,415	44 %	10,477	46 %
Commercial	4,904	21	4,838	21	4,591	20
Industrial	5,630	23	5,270	22	4,881	21
Other	191	1	198	1	195	1
Total fully bundled	21,024	87	20,721	88	20,144	88
Distribution only service	2,786	11	2,646	11	2,425	11
Total retail	23,810	98	23,367	99	22,569	99
Wholesale	586	2	356	1	374	1
Total GWhs sold	24,396	100 %	23,723	100 %	22,943	100 %
Average number of retail customers (in thousands):						
Residential	886	89 %	871	88 %	856	88 %
Commercial	113	11	112	12	110	12
Industrial	2	—	2	—	2	—
Total	1,001	100 %	985	100 %	968	100 %
Sierra Pacific:						
GWhs sold:						
Residential	2,747	22 %	2,769	23 %	2,672	23 %
Commercial	3,124	26	3,056	26	2,977	26
Industrial	2,867	23	3,716	31	3,544	31
Other	13	—	15	—	15	—
Total fully bundled	8,751	71	9,556	80	9,208	80
Distribution only service	2,757	23	1,639	14	1,670	15
Total retail	11,508	94	11,195	94	10,878	95
Wholesale	741	6	656	6	548	5
Total GWhs sold	12,249	100 %	11,851	100 %	11,426	100 %
Average number of retail customers (in thousands):						
Residential	322	87 %	316	87 %	310	86 %
Commercial	49	13	49	13	49	14
Total	371	100 %	365	100 %	359	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, 48-52% of Nevada Power's and 37-40% 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. On July 11, 2022, customer usage of electricity caused an hourly peak demand of 6,033 MWs on Nevada Power's electric system, which is 267 MWs less than the record hourly peak demand of 6,300 MWs set July 9, 2021. On July 27, 2022, customer usage of electricity caused an hourly peak demand of 1,962 MWs on Sierra Pacific's electric system, which is 144 MWs less than the record hourly peak demand of 2,106 MWs set July 12, 2021.

Generating Facilities and Fuel Supply

The Nevada Utilities have ownership interest in a diverse portfolio of generating facilities. The following table presents certain information regarding the Nevada Utilities' owned generating facilities as of December 31, 2022:

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	1,185	1,185
Clark	Las Vegas, NV	Natural gas	1973-2008	1,102	1,102
Harry Allen	Las Vegas, NV	Natural gas	1995-2011	628	628
Higgins	Primm, NV	Natural gas	2004	589	589
Silverhawk	Las Vegas, NV	Natural gas	2004	590	590
Las Vegas	Las Vegas, NV	Natural gas	1994-2003	272	272
Sun Peak	Las Vegas, NV	Natural gas/oil	1991	210	210
				4,576	4,576
RENEWABLES:					
Nellis	Las Vegas, NV	Solar	2015	15	15
Goodsprings	Goodsprings, NV	Waste heat	2010	5	5
				20	20
Total Available Generating Capacity				4,596	4,596
Sierra Pacific:					
NATURAL GAS:					
Tracy	Sparks, NV	Natural gas	1974-2008	773	773
Ft. Churchill	Yerington, NV	Natural gas	1968-1971	196	196
Clark Mountain	Sparks, NV	Natural gas	1994	132	132
				1,101	1,101
COAL:					
Valmy Unit Nos. 1 and 2	Valmy, NV	Coal	1981-1985	522	261
RENEWABLES:					
Ft. Churchill	Yerington, NV	Solar	2015	20	20
Total Available Generating Capacity				1,643	1,382
Total NV Energy Available Generating Capacity				6,239	5,978
PROJECTS UNDER CONSTRUCTION:					
Dry Lake	Dry Lake, NV	Solar	Est. 2023	150	150
				6,389	6,128

(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.

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

	2022	2021	2020
Nevada Power:			
Total energy generated - natural gas	60 %	64 %	66 %
Energy purchased - long-term contracts (renewable)[(1)]	23	19	15
Energy purchased - long-term contracts (non-renewable)	9	10	13
Energy purchased - short-term contracts and other	8	7	6
	100 %	100 %	100 %
Sierra Pacific:			
Natural gas	41 %	43 %	48 %
Coal	11	11	8
Total energy generated	52	54	56
Energy purchased - long-term contracts (renewable)[(1)]	28	17	15
Energy purchased - long-term contracts (non-renewable)	11	14	24
Energy purchased - short-term contracts and other	9	15	5
	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.

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 transportation costs; weather; environmental considerations; transmission constraints; and wholesale market prices of electricity. The Nevada Utilities evaluate these factors continuously in order to facilitate economic 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 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 policy setting (or 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 3,522 MWs with contract termination dates ranging from 2023 to 2067. Included in these contracts are 3,352 MWs of capacity from renewable energy, of which 1,818 MWs of capacity are under development or construction and not currently available. Sierra Pacific has entered into contracts with a total capacity of 985 MWs with contract termination dates ranging from 2023 to 2049. Included in these contracts are 973 MWs of capacity from renewable energy, of which 25 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 2022, natural gas supply net purchases averaged 299,831 and 149,418 Dths per day with the winter period contracts averaging 256,039 and 120,985 Dths per day and the summer period contracts averaging 330,731 and 189,714 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 relies on spot market solicitations for coal supplies and will regularly monitor the western coal market for opportunities to meet these needs. Sierra Pacific has a transportation services contract with Union Pacific Railroad Company to ship coal from various origins in central Utah, western Colorado and Wyoming that expires December 31, 2025. Sierra Pacific has a coal purchase agreement that extends through December 2023. The Valmy generating facility, Sierra Pacific's remaining facility requiring coal, has an approved retirement date of December 2025. 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. Outside the EIM footprint, utilities in the western U.S. do not utilize comparable technology and are largely limited to transactions within the borders of their balancing authority area to balance supply and demand intra-hour using a combination of manual and automated dispatch. 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 1,900 miles of transmission lines, 14,000 miles of distribution lines and 220 substations as of December 31, 2022. Sierra Pacific's transmission and distribution systems included approximately 4,200 miles of transmission lines, 9,600 miles of distribution lines and 210 substations as of December 31, 2022.

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 $2.6 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 renewable resources, facilitate development of existing designated solar energy zones, facilitate conventional generation retirement and achieve Nevada's carbon reduction and eventual net-zero objectives. The Greenlink program consists of a 350-mile, 525-kV transmission line, known as Greenlink West, connecting the Ft. Churchill substation to the Northwest substation to the Harry Allen substation; a 235-mile, 525-kV transmission line, known as Greenlink North, connecting the new Ft. Churchill substation to the Robinson Summit substation; a 46-mile, 345-kV transmission line from the new Ft. Churchill substation to the Mira Loma substations; and a 38-mile, 345-kV transmission line from the new Ft. Churchill substation to the Robinson Summit substations. The Greenlink program will be constructed in stages that are estimated to be placed in-service between December 2026 and December 2028. The Nevada Utilities will jointly own and operate the Greenlink transmission lines. Through December 31, 2022, $51 million had been spent.

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 June 2021, the Nevada Utilities filed a joint application for approval of their 2022-2041 Triennial IRP, 2022-2024 ESP and 2022-2024 Action Plan. As part of the filing, the Nevada Utilities requested approval of 600 MWs of solar photovoltaic generating resources with 480 MWs of battery energy storage capacity, three battery energy storage projects with 66 MWs of capacity, the acquisition of one existing solar photovoltaic generating facility with 19.5 MWs of capacity that is currently leased to Sierra Pacific, and network upgrades associated with the new renewable energy projects. In September 2021, a hearing was held for the generation upgrades portion of the application, which resulted in an order approving that portion of the joint IRP. The Nevada Utilities filed a partial party stipulation resolving all issues related to the ESP, load forecast and fuel and purchased power price portions of the joint IRP. In October 2021, the Nevada Utilities filed a corrected stipulation, which was approved by the PUCN. In November 2021, a hearing was conducted for the remaining portions of the joint IRP and in December 2021, the PUCN issued an order granting in part and denying in part. The PUCN approved the construction of the 600 MWs of solar photovoltaic generating resources with 480 MWs of battery energy storage capacity, the acquisition of the existing solar photovoltaic generating facility and the network upgrade, among other items. However, the three additional battery energy storage projects were deferred for approval in future plans and the PUCN declined to retire Valmy 1 early and made adjustments to the approved budget for developing and conducting the distributed resource energy trial.

In September 2021, in compliance with Senate Bill ("SB") 448, the Nevada Utilities filed an amendment to the 2021 joint IRP for approval of their Transmission Infrastructure for a Clean Energy Economy Plan that sets forth a plan for the construction of certain high-voltage transmission infrastructure which includes a 235-mile, 525-kV transmission line known as Greenlink North and a 32-mile, 525-kV transmission segment of Greenlink West. In January 2022, the Nevada Utilities reached a settlement with all the intervening parties and presented a stipulation before the PUCN related to the Greenlink transmission project. The settlement allows for the Nevada Utilities to receive approval to construct the Greenlink North project and the remaining segment of the Greenlink West project. The settlement allows the Nevada Utilities to designate these projects as critical facilities that will allow the Nevada Utilities to propose financial incentives in future proceedings. Potential financial incentives include construction work in process included in rate base and the ability to use regulatory asset accounting treatment. The Nevada Utilities agreed not to seek an enhanced return on investment at the state level as part of the settlement. The stipulation was approved by the PUCN in January 2022.

In March 2022, the Nevada Utilities filed the first amendment to the 2021 joint IRP for approval of the battery energy storage system with 220 MWs of capacity; a $3.5 million funding request to further study and perform due diligence on the pumped storage hydro project with a capacity of 1,000 MW, an addition of the geothermal facility purchase power agreement for 25 MW of renewable energy, peak firing project upgrades at the existing generating units to yield 48 MW of additional on-peak generation thermal energy storage project to increase the generating station's peak capacity by 18 MW, and network upgrades associated with the battery energy storage system. In April 2022, a partial stipulation was filed to remedy the redaction of the purchase power agreement pricing and in June 2022, the Nevada Utilities filed a settlement stipulation resolving all remaining issues. The PUCN approved the stipulation in July 2022.

In compliance with SB 448, the Nevada Utilities filed their second and third amendments to the 2021 joint IRP in July and September 2022, respectively. The Nevada Utilities requested an approval to amend the Demand Side Plan for the action period for 2022-2024 in July's filing and requested in September an approval of a DRP amendment to implement the state's first Transportation Electrification Plan ("TEP") and approve proposed tariffs and schedules to implement the TEP. In November 2022, the Nevada Utilities filed an all-party settlement stipulation of the second amendment to the IRP, resolving all issues. A hearing related to the application for approval of the third amendment was held in February 2023.

In November 2022, the Nevada Utilities filed their fourth amendment to the 2021 joint IRP requesting an approval of a generation update to the Supply Plan, an addition of 400 MW of peaking combustion turbines, a 120 MW geothermal portfolio long-term power purchase agreement, a 20 MW new geothermal technology long-term purchase power agreement, and a 200 MW grid-tied battery energy storage system at the Valmy generating facility as well as necessary transmission upgrades. An order is expected in the first half of 2023.

Energy Efficiency Programs

The Nevada Utilities have provided a comprehensive set of 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, 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. 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 2022, Nevada Power spent $34 million on energy efficiency programs, resulting in an estimated 205,974 MWhs of electric energy savings and an estimated 179 MWs of electric peak load management. During 2022, Sierra Pacific spent $8 million on energy efficiency programs, resulting in an estimated 40,539 MWhs of electric energy savings and an estimated 23 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 2022, 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 3,600 miles of natural gas mains and service lines as of December 31, 2022.

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:

	2022	2021	2020
Residential	55 %	53 %	56 %
Commercial(1)	28	28	28
Industrial(1)	11	10	10
Total retail	94	91	94
Wholesale(2)	6	9	6
	100 %	100 %	100 %
Total Dths of natural gas sold (in thousands)	20,622	20,050	18,622
Total Dths of transportation service (in thousands)	1,576	1,850	2,217
Total average number of retail customers (in thousands)	180	177	174

(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, 47-56% of Sierra Pacific's regulated natural gas revenue is reported in the months of December through March.

On December 18, 2022, Sierra Pacific recorded its highest peak-day natural gas delivery of 152,157 Dths, which is 11,417 Dths less than the record peak-day delivery of 163,574 Dths set on December 9, 2013. This peak-day delivery consisted of 96% traditional retail sales service and 4% transportation service.

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, 2022, Nevada Power had approximately 1,400 employees, of which approximately 700 were covered by a union contract with the International Brotherhood of Electrical Workers.

As of December 31, 2022, Sierra Pacific had approximately 1,000 employees, of which approximately 500 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 which owns 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 owns 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, a hydrocarbon exploration and development business that is focused on developing integrated upstream gas projects in Europe and Australia and ownership interests in 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 2022, E.ON and certain of its affiliates and British Gas Trading Limited represented 22% and 14%, 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.

During 2021, 28 suppliers went bankrupt due to rising wholesale prices, particularly for natural gas. This resulted in energy supply costs being higher than the Ofgem set variable tariff price cap that can be charged to customers. Any distribution use of system bad debts suffered by Northern Powergrid is recoverable in future distribution use of systems revenue.

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, 2015 and will continue through March 31, 2023. Ofgem has set the next price control for the five-year period from April 1, 2023 to March 31, 2028. The Northern Powergrid Distribution Companies published and filed their business plans for the next price control period with Ofgem in December 2021 with final determinations published in November 2022. The remaining necessary step for this price control to be effective is the statutory modification of the license, which was published by Ofgem on February 3, 2023 and will become effective on April 1, 2023.

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:

	2022		2021		2020	
GWhs distributed:						
Residential	11,880	37 %	13,334	39 %	12,946	40 %
Commercial	3,737	12	3,643	11	3,459	10
Industrial	16,239	50	16,424	49	15,917	49
Other	301	1	318	1	359	1
	32,157	100 %	33,719	100 %	32,681	100 %
Number of end-users (in thousands):	3,953		3,941		3,934	

As of December 31, 2022, the combined electricity distribution network of the Northern Powergrid Distribution Companies included approximately 17,000 miles of overhead lines, 43,400 miles of underground cables and 810 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 21,200 miles of pipeline with a design capacity of approximately 21.1 Bcf of natural gas per day, transported approximately 15% of the total natural gas consumed in the U.S. during 2022 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.

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 transportation costs. The Pipeline Companies also compete with midstream operators and gas marketers seeking to provide or arrange transportation, 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 transportation 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 transportation. To date, the Pipeline Companies have avoided significant pipeline system bypasses.

BHE GT&S

BHE GT&S' operations, through its ownership of 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, a field service company, and a gathering and processing company.

Eastern Energy Gas' principal subsidiaries are EGTS and Carolina Gas Transmission, LLC ("CGT"). EGTS' operations include natural gas transmission and storage pipelines 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 pipeline system located in South Carolina and southeastern Georgia. Eastern Energy Gas also owns a 50% equity interest in Iroquois Gas Transmission System L.P. ("Iroquois"). Iroquois owns and operates an interstate natural gas pipeline 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 Dth 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 owns a 25% limited partnership interest in the Cove Point LNG export, import and storage facility. BHE GT&S also operates and has ownership 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 12.6 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 9.9 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 365 active receipt and delivery points. In 2022, BHE GT&S delivered over 2.0 trillion cubic feet ("Tcf") of natural gas to its customers.

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, 2022, approximately 86% of BHE GT&S' transmission capacity is subscribed, including 81% under long-term contracts and 5% on a year-to-year basis, and approximately 97% of EGTS' storage capacity is subscribed with long-term contracts. As of December 31, 2022, the weighted average remaining contract term for Eastern Energy Gas' and EGTS' firm transmission contracts is seven years and six years, respectively, and EGTS' storage contracts is four 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):

	2022		2021	
Transmission	$ 849	35 %	$ 772	36 %
LNG	790	33	704	32
Storage	316	13	251	12
Gas, liquids and other sales	447	19	433	20
Total operating revenue	$ 2,402	100 %	$ 2,160	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 2022, BHE GT&S had two customers that each accounted for greater than 10% of its operating revenue and its 10 largest customers accounted for 45% 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.

Human Capital

As of December 31, 2022, Eastern Energy Gas had approximately 1,500 employees, consisting of approximately 1,200 natural gas operations employees and 300 corporate services employees. As of December 31, 2022, approximately 600 employees were covered by a union contract with the Utility Workers Union of America.

As of December 31, 2022, EGTS had approximately 1,300 employees, consisting of approximately 1,000 natural gas operations employees and 300 corporate services employees. As of December 31, 2022, approximately 600 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 14,400 miles of natural gas pipelines, including 5,900 miles of mainline transmission pipelines and 8,500 miles of branch and lateral pipelines, with a Market Area design capacity of 6.3 Bcf per day, a Field Area delivery capacity of 1.7 Bcf per day to the Market Area and 1.4 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 2,215 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 2022.

Northern Natural Gas' transportation 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 transportation revenue is generated from reservation charges, with the balance from usage charges. Most of Northern Natural Gas' transportation capacity in the Market Area is committed to customers under firm transportation 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, 2022, approximately 74% of Northern Natural Gas' customers' entitlement in the Market Area have terms beyond 2024 and approximately 61% beyond 2026. As of December 31, 2022, the weighted average remaining contract term for Northern Natural Gas' Market Area firm transportation contracts is six 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 transportation 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 over 2.2 Bcf per day of peak delivery capability. The average remaining contract term for firm storage contracts is five years.

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

	2022		2021		2020	
Transportation:						
Market Area	$ 688	66 %	$ 658	61 %	$ 633	65 %
Field Area	210	22	177	17	226	24
Total transportation	898	88	835	78	859	89
Storage	97	9	94	9	91	9
Total transportation and storage revenue	995	97	929	87	950	98
Gas, liquids and other sales	28	3	143	13	18	2
Total operating revenue	$ 1,023	100 %	$ 1,072	100 %	$ 968	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 2022, Northern Natural Gas had two customers that each accounted for greater than 10% of its transportation and storage revenue and its 10 largest customers accounted for 63% of its system-wide transportation 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 operates 1,400 miles of mainline natural gas pipelines, 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. The mainline pipeline 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 36-inch diameter pipeline and 100 miles of various laterals that connect to the mainline. Kern River primarily transports and stores natural gas for utilities, municipalities, gas marketing companies, industrial and commercial users.

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 with 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, 2022, approximately 87% of Kern River's design capacity, including seasonal bell curve, totaled 2,345,381 Dths per day and is contracted pursuant to long-term firm natural gas transportation 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 81% 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 transportation service agreements and Kern River's tariff. These long-term firm natural gas transportation service agreements expire between February 2023 and October 2036 and have a weighted-average remaining contract term of over eight years. As of December 31, 2022, 74% 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.

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 transportation rates are cost-based.

During 2022, 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, ownership 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

BHE Canada primarily owns 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, 2022, 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 that links Alberta with the North American western interconnected system, interconnection with Saskatchewan's transmission system and interconnection with Montana's transmission system.

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 is defined in the Electric Utilities Act (Alberta) and its regulations and requires the AESO to assess both current and future needs of Alberta's interconnected electrical system. In January 2022, the AESO released the 2022 Long-term Transmission Plan. Updated every two years, the Long-Term Transmission Plan seeks to optimize the use of the existing transmission system and plan the development of new transmission to ensure a safe and reliable electricity system that enables a fair, efficient and openly competitive electricity market. The 2022 Long-Term Transmission Plan identifies C$1.3 billion in transmission projects over a 10 year period, which results in C$150 million to C$200 million per year on average over that 10 year period. This results in a cumulative transmission rate impact of C$2 per MWh for the first five to eight years, increasing to C$3 per MWh after 15 years. The Long-Term Transmission Plan identifies approximately C$900 million of projects in AltaLink's service territory with in-service dates before 2030.

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, 2022, had total assets of $3.5 billion. ETT's transmission system includes approximately 1,900 miles of transmission lines and 42 substations as of December 31, 2022. Prairie Wind Transmission, LLC, owns and operates a 108-mile, 345-kV transmission project in Kansas having total assets of $133 million as of December 31, 2022.

Generating Facilities

BHE Transmission has ownership interests in the following generating facilities as of December 31, 2022:

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	Montana	Wind	2012	2026	Morgan Stanley	189	189
Glacier 1	Montana	Wind	2008	N/A	N/A	107	107
Glacier 2	Montana	Wind	2009	N/A	N/A	103	103
						529	529
NATURAL GAS:							
Nat-1	Alberta	Natural gas	2015	N/A	N/A	20	20
						20	20
Total Available Generating Capacity						549	549

(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.

BHE RENEWABLES

The subsidiaries comprising the BHE Renewables reportable segment own interests in several independent power projects in the U.S. The following table presents certain information concerning these independent power projects as of December 31, 2022:

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	2025-2038	KC, CODTX, MES	300	300
Mariah Del Norte	Texas	Wind	2016	N/A	N/A	230	230
Walnut Ridge	Illinois	Wind	2018	2028	USGSA	212	212
Flat Top	Texas	Wind	2019	2031	Citi Commodities	200	200
Pinyon Pines I	California	Wind	2012	2035	SCE	168	168
Fluvanna II	Texas	Wind	2019	2024	JP Morgan	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
						2,307	2,307
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	212	212
Saranac	New York	Natural Gas	1994	N/A	N/A	245	196
Yuma	Arizona	Natural Gas	1994	2024	SDG&E	50	50
						1,019	970
GEOTHERMAL:							
Imperial Valley Projects	California	Geothermal	1982-2000	(3)	(3)	345	345
						345	345
HYDROELECTRIC:							
Wailuku	Hawaii	Hydroelectric	1993	2023	HELCO	10	10
						10	10
Total Available Generating Capacity						5,365	5,168

(1) San Diego Gas & Electric Company ("SDG&E"); Pacific Gas and Electric Company ("PG&E"), Ameren Illinois Company ("Ameren"), Southern California Edison ("SCE"), Hawaii Electric Light Company, Inc. ("HELCO"); Austin Energy ("AE"); Omaha Public Power District ("OPPD"); Kimberly-Clark Corporation ("KC"); City of Denton, TX ("CODTX"); MidAmerican Energy Services, LLC ("MES"); U.S. General Services Administration ("USGSA"); Missouri Joint Municipal Electric Commission ("MJMEC"); Kansas Power Pool ("KPP"); Kansas Municipal Energy Agency ("KMEA"); City of Independence, MO ("COIMO"); CPS Energy ("CPS"); and Central Iowa Power Cooperative ("CIPCO").

(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 12% of the Company's interests in the Imperial Valley Projects' Contract Capacity are currently sold to Southern California Edison Company under a long-term power purchase agreement 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.

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

	2022		2021		2020	
Solar	$ 477	48 %	$ 468	48 %	$ 455	48 %
Wind	228	23	160	16	183	20
Geothermal	212	21	178	18	173	18
Hydro	5	1	32	3	26	3
Natural gas	71	7	143	15	99	11
Total operating revenue	$ 993	100 %	$ 981	100 %	$ 936	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 nearly 930 offices in 33 states and the District of Columbia with approximately 45,000 real estate agents under 55 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 network currently includes approximately 300 franchisees and over 1,500 brokerage offices with nearly 51,000 real estate agents under two brand names, primarily in the U.S. In exchange for certain fees, HomeServices provides 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 a fair opportunity to earn a 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. 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 not to exceed more than six months, with an additional three-month extension, 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 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.

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 is also included in the mechanism. Beginning in 2021, the mechanism includes a true-up of PTCs at 100%. Balancing account to provide for 100% recovery or refund of the difference between the level of REC revenues included in base rates and actual REC revenues after adjusting for a 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. Effective January 1, 2021, 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.
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. RAC 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. Effective January 1, 2021, Annual Wildfire Mitigation and Vegetation Management Cost Recovery Mechanism approved through 2024 to recover vegetation management and wildfire mitigation operations and maintenance costs and wildfire mitigation capital costs, incremental to those included in base rates. Recovery is subject to performance metrics and earnings tests. After 2024, the mechanism will be assessed to determine whether continued use is warranted.

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 recovery or refund of 100% of any difference between actual REC and SO_2 revenues and the level in rates.
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). Beginning in 2021, 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, subject to an earnings test. Under the earnings test, 50% of any proportional excess earnings over PacifiCorp's authorized return on equity is returned to customers in addition to any surcharge or surcredit related to the revenue variance. The earnings test is asymmetrical, and adjustments are not made when PacifiCorp earns at or below authorized returns on equity. 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 between the level of REC revenues included in base rates and actual REC revenues and differences in actual PTCs compared to the amount in base rates.
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.

(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 IUB review and subject to refund, on or after 10 days of filing a request for higher base rates. If the IUB 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 IUB prior to the construction of certain types of new generating facilities. Pursuant to this law, MidAmerican Energy has applied for and obtained IUB 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 6,639 MWs (nominal ratings) of wind-powered generating facilities as of December 31, 2022. These ratemaking principles established cost caps for the projects, below which such costs are deemed prudent by the IUB 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, 2022, the generating facilities in-service totaled $7.6 billion, or 36%, 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 11.4% with a weighted average remaining life of 32 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 XII 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 placed in-service in 2016 under the Wind X project and facilities constructed under the Wind XII project approved by the IUB in 2018. Rate base reductions under these mechanisms are applied to coal and other generation facilities in specified orders.

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, 2022, 5,022 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 2017 Tax Reform, which enacted significant changes to the Internal Revenue Code, including, among other things, a reduction in the U.S. federal corporate income tax rate from 35% to 21%. South Dakota implemented changes to base rates in response to 2017 Tax Reform. As a result of 2017 Tax Reform, 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 IUB 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, which, among other items, reduced the state of Iowa corporate tax rate from 12% to 9.8% effective in 2021, at which time, the impacts of Iowa Senate File 2417 began to be 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 once every three years with the PUCN. 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. As of December 31, 2022, the cumulative installed and applied-for capacity of net metering systems under AB 405 in Nevada was 583 MWs.

Natural Disaster Protection Plan ("NDPP")

SB 329, Natural Disaster Mitigation Measures, was signed into law on May 22, 2019. The legislation requires the Nevada Utilities to submit a 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 required to be held in a regulatory asset account, with the Nevada Utilities filing an application for recovery on or before March 1 of each year. The PUCN reopened its investigation and rulemaking on SB 329 and the comment period for the reopened investigation ended in early February 2021. Final regulations are pending.

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 of up to $1.5 million per day per 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 ownership 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, Nevada Utilities, Idaho Power Company and NorthWestern Energy 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 2022 and is under review 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 2020 and an order accepting it was issued in December 2020. 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 2020 and an order accepting it was issued in March 2022. 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. MidAmerican Energy most recently filed a notice of non-material change in status in July 2022, 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.

For an update regarding PacifiCorp's Klamath River hydroelectric system, refer to Note 16 of the Notes to Consolidated Financial Statements of Berkshire Hathaway Energy in Item 8 of this Form 10-K and Note 14 of the Notes to Consolidated Financial Statements of PacifiCorp in Item 8 of this Form 10-K.

Nuclear Regulatory Commission

General

MidAmerican Energy is subject to the jurisdiction of the NRC with respect to its license and 25% ownership 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 in order 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 operating licenses.

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 $450 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 $69 million per incident, payable in installments not to exceed $10 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 $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 $450 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 March 24, 2022, the FERC revoked application of the policies and sought further comments.

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 next price control, Electricity Distribution 2 ("ED2"), will be set for a period of five years, starting April 1, 2023, although the formula has been, and may be, reviewed by the regulator following public consultation. 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, 2015 and is due to terminate on March 31, 2023, 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, 2015, as did one other party, and the CMA subsequently revised GEMA's decision.

The current price control was the first to be set for electricity distribution in Great Britain since Ofgem completed its review of network regulation (known as the RPI-X @ 20 project). The key changes to the price control calculations, compared to those used in previous price controls are that:

- the period over which new regulatory assets are depreciated is being gradually lengthened, from 20 years to 45 years, with the change being phased over eight years;

- allowed revenues will be adjusted during the price control period, rather than at the next price control review, to partially reflect cost variances relative to cost allowances;
- the allowed cost of debt will be updated within the price control period by reference to a long-run trailing average based on external benchmarks of utility debt costs;
- allowed revenues will be adjusted in relation to some new service standard incentives, principally relating to speed and service standards for new connections to the network; and
- there was scope for a mid-period review and adjustment to revenues in the latter half of the period for any changes in the outputs required of licensees for certain specified reasons, although GEMA made no adjustments under this provision.

Under the current price control, as revised by the CMA, and excluding the effects of incentive schemes and any deferred revenues from the prior price control, the opening base allowed revenue of Northern Powergrid (Northeast) plc and Northern Powergrid (Yorkshire) plc remains constant in all subsequent years within the price control period (ED1) through 2022-23, before the addition of inflation. Nominal opening base allowed revenues will increase in line with inflation. Adjustments are made annually to recognize the effect of factors such as changes in the allowed cost of debt, performance on incentive schemes and catch up of prior year under- or over- recoveries.

Ofgem has completed the price control review that will result 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 may be subject to appeal to the CMA if an appeal is filed by March 3, 2023. Many aspects of the current 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, 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 and system access problems. 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, and approval of 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; 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. The Electric Utilities Act (Alberta) and related regulations require the AUC to consider that it is in the public interest to provide consumers the benefit of unconstrained transmission access to competitive generation and the wholesale electricity market. 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, 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, Alamo 6 and Pearl independent power projects are Exempt Wholesale Generators ("EWG") under the Energy Policy Act, while the Community Solar Gardens, Imperial Valley and Wailuku independent power projects are currently certified as Qualifying Facilities ("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, 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, 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 2022 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 2020 and an order accepting it was issued in December 2020. 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 2020 and an order accepting it was issued in March 2021. 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 2021, was supplemented in July 2022 and an order accepting it was issued in January 2023. 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 2022, and is awaiting FERC action.

The entire output of Jumbo Road, Santa Rita, Fluvanna II, Flat Top, Mariah del Norte, Alamo 6, Pearl and Power Resources is within the 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

Oregon

In July 2021, in accordance with the OPUC's December 2020 general rate case order, PacifiCorp filed an application with the OPUC to initiate the review of PacifiCorp's estimated decommissioning and other closure costs per third-party studies associated with its coal-fueled generating facilities. The application requested an initial rate increase of $35 million, or 2.8%, to become effective January 1, 2022, to recover the incremental costs from those approved in the last general rate case. In November 2023, an independent evaluator was selected. Until the independent evaluator completes its work reviewing the third party studies that contain the estimated decommissioning and other closure costs and the OPUC issues an order, there will be no change to rates related to this filing.

In March 2022, PacifiCorp filed a general rate case requesting an overall rate change of $82 million, or 6.6%, to become effective January 1, 2023, that includes cost increases associated with the implementation of PacifiCorp's wildfire mitigation and vegetation management plans. Parties to the case filed testimony in June 2022. PacifiCorp filed reply testimony in July 2022 supporting an overall rate increase of $94 million but proposing that the request be capped at PacifiCorp's original request. PacifiCorp and parties to the case settled various aspects of the general rate case in multiple settlement stipulations. In August 2022, the first partial stipulation was filed resolving issues related to wildfire mitigation and vegetation management, including addressing the associated costs increases. Also in August 2022, a second partial stipulation was filed representing the settlement of certain revenue requirement issues among the stipulating parties, including the extension of Oregon's recovery period for Jim Bridger Units 1 and 2 that will be converted to natural gas-fueled units and certain other issues. In September 2022, a third stipulation was filed resolving most of the remaining issues in the general rate case following the first and second partial stipulations. The stipulations together result in a total rate increase of $49 million, or 3.9%, effective January 1, 2023. The stipulating parties also agreed to amortize certain deferrals totaling approximately $10 million, or 0.8 %, in the first year of amortization, effective April 1, 2023. Further, in the third stipulation, PacifiCorp agreed to a general rate case stay-out provision under which it agreed not to file a general rate case with rates effective any earlier than January 1, 2025. In September 2022, the fourth and final partial stipulation was filed resolving technical issues related to a voluntary renewable energy tariff that will allow non-residential customers to purchase energy from renewable resources not currently in PacifiCorp's rates. In December 2022, the OPUC approved the first, second and third stipulations. The fourth stipulation was approved by the OPUC in February 2023.

In May 2022, PacifiCorp filed its 2021 PCAM, which is the first time since the mechanism has been in place that a rate change has been warranted. After consideration of the mechanism's deadband, sharing band and earnings test, PacifiCorp requested recovery of $52 million, or a 4.2% increase, to become effective January 1, 2023. This request is incremental to the rate change sought in the general rate case. In September 2022, a settlement stipulation was filed agreeing to the recovery of the requested $52 million over a four-year period beginning April 1, 2023. In December 2022, the OPUC approved the settlement stipulation.

In July 2022, PacifiCorp filed an application requesting approval of an automatic adjustment clause with a balancing account to recover costs associated with implementing PacifiCorp's wildfire protection plan in Oregon. Oregon Senate Bill 762 provides for utilities to timely recover these costs through an automatic adjustment clause. The filing requests a rate increase of $20 million, or 1.6%, to recover incremental costs in 2022 and is incremental to costs addressed in PacifiCorp's wildfire mitigation and vegetation management mechanism through the general rate case stipulation described above. While PacifiCorp requested an effective date of August 24, 2022, the OPUC has suspended the filing for further review. In December 2022, a stipulation with certain parties was filed agreeing to the establishment of an automatic adjustment clause. A decision on the stipulation is expected in 2023.

Washington

In June 2021, PacifiCorp filed a power cost only rate case to update baseline net power costs for 2022. PacifiCorp requested a $13 million, or 3.7%, rate increase with an effective date of January 1, 2022. In November 2021, PacifiCorp reached a proposed settlement with most of the parties, which includes an agreement to adjust the PTC rate in base rates and apply a production factor and include a net power cost update as part of the compliance filing. A hearing was held in January 2022 and the WUTC issued an order approving the settlement in March 2022. A compliance filing reflecting a $43 million, or 12.2%, increase was filed in April 2022 and was approved by the WUTC the same month with rates effective May 1, 2022.

In June 2022, PacifiCorp filed its 2021 PCAM and the new tracking mechanism for PTCs approved in the 2021 general rate case. For the 2021 PCAM, PacifiCorp is requesting a recovery of $26 million, or a 6.5% increase. PacifiCorp proposed that the 2021 PCAM be amortized over two years, rather than the one-year period required under the current terms of the PCAM. For the new 2021 PTC tracker, PacifiCorp is seeking recovery of $3 million, or an 0.8% increase. In November 2022, the WUTC approved PacifiCorp's proposal resulting in a combined annual increase of $16 million, or 4.0%, effective January 1, 2023.

Idaho

In October 2022, PacifiCorp filed an application for authority to implement the residential rate modernization plan. The plan proposes a five-year transition to increase the monthly customer service charge from $8.00 to $29.25 per month with a corresponding reduction to the energy rate, eliminates the tiered rates, and adjusts the on-peak off-peak period for time-of-day customers.

California

In August 2021, PacifiCorp filed an application with the CPUC to address California energy costs and GHG allowance costs, and in January 2022, an amended application was filed, per CPUC direction, to reflect ECAC rates which had been approved since the original filing was made. The amended application included an over $3 million rate increase associated with higher energy costs, and the previously sought increase of $3 million to recover GHG allowances. In March 2022, the CPUC approved the increase of $3 million to recover costs for purchasing GHG allowances as required by the state's Cap-and-Trade program. In November 2022, the CPUC approved and made effective the over $3 million rate increase associated with higher energy costs, for a combined rate increase of $7 million, or 6.6%.

In May 2022, PacifiCorp filed a general rate case requesting an overall rate change of $28 million, or 25.7%, 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, upon the issuance of a decision in late 2023. PacifiCorp filed rebuttal testimony in February 2023 with a slight adjustment of an overall rate increase of $27 million, or 25.0%. Also 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.

In August 2022, PacifiCorp filed its 2023 combined ECAC and GHG application requesting an overall rate increase of $15 million, or 13.6%, effective January 1, 2023. Approximately $4 million of the increase, or 3.6%, is attributed to the ECAC rate and $11 million of the increase, or 10.0%, to the GHG rate. In February 2023, PacifiCorp filed an amended application, per CPUC direction, to reflect ECAC rates which had been approved since the original filing was made in August 2022. The amended application would result in an overall rate increase of $11 million, or 10.1%. PacifiCorp anticipates interim approval of its GHG rates in March 2023 based on settlement discussions with parties.

FERC Show Cause Order

On April 15, 2021, the FERC issued an order to show cause and notice of proposed penalty related to allegations made by FERC Office of Enforcement staff that PacifiCorp failed to comply with certain NERC reliability standards associated with facility ratings on PacifiCorp's bulk electric system. The order directs PacifiCorp to show cause as to why it should not be assessed a civil penalty of $42 million as a result of the alleged violations. The allegations are related to PacifiCorp's response to a 2010 industry-wide effort directed by the NERC to identify and remediate certain discrepancies resulting from transmission facility design and actual field conditions, including transmission line clearances. In July 2021, PacifiCorp filed its answer to the FERC's show cause order denying the alleged violation of certain NERC reliability standards. The FERC Office of Enforcement staff replied in September 2021. In December 2022, the FERC issued a final order approving a stipulation and consent agreement between the FERC Office of Enforcement and PacifiCorp whereby PacifiCorp agreed to pay a $1.9 million cash penalty and committed to invest $2.5 million in reliability enhancements. The final order concludes the matter.

MidAmerican Energy

South Dakota

In May 2022, MidAmerican Energy filed a request with the South Dakota Public Utilities Commission ("SDPUC") for an increase in its South Dakota retail natural gas rates, which would increase revenue by $7 million annually. If approved, the requested rates would increase retail customers' bills by an average of 6.4%.

Wind PRIME

In January 2022, MidAmerican Energy filed an application with the IUB for advance ratemaking principles for Wind PRIME. If approved, MidAmerican Energy expects to proceed with Wind PRIME, which consists of up to 2,042 MWs of new wind generation and up to 50 MWs of solar generation. If all of Wind PRIME generation is constructed, MidAmerican Energy will own over 9,300 MWs of wind generation and nearly 200 MWs of solar generation. Wind PRIME is projected to allow MidAmerican Energy to generate renewable energy greater than or equal to all of its Iowa retail customers' annual energy needs. MidAmerican Energy secured sufficient safe harbor equipment necessary to remain eligible for 100% PTCs under current tax law. Procedural hearings with the IUB began in February 2023.

Iowa Transmission Legislation

In June 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. Also known as the Right of First Refusal, the law ensures MidAmerican Energy, as an incumbent electric transmission owner, has the legal right to construct, own and maintain transmission lines that have been approved by the MISO (or another federally registered planning authority) in MidAmerican Energy's service territory. To exercise the legal right, MidAmerican Energy must notify the IUB within 90 days of any such approval for construction that it intends to construct, own and maintain the electric transmission line. The law still requires an incumbent electric transmission owner to obtain a state franchise from the IUB to construct, erect, maintain or operate an electric transmission line and, upon issuance of a franchise, the incumbent electric transmission owner must provide the IUB an estimate of the cost to construct the electric transmission line and, until the construction is complete, a quarterly report updating the estimated cost to construct the electric transmission line. Legal challenges have been brought against similar laws in other states, but courts that have ruled on such cases have upheld the states' laws. In October 2020, a lawsuit challenging the law was filed in Iowa by national transmission interests. The suit raised issues specific to Iowa law, and the State of Iowa defended the law in the suit. MidAmerican Energy intervened and defended the law as well. The Iowa district court dismissed the lawsuit in March 2021 for lack of standing, and the national transmission interests appealed. In June 2022, the Iowa Court of Appeals upheld the district court's decision, after which the national transmission interests asked the Iowa Supreme Court to reconsider. In November 2022, the Iowa Supreme Court granted the motion to reconsider and accepted the case on the briefs already submitted; it is expected that oral arguments will be held in spring 2023. No stay of the law has been granted, and the law remains in effect pending appeal.

NV Energy (Nevada Power and Sierra Pacific)

Senate Bill 448 ("SB 448")

SB 448 was signed into law on June 10, 2021. The legislation is intended to accelerate transmission development, renewable energy and storage, and accelerate transportation electrification within the state of Nevada. In September 2021, the Nevada Utilities filed an amendment to the 2021 Joint IRP for the approval of their Transmission Infrastructure for a Clean Energy Economy Plan that sets forth a plan for the construction of high-voltage transmission infrastructure, Greenlink North among others, that will be placed into service no later than December 31, 2028, and requires the IRP to include at least one scenario that uses sources of supply that will achieve certain reductions in carbon dioxide emissions. In September 2021, the Nevada Utilities filed an application for the approval of their Economic Recovery Transportation Electrification Plan to accelerate transportation electrification in the state of Nevada. The plan establishes requirements for the contents of the transportation electrification investment as well as requirements for review, cost recovery and monitoring. The plan covers an initial period beginning January 1, 2022 and ending on December 31, 2024. In November 2021, the PUCN issued an order granting the application and accepting the Economic Recovery Transportation Electrification Plan with some modifications. The PUCN opened rulemakings to address other regulations that resulted from SB 448. In February 2022, the PUCN adopted regulations regarding the Economic Development Electric Rate Rider Program to revise the discounted electric rates to ease the economic burden on small businesses who take advantage of the discounted rates under the tariff. In September 2022, the PUCN adopted regulations regarding resource planning, which incorporates a plan to accelerate transportation electrification into the distributed resources plan pursuant to SB 448.

Transportation Electrification Plan ("TEP")

In September 2022, the Nevada Utilities filed an amendment to the 2021 joint IRP for the approval of a Distributed Resource Plan amendment to implement the state's first TEP pursuant to Section 51 of SB 448 and approve proposed tariffs and schedules to implement the TEP. The 2022 TEP outlines programs, investments and incentives to accelerate transportation electrification across Nevada. The Nevada Utilities proposed a budget of $348 million, which represents the maximum cost over the depreciable life of the TEP's programs and assets, to deploy the TEP in 2023 through 2024. A hearing related to the application for approval of the TEP was held in February 2023.

ON Line Temporary Rider ("ONTR")

In October 2021, Sierra Pacific filed an application with the PUCN for approval of the ONTR with corresponding updates to its electric rate tariffs to authorize recovery of the One Nevada Transmission Line ("ON Line") regulatory asset being accumulated as a result of the ON Line cost reallocation as well as the related on-going reallocated revenue requirement. Sierra Pacific's application would have, if approved by the PUCN as filed, resulted in a one-time rate increase of $28 million to be collected over a nine-month period starting on April 1, 2022. In March 2022, the PUCN issued an order directing Sierra Pacific to recover $14 million of the ON Line regulatory asset as a one-time rate increase collectable over a nine-month period effective April 1, 2022, with the expected remaining balance at December 31, 2022 to be included in rate base in the 2022 regulatory rate review for inclusion in the rates set in that case. In December 2022, the PUCN issued an order in the general rate review proceeding allowing for recovery of the remaining regulatory asset balance and directed Sierra Pacific to establish a regulatory liability for any over-collection of revenues from the ONTR rate rider which shall accrue carry charges.

Merger Application

In March 2022, the Nevada Utilities filed a joint application with the PUCN for authorization to merge Sierra Pacific with and into Nevada Power, with Nevada Power being the surviving entity. If approved by the PUCN as filed, Nevada Power will have two distinct electric service territories in northern and southern Nevada each with their own rates and one natural gas service territory in the Reno and Sparks area. In October 2022, all parties to the proceedings relating to the joint application entered into a Stipulation to delay the procedural schedule. The Nevada Utilities made a supplemental filing on December 30, 2022. An order is expected in the first half of 2023.

Regulatory Rate Review

In June 2022, Sierra Pacific filed a regulatory rate review with the PUCN that requested an annual revenue increase of $88 million, or 9.7%. In addition, a filing was made to revise depreciation rates based on a study, the results of which are reflected in the proposed revenue requirement. In August 2022, Sierra Pacific filed an updated certification filing that updated the requested annual revenue increase to $77 million, or 8.5%. Parties to the docket filed testimony and supporting documentation in August and September 2022 while rebuttal testimony was filed in September and October 2022. Hearings in the cost of capital, revenue requirement, and rate design phases were held in September, October, and November 2022, respectively. In December 2022, the PUCN issued an order approving an increase in base rates of $58 million, effective January 1, 2023, reflecting a reduction in Sierra Pacific's requested rate of return, updated depreciation and amortization rates for its electric operations and updated time of use periods to reflect the changes in system costs due to the increased solar generation on the system.

BHE Pipeline Group

BHE GT&S

In September 2021, EGTS filed a general rate case for its FERC-jurisdictional services, with proposed rates to be effective November 1, 2021. EGTS' previous general rate case was settled in 1998. EGTS proposed an annual cost-of-service of approximately $1.1 billion, and requested increases in various rates, including general system storage rates by 85% and general system transmission rates by 60%. In October 2021, the FERC issued an order that accepted the November 1, 2021 effective date for certain changes in rates, while suspending the other changes for five months following the proposed effective date, until April 1, 2022, subject to refund. In September 2022, a settlement agreement was filed with the FERC, resolving EGTS' general rate case for its FERC-jurisdictional services and providing for increased service rates and decreased depreciation rates. Under the terms of the settlement agreement, EGTS' rates result in an increase to annual firm transmission and storage revenues of approximately $160 million and a decrease in annual depreciation expense of approximately $30 million, compared to the rates in effect prior to April 1, 2022. As of December 31, 2022, EGTS' provision for rate refund for April 2022 through December 2022 totaled $90 million and was included in other current liabilities on the Consolidated Balance Sheet. In November 2022, the FERC approved the settlement agreement.

In January 2020, pursuant to the terms of a previous settlement, Cove Point filed a general rate case for its FERC-jurisdictional services, with proposed rates to be effective March 1, 2020. Cove Point proposed an annual cost-of-service of approximately $182 million. In February 2020, the FERC approved suspending the changes in rates for five months following the proposed effective date, until August 1, 2020, subject to refund. In November 2020, Cove Point reached an agreement in principle with the active participants in the general rate case proceeding. Under the terms of the agreement in principle, Cove Point's rates effective August 1, 2020 resulted in an increase to annual revenues of approximately $4 million and a decrease in annual depreciation expense of approximately $1 million, compared to the rates in effect prior to August 1, 2020. The interim settlement rates were implemented November 1, 2020, and Cove Point's provision for rate refunds for August 2020 through October 2020 totaled $7 million. The agreement in principle was reflected in a stipulation and agreement filed with the FERC in January 2021. In March 2021, the FERC approved the stipulation and agreement and the rate refunds to customers were processed in late April 2021.

Northern Natural Gas

In July 2022, Northern Natural Gas filed a general rate case that proposed an overall annual cost-of-service of $1.3 billion. This is an increase of $323 million above the cost of service filed in its 2019 rate case of $1.0 billion. Depreciation on increased rate base and an increase in depreciation and negative salvage rates account for $115 million of the $323 million increase in the filed cost of service. Northern Natural Gas has requested increases in various rates, including transportation and storage reservation rates. In January 2023, the FERC approved Northern Natural Gas filing to implement its interim rates effective January 1, 2023, subject to refund and the outcome of hearing procedures.

BHE Transmission

AltaLink

2022-2023 General Tariff Application

In April 2021, AltaLink filed its 2022-2023 GTA delivering on the last two years of its commitment to keep rates flat for customers at or below the 2018 level of C$904 million for the five-year period from 2019 to 2023. The two-year application achieves flat tariffs by continuing to transition to the AUC-approved salvage recovery method and continuing the use of the flow-through income tax method, with an overall year-over-year increase of approximately 2% in 2022 and 2023 revenue requirements. AltaLink's 2022-2023 GTA reflected its continued commitment to provide rate stability to customers by maintaining flat tariffs and providing additional tariff relief measures, including a proposed tariff refund of C$60 million of accumulated depreciation in each of 2022 and 2023. The application requested the approval of transmission tariffs of C$824 million and C$847 million for 2022 and 2023, respectively after proposed refunds. In September 2021, AltaLink provided responses to information requests from the AUC and filed an amended application to reflect certain adjustments and forecast updates.

In January 2022, the AUC issued its decision with respect to AltaLink's 2022-2023 GTA. The AUC did not approve AltaLink's proposed refund due to an anticipated improvement in general economic conditions in Alberta. In March 2022, AltaLink filed a review and variance application requesting the AUC to review and vary its decision to deny AltaLink's proposed C$120 million refund of accumulated depreciation surplus, given material changes in circumstances since the decision was issued in January 2022. In May 2022, the AUC issued a decision with respect to AltaLink's application to review and vary its proposed $120 million refund of accumulated depreciation surplus. The AUC did not agree that the Alberta economy had materially deteriorated and determined that the long-term costs outweigh the short-term benefits of the refund.

In July 2022, AltaLink submitted its second compliance filing application with total 2022 and 2023 revenue requirements at C$879 million and C$883 million, respectively. In August 2022, the AUC approved the revised revenue requirements as filed, allowing AltaLink to fully deliver on its flat-for-five commitment to customers.

Generic Cost of Capital Proceeding

In January 2022, the AUC initiated the 2023 generic cost of capital proceeding. The proceeding will be conducted in two stages. The first stage will determine the cost of capital parameters for 2023 and the second stage will consider returning to a formula-based approach to establish cost of capital adjustments, commencing in 2024. In March 2022, the AUC issued its decision with respect to the first stage of the 2023 GCOC proceeding by approving the extension of the 2022 return on equity of 8.5% and deemed equity ratio of 37% for 2023, recognizing lingering uncertainty and continued volatility of financial markets due to the COVID-19 pandemic. In June 2022, the AUC initiated the second stage to explore a formula-based approach to determine the return on equity for 2024 and future test periods.

BHE U.S. Transmission

A significant portion of ETT's revenues are based on interim rate changes that can be filed twice annually and are subject to review and possible true-up in the next filed base regulatory rate review scheduled for no later than February 1, 2025. In February 2023, the Public Utilities Commission of Texas ("PUCT") approved ETT's request to suspend a base regulatory rate review filing scheduled for February 2023. Results of a base regulatory rate review would be prospective except for any deemed disallowance by the PUCT of the transmission investment since the initial base regulatory rate review in 2007. In June 2018, the PUCT approved ETT's application to reduce its transmission revenue by $28 million to reflect the lower federal income tax rate due to 2017 Tax Reform with the amortization of excess accumulated deferred federal income taxes expected to be addressed in the next base rate case.

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 of $31.6 billion and (ii) wind tax equity investments of $5.8 billion and has retired 16 coal-fueled generation facilities. As a result, as of December 31 2022, the Company reduced its annual GHG emissions by more than 27% as compared to 2005 levels. The Company plans to continue investing in wind, solar and other low-carbon generation and storage in the future, including (i) $6.4 billion on the construction of renewable generating facilities and repowering certain existing wind-powered generating facilities through 2025 and (ii) $1.3 billion on the construction of electric battery and pumped hydro storage facilities through 2025, and to retire an additional 16 coal-fueled generation facilities between 2023 and 2030 in a reliable and cost-effective manner, thereby achieving a 50% reduction in GHG emissions from 2005 levels in 2030. 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 August 16, 2022, the Inflation Reduction Act of 2022 (the "2022 Act") was signed into law. The 2022 Act contains numerous provisions, including expanded tax credits for clean energy incentives and a 15% corporate alternative minimum income tax on "adjusted financial statement income". The provisions of the 2022 Act become effective for tax years beginning after December 31, 2022. The Company currently does not expect a material impact on its consolidated financial statements. However, the Company expects future guidance from the Treasury Department and will continue to evaluate the impact of the 2022 Act as more guidance becomes available.

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 is also reevaluating 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, will be reclassified as Moderate Non-Attainment, and will have until August 3, 2024 to meet the standard. Until the EPA takes final action on the proposal and the affected states submit any required SIPs, the relevant Registrants cannot determine the impacts of the proposed rule.

Cross-State Air Pollution Rule

The EPA promulgated an initial rule in March 2005 to reduce emissions of NO_x and SO_2, precursors of ozone and particulate matter, from down-wind sources in the eastern U.S. to reduce emissions by implementing a plan based on a market-based cap-and-trade system, emissions reductions, or both. After numerous appeals, the CSAPR was promulgated to address interstate transport of SO_2 and NO_x emissions in 27 Eastern and Midwestern states. In March 2022, the EPA released its Good Neighbor Rule, which contains proposed revisions to the CSAPR framework and is intended to address ozone transport for the 2015 ozone NAAQS. The rule focuses on reductions of NO_x and covers 26 states. Relevant to the Registrants, four states are included in the cross-state program for the first time - California, Nevada, Utah and Wyoming. The EPA proposes to retain emissions allowance trading for generating facilities. Beginning in 2023, emissions budgets would be set at the level of reductions achievable through immediately available measures such as consistently operating existing emissions controls. Starting in 2026, emissions budgets would be set at levels achievable by the installation of SCR controls at certain generating facilities. The proposal also includes additional industries beyond the power sector for the first time, with a focus on the top NO_x emitting stationary source categories. These include natural gas pipeline compressor stations, among others. These sources will not have access to trading and will instead be subject to rate-based limits that are assigned for each source category. The EPA accepted comments on the proposal through June 21, 2022. On February 1, 2023, the EPA released updated air transport modeling that indicates two states, Delaware and Wyoming, do not significantly contribute to downwind maintenance receptors; and that four states, Arizona, Iowa, Kansas and New Mexico, in fact do significantly contribute to downwind maintenance receptors. It is anticipated that the EPA will rely on this updated modeling in the final good neighbor rule, which it intends to finalize in March 2023. Additional notice and comment rulemaking, such as a supplemental rule, would be required to rescind Iowa's approved SIP and incorporate additional states into the program. Until the EPA takes final action consistent with this decree, impacts to the relevant Registrants cannot be determined.

Regional Haze

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"). Some of PacifiCorp's coal-fueled generating facilities in Utah, Wyoming, Arizona and Colorado and certain of Nevada Power's and Sierra Pacific's fossil-fueled generating facilities are subject to the Clean Air Visibility Rules. In accordance with the federal requirements, states are required to submit SIPs that address emissions from sources subject to BART requirements and demonstrate progress towards achieving natural visibility requirements in Class I areas by 2064.

In June 2019, the state of Utah incorporated a BART alternative into its SIP for regional haze planning period one. The BART alternative makes the shutdown of PacifiCorp's Carbon generating facility enforceable under the SIP and removes the requirement to install SCR equipment on Hunter Units 1 and 2 and Huntington Units 1 and 2. The EPA approved the SIP revision with the BART alternative in October 2020. The EPA's actions also withdrew a prior FIP that required installation of SCR equipment on Hunter Units 1 and 2 and Huntington Units 1 and 2. On January 19, 2021, Heal Utah, National Parks Conservation Association, Sierra Club and Utah Physicians for a Healthy Environment filed a petition for review of the Utah Regional Haze SIP Alternative in the Tenth Circuit. PacifiCorp and the state of Utah moved to intervene in the litigation. After review of the rule by the Biden administration, the EPA determined it would defend the rule and briefing has been completed. A date for oral arguments has not been scheduled. The Utah Air Quality Board approved the Utah Division of Air Quality's SIP for the regional haze second planning period on June 6, 2022. The SIP sets mass-based NO_x emissions limits and rate-based SO_2 limits for PacifiCorp's Hunter and Huntington generating facilities to ensure reasonable visibility progress for the second planning period.

The state of Wyoming issued two regional haze SIPs requiring the installation of SO_2, NO_x and particulate matter controls on certain PacifiCorp coal-fueled generating facilities in Wyoming. The EPA approved the SO_2 SIP in December 2012 and the EPA's approval was upheld on appeal by the Tenth Circuit in October 2014. The EPA's final action on the Wyoming SIP in 2014 approved the state's plan to have PacifiCorp install low-NO_x burners at Naughton Units 1 and 2, SCR controls at Naughton Unit 3 by December 2014, SCR controls at Jim Bridger Units 1 through 4 between 2015 and 2022, and low-NO_x burners at Dave Johnston Unit 4. The EPA disapproved a portion of the Wyoming SIP and issued a FIP for Dave Johnston Unit 3, where it required the installation of SCR controls by 2019 or, in lieu of installing SCR controls, a commitment to shut down Dave Johnston Unit 3 by 2027, its currently approved depreciable life. The EPA also disapproved a portion of the Wyoming SIP and issued a FIP for the Wyodak coal-fueled generating facility, requiring the installation of SCR controls by 2019. PacifiCorp filed an appeal of the EPA's final action on Wyodak in March 2014. The state of Wyoming and several environmental groups also filed an appeal of the EPA's final action. In September 2014, the Tenth Circuit issued a stay of the March 2019 compliance deadline for Wyodak, pending further action by the Tenth Circuit in the appeal. The abatement on litigation was lifted September 28, 2022, and opening briefs were submitted in October 2022. PacifiCorp objects to the EPA's FIP requiring SCR on the Wyodak Unit. That requirement in the agency's plan remains stayed by the court. PacifiCorp has also intervened on behalf of the EPA against claims that Naughton Units 1 and 2 should have been subject to a SCR requirement. Separately, on February 14, 2022, the First Judicial District Court for the State of Wyoming entered a consent decree reached between the state of Wyoming and PacifiCorp resolving claims of threatened violations of the Clean Air Act, the Wyoming Environmental Quality Act and the Wyoming Air Quality Standards and Regulations at the Jim Bridger facility. No penalties were imposed under the consent decree. Consistent with the terms and conditions of the consent decree, PacifiCorp must convert both units to natural gas and begin meeting emissions limits consistent with that conversion by January 1, 2024. The EPA and PacifiCorp executed an administrative order on consent June 9, 2022, covering compliance for Jim Bridger Units 1 and 2 under the regional haze rule. The federal order contains the same emission and operating limits as the Wyoming consent decree and adds federal approval of the compliance pathway outlined in the state consent decree, including revision of the SIP to include conversion of Jim Bridger Units 1 and 2 to natural gas. The order includes a one-year deadline to complete the SIP revision. On December 30, 2022, the Wyoming Air Quality Division submitted the state-approved revised regional haze state implementation plan requiring natural gas conversion of Jim Bridger units 1 and 2 to the EPA for approval. The plan revision replaces a previous requirement for selective catalytic reduction at the units. The Wyoming Air Quality Division also issued an air permit for the natural gas conversion of Jim Bridger units 1 and 2 on December 28, 2022. The EPA is expected to conduct a separate federal public comment process on the plan. For the second round of regional haze planning, Wyoming determined that no controls will be necessary on any Wyoming resources to make reasonable progress.

The state of Colorado regional haze SIP requires SCR equipment at Craig Unit 2 and Hayden Units 1 and 2, in which PacifiCorp has ownership 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 ownership 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 identified a December 31, 2025, retirement date for Craig Unit 1 in its 2017 and 2019 IRPs.

Nevada, Utah and Wyoming each submitted regional haze SIPs for the regional haze second planning period to the EPA in August 2022. The EPA has 18 months to approve or disapprove all or parts of the states' plans. 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 finding says the agency intends to continue to work with states in developing approvable SIP submittals in a timely manner. The Iowa Department of Natural Resources continues to work with the EPA on development of its SIP. On February 13, 2023, Iowa issued a draft SIP and will accept comment on the draft plan through March 16, 2023. Iowa proposes to require operational improvements to existing control equipment at MidAmerican Energy Company's Louisa Generation Station and Walter Scott Jr. Energy Center - Unit 3. Iowa anticipates submitting a final plan to the EPA in spring 2023.

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. In the context of the Paris Agreement, the U.S. agreed to reduce GHG emissions 26% to 28% by 2025 from 2005 levels. 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 withdrawal from the Paris Agreement on November 4, 2020. President Biden accepted the terms of the climate agreement on January 20, 2021, and the U.S. completed its reentry February 19, 2021. New commitments to the Paris Agreement were announced in April 2021, with the U.S. pledging to cut its overall GHG emissions 50% to 52% from 2005 levels by 2030 and to reach 100% carbon pollution-free electricity by 2035. Increasingly, states are adopting legislation and regulations to reduce GHG emissions, and local governments and consumers are seeking increasing amounts of clean and renewable energy.

GHG Performance Standards

Affordable Clean Energy Rule

In June 2014, the EPA released proposed regulations to address GHG emissions from existing fossil-fueled generating facilities, referred to as the Clean Power Plan, under Section 111(d) of the Clean Air Act. The EPA's proposal calculated state-specific emission rate targets to be achieved based on the "best system of emission reduction." In August 2015, the final Clean Power Plan was released, which established the best system of emission reduction as including: (a) heat rate improvements; (b) increased utilization of existing combined-cycle natural gas-fueled generating facilities; and (c) increased deployment of new and incremental non-carbon generation placed in-service after 2012. The Clean Power Plan was stayed by the U.S. Supreme Court in February 2016 while litigation proceeded. On June 19, 2019, the EPA repealed the Clean Power Plan and issued the Affordable Clean Energy rule. In the Affordable Clean Energy rule, the EPA determined that the best system of emission reduction for existing coal-fueled generating facilities is limited to actions that can be taken at a point source facility, specifically heat rate improvements and identified a set of candidate technologies and measures that could improve heat rates. Measures taken to meet the standards of performance must be achieved at the source itself. The Affordable Clean Energy rule was challenged by environmental and health groups in the D.C. Circuit. On January 19, 2021, the D.C. Circuit vacated and remanded the Affordable Clean Energy rule to the EPA, finding that the rule "rested critically on a mistaken reading of the Clean Air Act" that limited the best system of emission reduction to actions taken at a facility. In October 2021, the U.S. Supreme Court agreed to hear an appeal of that decision. Arguments in the case were held February 28, 2022, and on June 30, 2022 the U.S. Supreme Court issued its decision regarding the scope of the EPA's authority to regulate greenhouse gas emissions under the Clean Air Act. The U.S. Supreme Court held that the "generation shifting" approach in the Clean Power Plan exceeded the powers granted to the EPA by Congress, although the court did not address whether the EPA may only adopt measures applied at the individual source as it did in the Affordable Clean Energy rule. A key area where the EPA went astray was using the Clean Power Plan to give states the option to promulgate regulations that would encourage "generation shifting," or moving away from higher-polluting power sources like coal to lower-polluting sources like natural gas or renewables. The U.S. Supreme Court found that type of regulation, which would impact larger economic forces beyond the fence lines of individual generating facilities, is not permitted under Section 111(d) of the Clean Air Act. The U.S. Supreme Court reversed the D.C. Circuit's vacatur of the Affordable Clean Energy rule and remanded the case for further proceedings. The ruling has no immediate impact on the Registrants, as there is no Section 111(d) rule currently in effect. The Biden administration plans to propose by March 2023 its own rule to replace the Clean Power Plan and Affordable Clean Energy rule.

New Source Performance Standards for Methane Emissions

In August 2020, the EPA finalized regulations to rescind standards for methane emissions from the oil and gas sector. The changes eliminate requirements to regulate methane emissions from the production, processing, transmission and storage of oil and gas. The rule was immediately challenged by environmental and tribal groups, as well as numerous states. In January 2021, the D.C. Circuit lifted an administrative stay and allowed the rule to take effect, finding that groups challenging the rule had not met the standard for a long-term stay. On June 30, 2021, President Biden signed into law a joint resolution of Congress, adopted under the Congressional Review Act, disapproving the August 2020 rule. The resolution reinstated the 2012 volatile organic compounds standards and the 2016 volatile organic compounds and methane standards for the oil and natural gas transmission and storage segments, as well as the methane standards for the production and processing segments of the oil and gas sector. On November 2, 2021, the EPA proposed rules that would reduce methane emissions from both new and existing sources in the oil and natural gas industry. The proposals would expand and strengthen emission reduction requirements for new, modified and reconstructed oil and natural gas sources and would require states to reduce methane emissions from existing sources nationwide. The EPA took comment on the proposed rules through January 31, 2022. The EPA issued a supplemental proposal in November 2022 to further strengthen emission reduction requirements and intends to finalize the rules by fall 2023. Until the rules are finalized, the relevant Registrants cannot determine the full impacts of the proposed rule.

Water Quality Standards

The Clean Water Act establishes the framework for maintaining and improving water quality in the U.S. through a program that regulates, among other things, discharges to and withdrawals from waterways. The Clean Water Act requires that cooling water intake structures reflect the "best technology available for minimizing adverse environmental impact" to aquatic organisms. After significant litigation, the EPA released a proposed rule under §316(b) of the Clean Water Act to regulate cooling water intakes at existing facilities. The final rule was released in May 2014 and became effective in October 2014. Under the final rule, existing facilities that withdraw at least 25% of their water exclusively for cooling purposes and have a design intake flow of greater than two million gallons per day are required to reduce fish impingement (i.e., when fish and other aquatic organisms are trapped against screens when water is drawn into a facility's cooling system) by choosing one of seven options. Facilities that withdraw at least 125 million gallons of water per day from waters of the U.S. must also conduct studies to help their permitting authority determine what site-specific controls, if any, would be required to reduce entrainment of aquatic organisms (i.e., when organisms are drawn into the facility). PacifiCorp's Dave Johnston generating facility and all of MidAmerican Energy's coal-fueled generating facilities, except Louisa, Ottumwa and Walter Scott, Jr. Unit 4, which have water cooling towers, withdraw more than 125 million gallons per day of water from waters of the U.S. for once-through cooling applications. PacifiCorp's Jim Bridger, Naughton, Gadsby, Hunter and Huntington generating facilities currently utilize closed cycle cooling towers but are designed to withdraw more than two million gallons of water per day. If PacifiCorp's or MidAmerican Energy's existing intake structures require modification, the costs are not anticipated to be significant to the consolidated financial statements. Nevada Power and Sierra Pacific are not impacted by the §316(b) final rule since they do not utilize once-through cooling water intake or discharge structures at any of their generating facilities.

In November 2015, the EPA published final effluent limitation guidelines and standards for the steam electric power generating sector which, among other things, regulate the discharge of bottom ash transport water, fly ash transport water, combustion residual leachate and non-chemical metal cleaning wastes. In November 2019, the EPA proposed updates to the 2015 rule, specifically addressing flue gas desulfurization wastewater and bottom ash transport water. The rule took effect in December 2020. The final rule changes the technology-basis for treatment of flue gas desulfurization wastewater and bottom ash transport water, revises the voluntary incentives program for flue gas desulfurization wastewater, and adds subcategories for high-flow units, low utilization units, and those that will transition away from coal combustion by 2028. While most of the issues raised by this rule are already being addressed through the CCR rule and are not expected to impose significant additional requirements, the Dave Johnston generating facility is impacted by the rule's bottom ash handling requirements at Units 1 and 2. The generating facility submitted notice to the Wyoming Department of Environmental Quality that it will either achieve a cessation of coal combustion at Units 1 and 2 by December 31, 2028, or install bottom ash transport treatment technology by December 31, 2025. The EPA anticipates proposing additional changes to the rule in spring 2023 to resolve outstanding issues from litigation.

In April 2014, the EPA and the U.S. Army Corps of Engineers ("Corps of Engineers") issued a joint proposal to address "waters of the United States" to clarify protection under the Clean Water Act for streams and wetlands. The proposed rule comes as a result of U.S. Supreme Court decisions in 2001 and 2006 that created confusion regarding jurisdictional waters that were subject to permitting under either nationwide or individual permitting requirements. The final rule was released in May 2015 but was appealed in multiple courts and a nationwide stay on the implementation of the rule was issued in October 2015. On June 9, 2021, the EPA and the Corps of Engineers announced their intention to again revise the definition of "waters of the United States." In December 2022, the agencies released a final rule updating the definition of "waters of the United States." The final rule generally restores and is broader than the pre-2015 "waters of the United States" definition and incorporates both the "relatively permanent" and "significant nexus" standards from U.S. Supreme Court decisions.

Coal Ash Disposal

In April 2015, the EPA released a final rule to regulate the management and disposal of coal combustion residuals (CCR) under the RCRA. The rule regulates coal combustion byproducts 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 byproducts will need to be closed unless they can meet the more stringent regulatory requirements.

At the time the rule was published in April 2015, PacifiCorp operated 18 surface impoundments and seven landfills that contained coal combustion byproducts. Prior to the effective date of the rule in October 2015, nine surface impoundments and three landfills were either closed or repurposed to no longer receive coal combustion byproducts and hence are not subject to the final rule. As PacifiCorp proceeded to implement the final coal combustion rule, it was determined that two surface impoundments located at the Dave Johnston generating facility were hydraulically connected and effectively constitute a single impoundment. In November 2017, a new surface impoundment was placed into service at the Naughton Generating Station. At the time the rule was published in April 2015, MidAmerican Energy owned or operated nine surface impoundments and four landfills that contain coal combustion byproducts. Prior to the effective date of the rule in October 2015, MidAmerican Energy closed or repurposed six surface impoundments to no longer receive coal combustion byproducts. Five of these surface impoundments were closed on or before December 21, 2017, and the sixth is undergoing closure. At the time the rule was published in April 2015, the Nevada Utilities operated 10 evaporative surface impoundments and two landfills that contained coal combustion byproducts. Prior to the effective date of the rule in October 2015, the Nevada Utilities closed four of the surface impoundments, four impoundments discontinued receipt of coal combustion byproducts making them inactive and two surface impoundments remain active and subject to the final rule. The two landfills remain active and subject to the final rule.

Multiple parties filed challenges over various aspects of the final rule in the D.C. Circuit, resulting in settlement of some of the issues and subsequent regulatory action by the EPA. The EPA finalized the first phase of the CCR rule amendments in July 2018 (the "Phase 1, Part 1 rule"). In addition to adopting alternative performance standards and revising groundwater performance standards for certain constituents, the EPA extended the deadline by which facilities must initiate closure of unlined ash ponds exceeding a groundwater protection standard and impoundments that do not meet the rule's aquifer location restrictions to October 31, 2020. Following submittal of competing motions from environmental groups and the EPA to stay or remand this deadline extension, on March 13, 2019, the D.C. Circuit granted the EPA's request to remand the rule and left the October 31, 2020 deadline in place while the agency undertakes a new rulemaking establishing a new deadline for initiating closure. On August 14, 2019, the EPA released its "Phase 2" proposal, which contains targeted amendments to the CCR rule in response to court remands and EPA settlement agreements, as well as issues raised in a rulemaking petition. The Phase 2 rule has not been finalized. In February 2020, the EPA proposed a federal CCR permit program as required by the WIIN Act of 2016. The federal permit rule has not been finalized. In October 2020, the EPA released an advanced notice of proposed rulemaking on legacy CCR surface impoundments, seeking comment on and information related to issues relevant to development of regulations for legacy impoundments. The EPA has not undertaken additional rulemaking related to the advanced notice. Until the proposals are finalized and fully litigated, the Registrants cannot determine whether additional action may be required.

In August 2020, the EPA finalized its Holistic Approach to Closure: Part A rule ("Part A rule"). This proposal addressed the D.C. Circuit's revocation of the provisions that allow unlined impoundments to continue receiving ash. The Part A rule established a new deadline of April 11, 2021, by which all unlined surface impoundments must initiate closure. The Part A rule also identifies two extensions to that date: (1) a site-specific extension to develop alternate disposal capacity and initiate closure by October 15, 2023; and (2) a site-specific extension for facilities that agree to shut down the coal-fueled unit and complete ash pond closure activities by October 17, 2028. PacifiCorp developed a demonstration for the development of alternative capacity for the Jim Bridger facility's FGD Pond 2 and a demonstration for closure of the Naughton facility and ash pond and submitted them to the EPA in November 2020. On January 11, 2022, the EPA deemed these submittals complete but has not taken additional action on them. No other Registrants used the provisions of the Part A rule.

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 byproducts. Some of these cases have been successful in imposing liability upon companies if coal combustion byproducts 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.

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 16 of the Notes to Consolidated Financial Statements of Berkshire Hathaway Energy in Item 8 of this Form 10-K and 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.

Corporate and Financial Structure Risks

BHE is a holding company and depends on distributions from subsidiaries, including joint ventures, to meet its obligations.

BHE is a holding company with no material assets other than the ownership interests in its subsidiaries and joint ventures, collectively referred to as its subsidiaries. Accordingly, cash flows and the ability to meet BHE's obligations are largely dependent upon the earnings of its subsidiaries and the payment of such earnings to BHE in the form of dividends or other distributions. BHE's subsidiaries are separate and distinct legal entities and have no obligation, contingent or otherwise, to pay amounts due pursuant to BHE's senior debt, junior subordinated debt or its other obligations, or to make funds available, whether by dividends or other payments, for the payment of amounts due pursuant to BHE's senior debt, junior subordinated debt or its other obligations, and do not guarantee the payment of any of its obligations. Distributions from subsidiaries may also be limited by:

- their respective earnings, capital requirements, and required debt and preferred stock 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.

BHE is substantially leveraged, the terms of its existing senior and junior subordinated debt do not restrict the incurrence of additional debt by BHE or its subsidiaries, and BHE's senior debt is structurally subordinated to the debt of its subsidiaries, and each of such factors could adversely affect BHE's consolidated 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, 2022, BHE had the following outstanding obligations:

- senior unsecured debt of $14.0 billion;
- junior subordinated debentures of $100 million;
- guarantees and letters of credit in respect of subsidiaries, equity method investments and other related parties aggregating $1.6 billion; and

BHE's consolidated subsidiaries also have significant amounts of outstanding debt, which totaled $38.4 billion as of December 31, 2022. 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.

Given BHE's substantial leverage, it 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. BHE'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.

The terms of BHE's and its subsidiaries' debt 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 senior 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 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, including the Subsidiary Registrants, 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, and the potential pool of investors and funding sources would likely decrease. Further, access to the commercial paper market could be significantly limited, resulting in higher interest costs.

Similarly, any downgrade 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.

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.

BHE's majority 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 and PacifiCorp's preferred stockholders.

Berkshire Hathaway is majority owner 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 owns 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 owns 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.

Business Risks

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.

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; 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 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 pipeline systems; 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, its revenue could decrease and its expenses could increase due to the need to obtain energy from more expensive sources.

Further, 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. 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.

The Registrants are subject to increasing risks from catastrophic wildfires and may be unable to obtain enough insurance coverage at a reasonable cost or at all and insurance coverage on existing wildfire claims could be insufficient to cover all losses should current estimates of those losses materially differ from the ultimate outcomes of the claims, 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. Uninsured losses and increases in the cost of insurance may be challenged when PacifiCorp seeks cost recovery and may not be recoverable in customer rates.

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.

Damage claims against PacifiCorp for wildfires may materially affect its financial condition and results of operations.

In September 2020, a severe weather event resulting in high winds, low humidity and warm temperatures contributed to several major wildfires, private and public property damages, personal injuries and loss of life and widespread power outages in Oregon and Northern California (the "2020 Wildfires"). Additionally, a major wildfire began in PacifiCorp's service territory in July 2022 causing private and public property damage, personal injuries, loss of life and power outages in Northern California (the "2022 McKinney Fire"). The wildfires spread across certain parts of PacifiCorp's service territory and surrounding areas across multiple counties in Oregon and California. Investigations into the cause and origin of each wildfire are complex and ongoing. Several lawsuits and complaints have been filed in Oregon and California associated with the wildfires, and it is possible that additional lawsuits and complaints against PacifiCorp may be filed. If PacifiCorp is found liable for damages related to the 2020 Wildfires or the 2022 McKinney Fire and is unable to, or believes that it will be unable to, recover those damages through insurance or customer rates, or access the bank and capital markets on reasonable terms, PacifiCorp's financial results could be adversely affected. 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 2020 Wildfires and the 2022 McKinney Fire.

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, 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.

Each Registrant is 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 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 initiatives regarding deregulation and restructuring of the utility industry, are continually being proposed and enacted that impose new or revised requirements or standards on each Registrant.

Each Registrant is required to comply with numerous federal, state, local and 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 requirements, including the implementation of or changes to the Affordable Clean Energy rule, 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. For example, in April 2022, the EPA proposed the "Cross-State Ozone Transport Rule", which contains requirements intended to address ozone transport between states through federally required nitrogen oxide reductions from fossil-fuel generating facilities. The rule included Wyoming, Utah and Nevada for the first time. If finalized as proposed, the rule will have impacts on PacifiCorp's coal-fueled generating facilities in both Utah and Wyoming that do not have an SCR as early as 2026 and threatens early coal-fueled unit retirements and reliability impacts. PacifiCorp has engaged with state and federal agencies to make adjustments to the rule and mitigate potential reliability impacts. 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 service 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 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. Any of these consequences could adversely affect each Registrant's financial results.

FERC Jurisdiction

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 system's regulatory cost of service that are associated with the construction, operation and maintenance of their pipeline system 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 Natural Gas Act of 1938 ("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.

GEMA Jurisdiction

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.

AUC Jurisdiction

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 and system access problems.

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 and approval of 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 regulations and standards;
- adjudicating enforcement issues including the imposition of administrative penalties that arise when market participants violate the rules of the AESO; 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.

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 those of many large businesses, certain of the Registrant's technology systems have been subject to computer viruses, malicious codes, unauthorized access, phishing efforts, denial-of-service attacks and other cyber attacks and each Registrant expects to be subject to similar attacks in the future as such attacks become more sophisticated and frequent. A significant disruption or failure of its technology systems by physical or cyber 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.

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 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.

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 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 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.

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, such as Russia's invasion of Ukraine in February 2022 and the resulting economic sanctions on Russia and the sale of Russian natural gas and petroleum, as well as the existing and potential further responses from Russia or other countries to such sanctions and military actions, could adversely affect global and regional economies and financial markets. For instance, the current ban on imports of Russian 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.

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% ownership 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, 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 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.

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 continues to monitor 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 any Registrant's wholesale suppliers' or customers' financial condition deteriorates or they otherwise become unable to pay, it could have a significant adverse impact on each 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 with E.ON and British Gas Trading Limited accounting for approximately 22% and 14%, respectively, of distribution revenue in 2022. 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. For example, certain of BHE Renewables' solar and wind independent power projects sell all of their electrical production to either PG&E or SCE, respectively. 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.

BHE owns 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 (including potentially in relation to COVID-19 variants), 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.

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 and 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 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.

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

Inflation and increases in commodity prices and fuel transportation 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 costs of inflation on to its customers. If each Registrant is unable to manage cost increases or pass them on to its customers, its financial results could be adversely affected.

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.

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.

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 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 or permitting of facilities. Any of these outcomes could have a material adverse effect on such Registrant's financial results.

Item 1B. Unresolved Staff Comments

Not applicable.

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 and Notes 4 and 5 of the Notes to Consolidated Financial Statements of Eastern Energy Gas in Item 8 of this Form 10-K.

The following table summarizes Berkshire Hathaway Energy's operating electric generating facilities as of December 31, 2022:

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	12,282	12,282
Natural gas	PacifiCorp, MidAmerican Energy, NV Energy, BHE Canada and BHE Renewables	Nevada, Utah, Iowa, Illinois, Washington, Wyoming, Oregon, Texas, New York, Arizona and Canada	11,284	11,005
Coal	PacifiCorp, MidAmerican Energy and NV Energy	Wyoming, Iowa, Utah, Nevada, Colorado and Montana	13,210	8,178
Solar	MidAmerican Energy, NV Energy, Northern Powergrid and BHE Renewables	California, Australia, Texas, Arizona, Iowa, Minnesota and Nevada	2,120	1,972
Hydroelectric	PacifiCorp, MidAmerican Energy and BHE Renewables	Washington, Oregon, Idaho, Utah, Hawaii, Montana, Illinois, California and Wyoming	985	985
Nuclear	MidAmerican Energy	Illinois	1,822	455
Geothermal	PacifiCorp and BHE Renewables	California and Utah	377	377
		Total	42,080	35,254

Additionally, as of December 31, 2022, the Company has electric generating facilities that are under construction in Nevada and Wyoming having total Facility Net Capacity and Net Owned Capacity of 243 MWs.

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

On September 30, 2020, a putative class action complaint against PacifiCorp was filed, captioned *Jeanyne James et al. v. PacifiCorp et al.*, Case No. 20CV33885, Circuit Court, Multnomah County, Oregon. The complaint was filed by Oregon residents and businesses who seek 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. On November 3, 2021, the plaintiffs filed an amended complaint to limit the class to include Oregon citizens allegedly impacted by the Echo Mountain Complex, South Obenchain, Two Four Two and Santiam Canyon fires, as well as to add claims for noneconomic damages. The amended complaint alleges 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 the following damages for the plaintiffs and the putative class: (i) noneconomic damages, including mental suffering, emotional distress, inconvenience and interference with normal and usual activities, in excess of $1 billion; (ii) damages for real and personal property and other economic losses of not less than $600 million; (iii) double the amount of property and economic damages; (iv) treble damages for specific costs associated with loss of timber, trees and shrubbery; (v) double the damages for the costs of litigation and reforestation; (vi) prejudgment interest; and (vii) reasonable attorney fees, investigation costs and expert witness fees. The plaintiffs demand a trial by jury and have reserved their right to further amend the complaint to allege claims for punitive damages. In May 2022, the Multnomah Circuit Court granted issue class certification and consolidated this case with others as described below. PacifiCorp requested an immediate appeal of the issue class certification before the Oregon Court of Appeals. In January 2023, the Oregon Court of Appeals denied PacifiCorp's request for appeal. In February 2023, the plaintiffs filed a motion to amend the complaint to add punitive damages in an unspecified amount.

On August 20, 2021, a complaint against PacifiCorp was filed, captioned *Shylo Salter et al. v. PacifiCorp*, Case No. 21CV33595, Multnomah County, Oregon, in which two complaints, Case No. 21CV09339 and Case No. 21CV09520, previously filed in Circuit Court, Marion County, Oregon, were combined. The plaintiffs voluntarily dismissed the previously filed complaints in Marion County, Oregon. The refiled complaint was filed by Oregon residents and businesses who allege that they were injured by the Beachie Creek fire, which the plaintiffs allege began on or around September 7, 2020, but which government reports indicate began on or around August 16, 2020. The complaint alleges that PacifiCorp's assets contributed to the Beachie Creek fire and that PacifiCorp acted with gross negligence, among other things. The complaint seeks the following damages: (i) damages related to real and personal property in an amount determined by the jury to be fair and reasonable, estimated not to exceed $75 million; (ii) other economic losses in an amount determined by the jury to be fair and reasonable, but not to exceed $75 million; (iii) noneconomic damages in the amount determined by the jury to be fair and reasonable, but not to exceed $500 million; (iv) double the damages for economic and property damages under specified Oregon statutes; (v) alternatively, treble the damages under specified Oregon statutes; (vi) attorneys' fees and other costs; and (vii) pre- and post-judgment interest. The plaintiffs demand a trial by jury and have reserved their right to amend the complaint with an intent to add a claim for punitive damages. In May 2022, this case was consolidated with others as described below.

In May 2022, the Multnomah County Circuit Court granted plaintiffs' motion to consolidate *Shylo Salter et al. v. PacifiCorp*, Case No. 21CV33595 (described above) and *Amy Allen, et al. v. PacifiCorp*, Case No. 20CV37430 ("Allen") into *Jeanyne James et al. v. PacifiCorp et al.*, Case No. 20CV33885 (described above). Plaintiffs' motion to bifurcate issues for trial between class-wide liability and individual damages was also granted. The Allen case was filed by five individuals as amended in September 2021 claiming in excess of $32 million in economic and noneconomic damages, as well as claims for statutory doubling or trebling of damages, attorneys' fees and other costs and pre- and post-judgment interest.

In June 2022, an amended complaint against PacifiCorp was filed, captioned *Tim Goforth et al. v. PacifiCorp*, Case No. 20CV37637, Douglas County, Oregon, in which a previously filed complaint associated with the Archie Creek, Susan Creek and Smith Springs Road fires in Douglas County in September 2020 was amended to add punitive damages. The complaint alleges (i) PacifiCorp's conduct not only constituted common law negligence but gross negligence and contributed to or was the cause of ignition and spread of the aforementioned fires; (ii) PacifiCorp violated certain Oregon rules and regulations; and (iii) as an alternative to negligence, inverse condemnation. The complaint seeks the following damages: (i) economic and property damages of $11 million under a determination of negligence or inverse condemnation and subject to doubling under Oregon statute if applicable; (ii) doubling of those economic and property damages to $22 million under a determination of gross negligence; (iii) damages for injuries in excess of $47 million; (iv) punitive damages not to exceed 10 times the amount of non-economic damages awarded; (v) all costs of the lawsuit; (vi) pre- and post-judgment interest as allowed by law; and (vii) attorneys' fees and other costs. Pursuant to a settlement stipulation agreed to in November 2022, the Douglas County Circuit Court issued an order dismissing the case with prejudice and without costs, disbursements or attorney fees to any of the parties.

On August 26, 2022, a putative class action complaint seeking declaratory and equitable relief against PacifiCorp was filed, captioned *Margaret Dietrich et al. v. PacifiCorp*, Case No. 22CV29187, Circuit Court, Multnomah County, Oregon. The complaint was filed by two Oregon residents individually and on behalf of a class initially 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, Beachie Creek, Lionshead, Echo Mountain Complex, Two Four Two or South Obenchain fires in September 2020. The complaint was amended on September 6, 2022, to seek damages of over $900 million that were originally demanded on August 4, 2022, pursuant to Oregon Rule of Civil Procedure 32 H. The amended complaint alleges: (i) negligence due to alleged failure to comply with certain Oregon statutes and administrative rules; (ii) gross negligence due to alleged conscious indifference to or reckless disregard for the probable consequences of defendant's actions or inactions; (iii) private nuisance; (iv) public nuisance; (v) trespass; (vi) inverse condemnation; (vii) accounting/injunction; (viii) negligent infliction of emotional distress. The amended complaint seeks the following: (i) an order certifying the matter as a class action; (ii) economic damages not less than $400 million; (iii) double the amount of economic and property damages to the extent applicable under Oregon statute; (iv) reasonable costs of reforestation activities; (v) doubling and trebling of certain other damages to the extent applicable under certain Oregon statutes; (vi) noneconomic damages not less than $500 million; (vii) prejudgment interest; (viii) an order requiring an accounting with respect to the amount of damages; (ix) an order enjoining PacifiCorp from leaving power lines energized in areas of Oregon experiencing extremely critical fire conditions; (x) an award of reasonable attorney fees, costs, investigation costs, disbursements and expert witness fees; and (xi) other relief the court finds appropriate. The plaintiffs and proposed class demand a trial by jury. On December 19, 2022, the Dietrich case was consolidated into *Jeanyne James et al. v. PacifiCorp et al.*, Case No. 20CV33885 (described above) and is currently stayed.

On September 1, 2022, a complaint against PacifiCorp was filed, captioned *Martin Klinger et al. v. PacifiCorp*, Case No. 22CV29674, Multnomah County, Oregon ("Klinger"). The complaint was filed by Oregon residents or Oregon property owners who allege damages resulting from the September 2020 Echo Mountain Complex fires. The allegations made and damages sought are described below.

On September 1, 2022, a complaint against PacifiCorp was filed, captioned *Jeremiah E. Bowen et al. v. PacifiCorp*, Case No. 22CV29681, Multnomah County, Oregon ("Bowen"). The complaint was filed by Oregon residents, occupants and real and personal property owners who allege injuries and damages resulting from the September 2020 Echo Mountain Complex fires. The allegations made and damages sought are described below.

On September 1, 2022, a complaint against PacifiCorp was filed, captioned *James Weathers et al. v. PacifiCorp*, Case No. 22CV29683, Multnomah County, Oregon ("Weathers"). The complaint was filed by Oregon residents, occupants and real and personal property owners who allege injuries and damages resulting from the September 2020 Echo Mountain Complex fires. The allegations made and damages sought are described below.

On September 6, 2022, a complaint against PacifiCorp was filed, captioned *Blair Barnholdt et al. v. PacifiCorp*, Case No. 22CV30097, Multnomah County, Oregon ("Barnholdt"). The complaint was filed by Oregon residents or Oregon property owners who allege damages resulting from the September 2020 Echo Mountain Complex fires. The allegations made and damages sought are described below.

On September 7, 2022, a complaint against PacifiCorp was filed, captioned *Estate of Nancy Darlene Hunter, et al. v. PacifiCorp*, Case No. 22CV30214, Multnomah County, Oregon ("Hunter"). The complaint was filed by Oregon residents, occupants and real and personal property owners who allege injuries and damages resulting from the September 2020 Echo Mountain Complex fires. The allegations made and damages sought are described below.

On September 7, 2022, a complaint against PacifiCorp was filed, captioned *Willard K. Pratt et al. v. PacifiCorp*, Case No. 22CV30217, Multnomah County, Oregon ("Pratt"). The complaint was filed by Oregon residents, occupants and real and personal property owners who allege injuries and damages resulting from the September 2020 Echo Mountain Complex fires. The allegations made and damages sought are described below.

On September 7, 2022, a complaint against PacifiCorp was filed, captioned *April Thompson et al. v. PacifiCorp*, Case No. 22CV30451, Multnomah County, Oregon ("Thompson"). The complaint was filed by Oregon residents, occupants and real and personal property owners who allege injuries and damages resulting from the September 2020 Echo Mountain Complex fires. The allegations made and damages sought are described below.

The Klinger, Bowen, Weathers, Barnholdt, Hunter, Pratt and Thompson cases are in the process of being consolidated with *Sparks et al. v. PacifiCorp*, Case No. 21CV48022 ("Sparks") and *Russie et al. v. PacifiCorp*, Case No. 22CV15840 ("Russie") into *Ashley Andersen et al. v. PacifiCorp*, Case No. 21CV36567 ("Andersen"). The Klinger, Bowen, Weathers, Barnholdt, Pratt and Thompson complaints each 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; and (v) inverse condemnation. The Klinger, Bowen, Weathers, Barnholdt, Pratt and Thompson complaints each seek the following damages: (i) economic and property related damages of $83 million; (ii) doubling of those economic and property related damages to $167 million to the extent eligible for doubling of damages under the specified Oregon statute; (iii) non-economic damages to the plaintiffs' persons in an amount not less than $83 million for physical injury, mental suffering, emotional distress and other damages; (iv) loss of wages, loss of earnings capacity, evacuation expenses, displacement expenses and similar damages; (v) attorneys' fees and other costs; and (vii) pre-judgment interest. The plaintiffs for each Klinger, Bowen, Weathers, Barnholdt, Pratt and Thompson request a trial by jury and have reserved their right to amend the complaint to add a claim for punitive damages. The Hunter complaint seeks $50 million in damages and alleges claims for: (i) negligence, (ii) trespass, (iii), nuisance, (iv) inverse condemnation, and (v) wrongful death. The Andersen case was filed by 50 individuals as amended in August 2022 seeking $250 million in economic and noneconomic damages, as well as claims for statutory doubling or trebling of damages, attorneys' fees and other costs and pre-judgment interest. The Sparks case was filed by 17 individuals in December 2021 claiming $125 million in economic and noneconomic damages, as well as claims for statutory doubling or trebling of damages, attorneys' fees and other costs and pre-judgment interest. The Russie case was filed by 45 individuals as amended in September 2022 seeking $250 million in economic and noneconomic damages, as well as claims for statutory doubling or trebling of damages, attorneys' fees and other costs and pre-judgment interest.

On September 1, 2022, a complaint against PacifiCorp was filed, captioned *Aaron Macy-Wyngarden et al. v. PacifiCorp*, Case No. 22CV29684, Multnomah County, Oregon ("Macy-Wyngarden"). The complaint was filed by Oregon residents or Oregon property owners who allege injuries and damages resulting from the September 2020 Beachie Creek, Santiam Canyon, Lionshead and Riverside fires. The allegations made and damages sought are described below.

On September 22, 2022, a complaint against PacifiCorp was filed, captioned *Zachary Bogle et al. v. PacifiCorp*, Case No. 22CV29717, Multnomah County, Oregon ("Bogle"). The complaint was filed by Oregon residents who allege injuries and damages resulting from the September 2020 Beachie Creek, Santiam Canyon, Lionshead and Riverside fires. The allegations made and damages sought are described below.

The Macy-Wyngarden and Bogle complaints each 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; and (v) inverse condemnation. The Macy-Wyngarden and Bogle complaints each seek the following damages: (i) economic and property related damages of $83 million; (ii) doubling of those economic and property related damages to $167 million to the extent eligible for doubling of damages under the specified Oregon statute; (iii) non-economic damages to the plaintiffs' persons in an amount not less than $83 million for physical injury, mental suffering, emotional distress and other damages; (iv) loss of wages, loss of earnings capacity, evacuation expenses, displacement expenses and similar damages; (v) attorneys' fees and other costs; and (vii) pre-judgment interest. The plaintiffs for each Macy-Wyngarden and Bogle request a trial by jury and have reserved their right to amend the complaint to add a claim for punitive damages.

On September 2, 2022, a complaint against PacifiCorp was filed, captioned *Logan et al. v. PacifiCorp*, Case No. 22CV29859, Multnomah County, Oregon ("Logan"). The Logan complaint was filed by Oregon residents or Oregon property owners who allege injuries and damages resulting from the September 2020 Echo Mountain Complex fires. The Logan case is in the process of being consolidated with *Cady et al. v. PacifiCorp*, Case No. 22CV13946 ("Cady") into *Jeanyne James et al. v. PacifiCorp et al.*, Case No. 20CV33885 (described above). The Logan and Cady complaints each allege: (i) negligence; (ii) trespass; (iii) nuisance, and (iv) inverse condemnation. The Logan case was filed by five individuals claiming $10 million in economic and noneconomic damages, as well as claims for statutory doubling or trebling of damages, attorneys' fees and other costs and pre- and post-judgment interest. The Cady case was filed by 21 individuals as amended in April 2022 claiming $10 million in economic and noneconomic damages, as well as claims for statutory doubling or trebling of damages, attorneys' fees and other costs and pre-judgment interest.

On October 14, 2022, the Multnomah County Circuit Court consolidated *21st Century Centennial Insurance Company, et al. v. PacifiCorp*, Case No. 22CV26326 ("21st Century") and *Allstate Vehicle and Property Insurance Company, et al. v. PacifiCorp*, Case No. 22CV29976 into *Jeanyne James et al. v. PacifiCorp et al.*, Case No. 20CV33885 (described above). The 21st Century and Allstate complaints were each filed by subrogated insurance carriers alleging claims of (i) negligence, (ii) gross negligence, and (iii) inverse condemnation resulting from the September 2020 Santiam Canyon, Echo Mountain Complex, 242, and South Obenchain fires. The 21st Century case was filed in August 2022 by 177 insurance carriers seeking $20 million in damages. The Allstate case was filed in September 2022 by 11 insurance carriers seeking $40 million in damages.

On October 17, 2022, the Multnomah County Circuit Court consolidated *Michael Bell, et al. v. PacifiCorp*, Case No. 22CV30450 ("Bell") into *Jeanyne James et al. v. PacifiCorp et al.*, Case No. 20CV33885 (described above). The Bell case was filed in Oregon Circuit Court in Multnomah County, Oregon on September 7, 2022, by 59 plaintiffs seeking $35 million in damages for claims of (i) negligence, (ii) trespass, (iii) nuisance, and (iv) inverse condemnation.

On October 19, 2022, the Multnomah County Circuit Court consolidated *Freres Timber, Inc. v. PacifiCorp*, Case No. 22CV29694 ("Freres") into *Jeanyne James et al. v. PacifiCorp et al.*, Case No. 20CV33885 (described above). The Freres case was filed in Oregon Circuit Court in Multnomah County, Oregon on September 1, 2022, by one plaintiff and seeks $40m for claims of (i) negligence, (ii) gross negligence, and (iii) inverse condemnation.

On December 6, 2022, *CW Specialty Lumber, Inc., et al. v. PacifiCorp*, Case No. 22CV41640 ("CW Specialty") was filed in Oregon Circuit Court in Multnomah County, Oregon by two plaintiffs seeking $28.6 million in damages for claims of (i) negligence, (ii) gross negligence, (iii) trespass, and (iv) inverse condemnation. The CW Specialty case is in the process of being consolidated into *Jeanyne James et al. v. PacifiCorp et al.*, Case No. 20CV33885 (described above).

Other individual lawsuits alleging similar claims have been filed in Oregon and California related to the 2020 Wildfires, including multiple complaints filed in California for the September 2020 Slater Fire. Multiple complaints have also been filed in California for the 2022 McKinney fire. The complaints filed in California do not specify damages sought. Investigations into the causes and origins of those wildfires are ongoing. For more information regarding 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.

PacifiCorp

On March 17, 2022, a complaint against PacifiCorp was filed, captioned *Roseburg Resources Co et al. v. PacifiCorp*, Case No. 22CV09346, Circuit Court, Douglas County, Oregon. The complaint was filed by nine businesses and public pension plans that own and/or operate timberlands or possess property in Douglas County who allege damages, losses and injuries associated with their timberlands as a result of the French Creek, Archie Creek, Susan Creek and Smith Springs Road fires in Douglas County in September 2020. The complaint alleges (i) PacifiCorp's conduct constituted not only common law negligence but also gross negligence and that such conduct contributed to or caused the ignition and spread of the aforementioned fires; (ii) PacifiCorp violated certain Oregon rules and regulations; and (iii) as an alternative to negligence, inverse condemnation. The complaint seeks the following damages as amended: (i) economic and property damages in excess of $195 million under a determination of negligence or inverse condemnation; (ii) doubling of those economic damages to in excess of $390 million under a determination of gross negligence pursuant to Oregon statutes; (iii) all costs of the lawsuit; (iv) prejudgment and post-judgment interest as allowed by law; and (v) attorneys' fees and other costs.

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 beneficially owned by Berkshire Hathaway and family members and related or affiliated entities of the late Mr. Walter Scott, Jr., a former member of BHE's Board of Directors, 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 ownership 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 $300 million in 2023, $100 million in 2022 and $150 million in 2021.

MIDAMERICAN FUNDING AND MIDAMERICAN ENERGY

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 is an Iowa limited liability company whose membership interest is held solely by BHE. MidAmerican Funding declared and paid cash distributions to BHE of $100 million in 2023, $69 million in 2022 and $— million in 2021. MidAmerican Energy declared and paid cash dividends to MHC totaling $100 million in 2023, $275 million in 2022 and $— million in 2021.

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 $— million in 2022 and $213 million in 2021.

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 $70 million in 2022 and $— million in 2021.

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 $— million in 2022 and 2021.

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 $215 million in 2022 and $18 million in 2021.

Item 6. [Reserved]

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

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Item 8. Financial Statements and Supplementary Data

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 entities, including MES, 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):

	2022	2021	Change		2021	2020	Change	
Operating revenue:								
PacifiCorp	$ 5,679	$ 5,296	$ 383	7 %	$ 5,296	$ 5,341	$ (45)	(1)%
MidAmerican Funding	4,025	3,547	478	13	3,547	2,728	819	30
NV Energy	3,824	3,107	717	23	3,107	2,854	253	9
Northern Powergrid	1,365	1,188	177	15	1,188	1,022	166	16
BHE Pipeline Group	3,844	3,544	300	8	3,544	1,578	1,966	*
BHE Transmission	732	731	1	—	731	659	72	11
BHE Renewables	994	981	13	1	981	936	45	5
HomeServices	5,268	6,215	(947)	(15)	6,215	5,396	819	15
BHE and Other	606	541	65	12	541	438	103	24
Total operating revenue	$26,337	$25,150	$ 1,187	5 %	$25,150	$20,952	$ 4,198	20 %
Earnings on common shares:								
PacifiCorp	$ 921	$ 889	$ 32	4 %	$ 889	$ 741	$ 148	20 %
MidAmerican Funding	947	883	64	7	883	818	65	8
NV Energy	427	439	(12)	(3)	439	410	29	7
Northern Powergrid	385	247	138	56	247	201	46	23
BHE Pipeline Group	1,040	807	233	29	807	528	279	53
BHE Transmission	247	247	—	—	247	231	16	7
BHE Renewables[(1)]	625	451	174	39	451	521	(70)	(13)
HomeServices	100	387	(287)	(74)	387	375	12	3
BHE and Other	(2,017)	1,319	(3,336)	*	1,319	3,092	(1,773)	(57)
Total earnings on common shares	$ 2,675	$ 5,669	$ (2,994)	(53)%	$ 5,669	$ 6,917	$ (1,248)	(18)%

(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 $2,994 million for 2022 compared to 2021. Included in these results was a pre-tax loss in 2022 of $1,950 million ($1,540 million after-tax) compared to a pre-tax gain in 2021 of $1,796 million ($1,777 million after-tax) related to the Company's investment in BYD Company Limited. Excluding the impact of this item, adjusted earnings on common shares in 2022 was $4,215 million, an increase of $323 million, or 8%, compared to adjusted earnings on common shares in 2021 of $3,892 million.

The decrease in net income attributable to BHE shareholders for 2022 compared to 2021 was primarily due to:

- The Utilities' earnings increased $84 million reflecting higher electric utility margin and favorable income tax expense, primarily from higher PTCs recognized of $157 million, partially offset by higher operations and maintenance expense and higher depreciation and amortization expense. Electric retail customer volumes increased 2.4% for 2022 compared to 2021, primarily due to higher customer usage, an increase in the average number of customers and the favorable impact of weather;
- Northern Powergrid's earnings increased $138 million for 2022 compared to 2021, primarily due to a deferred income tax charge of $109 million related to a June 2021 enacted increase in the United Kingdom corporate income tax rate from 19% to 25% effective April 1, 2023 and favorable earnings from new gas and solar projects, partially offset by $41 million from the stronger U.S. dollar;
- BHE Pipeline Group's earnings increased $233 million due to higher earnings at BHE GT&S from the impacts of the EGTS general rate case, favorable income tax adjustments, lower operations and maintenance expense and higher margin from non-regulated activities;
- BHE Renewables' earnings increased $174 million, primarily due to higher operating revenue from owned renewable energy projects and higher earnings from tax equity investments, mainly due to the unfavorable impacts from the February 2021 polar vortex weather event;
- HomeServices' earnings decreased $287 million, reflecting lower earnings from brokerage and settlement services largely attributable to a decrease in closed units at existing companies and lower earnings from mortgage services mainly from a decrease in funded volumes; and
- BHE and Other's earnings decreased $3,336 million, primarily due to the $3,317 million unfavorable comparative change related to the Company's investment in BYD Company Limited.

Earnings on common shares decreased $1,248 million for 2021 compared to 2020. Included in these results was a pre-tax gain in 2021 of $1,796 million ($1,777 million after-tax) compared to a pre-tax gain in 2020 of $4,774 million ($3,470 million after-tax) related to the Company's investment in BYD Company Limited. Excluding the impact of this item, adjusted earnings on common shares in 2021 was $3,892 million, an increase of $445 million, or 13%, compared to adjusted earnings on common shares in 2020 of $3,447 million.

The decrease in net income attributable to BHE shareholders for 2021 compared to 2020 was primarily due to:

- The Utilities' earnings increased $242 million reflecting higher electric utility margin, favorable income tax expense, from higher PTCs recognized of $139 million and the impacts of ratemaking, and lower operations and maintenance expense, partially offset by higher depreciation and amortization expense. Electric retail customer volumes increased 3.8% for 2021 compared to 2020, primarily due to higher customer usage, an increase in the average number of customers and the favorable impact of weather;
- Northern Powergrid's earnings increased $46 million, primarily due to higher distribution performance, lower write-offs of gas exploration costs and $16 million from the weaker U.S. dollar, partially offset by the comparative unfavorable impact of deferred income tax charges ($109 million in second quarter 2021 and $35 million in third quarter 2020) related to enacted increases in the United Kingdom corporate income tax rate;
- BHE Pipeline Group's earnings increased $279 million, primarily due to $244 million of incremental earnings at BHE GT&S;
- BHE Renewables' earnings decreased $70 million, primarily due to lower tax equity investment earnings from the February 2021 polar vortex weather event, partially offset by earnings from tax equity investment projects reaching commercial operation and higher operating performance from owned renewable energy projects; and
- BHE and Other's earnings decreased $1,773 million, primarily due to the $1,693 million unfavorable comparative change related to the Company's investment in BYD Company Limited and $95 million of higher dividends on BHE's 4.00% Perpetual Preferred Stock issued in October 2020, partially offset by favorable comparative consolidated state income tax benefits.

Reportable Segment Results

PacifiCorp

Operating revenue increased $383 million for 2022 compared to 2021, primarily due to higher retail revenue of $263 million and higher wholesale and other revenue of $120 million, largely from higher average wholesale prices. Retail revenue increased primarily due to price impacts of $166 million from higher average retail rates largely due to product mix and tariff changes and $97 million from higher retail volumes. Retail customer volumes increased 1.6%, primarily due to the favorable impact of weather and an increase in the average number of customers, partially offset by lower customer usage.

Earnings increased $32 million for 2022 compared to 2021, primarily due to higher utility margin of $235 million and higher allowances for equity and borrowed funds used during construction of $28 million, partially offset by higher operations and maintenance expense of $196 million, higher depreciation and amortization expense of $32 million, mainly from additional assets placed in-service, unfavorable changes in the cash surrender value of corporate-owned life insurance policies and an unfavorable income tax benefit. Utility margin increased primarily due to favorable deferred net power costs, higher retail rates and volumes and higher average wholesale prices, partially offset by higher purchased power and thermal generation costs. Operations and maintenance expense increased mainly due to an increase in loss accruals and other costs associated with the September 2020 wildfires, net of estimated insurance recoveries, and higher general and plant maintenance costs. The unfavorable income tax benefit was largely due to state income tax impacts, partially offset by higher PTCs recognized of $21 million.

Operating revenue decreased $45 million for 2021 compared to 2020, primarily due to lower retail revenue of $98 million, partially offset by higher wholesale and other revenue of $53 million. Retail revenue decreased mainly due to $234 million from the Utah and Oregon general rate case orders issued in 2020 (fully offset in expense, primarily depreciation) and price impacts of $41 million from lower rates primarily due to certain general rate case orders, partially offset by higher customer volumes of $177 million. Retail customer volumes increased 3.1%, primarily due to higher customer usage, an increase in the average number of customers and the favorable impact of weather. Wholesale and other revenue increased mainly due to higher wheeling revenue, average wholesale prices and REC sales, partially offset by $34 million from the Oregon RAC settlement (fully offset in depreciation expense) recognized in 2020.

Earnings increased $148 million for 2021 compared to 2020, primarily due to favorable income tax expense from higher PTCs recognized of $75 million from new wind-powered generating facilities placed in-service, and the impacts of ratemaking, lower operations and maintenance expense of $178 million and higher utility margin of $145 million, partially offset by higher depreciation and amortization expense of $255 million and lower allowances for equity and borrowed funds used during construction of $72 million. Operations and maintenance expense decreased primarily due to lower costs associated with wildfires and the Klamath Hydroelectric Settlement Agreement and lower thermal plant maintenance expense, partially offset by higher costs associated with additional wind-powered generating facilities placed in-service as well as higher distribution maintenance costs. Utility margin increased primarily due to the higher retail customer volumes, higher wheeling and wholesale revenue and higher deferred net power costs in accordance with established adjustment mechanisms, partially offset by higher purchased power and thermal generation costs, the price impacts from lower retail rates and higher wheeling expenses. The increase in depreciation and amortization expense was primarily due to the impacts of a depreciation study effective January 1, 2021, as well as additional assets placed in-service.

MidAmerican Funding

Operating revenue increased $478 million for 2022 compared to 2021, primarily due to higher electric operating revenue of $459 million and higher natural gas operating revenue of $27 million. Electric operating revenue increased due to higher wholesale and other revenue of $261 million and higher retail revenue of $198 million. Electric wholesale and other revenue increased mainly due to higher average wholesale per-unit prices of $229 million and higher wholesale volumes of $36 million. Electric retail revenue increased primarily due to higher recoveries through adjustment clauses of $134 million (fully offset in expense, primarily cost of sales) and higher customer volumes of $62 million. Electric retail customer volumes increased 4.3%, primarily due to higher customer usage and the favorable impact of weather. Natural gas operating revenue increased due to higher customer usage of $9 million, the favorable impact of weather of $9 million and the impacts of tax reform of $5 million.

Earnings increased $64 million for 2022 compared to 2021, primarily due to higher electric utility margin of $319 million, a favorable income tax benefit and higher natural gas utility margin of $25 million, partially offset by higher depreciation and amortization expense of $254 million, higher operations and maintenance expense of $53 million, unfavorable changes in the cash surrender value of corporate-owned life insurance policies and higher non-service benefit plan costs of $17 million. Electric utility margin increased primarily due to higher wholesale and retail revenues, partially offset by higher purchased power and thermal generation costs. The favorable income tax benefit was mainly due to higher PTCs recognized of $136 million, partially offset by state income tax impacts. Depreciation and amortization expense increased primarily from the impacts of certain regulatory mechanisms and additional assets placed in-service. Operations and maintenance expense increased due to higher general and plant maintenance costs.

Operating revenue increased $819 million for 2021 compared to 2020, primarily due to higher natural gas operating revenue of $430 million and higher electric operating revenue of $390 million. Natural gas operating revenue increased due to a higher average per-unit cost of natural gas sold resulting in higher purchased gas adjustment recoveries of $440 million (fully offset in cost of sales), largely due to the February 2021 polar vortex weather event. Electric operating revenue increased due to higher retail revenue of $198 million and higher wholesale and other revenue of $192 million. Electric retail revenue increased primarily due to higher recoveries through adjustment clauses of $116 million (fully offset in expense, primarily cost of sales), higher customer volumes of $63 million and price impacts of $19 million from changes in sales mix. Electric retail customer volumes increased 5.8% due to increased usage of certain industrial customers and the favorable impact of weather. Electric wholesale and other revenue increased primarily due to higher average wholesale prices of $116 million and higher wholesale volumes of $71 million.

Earnings increased $65 million for 2021 compared to 2020, primarily due to higher electric utility margin of $190 million and a favorable income tax benefit, partially offset by higher depreciation and amortization expense of $198 million, higher operations and maintenance expense of $20 million and lower allowances for equity and borrowed funds of $8 million. Electric utility margin increased primarily due to the higher retail and wholesale revenues, partially offset by higher thermal generation and purchased power costs. The favorable income tax benefit was largely due to higher PTCs recognized of $64 million, from new wind-powered generating facilities placed in-service, partially offset by state income tax impacts. The increase in depreciation and amortization expense was primarily due to the impacts of certain regulatory mechanisms and additional assets placed in-service. Operations and maintenance expense increased primarily due to higher costs associated with additional wind-powered generating facilities placed in-service and higher natural gas distribution costs, partially offset by 2020 costs associated with storm restoration activities.

NV Energy

Operating revenue increased $717 million for 2022 compared to 2021, primarily due to higher electric operating revenue of $668 million and higher natural gas operating revenue of $51 million from a higher average per-unit cost of natural gas sold (fully offset in cost of sales). Electric operating revenue increased primarily due to higher fully-bundled energy rates (fully offset in cost of sales) of $636 million, higher regulatory-related revenue deferrals of $15 million and higher customer volumes of $6 million. Electric retail customer volumes increased 2.2%, primarily due to an increase in the average number of customers, partially offset by the unfavorable impact of weather.

Earnings decreased $12 million for 2022 compared to 2021, primarily due to higher operations and maintenance expense of $24 million, higher depreciation and amortization expense of $17 million, higher interest expense of $15 million, unfavorable changes in the cash surrender value of corporate-owned life insurance policies and higher non-service benefit plan costs of $11 million, partially offset by higher interest and dividend income of $36 million from carrying charges on regulatory balances and higher electric utility margin of $32 million. Operations and maintenance expense increased mainly due to higher general and plant maintenance costs and an unfavorable change in earnings sharing at the Nevada Utilities. Depreciation and amortization expense increased mainly from additional assets placed in-service. Electric utility margin increased mainly due to higher regulatory-related revenue deferrals of $15 million and higher electric retail customer volumes.

Operating revenue increased $253 million for 2021 compared to 2020, primarily due to higher electric operating revenue of $252 million. Electric operating revenue increased primarily due to higher fully-bundled energy rates (fully offset in cost of sales) of $229 million, a $120 million one-time bill credit in the fourth quarter of 2020 resulting from a regulatory rate review decision (fully offset in operations and maintenance and income tax expenses) and higher retail customer volumes of $10 million, partially offset by lower base tariff general rates of $71 million at Nevada Power and a favorable regulatory decision in 2020. Electric retail customer volumes increased 3.3%, primarily due to an increase in the average number of customers, higher customer usage and the favorable impact of weather.

Earnings increased $29 million for 2021 compared to 2020, primarily due to lower operations and maintenance expense of $90 million, lower income tax expense mainly from the impacts of ratemaking, lower interest expense of $21 million, higher interest and dividend income of $16 million and lower pension expense of $10 million, partially offset by lower electric utility margin of $97 million and higher depreciation and amortization expense of $47 million. Operations and maintenance expense decreased primarily due to lower regulatory deferrals and amortizations and lower earnings sharing at the Nevada Utilities. Electric utility margin decreased primarily due to lower base tariff general rates at Nevada Power and a favorable regulatory decision in 2020, partially offset by higher retail customer volumes. The increase in depreciation and amortization expense was mainly due to the regulatory amortization of decommissioning costs and additional assets placed in-service.

Northern Powergrid

Operating revenue increased $177 million for 2022 compared to 2021, primarily due to higher distribution revenue of $167 million and higher revenue of $158 million, due to a gas project that commenced commercial operation in March 2022 and a solar project that commenced commercial operation in July 2022, partially offset by $155 million from the stronger U.S. dollar. Distribution revenue increased primarily due to the recovery of Supplier of Last Resort payments of $135 million (fully offset in cost of sales) and higher tariff rates of $78 million, partially offset by a 4.6% decline in units distributed of $36 million.

Earnings increased $138 million for 2022 compared to 2021, primarily due to a deferred income tax charge of $109 million related to a June 2021 enacted increase in the United Kingdom corporate income tax rate from 19% to 25% effective April 1, 2023, the higher distribution tariff rates and improved earnings of $47 million from the new gas and solar projects, partially offset by $41 million from the stronger U.S. dollar, the decline in units distributed and higher distribution-related operating and depreciation expenses of $25 million.

Operating revenue increased $166 million for 2021 compared to 2020, primarily due to higher distribution revenue of $80 million, mainly from increased tariff rates of $40 million and a 3.2% increase in units distributed totaling $26 million, and $77 million from the weaker U.S. dollar.

Earnings increased $46 million for 2021 compared to 2020, primarily due to the higher distribution revenue, lower write-offs of gas exploration costs of $36 million, $16 million from the weaker U.S. dollar, favorable pension expense of $14 million and lower interest expense of $8 million, partially offset by higher income tax expense and higher distribution-related operating and depreciation expenses of $29 million. Earnings in 2021 included a deferred income tax charge of $109 million related to a June 2021 enacted increase in the United Kingdom corporate income tax rate from 19% to 25% effective April 1, 2023, while earnings in 2020 included a deferred income tax charge of $35 million related to a July 2020 enacted increase in the United Kingdom corporate income tax rate from 17% to 19% effective April 1, 2020.

BHE Pipeline Group

Operating revenue increased $300 million for 2022 compared to 2021, primarily due to higher operating revenue of $242 million at BHE GT&S and $47 million at Northern Natural Gas. The increase in operating revenue at BHE GT&S was primarily due to higher nonregulated revenue of $109 million (largely offset in cost of sales) from favorable commodity prices, an increase in regulated gas transportation and storage services rates due to the settlement of EGTS' general rate case of $101 million and higher LNG revenue of $56 million at Cove Point, largely from favorable variable revenue, partially offset by lower gas sales of $49 million at EGTS from operational and system balancing activities. The increase in operating revenue at Northern Natural Gas was mainly due to higher transportation revenue of $63 million offset by lower gas sales of $14 million from system balancing activities. The variances in transportation revenue and gas sales included favorable impacts recognized of $49 million and $77 million, respectively, from the February 2021 polar vortex weather event. Excluding this item, transportation revenue increased $112 million due to higher volumes and rates and gas sales increased $63 million (largely offset in cost of sales).

Earnings increased $233 million for 2022 compared to 2021, primarily due to higher earnings of $232 million at BHE GT&S. Earnings at BHE GT&S increased mainly due to the impacts of the EGTS general rate case of $124 million, favorable income tax adjustments, lower operations and maintenance and property and other tax expense of $30 million, higher margin of $26 million from nonregulated activities and increased earnings at Cove Point of $16 million.

Operating revenue increased $1,966 million for 2021 compared to 2020, primarily due to $1,828 million of incremental revenue at BHE GT&S, acquired in November 2020, higher gas sales of $115 million ($38 million largely offset in costs of sales) at Northern Natural Gas and higher transportation revenue of $29 million at Kern River largely due to higher rates and volumes, partially offset by lower transportation revenue of $24 million at Northern Natural Gas primarily due to lower volumes. The variances in gas sales and transportation revenue at Northern Natural Gas included favorable impacts of $77 million and $49 million, respectively, from the February 2021 polar vortex weather event.

Earnings increased $279 million for 2021 compared to 2020, primarily due to $244 million of incremental earnings at BHE GT&S, favorable earnings of $19 million at Kern River from the higher transportation revenue and higher earnings of $15 million at Northern Natural Gas, primarily due to higher gross margin on gas sales and higher transportation revenue, each due to the favorable impacts of the February 2021 polar vortex weather event, offset by the lower transportation revenue.

BHE Transmission

Operating revenue increased $1 million for 2022 compared to 2021, primarily due to higher nonregulated revenue from wind-powered generating facilities, partially offset by $27 million from the stronger U.S. dollar.

Earnings for 2022 were equal to 2021, primarily due to improved equity earnings from ETT offset by $7 million from the stronger U.S. dollar.

Operating revenue increased $72 million for 2021 compared to 2020, primarily due to $47 million from the weaker U.S. dollar, a regulatory decision received in November 2020 at AltaLink and higher revenue from the Montana-Alberta Tie Line of $11 million.

Earnings increased $16 million for 2021 compared to 2020, primarily due to $12 million from the weaker U.S. dollar, higher earnings from the Montana-Alberta Tie Line and lower nonregulated interest expense at BHE Canada, partially offset by the impact of a regulatory decision received in April 2020 at AltaLink.

BHE Renewables

Operating revenue increased $13 million for 2022 compared to 2021, primarily due to higher wind, geothermal, and solar revenues of $140 million from higher generation and pricing, partially offset by lower natural gas revenues of $72 million from lower generation and hedge losses, lower hydro revenues of $28 million due to the transfer of the Casecnan generating facility to the Philippine government in December 2021 and $27 million from unfavorable changes in the valuation of certain derivative contracts.

Earnings increased $174 million for 2022 compared to 2021, primarily due to higher wind earnings of $214 million, higher geothermal earnings of $16 million and higher solar earnings of $14 million, partially offset by lower natural gas earnings of $44 million and lower hydro earnings of $18 million due to the Casecnan generating facility transfer. Wind earnings increased due to higher earnings from tax equity investments of $153 million, largely as a result of the unfavorable impacts recognized in 2021 from the February 2021 polar vortex weather event and higher production tax credits, and higher earnings from owned projects of $61 million.

Operating revenue increased $45 million for 2021 compared to 2020, primarily due to higher natural gas, solar, wind and hydro revenues from favorable market conditions and higher generation, partially offset by an unfavorable change in the valuation of a power purchase agreement of $30 million.

Earnings decreased $70 million for 2021 compared to 2020, primarily due to lower wind earnings of $83 million, largely from lower tax equity investment earnings of $90 million, and lower hydro earnings of $10 million, mainly due to lower income from a declining financial asset balance, partially offset by higher solar earnings of $22 million, mainly due to the higher operating revenue and lower depreciation expense. Tax equity investment earnings decreased due to unfavorable results from existing tax equity investments of $165 million, primarily due to the February 2021 polar vortex weather event, and lower commitment fee income, partially offset by $87 million of earnings from projects reaching commercial operation.

HomeServices

Operating revenue decreased $947 million for 2022 compared to 2021, primarily due to lower brokerage and settlement services revenue of $637 million and lower mortgage revenue of $305 million. The decrease in brokerage and settlement services revenue resulted from an 11% decrease in closed transaction volume driven by 23% fewer closed units at existing companies resulting from rising interest rates and a corresponding slowdown in home sales offset by acquisitions and a 7% increase in average sales price. The lower mortgage revenue was due to a 40% decrease in funded volume, primarily due to a decline in refinance activity resulting from rising interest rates.

Earnings decreased $287 million for 2022 compared to 2021, primarily due to lower earnings from brokerage and settlement services of $142 million and mortgage services of $126 million, largely from the decrease in funded volumes from rising interest rates. Earnings at brokerage and settlement services declined due to the decrease in closed units at existing companies, partially offset by favorable operating expense variances.

Operating revenue increased $819 million for 2021 compared to 2020, primarily due to higher brokerage revenue of $951 million, partially offset by lower mortgage revenue of $169 million from an 8% decrease in funded volume due to a decrease in refinance activity. The increase in brokerage revenue was due to a 21% increase in closed transaction volume at existing companies resulting from increases in average sales price and closed units.

Earnings increased $12 million for 2021 compared to 2020, primarily due to higher earnings from brokerage and franchise services of $81 million, largely attributable to the increase in closed transaction volume at existing companies, partially offset by lower earnings from mortgage services of $68 million from the decrease in refinance activity.

BHE and Other

Operating revenue increased $65 million for 2022 compared to 2021, primarily due to higher electric and natural gas sales revenue at MES, from favorable electric volumes and natural gas pricing, including changes in unrealized positions on derivative contracts, offset by lower electric pricing and natural gas volumes.

Earnings decreased $3,336 million for 2022 compared to 2021, primarily due to the $3,317 million unfavorable comparative change related to the Company's investment in BYD Company Limited, unfavorable comparative consolidated state income tax benefits, higher BHE corporate interest expense from an April 2022 debt issuance and unfavorable changes in the cash surrender value of corporate-owned life insurance policies, partially offset by $75 million of lower dividends on BHE's 4.00% Perpetual Preferred Stock issued to certain subsidiaries of Berkshire Hathaway and lower corporate costs.

Operating revenue increased $103 million for 2021 compared to 2020, primarily due to higher electricity and natural gas sales revenue at MES, from favorable pricing offset by lower volumes.

Earnings decreased $1,773 million for 2021 compared to 2020, primarily due to the $1,693 million unfavorable comparative change related to the Company's investment in BYD Company Limited, $95 million of higher dividends on BHE's 4.00% Perpetual Preferred Stock issued in October 2020 to certain subsidiaries of Berkshire Hathaway, higher corporate costs and higher BHE corporate interest expense from debt issuances in March and October 2020, partially offset by favorable comparative consolidated state income tax benefits and higher earnings of $17 million at MES.

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, 2022, 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	$ 32	$ 641	$ 261	$ 108	$ 37	$ 56	$ 239	$ 217	$ 1,591
Credit facilities[1]	3,500	1,200	1,509	650	296	793	2,925	—	10,873
Less:									
Short-term debt	(245)	—	—	—	(120)	(197)	(557)	—	(1,119)
Tax-exempt bond support and letters of credit	—	(249)	(370)	—	—	(1)	—	—	(620)
Net credit facilities	3,255	951	1,139	650	176	595	2,368	—	9,134
Total net liquidity	$3,287	$ 1,592	$ 1,400	$ 758	$ 213	$ 651	$ 2,607	$ 217	$10,725
Credit facilities:									
Maturity dates	2025	2025	2023, 2025	2025	2025, 2026	2023, 2026, 2027	2023, 2026		

(1) Includes $55 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.

Operating Activities

Net cash flows from operating activities for the years ended December 31, 2022 and 2021 were $9.4 billion and $8.7 billion, respectively. The increase was primarily due to an increase in income tax receipts and improved operating results, partially offset by changes in regulatory assets and working capital.

Net cash flows from operating activities for the years ended December 31, 2021 and 2020 were $8.7 billion and $6.2 billion, respectively. The increase was primarily due to $970 million of incremental net cash flows from operating activities at BHE GT&S, improved operating results and changes in working capital.

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, 2022 and 2021 were $(7.8) billion and $(5.8) billion, respectively. The change was primarily due to the July 2021 receipt of $1.3 billion due to the termination of the second Purchase and Sale Agreement (the "Q-Pipe Purchase Agreement" with Dominion Questar, higher capital expenditures of $894 million and higher cash paid for acquisitions, partially offset by lower funding of tax equity investments. Refer to "Future Uses of Cash" for further discussion of capital expenditures.

Net cash flows from investing activities for the years ended December 31, 2021 and 2020 were $(5.8) billion and $(13.2) billion, respectively. The change was primarily due to lower funding of tax equity investments, lower cash paid for acquisitions and the July 2021 receipt of $1.3 billion due to the termination of the Q-Pipe Purchase Agreement. Refer to "Future Uses of Cash" for further discussion of capital expenditures.

Natural Gas Transmission and Storage Business Acquisition

On November 1, 2020, BHE completed its acquisition of substantially all of the natural gas transmission and storage business of DEI and Dominion Questar, exclusive of the Questar Pipeline Group. Under the terms of the Purchase and Sale Agreement, dated July 3, 2020, BHE paid approximately $2.5 billion in cash, after post-closing adjustments (the "GT&S Cash Consideration").

On October 5, 2020, BHE entered into the "Q-Pipe Purchase Agreement") with Dominion Questar providing for BHE's purchase of the Questar Pipeline Group from Dominion Questar after receipt of HSR Approval for a cash purchase price of approximately $1.3 billion (the "Q-Pipe Cash Consideration"), subject to adjustment for cash and indebtedness as of the closing. Under the Q-Pipe Purchase Agreement, BHE delivered the Q-Pipe Cash Consideration of approximately $1.3 billion to Dominion Questar on November 2, 2020.

On July 9, 2021, Dominion Questar and DEI delivered a written notice to BHE stating that BHE and Dominion Questar have mutually elected to terminate the Q-Pipe Purchase Agreement. On July 14, 2021, BHE received the Purchase Price Repayment Amount of approximately $1.3 billion in cash.

Financing Activities

Net cash flows from financing activities for the year ended December 31, 2022 were $(1.0) billion. Sources of cash totaled $3.9 billion and consisted of proceeds from subsidiary debt issuances of $2.9 billion and proceeds from BHE senior debt issuances of $1.0 billion. Uses of cash totaled $4.9 billion and consisted mainly of repayments of subsidiary debt totaling $1.5 billion, purchases of common stock of $870 million, net repayments of short-term debt totaling $867 million, preferred stock redemptions totaling $800 million and distributions to noncontrolling interests of $524 million.

Net cash flows from financing activities for the year ended December 31, 2021 were $(3.1) billion. Sources of cash totaled $2.4 billion and consisted of proceeds from subsidiary debt issuances. Uses of cash totaled $5.5 billion and consisted mainly of preferred stock redemptions totaling $2.1 billion, repayments of subsidiary debt totaling $2.0 billion, distributions to noncontrolling interests of $488 million, repayments of BHE senior debt totaling $450 million and net repayments of short-term debt totaling $276 million.

Net cash flows from financing activities for the year ended December 31, 2020 were $7.1 billion. Sources of cash totaled $11.7 billion and consisted of proceeds from BHE senior debt issuances of $5.2 billion, proceeds from preferred stock issuances of $3.8 billion and proceeds from subsidiary debt issuances totaling $2.7 billion. Uses of cash totaled $4.5 billion and consisted mainly of $2.8 billion for repayments of subsidiary debt, net repayments of short-term debt of $939 million and $350 million for repayments of BHE senior debt.

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 Issuance

On October 29, 2020, BHE issued $3.75 billion of its 4.00% Perpetual Preferred Stock to certain subsidiaries of Berkshire Hathaway Inc. in order to fund the GT&S Cash Consideration and the Q-Pipe Cash Consideration.

Preferred Stock Redemptions

For the years ended December 31, 2022 and 2021, BHE redeemed at par 800,006 and 2,100,012 shares of its 4.00% Perpetual Preferred Stock from certain subsidiaries of Berkshire Hathaway Inc. for $800 million and $2.1 billion.

Common Stock Transactions

For the year ended December 31, 2022, BHE purchased 740,961 shares of its common stock held by Mr. Gregory E. Abel, BHE's Chair, for $870 million. The purchase was pursuant to the terms of BHE's Shareholders Agreement.

For the year ended December 31, 2020, BHE repurchased 180,358 shares of its common stock for $126 million.

There were no common stock repurchases for the year ended December 31, 2021.

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		
	2020	2021	2022	2023	2024	2025
PacifiCorp	$ 2,540	$ 1,513	$ 2,166	$ 3,579	$ 3,069	$ 3,986
MidAmerican Funding	1,836	1,912	1,869	2,451	2,149	1,791
NV Energy	675	749	1,113	1,614	1,729	1,622
Northern Powergrid	682	742	768	569	632	659
BHE Pipeline Group	659	1,128	1,157	1,001	855	926
BHE Transmission	372	279	200	203	300	433
BHE Renewables	95	225	138	251	399	316
HomeServices	36	42	48	54	57	57
BHE and Other(1)	(130)	21	46	4	2	—
Total	$ 6,765	$ 6,611	$ 7,505	$ 9,726	$ 9,192	$ 9,790

(1) BHE and Other includes intersegment eliminations.

	Historical			Forecast		
	2020	2021	2022	2023	2024	2025
Wind generation	$ 2,125	$ 1,339	$ 774	$ 2,201	$ 1,710	$ 1,197
Electric distribution	1,705	1,679	1,806	1,860	1,732	2,337
Electric transmission	968	823	1,725	1,973	2,154	2,837
Natural gas transmission and storage	640	1,068	945	824	617	843
Solar generation	16	157	422	248	630	450
Electric battery and pumped hydro storage	—	23	16	317	392	575
Other	1,311	1,522	1,817	2,303	1,957	1,551
Total	$ 6,765	$ 6,611	$ 7,505	$ 9,726	$ 9,192	$ 9,790

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

- Wind generation includes both growth and operating expenditures. Growth expenditures include spending for the following:
  - Construction and acquisition of wind-powered generating facilities at MidAmerican Energy totaling $72 million for 2022, $540 million for 2021 and $848 million for 2020. MidAmerican Energy placed in-service 294 MWs during 2021 and 729 MWs during 2020. All of these wind-powered generating facilities placed in-service in 2021 and 2020 qualify for 100% of PTCs available. PTCs from these projects are excluded from MidAmerican Energy's Iowa EAC until these generation assets are reflected in base rates. Planned spending for the construction of wind-powered generating facilities totals $1,232 million in 2023, $1,032 million in 2024 and $740 million in 2025.
  - Repowering of wind-powered generating facilities at MidAmerican Energy totaling $500 million for 2022, $354 million for 2021 and $37 million for 2020. Planned spending for repowering totals $20 million in 2023, $179 million in 2024 and $84 million in 2025. MidAmerican Energy expects its repowered facilities to meet IRS guidelines for the re-establishment of PTCs 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 $23 million for 2022, $118 million for 2021 and $1,148 million for 2020. PacifiCorp placed in-service 516 MWs of new wind-powered generating facilities in 2021 and 674 MWs in 2020. Planned spending for the construction of additional new wind-powered generating facilities and those at acquired sites totals $771 million in 2023, $385 million in 2024 and $251 million in 2025 and is primarily for projects totaling approximately 683 MWs that are expected to be placed in-service in 2023 through 2025.
  - Construction of wind-powered generating facilities at BHE Renewables totaling $155 million for 2021. In May 2021, BHE Renewables completed the asset acquisition of a 54-MW wind-powered generating facility located in Iowa. In December 2021, BHE Renewables completed asset acquisitions of 158-MW and 200-MW wind-powered generating facilities located in Texas.
  - Repowering of wind-powered generating facilities at BHE Renewables totaling $45 million for 2022. Planned spending for repowering totals $50 million in 2023.
- 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, wildfire mitigation, storm damage restoration and repairs and investments in routine expenditures for distribution needed to serve existing and expected demand.

- Electric transmission includes both growth and operating expenditures. Growth expenditures include spending for the following:
  - PacifiCorp's transmission investment primarily reflects planned costs for the following Energy Gateway Transmission segments: the 416-mile, 500-kV high-voltage transmission line between the Aeolus substation near Medicine Bow, Wyoming and the Clover substation near Mona, Utah; the 59-mile, 230-kV high-voltage transmission line between the Windstar substation near Glenrock, Wyoming and the Aeolus substation; the 290-mile, 500-kV high-voltage transmission line from the Longhorn substation near Boardman, Oregon to the Hemingway substation near Boise, Idaho; the 14-mile, 345-kV high-voltage transmission line between the Oquirrh substation in the Salt Lake Valley and the Terminal substation near the Salt Lake City Airport; the 40-mile, 500-kV high-voltage transmission line between the Limber substation in central Utah and the Terminal substation; and the 195-mile, 500-kV high-voltage transmission line between the Anticline substation near Point of Rocks, Wyoming and the Populus substation in Downey, Idaho. Planned spending for these Energy Gateway Transmission segments that are expected to be placed in-service in 2024 through 2028 totals $1,005 million in 2023, $661 million in 2024 and $763 million in 2025.
  - Nevada Utilities' Greenlink Nevada transmission expansion program. In this project, the company has received approval from the PUCN to build a 350-mile, 525-kV transmission line, known as Greenlink West, connecting the Ft. Churchill substation to the Northwest substation to the Harry Allen substation; a 235-mile, 525-kV transmission line, known as Greenlink North, connecting the new Ft. Churchill substation to the Robinson Summit substation; a 46-mile, 345-kV transmission line from the new Ft. Churchill substation to the Mira Loma substations; and a 38-mile, 345-kV transmission line from the new Ft. Churchill substation to the Robinson Summit substations. Planned spending for the expansion programs estimated to be placed in-service in 2026-2028 totals $46 million in 2023, $380 million in 2024 and $502 million in 2025.
  - 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.
- Natural gas transmission and storage includes both growth and operating expenditures. Growth expenditures include, among other items, spending for asset modernization and the Northern Natural Gas Twin Cities Area Expansion and Spraberry Compression projects. Operating expenditures include, among other items, 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 and LNG terminalling infrastructure needs to serve existing and expected demand.
- Solar generation includes growth expenditures, including spending for the following:
  - Construction of solar-powered generating facilities at PacifiCorp totaling 377 MWs of new generation and are expected to be placed in-service in 2026. Planned spending totals $381 million from 2023 through 2025.
  - Construction of solar-powered generating facilities at MidAmerican Energy totaling 141 MWs of small- and utility-scale solar generation, all of which were placed in-service in 2022, with total spend of $119 million in 2022 and $132 million in 2021.
  - Construction of solar-powered generating facility at the Nevada Utilities includes expenditures for a 150-MW solar photovoltaic facility with an additional 100 MWs of co-located battery storage that will be developed in Clark County, Nevada, with commercial operation expected by the end of 2023.
  - Construction of solar-powered generating facilities at BHE Renewables' includes expenditures for a 48-MW solar photovoltaic facility with an additional 52 MWs of capacity of co-located battery storage in Kern County, California, with commercial operation expected by November 30, 2024. Planned spending totals $174 million in 2024.
- Electric battery and pumped hydro storage includes growth expenditures, including spending for the following:
  - Construction of 38 MWs of new pumped hydro storage on the North Umpqua River system expected to be placed in-service in 2024 and 2026 as well as other battery storage projects providing approximately 419 MWs of storage that are expected to be placed in-service in 2026 at PacifiCorp. Planned spending for these project totals $398 million from 2023 through 2025. Planned spending for other pumped hydro storage projects that are expected to be placed in-service beyond 2026 totals $95 million from 2023 through 2025

    - Construction at the Nevada Utilities of a 100-MW battery energy storage system co-located with a 150-MW solar photovoltaic facility that will be developed in Clark County, Nevada and a 220-MW grid-tied battery energy storage system that will be developed on the site of the retired Reid Gardner generating station in Clark County, Nevada, both with commercial operation expected by the end of 2023. Also, a 200-MW battery energy storage system that will be developed on the site of the Valmy generating station in Humboldt County, Nevada with commercial operation expected by the end of 2025.
- 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, 2022, the Company's investments that are accounted for under the equity method had short- and long-term debt of $2.7 billion, unused revolving credit facilities of $122 million and letters of credit outstanding of $88 million. As of December 31, 2022, the Company's pro-rata share of such short- and long-term debt was $1.3 billion, unused revolving credit facilities was $61 million and outstanding letters of credit was $43 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 $35.1 billion on long-term debt, including $2.2 billion due in 2023.

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.

Quad Cities Generating Station Operating Status

Constellation Energy Generation, LLC ("Constellation Energy"), the operator of Quad Cities Generating Station Units 1 and 2 ("Quad Cities Station") of which MidAmerican Energy has a 25% ownership interest, receives financial support for continued operation of Quad Cities Station from the zero emission standard enacted by the Illinois legislature in December 2016. 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. The proceeds from the ZECs provide Constellation Energy additional revenue through 2027 as an incentive for continued operation of Quad Cities Station. MidAmerican Energy does not receive additional revenue from the subsidy.

The PJM Interconnection, L.L.C. ("PJM") capacity market includes a Minimum Offer Price Rule ("MOPR"). If a generation resource is subjected to a MOPR, its offer price in the market is adjusted to effectively remove the revenues it receives through a state government-provided financial support program like the Illinois zero emission standard, resulting in a higher offer that may not clear the capacity market. Prior to December 19, 2019, the PJM MOPR applied only to certain new gas-fueled resources.

On December 19, 2019, the FERC issued an order requiring the PJM to broadly apply the MOPR to all new and existing resources, including nuclear. This greatly expanded the breadth and scope of the PJM's MOPR, which became effective as of the PJM's capacity auction for the 2022-2023 planning year. While the FERC included some limited exemptions, no exemptions were available to state-supported nuclear resources, such as Quad Cities Station. The FERC denied rehearing of that order on April 16, 2020. A number of parties, including Constellation Energy, have filed petitions for review of the FERC's orders in this proceeding, which remain pending before the Court of Appeals for the Seventh Circuit. MidAmerican Energy cannot predict the outcome of this proceeding.

While this litigation is pending, the MOPR applied to Quad Cities Station in the capacity auction for the 2022-2023 planning year in May 2021, which prevented Quad Cities Station from clearing in that capacity auction.

At the direction of the PJM Board of Managers, the PJM and its stakeholders developed further MOPR reforms to ensure that the capacity market rules respect and accommodate state resource preferences such as the ZEC programs. The PJM filed related tariff revisions with the FERC on July 30, 2021, and, on September 29, 2021, the PJM's proposed MOPR reforms became effective by operation of law. Under the new tariff provisions, the MOPR applied in the capacity auction for the 2023-2024 delivery year but did not restrict the offers of Quad Cities Station, which cleared in the capacity auction. Requests for rehearing of the FERC's notice establishing the effective date for the PJM's proposed market reforms were filed in October 2021 and denied by operation of law on November 4, 2021. Several parties have filed petitions for review of the FERC's orders in this proceeding, which remain pending before the Court of Appeals for the Third Circuit.

Assuming the continued effectiveness of the Illinois zero emission standard, Constellation Energy no longer considers Quad Cities Station to be at heightened risk for early retirement. However, to the extent the Illinois zero emission standard does not operate as expected over its full term, Quad Cities Station would be at heightened risk for early retirement. The FERC provided no new mechanism for accommodating state-supported resources like Quad Cities Station other than the existing Fixed Resource Requirement ("FRR") mechanism under which an entire utility zone would be removed from PJM's capacity auction along with sufficient resources to support the load in such zone. Depending on the outcome of the proceedings related to the PJM MOPR, the continued effectiveness of the Illinois zero emission standard may be undermined unless the PJM adopts further changes to the MOPR or Illinois implements an FRR mechanism, under which Quad Cities Station would be removed from the PJM's capacity auction.

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 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, 2022, 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, 2022, the Company would have been required to post $704 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.

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 $5.1 billion and total regulatory liabilities were $7.4 billion as of December 31, 2022. 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, 2022 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, 2022. Additionally, no indicators of impairment were identified as of December 31, 2022. 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, 2022, the Company recognized a net asset totaling $206 million for the funded status of the defined benefit pension and other postretirement benefit plans. As of December 31, 2022, amounts not yet recognized as a component of net periodic benefit cost that were included in net regulatory assets totaled $376 million and in AOCI totaled $527 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, 2022.

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 2028, 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, 2022						
Benefit Obligations:						
Discount rate	$ (76)	$ 82	$ (21)	$ 23	$ (75)	$ 86
Effect on 2022 Periodic Cost:						
Discount rate	$ 5	$ (3)	$ 1	$ (1)	$ (4)	$ 4
Expected rate of return on plan assets	(13)	13	(4)	4	(7)	7

A variety of factors affect the funded status of the plans, including asset returns, discount rates, 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% as a result of 2017 Tax Reform, certain property-related basis differences and other various differences on to their customers. As of December 31, 2022, these amounts were recognized as a net regulatory liability of $2.5 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 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.

Revenue Recognition - Unbilled Revenue

Revenue recognized is equal to what the Company has the right to invoice as it corresponds directly with the value to the customer of the Company's performance to date and includes billed and unbilled amounts. The determination of customer invoices is based on a systematic reading of meters, fixed reservation charges based on contractual quantities and rates or, in the case of the Great Britain distribution businesses, when information is received from the national settlement system. 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. Unbilled revenue was $828 million as of December 31, 2022. 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.

Wildfire Loss Contingencies

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 wildfires. In determining this exposure, the Company is required to assess whether the likelihood of loss for each of the wildfires and lawsuits 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 various parties. 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 these estimates, including identifying the various categories of potential loss such as fire suppression costs, real and personal property damages, natural resource damages for certain areas 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. 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 the 2020 Wildfires and the 2022 McKinney fire.

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, equity prices, 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 business platforms 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 Company also provides nonregulated retail electricity and natural gas services in competitive markets. 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 $(88) million and $26 million, respectively, as of December 31, 2022 and 2021, 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, 2022:			
Not designated as hedging contracts	$ 335	$ 520	$ 150
Designated as hedging contracts	12	40	(16)
Total commodity derivative contracts	$ 347	$ 560	$ 134
As of December 31, 2021:			
Not designated as hedging contracts	$ 20	$ 116	$ (76)
Designated as hedging contracts	(10)	(5)	(15)
Total commodity derivative contracts	$ 10	$ 111	$ (91)

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, 2022 and 2021, a net regulatory liability of $231 million and a net regulatory asset of $71 million, respectively, was recorded related to the net derivative asset of $335 million and $20 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, 2022 and 2021, the Company had short- and long-term variable-rate obligations totaling $3.2 billion and $3.7 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, 2022 and 2021.

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, 2022 and 2021, the Company had variable-to-fixed interest rate swaps with notional amounts of $481 million and $533 million, respectively, and £272 million and £174 million, respectively, to protect the Company against an increase in interest rates. Additionally, as of December 31, 2022 and 2021, the Company had mortgage commitments, net, with notional amounts of $438 million and $1,512 million, 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 $108 million and $16 million as of December 31, 2022 and 2021, 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, 2022, 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 as of December 31.

Equity Price Risk

Market prices for equity securities are subject to fluctuation and consequently the amount realized in the subsequent sale of an investment may significantly differ from the reported market value. Fluctuation in the market price of a security may result from perceived changes in the underlying economic characteristics of the investee, the relative price of alternative investments and general market conditions.

As of December 31, 2022 and 2021, the Company's investment in BYD Company Limited common stock represented approximately 86% and 92%, respectively, of the total fair value of the Company's equity securities. The majority of the Company's remaining equity securities are held in a trust related to the decommissioning of nuclear generation assets and the realized and unrealized gains and losses are recorded as a net regulatory liability since the Company expects to recover costs for these activities through regulated rates. The following table summarizes the Company's investment in BYD Company Limited as of December 31, 2022 and 2021 and the effects of a hypothetical 30% increase and a 30% decrease in market price as of those dates. The selected hypothetical change does not reflect what could be considered the best or worst case scenarios (dollars in millions).

	Fair Value	Hypothetical Price Change	Estimated Fair Value after Hypothetical Change in Prices	Hypothetical Percentage Increase (Decrease) in BHE Shareholders' Equity
As of December 31, 2022	$ 3,763	30% increase	$ 4,892	1 %
		30% decrease	2,634	(1)
As of December 31, 2021	$ 7,693	30% increase	$ 10,001	3 %
		30% decrease	5,385	(3)

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, 2022, 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 $491 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 $39 million in 2022.

BHE Canada's functional currency is the Canadian dollar. As of December 31, 2022, 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 $387 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 $18 million in 2022.

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, 2022, 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, 2022, MidAmerican Energy's aggregate direct credit exposure from electric wholesale marketing counterparties was not material.

As of December 31, 2022, 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 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 2022, E.ON and certain of its affiliates and British Gas Trading Limited represented approximately 22% and 14%, 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 $681 million for the year ended December 31, 2022.

BHE Renewables

BHE Renewables owns independent power projects that generally have separate project financing agreements. These projects source of operating revenue is derived primarily from long-term power purchase agreements with single customers, primarily utilities, which expire between 2023 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 was $994 million for the year ended December 31, 2022.

Item 8. Financial Statements and Supplementary Data

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, 2022 and 2021, 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, 2022, 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, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022, 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 audit committee and that (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing a 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 Notes 2 and 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 electric and natural gas rates of the Company's regulated businesses 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 their 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) refunds to customers. Given that management's accounting judgments are based on assumptions about the future 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, including the balances recorded and regulatory developments.
- We read relevant regulatory orders issued by the Commissions, regulatory statutes, interpretations, procedural memorandums, filings made by interveners, and other external information. We evaluated the external information and compared to management's recorded regulatory asset and liability balances for completeness.
- For regulatory matters in process, 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.
- We inquired of management about property, plant, and equipment that may be abandoned. We inquired of management to identify projects that are designed to replace assets that may be retired prior to the end of the useful life. We inspected minutes of the board of directors and regulatory orders and other filings with the Commissions to identify any evidence that may contradict management's assertion regarding probability of an abandonment.

Wildfires — Contingencies — See 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 the potential loss or range of potential loss and disclose any material amounts.

Management has recorded estimated liabilities of $424 million and receivables of $246 million, which represent its best estimate of probable losses and expected insurance recoveries associated with the 2020 Wildfires. During the years ended December 31, 2022, 2021 and 2020, the Company recognized probable losses, net of expected insurance recoveries associated with the 2020 Wildfires of $64 million, $— million and $136 million, respectively. Management has disclosed reasonably possible estimated losses of $31 million, net of potential insurance recoveries of $103 million, associated with the 2022 McKinney Fire.

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 or reasonably possible losses and insurance recoveries. This required the application of a high degree of judgment and extensive effort when performing audit procedures to evaluate the reasonableness of management's judgments, estimates and disclosures related to wildfire-related loss contingencies.

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 insurance recoveries, and related disclosures for wildfire-related contingencies included the following, among others:

- We evaluated management's judgments related to whether a loss was probable or reasonably possible for the Wildfires by inquiring of management and the Company's external and internal legal counsel regarding the likelihood and amounts of probable and reasonably possible losses, including the potential impact of information gained through 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 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 management's judgments related to whether related insurance recoveries were probable of collection by inquiring of management and the Company's external and internal legal counsel regarding the amounts of insurance recoveries recorded or disclosed. With the assistance of our insurance specialists, we tested the significant assumptions used in the determination of collectability, including obtaining and reading related policies to determine whether the types of insurance claims are included or excluded from coverage.
- 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 24, 2023

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,	
	2022	**2021**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,591	$ 1,096
Investments and restricted cash and cash equivalents	2,141	172
Trade receivables, net	2,876	2,468
Inventories	1,256	1,122
Mortgage loans held for sale	474	1,263
Regulatory assets	1,319	544
Other current assets	1,345	1,583
Total current assets	11,002	8,248
Property, plant and equipment, net	93,043	89,816
Goodwill	11,489	11,650
Regulatory assets	3,743	3,419
Investments and restricted cash and cash equivalents and investments	11,273	15,788
Other assets	3,290	3,144
Total assets	$ 133,840	$ 132,065

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)

	As of December 31,	
	2022	**2021**
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 2,679	$ 2,136
Accrued interest	558	537
Accrued property, income and other taxes	746	606
Accrued employee expenses	333	372
Short-term debt	1,119	2,009
Current portion of long-term debt	3,201	1,265
Other current liabilities	1,677	1,837
Total current liabilities	10,313	8,762
BHE senior debt	13,096	13,003
BHE junior subordinated debentures	100	100
Subsidiary debt	35,238	35,394
Regulatory liabilities	7,070	6,960
Deferred income taxes	12,678	12,938
Other long-term liabilities	4,706	4,319
Total liabilities	83,201	81,476
Commitments and contingencies (Note 16)		
Equity:		
BHE shareholders' equity:		
Preferred stock - 100 shares authorized, $0.01 par value, 1 and 2 shares issued and outstanding	850	1,650
Common stock - 115 shares authorized, no par value, 76 shares issued and outstanding	—	—
Additional paid-in capital	6,298	6,374
Long-term income tax receivable	—	(744)
Retained earnings	41,833	40,754
Accumulated other comprehensive loss, net	(2,149)	(1,340)
Total BHE shareholders' equity	46,832	46,694
Noncontrolling interests	3,807	3,895
Total equity	50,639	50,589
Total liabilities and equity	$ 133,840	$ 132,065

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,		
	2022	**2021**	**2020**
Operating revenue:			
Energy	$ 21,069	$ 18,935	$ 15,556
Real estate	5,268	6,215	5,396
Total operating revenue	26,337	25,150	20,952
Operating expenses:			
Energy:			
Cost of sales	6,757	5,504	4,187
Operations and maintenance	4,217	3,991	3,545
Depreciation and amortization	4,230	3,829	3,410
Property and other taxes	775	789	634
Real estate	5,117	5,710	4,885
Total operating expenses	21,096	19,823	16,661
Operating income	5,241	5,327	4,291
Other income (expense):			
Interest expense	(2,216)	(2,118)	(2,021)
Capitalized interest	76	64	80
Allowance for equity funds	167	126	165
Interest and dividend income	154	89	71
(Losses) gains on marketable securities, net	(2,002)	1,823	4,797
Other, net	(7)	(17)	88
Total other income (expense)	(3,828)	(33)	3,180
Income before income tax (benefit) expense and equity loss	1,413	5,294	7,471
Income tax (benefit) expense	(1,916)	(1,132)	308
Equity loss	(185)	(237)	(149)
Net income	3,144	6,189	7,014
Net income attributable to noncontrolling interests	423	399	71
Net income attributable to BHE shareholders	2,721	5,790	6,943
Preferred dividends	46	121	26
Earnings on common shares	$ 2,675	$ 5,669	$ 6,917

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,		
	2022	2021	2020
Net income	$ 3,144	$ 6,189	$ 7,014
Other comprehensive (loss) income, net of tax:			
Unrecognized amounts on retirement benefits, net of tax of $(23), $55 and $(19)	(72)	174	(65)
Foreign currency translation adjustment	(810)	(24)	234
Unrealized gains (losses) on cash flow hedges, net of tax of $20, $10 and $(3)	76	67	(15)
Total other comprehensive (loss) income, net of tax	(806)	217	154
Comprehensive income	2,338	6,406	7,168
Comprehensive income attributable to noncontrolling interests	426	404	71
Comprehensive income attributable to BHE shareholders	$ 1,912	$ 6,002	$ 7,097

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	Long-term Income Tax Receivable	Retained Earnings	Accumulated Other Comprehensive Loss, Net	Noncontrolling Interests	Total Equity
Balance, December 31, 2019	$ —	$ —	$ 6,389	$ (530)	$ 28,296	$ (1,706)	$ 129	$ 32,578
Net income	—	—	—	—	6,943	—	70	7,013
Other comprehensive income	—	—	—	—	—	154	—	154
Long-term income tax receivable adjustments	—	—	—	(128)	—	—	—	(128)
Issuance of preferred stock	3,750	—	—	—	—	—	—	3,750
Preferred stock dividend	—	—	—	—	(26)	—	—	(26)
Common stock purchases		—	(6)	—	(120)	—	—	(126)
Distributions	—	—	—	—	—	—	(121)	(121)
Purchase of noncontrolling interest	—	—	(5)	—	—	—	(28)	(33)
BHE GT&S acquisition - noncontrolling interest	—	—	—	—	—	—	3,916	3,916
Other equity transactions	—	—	(1)	—	—	—	1	—
Balance, December 31, 2020	3,750	—	6,377	(658)	35,093	(1,552)	3,967	46,977
Net income	—	—	—	—	5,790	—	397	6,187
Other comprehensive income	—	—	—	—	—	212	5	217
Long-term income tax receivable adjustments	—	—	—	(86)	(8)	—	—	(94)
Preferred stock redemptions	(2,100)	—	—	—	—	—	—	(2,100)
Preferred stock dividend	—	—	—	—	(121)	—	—	(121)
Distributions		—	—	—	—	—	(478)	(478)
Contributions	—	—	—	—	—	—	9	9
Purchase of noncontrolling interest	—	—	(3)	—	—	—	(4)	(7)
Other equity transactions	—	—	—	—	—	—	(1)	(1)
Balance, December 31, 2021	1,650	—	6,374	(744)	40,754	(1,340)	3,895	50,589
Net income	—	—	—	—	2,721	—	421	3,142
Other comprehensive (loss) income	—	—	—	—	—	(809)	3	(806)
Long-term income tax receivable adjustments	—	—	—	744	(791)	—	—	(47)
Preferred stock redemptions	(800)	—	—	—	—	—	—	(800)
Preferred stock dividend	—	—	—	—	(46)	—	—	(46)
Common stock purchases	—	—	(77)	—	(793)	—	—	(870)
Distributions		—	—	—	—	—	(522)	(522)
Contributions	—	—	—	—	—	—	5	5
Purchase of noncontrolling interest	—	—	—	—	—	—	6	6
Other equity transactions	—	—	1	—	(12)	—	(1)	(12)
Balance, December 31, 2022	$ 850	$ —	$ 6,298	$ —	$ 41,833	$ (2,149)	$ 3,807	$ 50,639

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,		
	2022	2021	2020
Cash flows from operating activities:			
Net income	$ 3,144	$ 6,189	$ 7,014
Adjustments to reconcile net income to net cash flows from operating activities:			
Losses (gains) on marketable securities, net	2,002	(1,823)	(4,797)
Depreciation and amortization	4,286	3,881	3,455
Allowance for equity funds	(167)	(126)	(165)
Equity loss, net of distributions	319	380	248
Net power cost deferrals	(1,290)	(520)	(62)
Amortization of net power cost deferrals	357	107	(5)
Other changes in regulatory assets and liabilities	(146)	(255)	(348)
Deferred income taxes and investment tax credits, net	(467)	646	1,880
Other, net	59	(57)	(23)
Changes in other operating assets and liabilities, net of effects from acquisitions:			
Trade receivables and other assets	20	553	(1,318)
Derivative collateral, net	121	82	43
Pension and other postretirement benefit plans	(27)	(39)	(65)
Accrued property, income and other taxes, net	397	(489)	(134)
Accounts payable and other liabilities	751	163	501
Net cash flows from operating activities	9,359	8,692	6,224
Cash flows from investing activities:			
Capital expenditures	(7,505)	(6,611)	(6,765)
Acquisitions, net of cash acquired	(314)	(122)	(2,397)
Purchases of marketable securities	(574)	(297)	(370)
Proceeds from sales of marketable securities	2,464	273	325
Purchases of other investments	(1,958)	(20)	(1,323)
Proceeds from other investments	6	1,300	13
Equity method investments	119	(212)	(2,724)
Other, net	12	(74)	76
Net cash flows from investing activities	(7,750)	(5,763)	(13,165)
Cash flows from financing activities:			
Proceeds from issuance of preferred stock	—	—	3,750
Preferred stock redemptions	(800)	(2,100)	—
Preferred dividends	(50)	(132)	(7)
Common stock purchases	(870)	—	(126)
Proceeds from BHE senior debt	986	—	5,212
Repayments of BHE senior debt	—	(450)	(350)
Proceeds from subsidiary debt	2,887	2,409	2,688
Repayments of subsidiary debt	(1,494)	(2,024)	(2,841)
Net repayments of short-term debt	(867)	(276)	(939)
Distributions to noncontrolling interests	(524)	(488)	(122)
Other, net	(274)	(70)	(162)
Net cash flows from financing activities	(1,006)	(3,131)	7,103
Effect of exchange rate changes	(30)	1	15
Net change in cash and cash equivalents and restricted cash and cash equivalents	573	(201)	177
Cash and cash equivalents and restricted cash and cash equivalents at beginning of period	1,244	1,445	1,268
Cash and cash equivalents and restricted cash and cash equivalents at end of period	$ 1,817	$ 1,244	$ 1,445

The accompanying notes are an integral part of these consolidated financial statements.

(1) Organization and Operations

Berkshire Hathaway Energy Company ("BHE") is a holding company that owns a highly diversified portfolio of locally managed and operated businesses principally engaged in the energy industry (collectively with its subsidiaries, the "Company") and is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

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, owns 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, the largest residential real estate brokerage firm in the U.S. and one of the largest residential real estate brokerage franchise networks 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; fair value of assets acquired and liabilities assumed in business combinations; 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

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, 2022 and 2021, as presented in 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,	
	2022	**2021**
Cash and cash equivalents	$ 1,591	$ 1,096
Investments and restricted cash and cash equivalents	173	127
Investments and restricted cash and cash equivalents and investments	53	21
Total cash and cash equivalents and restricted cash and cash equivalents	$ 1,817	$ 1,244

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 nuclear generation assets are recorded as a net regulatory liability since the Company expects to recover 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 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 nuclear generation assets are recorded as a net regulatory liability since the Company expects to recover 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 change 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):

	2022	2021	2020
Beginning balance	$ 108	$ 77	$ 44
Charged to operating costs and expenses, net	43	81	56
Acquisitions	—	—	5
Write-offs, net	(45)	(50)	(28)
Ending balance	$ 106	$ 108	$ 77

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 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. 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.

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 $248 million and $296 million as of December 31, 2022 and 2021, respectively, and materials and supplies totaling $1,008 million and $826 million as of December 31, 2022 and 2021, 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 $22 million and $27 million higher as of December 31, 2022 and 2021, 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 ("AUC"). 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 nuclear generating facilities 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 will be 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, 2022. 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 2022, 2021 and 2020, 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 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, 2022 and 2021, trade receivables, net on the Consolidated Balance Sheets relate substantially to Customer Revenue, including unbilled revenue of $828 million and $718 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.

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 income tax benefits and expense for 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 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 on the Consolidated Statements of Operations.

(3) Business Acquisitions

BHE GT&S Acquisition

Transaction Description

On November 1, 2020, BHE completed its acquisition of substantially all of the natural gas transmission and storage business of Dominion Energy, Inc. ("DEI") and Dominion Energy Questar Corporation ("Dominion Questar"), exclusive of Dominion Energy Questar Pipeline, LLC and related entities (the "Questar Pipeline Group") (the "GT&S Transaction"). Under the terms of the Purchase and Sale Agreement, dated July 3, 2020 (the "GT&S Purchase Agreement"), BHE paid approximately $2.5 billion in cash, after post-closing adjustments (the "GT&S Cash Consideration") for 100% of the equity interests of Eastern Gas Transmission and Storage, Inc. ("EGTS") and Carolina Gas Transmission, LLC; 50% of the equity interests of Iroquois Gas Transmission System L.P. ("Iroquois"); and a 25% economic interest in Cove Point LNG, LP ("Cove Point"), consisting of 100% of the general partnership interest and 25% of the total limited partnership interests. BHE became the operator of Cove Point after the GT&S Transaction.

On October 5, 2020, DEI and Dominion Questar, as permitted under the terms of the GT&S Purchase Agreement, delivered notice to BHE of their election to terminate the GT&S Transaction with respect to the Questar Pipeline Group and, in connection with the execution of the Q-Pipe Purchase Agreement referenced below, to waive the related termination fee under the GT&S Purchase Agreement. Also on October 5, 2020, BHE entered into a second Purchase and Sale Agreement (the "Q-Pipe Purchase Agreement") with Dominion Questar providing for BHE's purchase of the Questar Pipeline Group from Dominion Questar (the "Q-Pipe Transaction") for a cash purchase price of approximately $1.3 billion (the "Q-Pipe Cash Consideration"), subject to adjustment for cash and indebtedness as of the closing.

Under the Q-Pipe Purchase Agreement, BHE delivered the Q-Pipe Cash Consideration of approximately $1.3 billion to Dominion Questar on November 2, 2020. Pursuant to the Q-Pipe Purchase Agreement, Dominion Questar agreed that, if the Q-Pipe Transaction did not close, it would repay all or (depending upon the repayment date) substantially all of the Q-Pipe Cash Consideration (the "Purchase Price Repayment Amount") to BHE on or prior to December 31, 2021.

On July 9, 2021, Dominion Questar and DEI delivered a written notice to BHE stating that BHE and Dominion Questar have mutually elected to terminate the Q-Pipe Purchase Agreement and on July 14, 2021, BHE received the Purchase Price Repayment Amount of approximately $1.3 billion in cash, which was included in proceeds from other investments on the Consolidated Statements of Cash Flows for the year ended December 31, 2021.

Included in BHE's Consolidated Statement of Operations within the BHE Pipeline Group reportable segment for the years ended December 31, 2022, 2021 and 2020, is operating revenue of $2,402 million, $2,159 million and $331 million, respectively, and net income attributable to BHE shareholders of $549 million, $316 million and $73 million, respectively, as a result of including BHE GT&S from November 1, 2020. Additionally, BHE incurred $9 million of direct transaction costs associated with the GT&S Transaction that are included in operating expense on the Consolidated Statement of Operations for the year ended December 31, 2020.

Pro Forma Financial Information

The following unaudited pro forma financial information reflects the consolidated results of operations of BHE and the amortization of the purchase price adjustments assuming the acquisition had taken place on January 1, 2019, excluding non-recurring transaction costs incurred by BHE during 2020 (in millions):

	2020
Operating revenue	$ 22,581
Net income attributable to BHE shareholders	$ 6,800

Other

In 2022, the Company completed various acquisitions totaling $314 million, net of cash acquired. The purchase price for each acquisition was allocated to the assets acquired and liabilities assumed, which related to residential real estate brokerage businesses, 300 MWs of long-term transmission rights and 399 MWs of wind-powered generating facilities. As a result of the various acquisitions, the Company acquired assets of $363 million, assumed liabilities of $65 million and recognized goodwill of $16 million.

In 2021, the Company completed various acquisitions totaling $122 million, net of cash acquired. The purchase price for each acquisition was allocated to the assets acquired and liabilities assumed, which related to residential real estate brokerage businesses. As a result of the various acquisitions, the Company acquired assets of $54 million, assumed liabilities of $61 million and recognized goodwill of $129 million.

(4) Property, Plant and Equipment, Net

Property, plant and equipment, net consists of the following as of December 31 (in millions):

	Depreciable Life	2022	2021
Regulated assets:			
Utility generation, transmission and distribution systems	5-80 years	$ 92,759	$ 90,223
Interstate natural gas pipeline assets	3-80 years	18,328	17,423
		111,087	107,646
Accumulated depreciation and amortization		(34,599)	(32,680)
Regulated assets, net		76,488	74,966
Nonregulated assets:			
Independent power plants	2-50 years	8,545	7,665
Cove Point LNG facility	40 years	3,412	3,364
Other assets	2-30 years	2,693	2,666
		14,650	13,695
Accumulated depreciation and amortization		(3,452)	(3,041)
Nonregulated assets, net		11,198	10,654
		87,686	85,620
Construction work-in-progress		5,357	4,196
Property, plant and equipment, net		$ 93,043	$ 89,816

Construction work-in-progress includes $4.9 billion and $3.8 billion as of December 31, 2022 and 2021, 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, 2022 (dollars in millions):

	Company Share	Facility In Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
PacifiCorp:				
Jim Bridger Nos. 1-4	67 %	$ 1,529	$ 914	$ 39
Hunter No. 1	94	517	227	3
Hunter No. 2	60	305	148	6
Wyodak	80	491	273	1
Colstrip Nos. 3 and 4	10	262	178	—
Hermiston	50	189	106	—
Craig Nos. 1 and 2	19	372	331	—
Hayden No. 1	25	77	52	—
Hayden No. 2	13	44	31	—
Transmission and distribution facilities	Various	916	274	129
Total PacifiCorp		4,702	2,534	178
MidAmerican Energy:				
Louisa No. 1	88 %	976	511	4
Quad Cities Nos. 1 and 2(1)	25	730	482	11
Walter Scott, Jr. No. 3	79	964	624	13
Walter Scott, Jr. No. 4(2)	60	171	127	7
George Neal No. 4	41	321	184	6
Ottumwa No. 1(2)	52	569	280	19
George Neal No. 3	72	535	312	20
Transmission facilities	Various	267	101	2
Total MidAmerican Energy		4,533	2,621	82
NV Energy:				
Navajo	11 %	1	4	—
Valmy	50	399	327	2
On Line Transmission Line	25	161	34	1
Transmission facilities	Various	60	29	1
Total NV Energy		621	394	4
BHE Pipeline Group:				
Ellisburg Pool	39 %	32	11	—
Ellisburg Station	50	26	8	3
Harrison	50	53	18	—
Leidy	50	143	47	1
Oakford	50	202	70	4
Common Facilities	Various	275	176	—
Total BHE Pipeline Group		731	330	8
Total		$ 10,587	$ 5,879	$ 272

(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 $733 million and $150 million, respectively.

(6) Leases

The following table summarizes the Company's leases recorded on the Consolidated Balance Sheet as of December 31 (in millions):

	2022	2021
Right-of-use assets:		
Operating leases	$ 545	$ 524
Finance leases	418	448
Total right-of-use assets	$ 963	$ 972
Lease liabilities:		
Operating leases	$ 605	$ 577
Finance leases	432	463
Total lease liabilities	$ 1,037	$ 1,040

The following table summarizes the Company's lease costs for the years ended December 31 (in millions):

	2022	2021	2020
Variable	$ 552	$ 611	$ 592
Operating	136	161	151
Finance:			
Amortization	20	23	18
Interest	36	38	40
Short-term	44	15	20
Total lease costs	$ 788	$ 848	$ 821
Weighted-average remaining lease term (years):			
Operating leases	7.4	7.6	7.4
Finance leases	28.1	28.1	27.5
Weighted-average discount rate:			
Operating leases	4.1 %	4.3 %	4.5 %
Finance leases	8.6 %	8.6 %	8.5 %

The following table summarizes the Company's supplemental cash flow information relating to leases for the years ended December 31 (in millions):

	2022	2021	2020
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows from operating leases	$ (141)	$ (163)	$ (152)
Operating cash flows from finance leases	(36)	(38)	(40)
Financing cash flows from finance leases	(25)	(28)	(24)
Right-of-use assets obtained in exchange for lease liabilities:			
Operating leases	$ 131	$ 119	$ 83
Finance leases	3	2	19

The Company has the following remaining lease commitments as of December 31, 2022 (in millions):

	Operating	Finance	Total
2023	$ 158	$ 63	$ 221
2024	126	62	188
2025	101	61	162
2026	78	60	138
2027	53	56	109
Thereafter	189	559	748
Total undiscounted lease payments	705	861	1,566
Less - amounts representing interest	(100)	(429)	(529)
Lease liabilities	$ 605	$ 432	$ 1,037

(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	2022	2021
Deferred net power costs	1 year	$ 1,478	$ 531
Asset retirement obligations	15 years	835	742
Employee benefit plans(1)	14 years	490	472
Deferred income taxes(2)	Various	373	342
Asset disposition costs	Various	231	285
Demand side management	10 years	224	211
Levelized depreciation	28 years	151	135
Unrealized losses on regulated derivative contracts	1 year	112	157
Environmental costs	30 years	111	108
Wildfire mitigation and vegetation management costs	Various	111	21
Deferred operating costs	10 years	83	103
Other	Various	863	856
Total regulatory assets		$ 5,062	$ 3,963
Reflected as:			
Current assets		$ 1,319	$ 544
Noncurrent assets		3,743	3,419
Total regulatory assets		$ 5,062	$ 3,963

(1) Includes amounts not yet recognized as a component of net periodic benefit cost that are expected to be included in regulated rates when recognized.

(2) 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.

The Company had regulatory assets not earning a return on investment of $2.3 billion and $1.8 billion as of December 31, 2022 and 2021, 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	2022	2021
Deferred income taxes[1]	Various	$ 2,901	$ 3,185
Cost of removal[2]	27 years	2,578	2,424
Revenue sharing mechanisms	2 years	426	188
Unrealized gains on regulated derivative contracts	1 year	343	86
Asset retirement obligations	31 years	250	345
Levelized depreciation	28 years	245	259
Employee benefit plans[3]	Various	180	243
Other	Various	446	484
Total regulatory liabilities		$ 7,369	$ 7,214
Reflected as:			
Current liabilities		$ 299	$ 254
Noncurrent liabilities		7,070	6,960
Total regulatory liabilities		$ 7,369	$ 7,214

(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) 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.

(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):

	2022	2021
Investments:		
BYD Company Limited common stock	$ 3,763	$ 7,693
U.S. Treasury Bills	1,931	—
Rabbi trusts	433	492
Other	335	305
Total investments	6,462	8,490
Equity method investments:		
BHE Renewables tax equity investments	4,535	4,931
Electric Transmission Texas, LLC	623	595
Iroquois Gas Transmission System, L.P.	600	735
Other	304	293
Total equity method investments	6,062	6,554
Restricted cash and cash equivalents and investments:		
Quad Cities Station nuclear decommissioning trust funds	664	768
Other restricted cash and cash equivalents	226	148
Total restricted cash and cash equivalents and investments	890	916
Total investments and restricted cash and cash equivalents and investments	$ 13,414	$ 15,960
Reflected as:		
Other current assets	$ 2,141	$ 172
Noncurrent assets	11,273	15,788
Total investments and restricted cash and cash equivalents and investments	$ 13,414	$ 15,960

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.

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.

(Losses) gains on marketable securities, net recognized during the period consists of the following for the years ended December 31 (in millions):

	2022	2021	2020
Unrealized (losses) gains recognized on marketable securities held at the reporting date	$ (1,487)	$ 1,819	$ 4,791
Net (losses) gains recognized on marketable securities sold during the period	(515)	4	6
(Losses) gains on marketable securities, net	$ (2,002)	$ 1,823	$ 4,797

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 2022 and 2021 and $2,736 million in 2020. 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 Iroquois, which owns and operates an interstate natural gas pipeline located in the states of New York and Connecticut; (ii) 50% of Electric Transmission Texas, LLC, which owns and operates electric transmission assets in the Electric Reliability Council of Texas footprint; (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. 1-4 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, 2022, 2021 and 2020 totaled $100 million, $132 million and $128 million, respectively.

Restricted Investments

MidAmerican Energy has established a trust for the investment of funds for decommissioning the Quad Cities Nuclear Station Units 1 and 2 ("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)]
2022:								
Credit facilities[(2)]	$ 3,500	$ 1,200	$ 1,509	$ 650	$ 296	$ 793	$ 2,925	$ 10,873
Less:								
Short-term debt	(245)	—	—	—	(120)	(197)	(557)	(1,119)
Tax-exempt bond support and letters of credit	—	(249)	(370)	—	—	(1)	—	(620)
Net credit facilities	$ 3,255	$ 951	$ 1,139	$ 650	$ 176	$ 595	$ 2,368	$ 9,134
2021:								
Credit facilities[(2)]	$ 3,500	$ 1,200	$ 1,509	$ 650	$ 271	$ 851	$ 3,300	$ 11,281
Less:								
Short-term debt	—	—	—	(339)	(1)	(245)	(1,424)	(2,009)
Tax-exempt bond support and letters of credit	—	(218)	(370)	—	—	(1)	—	(589)
Net credit facilities	$ 3,500	$ 982	$ 1,139	$ 311	$ 270	$ 605	$ 1,876	$ 8,683

(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 $55 million and $1 million, respectively, drawn on capital expenditure and other uncommitted credit facilities at Northern Powergrid as of December 31, 2022 and 2021.

As of December 31, 2022, 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 2025 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, 2022 and 2021, BHE had $245 million and $— million of commercial paper borrowings outstanding at a weighted average interest rate of 4.55% and —%, 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, 2022 and 2021, BHE had $101 million of letters of credit outstanding outside of its credit facility. These letters of credit primarily support power purchase agreements and debt service requirements at certain subsidiaries of BHE Renewables, LLC expiring through January 2024 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 $1.2 billion unsecured credit facility expiring in June 2025 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 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 January 2023, PacifiCorp entered into an additional $800 million 364-day unsecured credit facility expiring in January 2024.No amounts are currently outstanding against this new credit facility.

As of December 31, 2022 and 2021, PacifiCorp did not have any commercial paper borrowings outstanding. The credit facility requires 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, 2022 and 2021, PacifiCorp had $38 million and $19 million, respectively, of fully available letters of credit issued under committed arrangements outside of its 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.

MidAmerican Funding

As of December 31, 2022, MidAmerican Energy has a $1.5 billion unsecured credit facility expiring in June 2025 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.

As of December 31, 2022 and 2021, 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, 2022 and 2021, MidAmerican Energy had $34 million and $42 million, respectively, of fully available letters of credit issued under committed arrangements outside of its 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 $400 million secured credit facility expiring in June 2025 and Sierra Pacific has a $250 million secured credit facility expiring in June 2025 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, 2022 and 2021, the Nevada Utilities had borrowings of $— million and $339 million outstanding under these credit facilities at a weighted average interest rate of —% and 0.86%, 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.

Northern Powergrid

Northern Powergrid has a £200 million unsecured credit facility expiring in December 2025 with a one-year maturity extension option remaining. 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 and a credit adjustment spread that varies based on the tenor of any borrowings. 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, 2022 and 2021, Northern Powergrid had $65 million and $— million outstanding under this facility at a weighted average interest rate of 3.56% and —%, respectively.

AltaLink

AltaLink has a C$500 million secured revolving term credit facility expiring in December 2027 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 the Bankers' Acceptance rate, at AltaLink's option, based on AltaLink's credit ratings for its senior secured long-term debt securities. In addition, AltaLink has a C$75 million secured revolving term credit facility expiring in December 2027 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, U.S. base rate, or a spread above the Bankers' Acceptance rate, at AltaLink's option, based on AltaLink's credit ratings for its senior secured long-term debt securities.

As of December 31, 2022 and 2021, AltaLink had $89 million and $108 million outstanding under these facilities at a weighted average interest rate of 4.59% and 0.35%, respectively. The credit facilities require 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 Investments, L.P. has a C$300 million unsecured revolving term credit facility expiring in December 2026 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 to a maximum of C$10 million, has a variable interest rate based on the Canadian bank prime lending rate, U.S. base rate, or a spread above the Bankers' Acceptance rate, at AltaLink Investments, L.P.'s option, based on AltaLink Investments, L.P.'s credit ratings for its senior unsecured long-term debt securities.

AltaLink Investments, L.P. also has a C$200 million revolving term credit facility expiring in April 2023 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 to a maximum of C$10 million, has a variable interest rate based on the Canadian bank prime lending rate, U.S. base rate, or a spread above the Bankers' Acceptance rate, at AltaLink Investments, L.P.'s option, based on AltaLink Investments, L.P.'s credit ratings for its senior unsecured long-term debt securities. On an annual basis, with the consent of the lenders, AltaLink Investments, L.P. can request that the maturity date of the credit facility be extended for a further 365 days.

As of December 31, 2022 and 2021, AltaLink Investments, L.P. had $108 million and $137 million outstanding under this facility at a weighted average interest rate of 5.71% and 1.46%, respectively. The credit facilities require 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.

HomeServices

HomeServices has an $700 million unsecured credit facility expiring in September 2026. 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 London Interbank Offered Rate ("LIBOR") 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, 2022 and 2021, HomeServices had $115 million and $250 million, respectively, outstanding under its credit facility with a weighted average interest rate of 5.17% and 0.95%, respectively.

Through its subsidiaries, HomeServices maintains mortgage lines of credit totaling $2.2 billion and $2.6 billion as of December 31, 2022 and 2021, respectively, used for mortgage banking activities that expire beginning in March 2023 through September 2023. The mortgage lines of credit have variable rates based on the Bloomberg Short-term Bank Yield Index or 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, 2022 and 2021, HomeServices had $442 million and $1.2 billion, respectively, outstanding under these mortgage lines of credit at a weighted average interest rate of 6.09% and 1.91%, respectively.

BHE Renewables Letters of Credit

As of December 31, 2022 and 2021, certain renewable projects collectively have letters of credit outstanding of $309 million and $311 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	2022	2021
2.80% Senior Notes, due 2023	$ 400	$ 400	$ 398
3.75% Senior Notes, due 2023	500	500	499
3.50% Senior Notes, due 2025	400	398	398
4.05% Senior Notes, due 2025	1,250	1,245	1,246
3.25% Senior Notes, due 2028	600	594	594
8.48% Senior Notes, due 2028	256	266	260
3.70% Senior Notes, due 2030	1,100	1,095	1,096
1.65% Senior Notes, due 2031	500	497	497
6.125% Senior Bonds, due 2036	1,670	1,661	1,661
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	740	740
4.50% Senior Notes, due 2045	750	738	738
3.80% Senior Notes, due 2048	750	738	738
4.45% Senior Notes, due 2049	1,000	990	990
4.25% Senior Notes, due 2050	900	889	889
2.85% Senior Notes, due 2051	1,500	1,487	1,488
4.60% Senior Notes, due 2053	1,000	987	—
Total BHE Senior Debt	$ 14,101	$ 13,996	$ 13,003

	2022	2021
Reflected as:		
Current liabilities	$ 900	$ —
Noncurrent liabilities	13,096	13,003
Total BHE Senior Debt	$ 13,996	$ 13,003

Junior Subordinated Debentures

BHE junior subordinated debentures consists of the following as of December 31 (in millions):

	Par Value	2022	2021
5.00% Junior subordinated debentures, due 2057	100	100	100
Total BHE junior subordinated debentures - noncurrent	$ 100	$ 100	$ 100

The junior subordinated debentures are held by a minority shareholder and are redeemable at BHE's option at any time from and after June 15, 2037, at par plus accrued and unpaid interest. Interest expense to the minority shareholder was $5 million for each of the years ended December 31, 2022, 2021 and 2020.

(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, 2022, all subsidiaries were in compliance with their long-term debt covenants.

Long-term debt of subsidiaries consists of the following, including fair value adjustments and unamortized premiums, discounts and debt issuance costs, as of December 31 (in millions):

	Par Value	2022	2021
PacifiCorp	$ 9,742	$ 9,666	$ 8,730
MidAmerican Funding	8,057	7,954	7,946
NV Energy	4,386	4,354	3,675
Northern Powergrid	3,085	3,054	3,287
BHE Pipeline Group	5,518	5,849	5,924
BHE Transmission	3,509	3,495	3,906
BHE Renewables	3,064	3,027	3,043
HomeServices	140	140	148
Total subsidiary debt	$ 37,501	$ 37,539	$ 36,659
Reflected as:			
Current liabilities		$ 2,301	$ 1,265
Noncurrent liabilities		35,238	35,394
Total subsidiary debt		$ 37,539	$ 36,659

PacifiCorp

PacifiCorp'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	2022	2021
First mortgage bonds:			
2.95% to 8.23%, due through 2026	$ 1,224	$ 1,223	$ 1,377
2.70% to 7.70%, due 2029 to 2031	1,100	1,095	1,094
5.25% to 6.25%, due 2034 to 2037	2,050	2,042	2,042
4.10% to 6.35%, due 2038 to 2042	1,250	1,239	1,238
2.90% to 5.35%, due 2049 to 2053	3,900	3,849	2,761
Variable-rate series, tax-exempt bond obligations (2022-3.75% to 4.10%; 2021-0.12% to 0.14%):			
Due 2025	25	25	25
Due 2024 to 2025(1)	193	193	193
Total PacifiCorp	$ 9,742	$ 9,666	$ 8,730

(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.

The issuance of PacifiCorp's first mortgage bonds is limited by available property, earnings tests and other provisions of PacifiCorp's mortgage. Approximately $33 billion of PacifiCorp's eligible property (based on original cost) was subject to the lien of the mortgage as of December 31, 2022.

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	2022	2021
MidAmerican Funding:			
6.927% Senior Bonds, due 2029	$ 239	$ 240	$ 240
Fair value adjustment	—	(15)	(15)
MidAmerican Funding, net of fair value adjustments	239	225	225
MidAmerican Energy:			
First Mortgage Bonds:			
3.70%, due 2023	250	250	250
3.50%, due 2024	500	500	501
3.10%, due 2027	375	374	373
3.65%, due 2029	850	859	860
4.80%, due 2043	350	347	346
4.40%, due 2044	400	395	395
4.25%, due 2046	450	446	446
3.95%, due 2047	475	471	470
3.65%, due 2048	700	689	689
4.25%, due 2049	900	875	874
3.15%, due 2050	600	592	592
2.70%, due 2052	500	492	492
Notes:			
6.75% Series, due 2031	400	397	397
5.75% Series, due 2035	300	298	298
5.80% Series, due 2036	350	348	348
Transmission upgrade obligation, 3.20% to 7.81%, due 2036 to 2042	48	27	22
Tax-exempt bond obligations -			
Variable-rate tax-exempt bond obligation series: (weighted average interest rate - 2022-3.83%, 2021-0.13%), due 2023-2047	370	369	368
Total MidAmerican Energy	7,818	7,729	7,721
Total MidAmerican Funding	$ 8,057	$ 7,954	$ 7,946

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 $24 billion of MidAmerican Energy's eligible property, based on original cost, was subject to the lien of the mortgage as of December 31, 2022. 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 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, 2022 and 2021. MidAmerican Energy maintains revolving credit facility agreements to provide liquidity for holders of these issues. Additionally, MidAmerican Energy's obligations associated with $180 million of the variable rate, tax-exempt bond obligations 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

NV Energy'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	2022	2021
Nevada Power:			
General and refunding mortgage securities:			
3.700% Series CC, due 2029	$ 500	$ 497	$ 497
2.400% Series DD, due 2030	425	422	422
6.650% Series N, due 2036	367	360	359
6.750% Series R, due 2037	349	346	346
5.375% Series X, due 2040	250	248	248
5.450% Series Y, due 2041	250	239	239
3.125% Series EE, due 2050	300	298	297
5.900% Series GG, due 2053	400	394	—
Tax-exempt refunding revenue bond obligations:			
Fixed-rate series:			
1.875% Pollution Control Bonds Series 2017A, due 2032[(1)]	40	39	39
1.650% Pollution Control Bonds Series 2017, due 2036[(1)]	40	39	39
1.650% Pollution Control Bonds Series 2017B, due 2039[(1)]	13	13	13
Variable-rate 4.821% Term Loan, due 2024[(2)]	300	300	—
Total Nevada Power	3,234	3,195	2,499
Fair value adjustments	—	10	11
Total Nevada Power, net of fair value adjustments	3,234	3,205	2,510
Sierra Pacific:			
General and refunding mortgage securities:			
3.375% Series T, due 2023	250	249	249
2.600% Series U, due 2026	400	397	397
6.750% Series P, due 2037	252	254	253
4.710% Series W, due 2052	250	248	—
Tax-exempt refunding revenue bond obligations:			
Fixed-rate series:			
1.850% Pollution Control Series 2016B, due 2029	—	—	30
3.000% Gas and Water Series 2016B, due 2036	—	—	60
0.625% Water Facilities Series 2016C, due 2036	—	—	30
2.050% Water Facilities Series 2016D, due 2036	—	—	25
2.050% Water Facilities Series 2016E, due 2036	—	—	25
2.050% Water Facilities Series 2016F, due 2036	—	—	75
1.850% Water Facilities Series 2016G, due 2036	—	—	20
Total Sierra Pacific	1,152	1,148	1,164
Fair value adjustments	—	1	1
Total Sierra Pacific, net of fair value adjustment	1,152	1,149	1,165
Total NV Energy	$ 4,386	$ 4,354	$ 3,675

(1) Subject to mandatory purchase by Nevada Power in March 2023 at which date the interest rate may be adjusted.

(2) Amounts borrowed under the facility bear interest at variable rates based on SOFR or a base rate, at Nevada Power's option, plus a pricing margin.

The issuance of General and Refunding Mortgage Securities by the Nevada Utilities are subject to 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, 2022, approximately $9.8 billion of Nevada Power's and $4.9 billion of Sierra Pacific's (based on original cost) property was subject to the liens of the mortgages.

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]	2022	2021
4.133% European Investment Bank loans, due 2022	$ —	$ —	$ 204
7.25% Bonds, due 2022	—	—	269
2.50% Bonds, due 2025	182	181	202
2.073% European Investment Bank loan, due 2025	60	62	69
2.564% European Investment Bank loans, due 2027	302	301	337
7.25% Bonds, due 2028	224	227	254
4.375% Bonds, due 2032	182	179	200
5.125% Bonds, due 2035	242	240	268
5.125% Bonds, due 2035	182	180	201
2.750% Bonds, due 2049	182	178	200
3.250% Bonds, due 2052	423	419	—
2.250% Bonds, due 2059	363	355	398
1.875% Bonds, due 2062	363	356	398
Variable-rate loan, due 2025[2]	163	164	—
Variable-rate loan, due 2026[3]	217	212	287
Total Northern Powergrid	$ 3,085	$ 3,054	$ 3,287

(1) The par values for these debt instruments are denominated in sterling.

(2) Amortizes quarterly and the loan is 70% floating and 30% fixed. The Company has entered into an interest rate swap that fixes the interest rate on 100% of the floating rate portion. The variable interest rate as of December 31, 2022, was 5.20% (including 2.00% margin) and the average fixed interest rate was 3.09% (including 2.00% margin).

(3) 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, 2022 was 4.98% (including 1.55% margin) and the fixed interest rate was 2.45% (including 1.55% margin), resulting in a blended rate of 2.95%.

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	2022	2021
Eastern Energy Gas:			
2.875% Senior Notes, due 2023	$ 250	$ 250	$ 250
3.55% Senior Notes, due 2023	400	399	399
2.50% Senior Notes, due 2024	600	598	597
3.60% Senior Notes, due 2024	339	338	338
3.32% Senior Notes, due 2026 (€250)(1)	268	267	283
3.00% Senior Notes, due 2029	174	173	173
3.80% Senior Notes, due 2031	150	150	150
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
EGTS:			
3.60% Senior Notes, due 2024	111	110	110
3.00% Senior Notes, due 2029	426	422	422
4.80% Senior Notes, due 2043	346	342	341
4.60% Senior Notes, due 2044	444	437	437
3.90% Senior Notes, due 2049	273	271	271
Total Eastern Energy Gas	3,918	3,892	3,906
Fair value adjustments	—	368	430
Total Eastern Energy Gas, net of fair value adjustments	3,918	4,260	4,336
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	652	651
3.40% Senior Bonds, due 2051	550	540	540
Total Northern Natural Gas	1,600	1,589	1,588
Total BHE Pipeline Group	$ 5,518	$ 5,849	$ 5,924

(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, 2022 and 2021 that averaged 3.32%.

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)]	2022	2021
AltaLink Investments, L.P.:			
Series 15-1 Senior Bonds, 2.244%, due 2022	$ —	$ —	$ 158
Total AltaLink Investments, L.P.	—	—	158
AltaLink, L.P.:			
Series 2012-2 Notes, 2.978%, due 2022	—	—	218
Series 2013-4 Notes, 3.668%, due 2023	369	369	395
Series 2014-1 Notes, 3.399%, due 2024	258	258	277
Series 2016-1 Notes, 2.747%, due 2026	258	258	276
Series 2020-1 Notes, 1.509%, due 2030	166	165	177
Series 2022-1 Notes, 4.692%, due 2032	203	202	—
Series 2006-1 Notes, 5.249%, due 2036	111	111	118
Series 2010-1 Notes, 5.381%, due 2040	92	92	99
Series 2010-2 Notes, 4.872%, due 2040	111	110	118
Series 2011-1 Notes, 4.462%, due 2041	203	202	217
Series 2012-1 Notes, 3.990%, due 2042	387	383	410
Series 2013-3 Notes, 4.922%, due 2043	258	258	276
Series 2014-3 Notes, 4.054%, due 2044	218	216	232
Series 2015-1 Notes, 4.090%, due 2045	258	257	275
Series 2016-2 Notes, 3.717%, due 2046	332	330	354
Series 2013-1 Notes, 4.446%, due 2053	184	184	197
Series 2014-2 Notes, 4.274%, due 2064	96	95	103
Total AltaLink, L.P.	3,504	3,490	3,742
Other:			
Construction Loan, 5.620%, due 2024	5	5	6
Total BHE Transmission	$ 3,509	$ 3,495	$ 3,906

(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	2022	2021
Fixed-rate[1]:			
Bishop Hill Holdings Senior Notes, 5.125%, due 2032	$ 57	$ 56	$ 62
Solar Star Funding Senior Notes, 3.950%, due 2035	244	242	256
Solar Star Funding Senior Notes, 5.375%, due 2035	787	781	819
Grande Prairie Wind Senior Notes, 3.860%, due 2037	269	267	297
Topaz Solar Farms Senior Notes, 5.750%, due 2039	573	568	600
Topaz Solar Farms Senior Notes, 4.875%, due 2039	162	160	170
Alamo 6 Senior Notes, 4.170%, due 2042	190	188	197
Other	—	—	5
Variable-rate[1]:			
TX Jumbo Road Term Loan, due 2025[2]	97	96	117
Marshall Wind Term Loan, due 2026[2]	57	56	63
Flat Top Wind I Term Loan, due 2028[2]	102	99	113
Mariah Del Norte Term Loan, due 2028[2]	56	54	—
Mariah Del Norte Term Loan, due 2032[2]	142	138	—
Pinyon Pines I and II Term Loans, due 2034[2]	328	322	344
Total BHE Renewables	$ 3,064	$ 3,027	$ 3,043

(1) Amortizes quarterly or semiannually.

(2) The term loans have variable interest rates based on LIBOR or 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, 2022 and 2021 ranged from 3.23% to 3.88%. The variable interest rate on the Flat Top Wind I and Mariah Del Norte outstanding debt was 9.82% as of December 31, 2022.

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	2022	2021
Variable-rate:			
Variable-rate term loan (2022 - 5.242%, 2021 - 0.950%), due 2026[1]	$ 140	$ 140	$ 148

(1) Term loan amortizes quarterly and variable-rate resets monthly.

Annual Repayments of Long-Term Debt

The annual repayments of BHE and subsidiary debt for the years beginning January 1, 2023 and thereafter, excluding fair value adjustments and unamortized premiums, discounts and debt issuance costs, are as follows (in millions):

	2023	2024	2025	2026	2027	2028 and Thereafter	Total
BHE senior notes	$ 900	$ —	$ 1,650	$ —	$ —	$ 11,551	$ 14,101
BHE junior subordinated debentures	—	—	—	—	—	100	100
PacifiCorp	449	591	302	100	—	8,300	9,742
MidAmerican Funding	317	538	15	3	378	6,806	8,057
NV Energy	250	300	—	400	—	3,436	4,386
Northern Powergrid	56	57	435	75	302	2,160	3,085
BHE Pipeline Group	650	1,050	—	268	—	3,550	5,518
BHE Transmission	368	263	—	258	—	2,620	3,509
BHE Renewables	203	210	241	218	235	1,957	3,064
HomeServices	8	9	15	108	—	—	140
Totals	$ 3,201	$ 3,018	$ 2,658	$ 1,430	$ 915	$ 40,480	$ 51,702

(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. As of December 31, 2022, the Company had a current income tax payable to Berkshire Hathaway for federal income tax of $113 million. As of December 31, 2021, the Company had a current income tax receivable from Berkshire Hathaway for federal income tax of $324 million and a long-term income tax receivable from Berkshire Hathaway, reflected as a component of BHE's shareholders' equity, of $744 million for Iowa state income tax. Additionally, for the year ended December 31, 2021 the Company generated $100 million of Iowa state net operating losses which were carried forward and increased the long-term income tax receivable from Berkshire Hathaway. In July 2022, the Company amended its tax allocation agreement with Berkshire Hathaway, which changed how state tax attributes will be settled with respect to state income tax returns that Berkshire Hathaway includes the Company. As a result, the Company no longer expects to receive the cash benefits from the state of Iowa net operating loss carryforward previously recorded as a long-term income tax receivable from Berkshire Hathaway as a component of BHE's shareholders' equity, and recognized a noncash distribution of $744 million to retained earnings.

Income tax (benefit) expense consists of the following for the years ended December 31 (in millions):

	2022	2021	2020
Current:			
Federal	$ (1,463)	$ (1,701)	$ (1,537)
State	(65)	(177)	(121)
Foreign	79	100	86
	(1,449)	(1,778)	(1,572)
Deferred:			
Federal	(408)	1,037	1,438
State	(49)	(476)	424
Foreign	(5)	89	21
	(462)	650	1,883
Investment tax credits	(5)	(4)	(3)
Total	$ (1,916)	$ (1,132)	$ 308

A reconciliation of the federal statutory income tax rate to the effective income tax rate applicable to income before income tax (benefit) expense is as follows for the years ended December 31:

	2022	2021	2020
Federal statutory income tax rate	21 %	21 %	21 %
Income tax credits	(124)	(27)	(16)
Effects of ratemaking	(16)	(4)	(3)
State income tax, net of federal income tax benefit	(6)	(10)	3
Non-controlling interest	(6)	(2)	—
Income tax effect of foreign income	(4)	1	—
Equity loss	(3)	(1)	—
Other, net	2	1	(1)
Effective income tax rate	(136)%	(21)%	4 %

Income tax credits relate primarily to production tax credits ("PTC") from wind- and solar-powered generating facilities owned by MidAmerican Energy, PacifiCorp 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. PTCs recognized for the years ended December 31, 2022, 2021 and 2020 totaled $1.7 billion, $1.4 billion, and $1.2 billion, respectively.

Income tax effect on foreign income includes, among other items, a deferred income tax charge of $105 million in 2021, related to the United Kingdom's corporate income tax rate. The United Kingdom's rate is scheduled to increase from 19% to 25%, effective April 1, 2023, through legislation enacted in June 2021. The United Kingdom's rate was scheduled to decrease from 19% to 17% effective April 1, 2020; however, the rate was maintained at 19% through amended legislation enacted in July 2020.

The net deferred income tax liability consists of the following as of December 31 (in millions):

	2022	2021
Deferred income tax assets:		
Regulatory liabilities	$ 1,323	$ 1,349
Federal, state and foreign carryforwards	812	820
AROs	283	304
Other	741	686
Total deferred income tax assets	3,159	3,159
Valuation allowances	(187)	(164)
Total deferred income tax assets, net	2,972	2,995
Deferred income tax liabilities:		
Property-related items	(12,244)	(11,814)
Investments	(1,998)	(2,877)
Regulatory assets	(898)	(764)
Other	(510)	(478)
Total deferred income tax liabilities	(15,650)	(15,933)
Net deferred income tax liability	$ (12,678)	$ (12,938)

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, 2022 (in millions):

	Federal		State		Foreign		Total	
Net operating loss carryforwards[(1)]	$	192	$	9,653	$	725	$	10,570
Deferred income taxes on net operating loss carryforwards		41		562		166		769
Expiration dates	2023 - indefinite		2023 - indefinite		2028 - 2042			
Tax credits	$	15	$	28	$	—	$	43
Expiration dates	2023 - 2034		2023 - indefinite					

(1) The federal net operating loss carryforwards relate principally to net operating loss carryforwards of subsidiaries that are tax residents in both the U.S. and the United Kingdom. The federal net operating loss carryforwards were generated prior to Berkshire Hathaway Inc.'s ownership and began to expire in 2022.

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 for other states through December 31, 2018, except for the impact of any federal audit adjustments. 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.

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):

	2022		2021	
Beginning balance	$	97	$	153
Additions based on tax positions related to the current year		15		24
Additions for tax positions of prior years		—		13
Reductions based on tax positions related to the current year		(12)		(19)
Reductions for tax positions of prior years		(23)		(83)
Settlements		—		(1)
Interest and penalties		(9)		10
Ending balance	$	68	$	97

As of December 31, 2022 and 2021, the Company had unrecognized tax benefits totaling $79 million and $100 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

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		
	2022	2021	2020	2022	2021	2020
Service cost	$ 22	$ 30	$ 17	$ 11	$ 12	$ 7
Interest cost	83	78	93	20	19	21
Expected return on plan assets	(108)	(134)	(140)	(29)	(22)	(34)
Curtailment	(10)	—	—	—	—	—
Settlement	17	3	—	—	—	—
Net amortization	19	25	32	(1)	(3)	(4)
Net periodic benefit cost (credit)	$ 23	$ 2	$ 2	$ 1	$ 6	$ (10)

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	
	2022	2021	2022	2021
Plan assets at fair value, beginning of year	$ 2,795	$ 2,824	$ 769	$ 744
Employer contributions	14	13	8	14
Participant contributions	—	—	8	9
Actual return on plan assets	(491)	234	(122)	53
Settlement	(164)	(134)	—	—
Benefits paid	(141)	(142)	(49)	(51)
Plan assets at fair value, end of year	$ 2,013	$ 2,795	$ 614	$ 769

The following table is a reconciliation of the benefit obligations for the years ended December 31 (in millions):

	Pension		Other Postretirement	
	2022	2021	2022	2021
Benefit obligation, beginning of year	$ 2,777	$ 3,077	$ 714	$ 758
Service cost	22	30	11	12
Interest cost	83	78	20	19
Participant contributions	—	—	8	9
Actuarial (gain) loss	(524)	(132)	(155)	(35)
Amendment	(3)	—	20	2
Curtailment	(10)	—	—	—
Settlement	(164)	(134)	—	—
Benefits paid	(141)	(142)	(49)	(51)
Benefit obligation, end of year	$ 2,040	$ 2,777	$ 569	$ 714
Accumulated benefit obligation, end of year	$ 2,003	$ 2,713		

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	
	2022	2021	2022	2021
Plan assets at fair value, end of year	$ 2,013	$ 2,795	$ 614	$ 769
Benefit obligation, end of year	2,040	2,777	569	714
Funded status	$ (27)	$ 18	$ 45	$ 55
Amounts recognized on the Consolidated Balance Sheets:				
Other assets	$ 125	$ 204	$ 52	$ 60
Other current liabilities	(13)	(13)	—	—
Other long-term liabilities	(139)	(173)	(7)	(5)
Amounts recognized	$ (27)	$ 18	$ 45	$ 55

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 $300 million and $343 million as of December 31, 2022 and 2021, 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 fair value of plan assets, projected benefit obligation and accumulated benefit obligation for (1) pension and other postretirement benefit plans with a projected benefit obligation in excess of the fair value of plan assets and (2) pension plans with an accumulated benefit obligation in excess of the fair value of plan assets as of December 31 are as follows (in millions):

	Pension		Other Postretirement	
	2022	2021	2022	2021
Fair value of plan assets	$ 490	$ —	$ 240	$ 137
Projected benefit obligation	$ 643	$ 186	$ 247	$ 142
Fair value of plan assets	$ —	$ —		
Accumulated benefit obligation	$ 142	$ 185		

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	
	2022	2021	2022	2021
Net loss (gain)	$ 365	$ 343	$ (38)	$ (34)
Prior service (credit) cost	(4)	(1)	21	(1)
Regulatory deferrals	29	11	1	2
Total	$ 390	$ 353	$ (16)	$ (33)

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost for the years ended December 31, 2022 and 2021 is as follows (in millions):

	Regulatory Asset	Regulatory Liability	Accumulated Other Comprehensive Loss	Total
Pension				
Balance, December 31, 2020	$ 600	$ (20)	$ 33	$ 613
Net gain arising during the year	(177)	(44)	(10)	(231)
Settlement	(9)	5	—	(4)
Net amortization	(24)	—	(1)	(25)
Total	(210)	(39)	(11)	(260)
Balance, December 31, 2021	390	(59)	22	353
Net loss (gain) arising during the year	58	38	(20)	76
Net prior service credit arising during the year	—	(3)	—	(3)
Settlement	(13)	(4)	—	(17)
Net amortization	(17)	—	(2)	(19)
Total	28	31	(22)	37
Balance, December 31, 2022	$ 418	$ (28)	$ —	$ 390

	Regulatory Asset	Regulatory Liability	Accumulated Other Comprehensive Loss	Total
Other Postretirement				
Balance, December 31, 2020	$ 47	$ (23)	$ 4	$ 28
Net gain arising during the year	(40)	(22)	(3)	(65)
Net prior service cost arising during the year	1	—	—	1
Net amortization	3	—	—	3
Total	(36)	(22)	(3)	(61)
Balance, December 31, 2021	11	(45)	1	(33)
Net loss (gain) arising during the year	20	(20)	(4)	(4)
Net prior service cost arising during the year	11	8	1	20
Net amortization	3	(2)	—	1
Total	34	(14)	(3)	17
Balance, December 31, 2022	$ 45	$ (59)	$ (2)	$ (16)

Plan Assumptions

Weighted-average assumptions used to determine benefit obligations and net periodic benefit cost were as follows:

	Pension			Other Postretirement		
	2022	2021	2020	2022	2021	2020
Benefit obligations as of December 31:						
Discount rate	5.65 %	2.98 %	2.60 %	4.54 %	2.95 %	2.59 %
Rate of compensation increase	3.00 %	2.75 %	2.75 %	N/A	N/A	N/A
Interest crediting rates for cash balance plan						
2020	N/A	N/A	2.44 %	N/A	N/A	N/A
2021	N/A	2.45 %	2.25 %	N/A	N/A	N/A
2022	3.25 %	2.56 %	2.25 %	N/A	N/A	N/A
2023	4.25 %	2.56 %	2.65 %	N/A	N/A	N/A
2024	4.25 %	2.83 %	2.65 %	N/A	N/A	N/A
2025 and beyond	3.65 %	2.83 %	2.65 %	N/A	N/A	N/A
Net periodic benefit cost for the years ended December 31:						
Discount rate	2.98 %	2.60 %	3.32 %	2.95 %	2.59 %	3.24 %
Expected return on plan assets	4.30 %	5.39 %	5.94 %	4.20 %	3.35 %	5.42 %
Rate of compensation increase	2.75 %	2.75 %	2.75 %	N/A	N/A	N/A
Interest crediting rate for cash balance plan	3.25 %	2.45 %	2.44 %	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.

	2022	2021
Assumed healthcare cost trend rates as of December 31:		
Healthcare cost trend rate assumed for next year	6.50 %	6.00 %
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	2028	2025

Contributions and Benefit Payments

Employer contributions to the pension and other postretirement benefit plans are expected to be $13 million and $7 million, respectively, during 2023. 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 2023 through 2027 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments	
	Pension	Other Postretirement
2023	$ 192	$ 53
2024	184	53
2025	180	53
2026	177	52
2027	172	52
2028-2032	782	235

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, 2022:

	Pension	Other Postretirement
	%	%
PacifiCorp:		
Debt securities[1]	73	77
Equity securities[1]	22	23
Limited partnership interests	5	0
MidAmerican Energy:		
Debt securities[1]	40-70	20-40
Equity securities[1]	35-60	60-80
Other	0-15	0-5
NV Energy:		
Debt securities[1]	65-80	68-89
Equity securities[1]	20-35	11-32

(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, 2022:			
Cash equivalents	$ —	$ 51	$ 51
Debt securities:			
U.S. government obligations	109	—	109
Corporate obligations	—	613	613
Municipal obligations	—	43	43
Agency, asset and mortgage-backed obligations	—	81	81
Equity securities:			
U.S. companies	198	—	198
International companies	1	—	1
Total assets in the fair value hierarchy	$ 308	$ 788	1,096
Investment funds[2] measured at net asset value			885
Limited partnership interests[3] measured at net asset value			32
Total assets measured at fair value			$ 2,013
As of December 31, 2021:			
Cash equivalents	$ —	$ 64	$ 64
Debt securities:			
U.S. government obligations	142	—	142
Corporate obligations	—	912	912
Municipal obligations	—	66	66
Agency, asset and mortgage-backed obligations	—	93	93
Equity securities:			
U.S. companies	135	—	135
Total assets in the fair value hierarchy	$ 277	$ 1,135	1,412
Investment funds[2] measured at net asset value			1,349
Limited partnership interests[3] measured at net asset value			34
Total assets measured at fair value			$ 2,795

(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 53% and 47%, respectively, for 2022 and 54% and 46%, respectively, for 2021. Additionally, these funds are invested in U.S. and international securities of approximately 95% and 5%, respectively, for 2022 and 89% and 11%, respectively, for 2021.

(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, 2022:			
Cash equivalents	$ 15	$ 9	$ 24
Debt securities:			
U.S. government obligations	8	—	8
Corporate obligations	—	52	52
Municipal obligations	—	35	35
Agency, asset and mortgage-backed obligations	—	49	49
Equity securities:			
U.S. companies	7	—	7
Investment funds[2]	307	—	307
Total assets in the fair value hierarchy	$ 337	$ 145	482
Investment funds[2] measured at net asset value			132
Limited partnership interests[3] measured at net asset value			—
Total assets measured at fair value			$ 614
As of December 31, 2021:			
Cash equivalents	$ 12	$ 4	$ 16
Debt securities:			
U.S. government obligations	27	—	27
Corporate obligations	—	85	85
Municipal obligations	—	43	43
Agency, asset and mortgage-backed obligations	—	38	38
Equity securities:			
U.S. companies	4	—	4
Investment funds[2]	394	—	394
Total assets in the fair value hierarchy	$ 437	$ 170	607
Investment funds[2] measured at net asset value			161
Limited partnership interests[3] measured at net asset value			1
Total assets measured at fair value			$ 769

(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 55% and 45%, respectively, for 2022 and 55% and 45%, respectively, for 2021. Additionally, these funds are invested in U.S. and international securities of approximately 88% and 12%, respectively, for 2022 and 88% and 12%, respectively, for 2021.

(3) Limited partnership interests include several funds that invest primarily in real estate, buyout, growth equity and venture capital.

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

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 (credit) cost for the UK Plan included the following components for the years ended December 31 (in millions):

	2022	2021	2020
Service cost	$ 14	$ 16	$ 16
Interest cost	35	31	40
Expected return on plan assets	(92)	(111)	(101)
Settlement	—	10	17
Net amortization	24	55	43
Net periodic benefit (credit) cost	$ (19)	$ 1	$ 15

Funded Status

The following table is a reconciliation of the fair value of plan assets for the years ended December 31 (in millions):

	2022	2021
Plan assets at fair value, beginning of year	$ 2,363	$ 2,334
Employer contributions	15	28
Participant contributions	1	1
Actual return on plan assets	(671)	148
Settlement	—	(51)
Benefits paid	(109)	(72)
Foreign currency exchange rate changes	(236)	(25)
Plan assets at fair value, end of year	$ 1,363	$ 2,363

The following table is a reconciliation of the benefit obligation for the years ended December 31 (in millions):

	2022	2021
Benefit obligation, beginning of year	$ 2,003	$ 2,205
Service cost	14	16
Interest cost	35	31
Participant contributions	1	1
Actuarial gain	(596)	(105)
Settlement	—	(51)
Amendment	27	—
Benefits paid	(109)	(72)
Foreign currency exchange rate changes	(200)	(22)
Benefit obligation, end of year	$ 1,175	$ 2,003
Accumulated benefit obligation, end of year	$ 1,060	$ 1,778

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):

	2022	2021
Plan assets at fair value, end of year	$ 1,363	$ 2,363
Benefit obligation, end of year	1,175	2,003
Funded status	$ 188	$ 360
Amounts recognized on the Consolidated Balance Sheets:		
Other assets	$ 188	$ 360

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):

	2022	2021
Net loss	$ 499	$ 400
Prior service cost	30	5
Total	$ 529	$ 405

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):

	2022	2021
Balance, beginning of year	$ 405	$ 618
Net loss (gain) arising during the year	167	(143)
Net prior service cost arising during the year	27	—
Settlement	—	(10)
Net amortization	(24)	(55)
Foreign currency exchange rate changes	(46)	(5)
Total	124	(213)
Balance, end of year	$ 529	$ 405

Plan Assumptions

Assumptions used to determine benefit obligations and net periodic benefit cost were as follows:

	2022	2021	2020
Benefit obligations as of December 31:			
Discount rate	4.80 %	1.95 %	1.40 %
Rate of compensation increase	3.20 %	3.45 %	3.05 %
Rate of future price inflation	2.95 %	2.95 %	2.55 %
Net periodic benefit cost for the years ended December 31:			
Discount rate	1.95 %	1.40 %	2.10 %
Expected return on plan assets	4.40 %	4.85 %	5.00 %
Rate of compensation increase	3.45 %	3.05 %	3.30 %
Rate of future price inflation	2.95 %	2.55 %	2.80 %

Contributions and Benefit Payments

Employer contributions to the UK Plan are expected to be £11 million during 2023. The expected benefit payments to participants in the UK Plan for 2023 through 2027 and for the five years thereafter, excluding lump sum settlement elections and using the foreign currency exchange rate as of December 31, 2022, are summarized below (in millions):

2023	$ 67
2024	69
2025	70
2026	72
2027	74
2028-2032	398

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, 2022:

	%
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, 2022:				
Cash equivalents	$ 1	$ 29	$ —	$ 30
Debt securities:				
United Kingdom government obligations	711	—	—	711
Equity securities:				
Investment funds(2)	—	312	—	312
Real estate funds	—	—	214	214
Total	$ 712	$ 341	$ 214	1,267
Investment funds(2) measured at net asset value				96
Total assets measured at fair value				$ 1,363
As of December 31, 2021:				
Cash equivalents	$ 5	$ 27	$ —	$ 32
Debt securities:				
United Kingdom government obligations	1,308	—	—	1,308
Equity securities:				
Investment funds(2)	—	646	—	646
Real estate funds	—	—	269	269
Total	$ 1,313	$ 673	$ 269	2,255
Investment funds(2) measured at net asset value				108
Total assets measured at fair value				$ 2,363

(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 25% and 75%, respectively, for 2022 and 23% and 77%, respectively, for 2021.

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		
	2022	**2021**	**2020**
Beginning balance	$ 269	$ 237	$ 243
Actual return on plan assets still held at period end	(27)	35	(13)
Foreign currency exchange rate changes	(28)	(3)	7
Ending balance	$ 214	$ 269	$ 237

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 $159 million, $137 million and $127 million for the years ended December 31, 2022, 2021 and 2020, 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 $2.6 billion and $2.4 billion as of December 31, 2022 and 2021, respectively.

The following table presents the Company's ARO liabilities by asset type as of December 31 (in millions):

	2022	**2021**
Quad Cities Station	$ 417	$ 427
Fossil-fueled generating facilities	396	466
Wind-powered generating facilities	353	299
Solar-powered generating facilities	30	25
Offshore pipeline facilities	14	14
Other	118	109
Total asset retirement obligations	$ 1,328	$ 1,340
Quad Cities Station nuclear decommissioning trust funds	$ 664	$ 768

The following table reconciles the beginning and ending balances of the Company's ARO liabilities for the years ended December 31 (in millions):

	2022	2021
Beginning balance	$ 1,340	$ 1,341
Change in estimated costs	2	81
Acquisitions	29	—
Additions	32	15
Retirements	(122)	(144)
Accretion	47	47
Ending balance	$ 1,328	$ 1,340
Reflected as:		
Other current liabilities	$ 76	$ 130
Other long-term liabilities	1,252	1,210
Total ARO liability	$ 1,328	$ 1,340

The Nuclear Regulatory Commission regulates the decommissioning of nuclear generating facilities, 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.

(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, 2022:					
Assets:					
Commodity derivatives	$ 6	$ 614	$ 51	$ (194)	$ 477
Interest rate derivatives	50	54	8	—	112
Mortgage loans held for sale	—	474	—	—	474
Money market mutual funds	1,178	—	—	—	1,178
Debt securities:					
U.S. government obligations	2,146	—	—	—	2,146
International government obligations	—	1	—	—	1
Corporate obligations	—	70	—	—	70
Municipal obligations	—	3	—	—	3
Agency, asset and mortgage-backed obligations	—	1	—	—	1
Equity securities:					
U.S. companies	360	—	—	—	360
International companies	3,771	—	—	—	3,771
Investment funds	231	—	—	—	231
	$ 7,742	$ 1,217	$ 59	$ (194)	$ 8,824
Liabilities:					
Commodity derivatives	$ (8)	$ (206)	$ (110)	$ 106	$ (218)
Foreign currency exchange rate derivatives	—	(21)	—	—	(21)
Interest rate derivatives	—	(2)	(2)	1	(3)
	$ (8)	$ (229)	$ (112)	$ 107	$ (242)

	Input Levels for Fair Value Measurements				
	Level 1	Level 2	Level 3	Other(1)	Total
As of December 31, 2021:					
Assets:					
Commodity derivatives	$ 5	$ 271	$ 73	$ (47)	$ 302
Foreign currency exchange rate derivatives	—	3	—	—	3
Interest rate derivatives	1	3	20	—	24
Mortgage loans held for sale	—	1,263	—	—	1,263
Money market mutual funds	554	—	—	—	554
Debt securities:					
U.S. government obligations	232	—	—	—	232
International government obligations	—	2	—	—	2
Corporate obligations	—	90	—	—	90
Municipal obligations	—	3	—	—	3
Agency, asset and mortgage-backed obligations	—	2	—	—	2
Equity securities:					
U.S. companies	428	—	—	—	428
International companies	7,703	—	—	—	7,703
Investment funds	237	—	—	—	237
	$ 9,160	$ 1,637	$ 93	$ (47)	$ 10,843
Liabilities:					
Commodity derivatives	$ (2)	$ (113)	$ (224)	$ 73	$ (266)
Foreign currency exchange rate derivatives	—	(3)	—	—	(3)
Interest rate derivatives	—	(7)	(1)	—	(8)
	$ (2)	$ (123)	$ (225)	$ 73	$ (277)

(1) Represents netting under master netting arrangements and a net cash collateral payable of $87 million and receivable of $26 million as of December 31, 2022 and 2021, 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		
	2022	2021	2020	2022	2021	2020
Beginning balance	$ (151)	$ 116	$ 97	$ 19	$ 62	$ 14
Changes included in earnings[1]	(85)	(43)	(10)	(13)	(43)	48
Changes in fair value recognized in OCI	9	(13)	—	—	—	—
Changes in fair value recognized in net regulatory assets	(52)	(118)	(17)	—	—	—
Purchases	3	(76)	5	—	—	—
Settlements	171	(34)	41	—	—	—
Transfers out of Level 3 into Level 2	46	17	—	—	—	—
Ending balance	$ (59)	$ (151)	$ 116	$ 6	$ 19	$ 62

(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):

	2022		2021	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 51,635	$ 46,906	$ 49,762	$ 57,189

(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, 2022 are as follows (in millions):

	2023	2024	2025	2026	2027	2028 and Thereafter	Total
Contract type:							
Fuel, capacity and transmission contract commitments	$ 3,431	$ 1,879	$ 1,381	$ 1,286	$ 1,234	$ 11,862	$ 21,073
Construction commitments	2,434	1,088	144	294	10	—	3,970
Easements	88	86	85	86	87	3,049	3,481
Maintenance, service and other contracts	461	350	297	283	256	1,472	3,119
	$ 6,414	$ 3,403	$ 1,907	$ 1,949	$ 1,587	$ 16,383	$ 31,643

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, 2022, 2021 and 2020, $100 million, $76 million and $90 million, respectively, were incurred for coal transportation services, the majority of which was related to the BNSF agreement.

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, and distribution projects.
- MidAmerican Energy's firm construction commitments primarily consisting of contracts for the repowering and construction of wind- and solar-powered generating facilities and the settlement of AROs.
- Nevada Utilities' firm construction commitments consisting of costs associated with a planned 150-MW solar photovoltaic facility with an additional 100 MWs of co-located battery storage that will be developed in Clark County, Nevada, a planned 220-MW grid-tied battery energy storage system that will be developed on the site of the retired Reid Gardner generating station in Clark County, Nevada and certain other generating plant projects and costs associated with two additional solar photovoltaic facility projects. The first project is a 250-MW solar photovoltaic facility with an additional 200 MWs of co-located battery storage that will be developed in Humboldt County, Nevada. The second project is a 350-MW solar photovoltaic facility with an additional 280 MWs of co-located battery storage that will be developed in Humboldt County, Nevada. Commercial operation has been delayed for both projects to an undetermined date. Both facilities will be jointly owned and operated by Nevada Power and Sierra Pacific.
- AltaLink's investments in directly assigned transmission projects from the AESO.

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.

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 the its current and future operations. The Company believes it is in material compliance with all applicable laws and regulations.

Hydroelectric Relicensing

PacifiCorp is a party to the 2016 amended Klamath Hydroelectric Settlement Agreement ("KHSA"), which is intended to resolve disputes surrounding PacifiCorp's efforts to relicense the Klamath Hydroelectric Project. The KHSA establishes a process for PacifiCorp, the states of Oregon and California ("States") and other stakeholders to assess whether dam removal can 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"), who would conduct dam removal; and (4) ability for PacifiCorp to operate the facilities for the benefit of customers until dam removal commences.

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 FERC approved the partial transfer of the Klamath license in a July 2020 order, subject to the condition that PacifiCorp remains co-licensee. Under the amended KHSA, PacifiCorp did not agree to remain co-licensee during the surrender and removal process given concerns about liability protections for PacifiCorp and its customers. In November 2020, PacifiCorp entered a memorandum of agreement (the "MOA") with the KRRC, the Karuk Tribe, the Yurok Tribe and the States to continue implementation of the KHSA. The agreement required the States, PacifiCorp and KRRC to file a new license transfer application to remove PacifiCorp from the license for the Lower Klamath Project and add the States and KRRC as co-licensees for the purposes of surrender. In addition, the MOA provides for additional contingency funding of $45 million, equally split between PacifiCorp and the States, and for PacifiCorp and the States to equally share in any additional cost overruns in the unlikely event that dam removal costs exceed the $450 million in funding to ensure dam removal is complete. The MOA also requires PacifiCorp to cover the costs associated with certain pre-existing environmental conditions. In June 2021, the FERC approved the transfer of the Lower Klamath Project dams from PacifiCorp to the KRRC and the States as co-licensees. In July 2021, the Oregon, Wyoming, Idaho and California state public utility commissions conditionally approved the required property transfer applications. In August 2021, PacifiCorp notified the Public Service Commission of Utah of the property transfer, however no formal approval is required in Utah. In August 2022, the FERC staff issued a final environmental impact statement for the project, concluding that dam removal is the preferred action. In November 2022, the FERC issued a license surrender order for the project, which was accepted by the KRRC and the States in December 2022, along with the transfer of the Lower Klamath Project dams. Although PacifiCorp no longer owns the Lower Klamath Project, PacifiCorp will continue to operate the facilities under an operation and maintenance agreement with the KRRC until each facility is ready for removal. Removal of the Copco No. 2 facility is anticipated to begin in 2023, and removal of the remaining three dams (J.C. Boyle, Copco No. 1, and Iron Gate) is anticipated to begin in 2024.

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 $282 million over the next 10 years.

Legal Matters

The Company is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. The Company does not believe that such normal and routine litigation will have a material impact on its consolidated financial results. The Company is also involved in other kinds of legal actions, some of which assert or may assert claims or seek to impose fines, penalties and other costs in substantial amounts and are described below.

Wildfires Overview - PacifiCorp

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. 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.

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 damages proximately caused by negligence, including real and personal property and natural resource damages; fire suppression costs; personal injury and loss of life damages; and interest.

2020 Wildfires

In September 2020, a severe weather event resulting in 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 "2020 Wildfires"). 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. Fire suppression costs estimated by various agencies total approximately $150 million.

Investigations into the cause and origin of each wildfire are complex and ongoing and being conducted by various entities, including the U.S. Forest Service, the California Public Utilities Commission, the Oregon Department of Forestry, the Oregon Department of Justice, PacifiCorp and various experts engaged by PacifiCorp.

As of the date of this filing, numerous lawsuits have been filed in Oregon and California, including a class action complaint in Oregon, on behalf of plaintiffs related to the 2020 Wildfires. The plaintiffs seek damages that include property damages, economic losses, punitive damages, exemplary damages, attorneys' fees and other damages. Additionally, several insurance carriers have filed subrogation complaints in Oregon and California with allegations similar to those made in the aforementioned lawsuits. The final determinations of liability, however, will only be made following the completion of comprehensive investigations and litigation processes.

PacifiCorp has accrued cumulative estimated probable losses associated with the 2020 Wildfires of $477 million through December 31, 2022. The accrual includes PacifiCorp's estimate of losses for fire suppression costs, real and personal property damages, natural resource damages for certain areas and noneconomic damages such as personal injury damages and loss of life damages that are considered probable of being incurred and that it is reasonably able to estimate at this time. For certain aspects of the 2020 Wildfires for which loss is considered probable, information necessary to reasonably estimate the potential losses, such as those related to certain areas of natural resource damages, is not currently available.

It is reasonably possible PacifiCorp will incur additional losses beyond the amounts accrued; however, PacifiCorp is currently unable to estimate the range of possible additional losses that could be incurred due to the number of properties and parties involved and the variation in those types of properties and lack of available details. To the extent losses beyond the amounts accrued are incurred, additional insurance coverage is expected to be available to cover a portion of the losses.

The following table presents changes in PacifiCorp's liability for estimated losses associated with the 2020 Wildfires for the years ended December 31 (in millions):

	2022	2021	2020
Beginning balance	$ 252	$ 252	$ —
Accrued losses	225	—	252
Payments	(53)	—	—
Ending balance	$ 424	$ 252	$ 252

PacifiCorp's receivable for expected insurance recoveries associated with the probable losses was $246 million and $116 million, respectively, as of December 31, 2022 and 2021. During the years ended December 31, 2022, 2021, and 2020, PacifiCorp recognized probable losses net of expected insurance recoveries associated with the 2020 Wildfires of $64 million, $— million and $136 million, respectively.

2022 McKinney Fire

According to California Department of Forestry and Fire Protection, on July 29, 2022, at approximately 2:16 p.m. Pacific Time, a wildfire began in the Oak Knoll Ranger District of the Klamath National Forest in Siskiyou County, California (the "2022 McKinney Fire") located in PacifiCorp's service territory. Third party reports indicate that the 2022 McKinney Fire resulted in 11 structures damaged, 185 structures destroyed, 12 injuries and four fatalities and consumed 60,000 acres. The cause of the 2022 McKinney Fire is undetermined and remains under investigation by the U.S. Forest Service.

Due to the preliminary nature of the investigation PacifiCorp does not believe a loss is probable and therefore has not accrued any loss as of the date of this filing. While the loss is not probable, PacifiCorp estimates the potential loss, excluding losses for natural resource damages, to be $31 million, net of expected insurance recoveries. The loss estimate includes PacifiCorp's estimate of losses for fire suppression costs; real and personal property damages; and noneconomic damages such as personal injury damages and loss of life damages. PacifiCorp is unable to estimate the total potential loss, including losses for natural resource damages, because there are a number of unknown facts and legal considerations that may impact the amount of any potential liability, including the total scope and nature of claims that may be asserted against PacifiCorp. PacifiCorp has insurance available and estimates the potential insurance recoveries to be $103 million, to cover potential losses.

As of the date of this filing, multiple lawsuits have been filed in California on behalf of plaintiffs related to the 2022 McKinney Fire. The plaintiffs seek damages that include property damages, economic losses, punitive damages, exemplary damages, attorneys' fees and other damages but the amount of damages sought are not specified. The final determinations of liability, however, will only be made following the completion of comprehensive investigations and litigation processes.

Guarantees

The Company has entered into guarantees as part of the normal course of business and the sale 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):

	2022								
	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	BHE Pipeline Group	BHE Transmission	BHE Renewables	BHE and Other(1)	Total
Customer Revenue:									
Regulated:									
Retail Electric	$ 5,099	$ 2,320	$ 3,465	$ —	$ —	$ —	$ —	$ —	$ 10,884
Retail Gas	—	855	167	—	—	—	—	—	1,022
Wholesale	260	668	92	—	8	—	—	(4)	1,024
Transmission and distribution	166	61	76	1,081	—	683	—	—	2,067
Interstate pipeline	—	—	—	—	2,603	—	—	(127)	2,476
Other	102	—	2	—	3	—	—	(2)	105
Total Regulated	5,627	3,904	3,802	1,081	2,614	683	—	(133)	17,578
Nonregulated	—	7	—	169	1,076	70	866	597	2,785
Total Customer Revenue	5,627	3,911	3,802	1,250	3,690	753	866	464	20,363
Other revenue	52	114	22	115	154	(21)	128	142	706
Total	$ 5,679	$ 4,025	$ 3,824	$ 1,365	$ 3,844	$ 732	$ 994	$ 606	$ 21,069

	2021								
	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	BHE Pipeline Group	BHE Transmission	BHE Renewables	BHE and Other(1)	Total
Customer Revenue:									
Regulated:									
Retail Electric	$ 4,847	$ 2,128	$ 2,828	$ —	$ —	$ —	$ —	$ (2)	$ 9,801
Retail Gas	—	859	115	—	—	—	—	—	974
Wholesale	157	454	62	—	57	—	—	(3)	727
Transmission and distribution	143	58	74	1,023	—	702	—	—	2,000
Interstate pipeline	—	—	—	—	2,404	—	—	(131)	2,273
Other	108	—	1	—	(1)	—	—	1	109
Total Regulated	5,255	3,499	3,080	1,023	2,460	702	—	(135)	15,884
Nonregulated	—	15	3	43	956	35	796	576	2,424
Total Customer Revenue	5,255	3,514	3,083	1,066	3,416	737	796	441	18,308
Other revenue	41	33	24	122	128	(6)	185	100	627
Total	$ 5,296	$ 3,547	$ 3,107	$ 1,188	$ 3,544	$ 731	$ 981	$ 541	$ 18,935

	2020								
	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	BHE Pipeline Group	BHE Transmission	BHE Renewables	BHE and Other(1)	Total
Customer Revenue:									
Regulated:									
Retail Electric	$ 4,932	$ 1,924	$ 2,566	$ —	$ —	$ —	$ —	$ (1)	$ 9,421
Retail Gas	—	505	114	—	—	—	—	—	619
Wholesale	107	199	45	—	17	—	—	(2)	366
Transmission and distribution	96	60	95	887	—	641	—	—	1,779
Interstate pipeline	—	—	—	—	1,397	—	—	(139)	1,258
Other	108	—	2	—	—	—	—	—	110
Total Regulated	5,243	2,688	2,822	887	1,414	641	—	(142)	13,553
Nonregulated	—	16	2	26	134	18	817	515	1,528
Total Customer Revenue	5,243	2,704	2,824	913	1,548	659	817	373	15,081
Other revenue	98	24	30	109	30	—	119	65	475
Total	$ 5,341	$ 2,728	$ 2,854	$ 1,022	$ 1,578	$ 659	$ 936	$ 438	$ 15,556

(1) The BHE and Other reportable segment represents amounts related principally to other entities, including MidAmerican Energy Services, LLC, 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		
	2022	2021	2020
Customer Revenue:			
Brokerage	$ 4,867	$ 5,498	$ 4,520
Franchise	66	85	76
Total Customer Revenue	4,933	5,583	4,596
Mortgage and other revenue	335	632	800
Total	$ 5,268	$ 6,215	$ 5,396

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, 2022, by reportable segment (in millions):

	Performance obligations expected to be satisfied		
	Less than 12 months	**More than 12 months**	**Total**
BHE Pipeline Group	$ 2,835	$ 20,619	$ 23,454
BHE Transmission	679	—	679
Total	$ 3,514	$ 20,619	$ 24,133

(18) BHE Shareholders' Equity

Preferred Stock

As of December 31, 2022 and 2021, BHE had 849,982 and 1,649,988 shares outstanding of its Perpetual Preferred Stock (the "4% Perpetual Preferred Stock") issued to certain subsidiaries of Berkshire Hathaway Inc. The 4% Perpetual Preferred Stock has a liquidation preference of $1,000 per share and currently pays a 4.00% dividend per share on the liquidation preference. Dividends shall accrue and accumulate daily, be cumulative, compound semi-annually and, if declared, be payable in cash semi-annually in arrears on May 15 and November 15 of each year. If dividends are not declared and paid, any accumulating dividends shall continue to accumulate and compound. BHE may 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 shall first receive, or simultaneously receive, a dividend in an amount at least equivalent to the amount accumulated and not previously paid. BHE may 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.

Common Stock

On March 14, 2000, and as amended on December 7, 2005, BHE's shareholders entered into a Shareholder Agreement that provides specific rights to certain shareholders. One of these rights allows certain shareholders the ability to put their common shares to BHE at the then-current fair value dependent on certain circumstances controlled by BHE.

In June 2022, BHE purchased 740,961 shares of its common stock held by Mr. Gregory E. Abel, BHE's Chair, for $870 million. The purchase was pursuant to the terms of BHE's Shareholders Agreement.

Restricted Net Assets

BHE has maximum debt-to-total capitalization percentage restrictions imposed by its senior unsecured credit facilities expiring in June 2025 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 $18.8 billion as of December 31, 2022.

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 $20.4 billion as of December 31, 2022.

(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, 2019	$ (417)	$ (1,296)	$ 7	$ —	$ (1,706)
Other comprehensive (loss) income	(65)	234	(15)	—	154
BHE GT&S acquisition	(10)	—	—	10	—
Balance, December 31, 2020	(492)	(1,062)	(8)	10	(1,552)
Other comprehensive income (loss)	174	(24)	67	(5)	212
Balance, December 31, 2021	(318)	(1,086)	59	5	(1,340)
Other comprehensive (loss) income	(72)	(810)	76	(3)	(809)
Balance, December 31, 2022	$ (390)	$ (1,896)	$ 135	$ 2	$ (2,149)

Reclassifications from AOCI to net income for the years ended December 31, 2022, 2021 and 2020 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 part of the GT&S Transaction, BHE acquired an indirect 25% economic interest in Cove Point, consisting of 100% of the general partnership interest and 25% of the total limited partnership interests. BHE concluded that Cove Point is a VIE due to the limited partners 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) Dominion Energy's 50% interest in Cove Point and Brookfield Super-Core Infrastructure Partner's 25% interest in Cove Point and (ii) preferred securities of subsidiaries of $58 million as of December 31, 2022 and 2021, consisting 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, and $2 million of nonredeemable preferred stock of PacifiCorp.

(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):

	2022	2021	2020
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	$ 2,071	$ 2,041	$ 1,855
Income taxes received, net[(1)]	$ 1,863	$ 1,309	$ 1,361
Supplemental disclosure of non-cash investing and financing transactions:			
Accruals related to property, plant and equipment additions	$ 1,049	$ 834	$ 801

(1) Includes $1,961 million, $1,441 million and $1,504 million of income taxes received from Berkshire Hathaway in 2022, 2021 and 2020, respectively.

(22) Segment Information

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 (in millions):

	Years Ended December 31,		
	2022	2021	2020
Operating revenue:			
PacifiCorp	$ 5,679	$ 5,296	$ 5,341
MidAmerican Funding	4,025	3,547	2,728
NV Energy	3,824	3,107	2,854
Northern Powergrid	1,365	1,188	1,022
BHE Pipeline Group	3,844	3,544	1,578
BHE Transmission	732	731	659
BHE Renewables	994	981	936
HomeServices	5,268	6,215	5,396
BHE and Other[(1)]	606	541	438
Total operating revenue	$ 26,337	$ 25,150	$ 20,952
Depreciation and amortization:			
PacifiCorp	$ 1,120	$ 1,088	$ 1,209
MidAmerican Funding	1,168	914	716
NV Energy	566	549	502
Northern Powergrid	361	305	266
BHE Pipeline Group	508	492	231
BHE Transmission	239	238	201
BHE Renewables	264	241	284
HomeServices	56	52	45
BHE and Other[(1)]	4	2	1
Total depreciation and amortization	$ 4,286	$ 3,881	$ 3,455

	Years Ended December 31,		
	2022	2021	2020
Operating income:			
PacifiCorp	$ 1,158	$ 1,133	$ 924
MidAmerican Funding	438	416	454
NV Energy	606	621	649
Northern Powergrid	551	543	421
BHE Pipeline Group	1,720	1,516	779
BHE Transmission	333	339	316
BHE Renewables	300	329	291
HomeServices	151	505	511
BHE and Other[1]	(16)	(75)	(54)
Total operating income	5,241	5,327	4,291
Interest expense	(2,216)	(2,118)	(2,021)
Capitalized interest	76	64	80
Allowance for equity funds	167	126	165
Interest and dividend income	154	89	71
(Losses) gains on marketable securities, net	(2,002)	1,823	4,797
Other, net	(7)	(17)	88
Total income before income tax (benefit) expense and equity loss	$ 1,413	$ 5,294	$ 7,471
Interest expense:			
PacifiCorp	$ 431	$ 430	$ 426
MidAmerican Funding	333	319	322
NV Energy	221	206	227
Northern Powergrid	133	130	130
BHE Pipeline Group	148	143	74
BHE Transmission	153	155	148
BHE Renewables	175	158	166
HomeServices	7	4	11
BHE and Other[1]	615	573	517
Total interest expense	$ 2,216	$ 2,118	$ 2,021
Income tax (benefit) expense:			
PacifiCorp	$ (61)	$ (78)	$ (75)
MidAmerican Funding	(776)	(680)	(574)
NV Energy	56	56	61
Northern Powergrid	75	192	96
BHE Pipeline Group	276	269	162
BHE Transmission	14	10	13
BHE Renewables[2]	(887)	(753)	(602)
HomeServices	47	138	138
BHE and Other[1]	(660)	(286)	1,089
Total income tax (benefit) expense	$ (1,916)	$ (1,132)	$ 308

	Years Ended December 31,		
	2022	2021	2020
Earnings on common shares:			
PacifiCorp	$ 921	$ 889	$ 741
MidAmerican Funding	947	883	818
NV Energy	427	439	410
Northern Powergrid	385	247	201
BHE Pipeline Group	1,040	807	528
BHE Transmission	247	247	231
BHE Renewables[2]	625	451	521
HomeServices	100	387	375
BHE and Other[1]	(2,017)	1,319	3,092
Total earnings on common shares	$ 2,675	$ 5,669	$ 6,917
Capital expenditures:			
PacifiCorp	$ 2,166	$ 1,513	$ 2,540
MidAmerican Funding	1,869	1,912	1,836
NV Energy	1,113	749	675
Northern Powergrid	768	742	682
BHE Pipeline Group	1,157	1,128	659
BHE Transmission	200	279	372
BHE Renewables	138	225	95
HomeServices	48	42	36
BHE and Other	46	21	(130)
Total capital expenditures	$ 7,505	$ 6,611	$ 6,765

	As of December 31,		
	2022	2021	2020
Property, plant and equipment, net:			
PacifiCorp	$ 24,430	$ 22,914	$ 22,430
MidAmerican Funding	21,092	20,302	19,279
NV Energy	10,993	10,231	9,865
Northern Powergrid	7,445	7,572	7,230
BHE Pipeline Group	16,216	15,692	15,097
BHE Transmission	6,209	6,590	6,445
BHE Renewables	6,231	6,103	5,645
HomeServices	188	169	159
BHE and Other	239	243	(22)
Total property, plant and equipment, net	$ 93,043	$ 89,816	$ 86,128

	As of December 31,		
	2022	2021	2020
Total assets:			
PacifiCorp	$ 30,559	$ 27,615	$ 26,862
MidAmerican Funding	26,077	25,352	23,530
NV Energy	16,676	15,239	14,501
Northern Powergrid	9,005	9,326	8,782
BHE Pipeline Group	21,005	20,434	19,541
BHE Transmission	9,334	9,476	9,208
BHE Renewables	11,458	11,829	12,004
HomeServices	3,436	4,574	4,955
BHE and Other	6,290	8,220	7,933
Total assets	$ 133,840	$ 132,065	$ 127,316

	Years Ended December 31,		
	2022	2021	2020
Operating revenue by country:			
U.S.	$ 24,263	$ 23,215	$ 19,254
United Kingdom	1,345	1,188	1,022
Canada	709	719	653
Australia	20	—	—
Other	—	28	23
Total operating revenue by country	$ 26,337	$ 25,150	$ 20,952
Income before income tax (benefit) expense and equity loss by country:			
U.S.	$ 771	$ 4,650	$ 6,954
United Kingdom	447	454	338
Canada	181	181	173
Australia	15	(8)	—
Other	(1)	17	6
Total income before income tax (benefit) expense and equity loss by country	$ 1,413	$ 5,294	$ 7,471

	As of December 31,		
	2022	2021	2020
Property, plant and equipment, net by country:			
U.S.	$ 79,578	$ 75,774	$ 72,583
United Kingdom	6,959	7,487	7,134
Canada	6,091	6,547	6,401
Australia	415	8	10
Total property, plant and equipment, net by country	$ 93,043	$ 89,816	$ 86,128

(1) The differences between the reportable segment amounts and the consolidated amounts, described as BHE and Other, relate to other corporate entities, including MidAmerican Energy Services, LLC, 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 shows the change in the carrying amount of goodwill by reportable segment for the years ended December 31, 2022 and 2021 (in millions):

	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	BHE Pipeline Group	BHE Transmission	BHE Renewables	HomeServices	Total
December 31, 2020	$ 1,129	$ 2,102	$ 2,369	$ 1,000	$ 1,803	$ 1,551	$ 95	$ 1,457	$ 11,506
Acquisitions	—	—	—	—	11	—	—	129	140
Foreign currency translation	—	—	—	(8)	—	12	—	—	4
December 31, 2021	1,129	2,102	2,369	992	1,814	1,563	95	1,586	11,650
Acquisitions	—	—	—	—	—	—	—	16	16
Foreign currency translation	—	—	—	(75)	—	(102)	—	—	(177)
December 31, 2022	$ 1,129	$ 2,102	$ 2,369	$ 917	$ 1,814	$ 1,461	$ 95	$ 1,602	$ 11,489

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, 2022, was $920 million, an increase of $32 million, or 4%, compared to 2021, primarily due to higher utility margin, lower other expense, including higher allowance for equity and borrowed funds used during construction and lower property and other taxes, partially offset by higher operations and maintenance expense, largely due to higher general and plant maintenance costs and an increase to the wildfire damage provision, higher depreciation and amortization expense, and lower income tax benefit. Utility margin increased primarily due to higher net power cost deferrals, higher retail prices and volumes, higher average wholesale market prices, lower coal-fueled generation volumes and higher net wheeling revenues, partially offset by higher natural gas-fueled generation prices and volumes, higher purchased electricity costs from higher volumes and prices, higher coal-fueled generation prices, lower wind-based ancillary revenues, and lower wholesale volumes. Retail customer volumes increased 1.6% primarily due to an increase in the average number of customers, favorable impacts of weather and an increase in commercial customer usage, partially offset by a decrease in residential and industrial customer usage. Energy generated decreased 4% for 2022 compared to 2021 primarily due lower coal-fueled generation, partially offset by higher wind-powered, natural gas-fueled and hydroelectric-powered generation. Wholesale electricity sales volumes decreased 5% and purchased electricity volumes increased 20%.

Net income for the year ended December 31, 2021, was $888 million, an increase of $149 million, or 20%, compared to 2020, primarily due to higher utility gross margin (excluding $231 million of decreases fully offset in depreciation, operating, other income/expense and income tax expense due to prior year regulatory adjustments); lower operations and maintenance expense primarily due to prior year costs associated with the 2020 Wildfires and changes in how obligations associated with the implementation of the Klamath Hydroelectric Settlement Agreement will be met; and favorable income tax expense from higher PTCs recognized due to new wind-powered generating facilities placed in-service and the impacts of ratemaking; partially offset by higher depreciation and amortization expense (excluding $376 million of decreases offset in operating revenue and income tax expense due to prior year regulatory adjustments) from the impacts of the depreciation study for which rates became effective January 2021 and higher plant in-service; and lower allowances for equity and borrowed funds used during construction. Utility margin increased $145 million (excluding the $231 million of fully offsetting decreases) primarily due to the higher retail, wheeling and wholesale revenue; higher deferred net power costs; and lower purchased electricity volumes; partially offset by higher purchased electricity prices; and higher natural gas- and coal-fueled generation costs. Retail customer volumes increased 3.1% due to increase in customer usage, increase in the average number of customers and favorable impacts of weather. Energy generated increased 10% for 2021 compared to 2020 primarily due higher wind-powered, natural gas-fueled and coal-fueled generation, partially offset by lower hydroelectric-powered generation. Wholesale electricity sales volumes decreased 3% 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, 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 profitability 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 running 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):

	2022	2021	Change		2021	2020	Change	
Utility margin:								
Operating revenue	$ 5,679	$ 5,296	$ 383	7 %	$ 5,296	$ 5,341	$ (45)	(1)%
Cost of fuel and energy	1,979	1,831	148	8	1,831	1,790	41	2
Utility margin	3,700	3,465	235	7	3,465	3,551	(86)	(2)
Operations and maintenance	1,227	1,031	196	19	1,031	1,209	(178)	(15)
Depreciation and amortization	1,120	1,088	32	3	1,088	1,209	(121)	(10)
Property and other taxes	195	213	(18)	(8)	213	209	4	2
Operating income	$ 1,158	$ 1,133	$ 25	2 %	$ 1,133	$ 924	$ 209	23 %

Utility Margin

A comparison of key operating results related to utility margin is as follows for the years ended December 31:

	2022	2021	Change		2021	2020	Change	
Utility margin (in millions):								
Operating revenue	$ 5,679	$ 5,296	$ 383	7 %	$ 5,296	$ 5,341	$ (45)	(1)%
Cost of fuel and energy	1,979	1,831	148	8	1,831	1,790	41	2
Utility margin	$ 3,700	$ 3,465	$ 235	7 %	$ 3,465	$ 3,551	$ (86)	(2)%
Sales (GWhs):								
Residential	18,425	17,905	520	3 %	17,905	17,150	755	4 %
Commercial[1]	19,570	18,839	731	4	18,839	17,727	1,112	6
Industrial[1]	17,622	17,909	(287)	(2)	17,909	18,039	(130)	(1)
Other[1]	1,547	1,621	(74)	(5)	1,621	1,644	(23)	(1)
Total retail	57,164	56,274	890	2	56,274	54,560	1,714	3
Wholesale	4,836	5,113	(277)	(5)	5,113	5,249	(136)	(3)
Total sales	62,000	61,387	613	1 %	61,387	59,809	1,578	3 %
Average number of retail customers (in thousands)	2,037	2,003	34	2 %	2,003	1,967	36	2 %
Average revenue per MWh:								
Retail	$ 89.33	$ 86.08	$ 3.25	4 %	$ 86.08	$ 90.59	$ (4.51)	(5)%
Wholesale	$ 61.39	$ 37.90	$ 23.49	62 %	$ 37.90	$ 35.56	$ 2.34	7 %
Heating degree days	10,767	9,914	853	9 %	9,914	10,155	(241)	(2)%
Cooling degree days	2,451	2,431	20	1 %	2,431	2,111	320	15 %
Sources of energy (GWhs)[1]:								
Coal	28,390	31,566	(3,176)	(10)%	31,566	30,636	930	3 %
Natural gas	13,686	13,323	363	3	13,323	12,045	1,278	11
Wind[2]	7,238	6,686	552	8	6,686	3,769	2,917	77
Hydroelectric and other[2]	3,206	3,010	196	7	3,010	3,223	(213)	(7)
Total energy generated	52,520	54,585	(2,065)	(4)	54,585	49,673	4,912	10
Energy purchased	13,968	11,601	2,367	20	11,601	14,054	(2,453)	(17)
Total	66,488	66,186	302	— %	66,186	63,727	2,459	4 %
Average cost of energy per MWh:								
Energy generated[3]	$ 22.86	$ 18.05	$ 4.81	27 %	$ 18.05	$ 18.74	$ (0.69)	(4)%
Energy purchased	$ 71.15	$ 66.93	$ 4.22	6 %	$ 66.93	$ 47.60	$ 19.33	41 %

(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, 2022 Compared to Year Ended December 31, 2021

Utility margin increased $235 million, or 7% for 2022 compared to 2021 primarily due to:

- $290 million from higher deferred net power costs in accordance with established adjustment mechanisms;
- $263 million of higher retail revenue primarily due to higher average prices and higher volumes. Retail customer volumes increased 1.6% primarily due to an increase in the average number of customers, favorable impacts of weather and an increase in commercial customer usage, partially offset by a decrease in residential and industrial customer usage;
- $103 million of higher wholesale revenue primarily due to higher average market prices, partially offset by lower volumes;
- $44 million of lower coal-fueled generation costs due to lower volumes, partially offset by higher average prices; and
- $19 million of favorable wheeling activities.

The increases above were partially offset by:

- $259 million of higher natural gas-fueled generation costs primarily due to higher average market prices and higher volumes;
- $217 million of higher purchased electricity costs from higher volumes and higher average market prices; and
- $10 million of lower wind-based ancillary revenue.

Operations and maintenance increased $196 million, or 19%, for 2022 compared to 2021 primarily due to a $64 million increase in the loss accruals associated with the September 2020 wildfires net of estimated insurance recoveries, $38 million of higher plant maintenance costs, $27 million of higher DSM amortization expense (offset in retail revenue), $25 million of changes in the prior year in how obligations associated with the implementation of the Klamath Hydroelectric Settlement Agreement will be met, $17 million of higher insurance premiums due to cost increases related to wildfire coverage, $37 million of higher consumption of materials, chemical and start-up fuel costs, partially offset by $22 million of deferrals of vegetation management costs in Oregon and Utah, net of higher vegetation management costs.

Depreciation and amortization increased $32 million, or 3%, for 2022 compared to 2021 primarily due to higher plant-in-service balances in the current year and prior year deferral of the 2018 depreciation study in Idaho compared to current year amortization, partially offset by current year allocation adjustment for Oregon incremental depreciation of certain coal units and Oregon deferral associated with the depreciation of certain wind-powered generating facilities.

Property and other taxes decreased $18 million, or 8%, for 2022 compared to 2021 primarily due to lower property tax rates in Utah.

Allowance for borrowed and equity funds increased $28 million, or 38%, for 2022 compared to 2021 primarily due to higher qualified construction work-in-progress balances and higher rates.

Interest and dividend income increased $20 million, or 83%, for 2022 compared to 2021 primarily due to the recording of interest on the 2021 Oregon PCAM deferral and higher investment income due to higher average interest rates.

Other, net decreased $23 million for 2022 compared to 2021 primarily due to lower cash surrender value of corporate-owned life insurance policies driven by market declines, unfavorable change in deferred compensation and long-term incentive plan primarily due to market movements (offset in operations and maintenance expense) and higher pension costs primarily due to lower expected return on net assets.

Income tax benefit decreased $17 million, or 22%, for 2022 compared to 2021. The effective tax rate was (7)% and (10)% for 2022 and 2021, respectively. The effective tax rate increased primarily as a result of lower effects of ratemaking associated with excess deferred income tax amortization and an increase to the valuation allowance for state net operating losses, partially offset by increased PTCs from PacifiCorp's wind-powered generating facilities in the current year.

Year Ended December 31, 2021 Compared to Year Ended December 31, 2020

Utility margin decreased $86 million (including the $231 million of fully offsetting decreases) for 2021 compared to 2020 primarily due to:

- $111 million of higher purchased electricity costs due to higher average prices, partially offset by lower volumes;
- $99 million of lower retail revenue primarily due to $234 million fully offset in depreciation expense, income tax expense, fuel expense, and other income (expense) due to accelerated depreciation of certain coal-fueled units in Utah and Oregon and recognition of certain Utah regulatory balances in the prior year, and lower average retail prices, partially offset by higher retail customer volumes. Retail customer volumes increased 3.1% due to an increase in residential and commercial customer usage, increase in the average number of customers and favorable impacts of weather, primarily in Oregon, Washington and Idaho;
- $88 million of higher natural gas-fueled generation costs primarily due to higher average prices and higher volumes; and
- $34 million of lower other revenue due to prior year recognition of previously deferred other revenue in Oregon that was used to accelerate the depreciation of certain retired wind equipment as a result of the 2020 Oregon RAC settlement (offset in depreciation expense).

The decreases above were partially offset by:

- $141 million primarily from higher deferred net power costs in accordance with established adjustment mechanisms;
- $43 million of favorable wheeling activities;
- $33 million of lower coal-fueled generation costs primarily due to $37 million of accelerated recognition of certain Utah regulatory balances associated with the 2015 Utah mine disposition and certain Cholla Unit 4 related closure costs in Oregon and Idaho (offset in income tax expense) in the prior year and lower prices, partially offset by higher volumes;
- $19 million of higher other revenue primarily due to higher REC, fly ash and by-product revenues; and
- $7 million of higher wholesale revenue due to higher average wholesale market prices, partially offset by lower wholesale volumes.

Operations and maintenance decreased $178 million, or 15%, for 2021 compared to 2020 primarily due to prior year estimated losses associated with the 2020 Wildfires of $136 million, net of expected insurance recoveries, changes in how obligations associated with the implementation of the Klamath Hydroelectric Settlement Agreement will be met, lower thermal plant maintenance expense and lower labor expenses, partially offset by higher wind plant and distribution maintenance and higher legal and insurance expenses associated with the 2020 Wildfires.

Depreciation and amortization decreased $121 million, or 10%, for 2021 compared to 2020 primarily due to prior year accelerated depreciation of $376 million as a result of regulatory adjustments ordered by the UPSC, the OPUC and the IPUC (fully offset in retail revenue, other revenue, and income tax expense), including accelerated depreciation of certain coal-fueled units and Oregon's share of certain retired wind equipment as a result the 2020 Oregon RAC settlement, partially offset by the impacts of the depreciation study for which rates became effective January 1, 2021 of approximately $158 million and higher plant in-service balances.

Property and other taxes increased $4 million, or 2%, for 2021 compared to 2020 primarily due to higher property taxes in Oregon and Wyoming, partially offset by lower property taxes in Utah and Washington.

Interest expense increased $4 million, or 1%, for 2021 compared to 2020 primarily due to higher average long-term debt balances, partially offset by a lower weighted average long-term debt interest rate.

Allowance for borrowed and equity funds decreased $72 million, or 49%, for 2021 compared to 2020 primarily due to lower qualified construction work-in-progress balances.

Interest and dividend income increased $14 million, or 140%, for 2021 compared to 2020 primarily due to higher carrying charges on DSM regulatory assets in the current year.

Income tax benefit increased $4 million, or 5% for 2021 compared to 2020. The effective tax rate was (10)% and (11)% for 2021 and 2020, respectively. The effective tax rate increased primarily as a result of lower effects of ratemaking associated with excess deferred income tax amortization, offset by increased PTCs from PacifiCorp's new wind-powered generating facilities in the current year. In 2020, $118 million of excess deferred income taxes was amortized pursuant to regulatory orders from Utah, Oregon and Idaho, whereby portions of excess deferred income taxes were used to accelerate depreciation of certain coal-fueled units and Oregon's share of certain retired wind equipment or offset other regulatory balances for these jurisdictions.

Liquidity and Capital Resources

As of December 31, 2022, PacifiCorp's total net liquidity was as follows (in millions):

Cash and cash equivalents	$ 641
Credit facility[(1)]	1,200
Less:	
Tax-exempt bond support and letters of credit	(249)
Net credit facility	951
Total net liquidity	$ 1,592
Credit facility:	
Maturity date	2025

(1) Refer to Note 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K and "Credit Facilities" below for further discussion regarding PacifiCorp's credit facilities.

Operating Activities

Net cash flows from operating activities for the years ended December 31, 2022 and 2021 were $1.82 billion and $1.80 billion, respectively. The increase is primarily due to higher collections from retail customers, collateral received from counterparties, transmission deposits and cash received for income taxes, partially offset by higher fuel, wholesale and material and supplies purchases.

Net cash flows from operating activities for the years ended December 31, 2021 and 2020 were $1.8 billion and $1.6 billion, respectively. The increase is primarily due to higher cash received for income taxes and higher collections from retail customers, partially offset by higher wholesale purchases and timing of operating payables.

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, 2022 and 2021 were $(2.2) billion and $(1.5) billion, respectively. The increase in net cash outflows from investing activities is mainly due to an increase in capital expenditures of $653 million.

Net cash flows from investing activities for the years ended December 31, 2021 and 2020 were $(1.5) billion and $(2.5) billion, respectively. The decrease in net cash outflows from investing activities is mainly due to a decrease in capital expenditures of $1.0 billion.

Financing Activities

Short-term Debt

As of December 31, 2022, regulatory authorities limited PacifiCorp to $1.5 billion of short-term debt. In January 2023, updated regulatory authorization provided PacifiCorp with an increased limit to $2.0 billion of short-term debt. As of December 31, 2022 and 2021, PacifiCorp had no short-term debt outstanding. 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 December 2022, PacifiCorp issued $1.1 billion of its 5.350% First Mortgage Bonds due December 2053. PacifiCorp intends within 24 months of the issuance date to allocate an amount equal to the net proceeds to finance or refinance, in whole or in part, new or existing investments or expenditures made in one or more eligible projects in alignment with BHE's Green Financing Framework. Proceeds will not knowingly be allocated to the same portion of a project that received allocation of proceeds under any other Green Financing Instrument; activities related to the exploration, production, transportation, or consumption of fossil fuels; or activities related to nuclear energy.

PacifiCorp made repayments on long-term debt totaling $155 million and $870 million during the years ended December 31, 2022 and 2021, respectively.

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, 2022, PacifiCorp estimated it would be able to issue up to $8.5 billion of new first mortgage bonds under the most restrictive issuance test in the mortgage. Any issuances are subject to market conditions and amounts are further limited by regulatory authorizations or commitments or by covenants and tests contained in other financing agreements. 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.

Credit Facilities

In June 2022, PacifiCorp amended and restated its existing $1.2 billion unsecured credit facility expiring in June 2024. The amendment extended the expiration date to June 2025 and amended pricing from the London Interbank Offered Rate to the Secured Overnight Financing Rate.

In January 2023, PacifiCorp entered into an additional $800 million 364-day unsecured credit facility expiring in January 2024.

Debt Authorizations

PacifiCorp currently has regulatory authority from the OPUC and the IPUC to issue an additional $900 million of long-term debt. PacifiCorp must make a notice filing with the WUTC prior to any future issuance. PacifiCorp currently has an effective shelf registration statement with the SEC to issue an indeterminate amount of first mortgage bonds through September 2023.

Preferred Stock

As of December 31, 2022 and 2021, PacifiCorp had non-redeemable preferred stock outstanding with an aggregate stated value of $2 million.

Common Shareholder's Equity

In 2022 and 2021, PacifiCorp declared and paid dividends of $100 million and $150 million, respectively, to PPW Holdings LLC.

In January 2023, PacifiCorp declared dividends of $300 million payable to PPW Holdings LLC in February 2023.

Capitalization

PacifiCorp manages its capitalization and liquidity position to maintain a prudent capital structure with the objective of retaining strong investment grade credit ratings, which is expected to facilitate continuing access to 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.

Under existing or prospective authoritative accounting guidance, such as guidance pertaining to consolidations and leases, it is possible that new purchase power 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 or waivers under financing agreements and from regulators, delay or reduce dividends or spending programs, seek additional new equity contributions from its indirect parent company, BHE, 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, 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 and conditions in the overall capital markets, including the condition of the utility industry.

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; 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		
	2020	**2021**	**2022**	**2023**	**2024**	**2025**
Wind generation	$ 1,278	$ 131	$ 37	$ 797	$ 422	$ 302
Electric distribution	603	608	678	658	536	894
Electric transmission	415	325	1,208	1,431	1,120	1,586
Solar generation	—	—	—	24	93	286
Electric battery and pumped hydro storage	—	5	8	32	105	361
Other	244	444	235	637	793	557
Total	$ 2,540	$ 1,513	$ 2,166	$ 3,579	$ 3,069	$ 3,986

PacifiCorp's 2021 IRP identified a roadmap for a significant increase in renewable and carbon free generation resources, coal-to-natural gas conversion of certain coal-fueled units, energy storage and associated transmission. PacifiCorp's 2021 IRP identified over 1,800 MWs of new wind-powered generation, over 2,100 MWs of new solar-powered generation and nearly 700 MWs of new battery storage capacity that are expected to be online by 2025. PacifiCorp anticipates that the additional new wind-powered generation will be a mixture of owned and contracted resources. PacifiCorp has included an estimate for these new generation resources and associated transmission in its forecast capital expenditures for 2023 through 2025. These estimates are likely to change as a result of the RFP process. PacifiCorp's historical and forecast capital expenditures include the following:

- 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 $23 million for 2022, $118 million for 2021 and $1,148 million for 2020. PacifiCorp placed in-service 516 MWs of new wind-powered generating facilities in 2021 and 674 MWs in 2020. Planned spending for the construction of additional new wind-powered generating facilities and those at acquired sites totals $771 million in 2023, $385 million in 2024 and $251 million in 2025 and is primarily for projects totaling approximately 683 MWs that are expected to be placed in-service in 2023 through 2025.
- Electric distribution includes both growth projects and operating expenditures. Operating expenditures includes spend on wildfire mitigation. Expenditures for these items totaled $135 million in 2022, $54 million in 2021 and $28 million in 2020, and planned spending totals $90 million in 2023, $124 million in 2024 and $127 million in 2025. The remaining investments primarily relate to expenditures for new connections and distribution operations.
- Electric transmission includes both growth projects and operating expenditures. Transmission growth investments primarily reflects costs associated with Energy Gateway Transmission projects. Expenditures for these projects totaled $944 million for 2022, $94 million for 2021 and $56 million for 2020. Forecast expenditures for Energy Gateway projects include planned costs for the following Energy Gateway Transmission segments:
    - 416-mile, 500-kV high-voltage transmission line between the Aeolus substation near Medicine Bow, Wyoming and the Clover substation near Mona, Utah;
    - 59-mile, 230-kV high-voltage transmission line between the Windstar substation near Glenrock, Wyoming and the Aeolus substation;
    - 290-mile, 500-kV high-voltage transmission line from the Longhorn substation near Boardman, Oregon to the Hemingway substation near Boise, Idaho;
    - 14-mile, 345-kV high-voltage transmission line between the Oquirrh substation in the Salt Lake Valley and the Terminal substation near the Salt Lake City Airport;
    - 40-mile, 500-kV high-voltage transmission line between the Limber substation in central Utah and the Terminal substation; and
    - 195-mile, 500-kV high-voltage transmission line between the Anticline substation near Point of Rocks, Wyoming and the Populus substation in Downey, Idaho.

  Planned spending for these Energy Gateway Transmission segments that are expected to be placed in-service in 2024 through 2028 totals $1,005 million in 2023, $661 million in 2024 and $763 million in 2025. The remaining investments primarily relate to expenditures for transmission operations, including wildfire mitigation, generation interconnection requests and other Energy Gateway Transmission segments.
- Solar generation includes growth projects. Planned spending for the construction of new solar projects will add approximately 377 MWs of new generation and are expected to be placed in-service in 2026.
- Electric battery and pumped hydro storage includes growth projects. Planned spending for the construction of storage projects from 2023 through 2025 includes $319 million for battery storage projects providing approximately 419 MWs of storage that are expected to be placed in-service in 2026 and $79 million for the construction of 38 MWs of new pumped hydro storage on the North Umpqua River system expected to be placed in-service in 2024 and 2026. The remaining investments relate to planned spending on projects that are expected to be placed in-service beyond 2026.
- Other includes both growth projects and operating expenditures. Expenditures for information technology totaled $155 million in 2022, $108 million in 2021 and $75 million for 2020. Planned information technology spending totals $224 million in 2023, $181 million in 2024 and $232 million in 2025. The remaining investments relate to operating projects that consist of routine expenditures for generation and other infrastructure needed to serve existing and expected demand.

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. In addition, PacifiCorp evaluates potential obligations that arise out of variable interests in unconsolidated entities, determined in accordance with authoritative accounting guidance. 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 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 (refer to Note 14), 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 $8.0 billion on long-term debt, including $449 million due in 2023.

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, water quality, emissions performance standards, coal ash disposal, wildfire prevention and mitigation 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 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 and preferred 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 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. As of December 31, 2022, PacifiCorp'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.

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 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 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, 2022, PacifiCorp would have been required to post $433 million of additional collateral. PacifiCorp's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation, outstanding accounts payable and receivable or other factors. 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.

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.

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 $1.9 billion and total regulatory liabilities were $2.9 billion as of December 31, 2022. 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, 2022, PacifiCorp recognized a net asset totaling $57 million for the funded status of its defined benefit pension and other postretirement benefit plans. As of December 31, 2022, amounts not yet recognized as a component of net periodic benefit cost included in net regulatory assets and accumulated other comprehensive loss totaled $255 million and $12 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, 2022.

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.

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, 2022 Benefit Obligations:				
Discount rate	$ (25)	$ 26	$ (8)	$ 8
Effect on 2022 Periodic Cost:				
Discount rate	$ 1	$ (1)	$ 1	$ (1)
Expected rate of return on plan assets	(5)	5	(2)	2

A variety of factors affect the funded status of the plans, including asset returns, discount rates, 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% as a result of 2017 Tax Reform, certain property-related basis differences and other various differences on to customers in certain state jurisdictions. As of December 31, 2022, these amounts were recognized as a net regulatory liability of $1.2 billion and will primarily be included in regulated rates over the estimated useful lives of the related properties.

Revenue Recognition - Unbilled Revenue

Revenue is recognized as electricity is delivered or services are provided. 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. Unbilled revenue was $301 million as of December 31, 2022. 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. Estimates are reversed in the following month and actual revenue is recorded based on subsequent meter readings.

Wildfire Loss Contingencies

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 wildfires. In determining this exposure, PacifiCorp is required to assess whether the likelihood of loss for each of the wildfires and lawsuits 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 various parties. 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 for certain areas 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. 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 2020 Wildfires and the 2022 McKinney fire.

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 PacifiCorp's 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.

Commodity Price Risk

PacifiCorp is principally exposed to electricity, natural gas, coal and fuel oil commodity price risk as PacifiCorp 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.

PacifiCorp maintained compliance with its risk management policy and limit procedures during the year ended December 31, 2022.

The table that follows summarizes PacifiCorp's price risk on commodity contracts accounted for as derivatives, excluding collateral netting of $(78) million and $5 million as of December 31, 2022 and 2021, 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 Asset (Liability)	Estimated Fair Value after Hypothetical Change in Price	
		10% increase	10% decrease
As of December 31, 2022:			
Total commodity derivative contracts	$ 270	$ 381	$ 159
As of December 31, 2021:			
Total commodity derivative contracts	$ 53	$ 104	$ 2

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, 2022 and 2021, a regulatory liability of $270 million and $53 million, respectively, was recorded related to the net derivative asset of $270 million and $53 million, respectively. Consolidated financial results would be negatively impacted if the costs of wholesale electricity, natural gas or fuel are higher or the level of wholesale electricity sales are lower than what is included in rates, including the impacts of adjustment mechanisms.

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 has the ability to 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, 2022 and 2021, PacifiCorp had long-term variable-rate obligations totaling $218 million 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, 2022 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, 2022 and 2021.

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, 2022, 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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of PacifiCorp

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of PacifiCorp and subsidiaries ("PacifiCorp") as of December 31, 2022 and 2021, the related consolidated statements of operations, comprehensive income, changes in shareholders' equity, and cash flows, for each of the three years in the period ended December 31, 2022, 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, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022, 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 audit committee and that (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Regulatory Matters — Effects of Rate Regulation on the Financial Statements — Refer to Notes 2 and 6 to the financial statements

Critical Audit Matter Description

PacifiCorp 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 PacifiCorp operates. Management has determined it meets 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 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 future decisions by the Commissions, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of future decisions by the Commissions included the following, among others:

- We evaluated PacifiCorp's disclosures related to the effects of rate regulation, including the balances recorded and regulatory developments.
- We read relevant regulatory orders issued by the Commissions, regulatory statutes, interpretations, procedural memorandums, filings made by interveners, and other external information. We evaluated the external information and compared to management's recorded regulatory asset and liability balances for completeness.
- For regulatory matters in process, 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.
- We inquired of management about property, plant, and equipment that may be abandoned. We inquired of management to identify projects that are designed to replace assets that may be retired prior to the end of the useful life. We inspected minutes of the board of directors and regulatory orders and other filings with the Commissions to identify any evidence that may contradict management's assertion regarding probability of an abandonment.

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 the potential loss or range of potential loss and disclose any material amounts.

Management has recorded estimated liabilities of $424 million and receivables of $246 million, which represent its best estimate of probable losses and expected insurance recoveries associated with the 2020 Wildfires. During the years ended December 31, 2022, 2021 and 2020, PacifiCorp recognized probable losses net of expected insurance recoveries associated with the 2020 Wildfires of $64 million, $— million and $136 million, respectively. Management has disclosed reasonably possible estimated losses of $31 million, net of potential insurance recoveries of $103 million, associated with the 2022 McKinney Fire.

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 or reasonably possible losses and insurance recoveries. This required the application of a high degree of judgment and extensive effort when performing audit procedures to evaluate the reasonableness of management's judgments, estimates and disclosures related to wildfire-related loss contingencies.

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 insurance recoveries, and related disclosures for wildfire-related contingencies included the following, among others:

- We evaluated management's judgments related to whether a loss was probable or reasonably possible for the Wildfires by inquiring of management and PacifiCorp's external and internal legal counsel regarding the likelihood and amounts of probable and reasonably possible losses, including the potential impact of information gained through 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 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 management's judgments related to whether related insurance recoveries were probable of collection by inquiring of management and PacifiCorp's external and internal legal counsel regarding the amounts of insurance recoveries recorded or disclosed. With the assistance of our insurance specialists, we tested the significant assumptions used in the determination of collectability, including obtaining and reading related policies to determine whether the types of insurance claims are included or excluded from coverage.
- We evaluated whether PacifiCorp's disclosures were appropriate and consistent with the information obtained in our procedures.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 24, 2023

We have served as PacifiCorp's auditor since 2006.

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2022	**2021**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 641	$ 179
Trade receivables, net	825	725
Other receivables, net	72	52
Inventories	474	474
Derivative contracts	184	76
Regulatory assets	275	65
Other current assets	213	150
Total current assets	2,684	1,721
Property, plant and equipment, net	24,430	22,914
Regulatory assets	1,605	1,287
Other assets	686	534
Total assets	$ 29,405	$ 26,456

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,	
	2022	**2021**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 1,049	$ 680
Accrued interest	128	121
Accrued property, income and other taxes	67	78
Accrued employee expenses	86	89
Current portion of long-term debt	449	155
Regulatory liabilities	96	118
Other current liabilities	271	219
Total current liabilities	2,146	1,460
Long-term debt	9,217	8,575
Regulatory liabilities	2,843	2,650
Deferred income taxes	3,152	2,847
Other long-term liabilities	1,306	1,011
Total liabilities	18,664	16,543
Commitments and contingencies (Note 14)		
Shareholders' equity:		
Preferred stock	2	2
Common stock - 750 shares authorized, no par value, 357 shares issued and outstanding	—	—
Additional paid-in capital	4,479	4,479
Retained earnings	6,269	5,449
Accumulated other comprehensive loss, net	(9)	(17)
Total shareholders' equity	10,741	9,913
Total liabilities and shareholders' equity	$ 29,405	$ 26,456

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,		
	2022	**2021**	**2020**
Operating revenue	$ 5,679	$ 5,296	$ 5,341
Operating expenses:			
Cost of fuel and energy	1,979	1,831	1,790
Operations and maintenance	1,227	1,031	1,209
Depreciation and amortization	1,120	1,088	1,209
Property and other taxes	195	213	209
Total operating expenses	4,521	4,163	4,417
Operating income	1,158	1,133	924
Other income (expense):			
Interest expense	(431)	(430)	(426)
Allowance for borrowed funds	31	24	48
Allowance for equity funds	71	50	98
Interest and dividend income	44	24	10
Other, net	(15)	8	10
Total other income (expense)	(300)	(324)	(260)
Income before income tax benefit	858	809	664
Income tax benefit	(62)	(79)	(75)
Net income	$ 920	$ 888	$ 739

The accompanying notes are an integral part of these consolidated financial statements.

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Amounts in millions)

	Years Ended December 31,		
	2022	**2021**	**2020**
Net income	$ 920	$ 888	$ 739
Other comprehensive income (loss), net of tax —			
Unrecognized amounts on retirement benefits, net of tax of $3, $1 and $(1)	8	2	(3)
Comprehensive income	$ 928	$ 890	$ 736

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, 2019	$ 2	$ —	$ 4,479	$ 3,972	$ (16)	$ 8,437
Net income	—	—	—	739	—	739
Other comprehensive loss	—	—	—	—	(3)	(3)
Balance, December 31, 2020	2	—	4,479	4,711	(19)	9,173
Net income	—	—	—	888	—	888
Other comprehensive income	—	—	—	—	2	2
Common stock dividends declared	—	—	—	(150)	—	(150)
Balance, December 31, 2021	2	—	4,479	5,449	(17)	9,913
Net income	—	—	—	920	—	920
Other comprehensive income	—	—	—	—	8	8
Common stock dividends declared	—	—	—	(100)	—	(100)
Balance, December 31, 2022	$ 2	$ —	$ 4,479	$ 6,269	$ (9)	$ 10,741

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,		
	2022	**2021**	**2020**
Cash flows from operating activities:			
Net income	$ 920	$ 888	$ 739
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	1,120	1,088	1,209
Allowance for equity funds	(71)	(50)	(98)
Net power cost deferrals	(482)	(159)	(1)
Amortization of net power cost deferrals	100	67	50
Other changes in regulatory assets and liabilities	(162)	(97)	(278)
Deferred income taxes and amortization of investment tax credits	157	64	(124)
Other, net	13	(5)	1
Changes in other operating assets and liabilities:			
Trade receivables, other receivables and other assets	(264)	17	(169)
Inventories	—	8	(88)
Derivative collateral, net	95	19	23
Accrued property, income and other taxes, net	(46)	(37)	(53)
Accounts payable and other liabilities	439	1	372
Net cash flows from operating activities	1,819	1,804	1,583
Cash flows from investing activities:			
Capital expenditures	(2,166)	(1,513)	(2,540)
Other, net	5	12	30
Net cash flows from investing activities	(2,161)	(1,501)	(2,510)
Cash flows from financing activities:			
Proceeds from long-term debt	1,087	984	987
Repayments of long-term debt	(155)	(870)	(38)
(Repayments of) net proceeds from short-term debt	—	(93)	(37)
Dividends paid	(100)	(150)	—
Other, net	(2)	(7)	(2)
Net cash flows from financing activities	830	(136)	910
Net change in cash and cash equivalents and restricted cash and cash equivalents	488	167	(17)
Cash and cash equivalents and restricted cash and cash equivalents at beginning of period	186	19	36
Cash and cash equivalents and restricted cash and cash equivalents at end of period	$ 674	$ 186	$ 19

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 owns subsidiaries principally engaged in energy businesses. BHE is a consolidated 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 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 the 2022 McKinney fire described 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, custodial and nuclear decommissioning funds. A reconciliation of cash and cash equivalents and restricted cash and cash equivalents as of December 31, 2022 and 2021 as presented in 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,	
	2022	2021
Cash and cash equivalents	$ 641	$ 179
Restricted cash included in other current assets	7	4
Restricted cash included in other assets	26	3
Total cash and cash equivalents and restricted cash and cash equivalents	$ 674	$ 186

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, 2022 and 2021, 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 change 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):

	2022	2021	2020
Beginning balance	$ 18	$ 17	$ 8
Charged to operating costs and expenses, net	18	13	18
Write-offs, net	(17)	(12)	(9)
Ending balance	$ 19	$ 18	$ 17

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. 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 office buildings, natural gas pipeline facilities, and generating facilities. 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 will be 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 considered variable lease payments as they are based on the amount of output.

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. Other revenue consists primarily of revenue recognized in accordance with ASC 815, "Derivatives and Hedging."

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. As of December 31, 2022 and 2021, trade receivables, net on the Consolidated Balance Sheets relate substantially to Customer Revenue, including unbilled revenue of $301 million and $264 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 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 on the Consolidated Statements of Operations.

Segment Information

PacifiCorp currently has one segment, which includes its regulated electric utility operations.

(3) Property, Plant and Equipment, Net

Property, plant and equipment, net consists of the following as of December 31 (in millions):

	Depreciable Life	2022	2021
Utility Plant:			
Generation	15 - 59 years	$ 13,726	$ 13,679
Transmission	60 - 90 years	8,051	7,894
Distribution	20 - 75 years	8,477	8,044
Intangible plant[1] and other	5 - 75 years	2,755	2,645
Utility plant in-service		33,009	32,262
Accumulated depreciation and amortization		(11,093)	(10,507)
Utility plant in-service, net		21,916	21,755
Nonregulated, net of accumulated depreciation and amortization	14 - 95 years	18	18
		21,934	21,773
Construction work-in-progress		2,496	1,141
Property, plant and equipment, net		$ 24,430	$ 22,914

(1) Computer software costs included in intangible plant are initially assigned a depreciable life of 5 to 10 years.

The average depreciation and amortization rate applied to depreciable property, plant and equipment was 3.5%, 3.5% and 4.1% for the years ended December 31, 2022, 2021 and 2020, respectively.

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, 2022 and 2021, and accumulated depreciation of $144 million and $143 million as of December 31, 2022 and 2021, respectively.

(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, 2022 (dollars in millions):

	PacifiCorp Share	Facility in Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
Jim Bridger Nos. 1 - 4	67 %	$ 1,529	$ 914	$ 39
Hunter No. 1	94	517	227	3
Hunter No. 2	60	305	148	6
Wyodak	80	491	273	1
Colstrip Nos. 3 and 4	10	262	178	—
Hermiston	50	189	106	—
Craig Nos. 1 and 2	19	372	331	—
Hayden No. 1	25	77	52	—
Hayden No. 2	13	44	31	—
Transmission and distribution facilities	Various	916	274	129
Total		$ 4,702	$ 2,534	$ 178

(5) Leases

The following table summarizes PacifiCorp's leases recorded on the Consolidated Balance Sheets as of December 31 (in millions):

	2022	2021
Right-of-use assets:		
Operating leases	$ 11	$ 11
Finance leases	9	11
Total right-of-use assets	$ 20	$ 22
Lease liabilities:		
Operating leases	$ 11	$ 11
Finance leases	11	12
Total lease liabilities	$ 22	$ 23

The following table summarizes PacifiCorp's lease costs for the years ended December 31 (in millions):

	2022	2021	2020
Variable	$ 61	$ 56	$ 60
Operating	3	3	3
Finance:			
Amortization	1	5	2
Interest	1	2	2
Short-term	5	3	1
Total lease costs	$ 71	$ 69	$ 68
Weighted-average remaining lease term (years):			
Operating leases	11.4	12.7	13.9
Finance leases	9.7	10.1	8.4
Weighted-average discount rate:			
Operating leases	3.9 %	3.7 %	3.8 %
Finance leases	11.4 %	11.1 %	10.5 %

Cash payments associated with operating and finance lease liabilities approximated lease cost for the years ended December 31, 2022, 2021 and 2020.

PacifiCorp has the following remaining lease commitments as of December 31, 2022 (in millions):

	Operating	Finance	Total
2023	$ 3	$ 2	$ 5
2024	2	2	4
2025	2	2	4
2026	1	2	3
2027	1	2	3
Thereafter	5	8	13
Total undiscounted lease payments	14	18	32
Less - amounts representing interest	(3)	(7)	(10)
Lease liabilities	$ 11	$ 11	$ 22

(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	2022	2021
Employee benefit plans[1]	16 years	$ 290	$ 286
Utah mine disposition[2]	Various	115	116
Unamortized contract values	1 year	18	36
Deferred net power costs	2 years	546	151
Environmental costs	30 years	111	108
Asset retirement obligation	29 years	275	241
Demand side management (DSM)	10 years	224	211
Wildfire mitigation and vegetation management costs	Various	111	21
Other	Various	190	182
Total regulatory assets		$ 1,880	$ 1,352
Reflected as:			
Current assets		$ 275	$ 65
Noncurrent assets		1,605	1,287
Total regulatory assets		$ 1,880	$ 1,352

(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.

PacifiCorp had regulatory assets not earning a return on investment of $1,200 million and $723 million as of December 31, 2022 and 2021, respectively.

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	2022	2021
Cost of removal[1]	26 years	$ 1,332	$ 1,187
Deferred income taxes[2]	Various	1,164	1,307
Unrealized gain on regulated derivatives	1 year	270	53
Other	Various	173	221
Total regulatory liabilities		$ 2,939	$ 2,768
Reflected as:			
Current liabilities		$ 96	$ 118
Noncurrent liabilities		2,843	2,650
Total regulatory liabilities		$ 2,939	$ 2,768

(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

The following table summarizes PacifiCorp's availability under its unsecured credit facility as of December 31 (in millions):

2022:	
Credit facility	$ 1,200
Less:	
Tax-exempt bond support and letters of credit	(249)
Net credit facility	$ 951
2021:	
Credit facility	$ 1,200
Less:	
Tax-exempt bond support	(218)
Net credit facility	$ 982

As of December 31, 2022, PacifiCorp was in compliance with the covenants of its credit facility and letter of credit arrangements.

PacifiCorp has a $1.2 billion unsecured credit facility expiring in June 2025 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 letters of credit, has a variable interest rate based on the Secured Overnight Financing Rate 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, 2022 and 2021, PacifiCorp did not have any commercial paper borrowings outstanding.

The credit facility requires 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.

In January 2023, PacifiCorp entered into an additional $800 million 364-day unsecured credit facility expiring in January 2024. No amounts are currently outstanding against this new credit facility.

As of December 31, 2022 and 2021, PacifiCorp had $38 million and $19 million, respectively, of fully available letters of credit issued under committed arrangements outside of its 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

PacifiCorp's long-term debt was as follows as of December 31 (dollars in millions):

	2022			2021	
	Principal Amount	Carrying Value	Average Interest Rate	Carrying Value	Average Interest Rate
First mortgage bonds:					
2.95% to 8.23%, due through 2026	$ 1,224	$ 1,223	4.07 %	$ 1,377	4.41 %
2.70% to 7.70%, due 2029 to 2031	1,100	1,095	4.35	1,094	4.35
5.25% to 6.25%, due 2034 to 2037	2,050	2,042	5.90	2,042	5.90
4.10% to 6.35%, due 2038 to 2042	1,250	1,239	5.63	1,238	5.63
2.90% to 5.35%, due 2049 to 2053	3,900	3,849	4.03	2,761	3.52
Variable-rate series, tax-exempt bond obligations (2022-3.75% to 4.10%; 2021-0.12% to 0.14%):					
Due 2025	25	25	4.10	25	0.12
Due 2024 to 2025(1)	193	193	3.81	193	0.13
Total long-term debt	$ 9,742	$ 9,666		$ 8,730	

Reflected as:		
	2022	2021
Current portion of long-term debt	$ 449	$ 155
Long-term debt	9,217	8,575
Total long-term debt	$ 9,666	$ 8,730

(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.

In December 2022, PacifiCorp issued $1.1 billion of its 5.35% First Mortgage Bonds due December 2053. PacifiCorp intends within 24 months of the issuance date to allocate an amount equal to the net proceeds to finance or refinance, in whole or in part, new or existing investments or expenditures made in one or more eligible projects in alignment with BHE's Green Financing Framework. Proceeds will not knowingly be allocated to the same portion of a project that received allocation of proceeds under any other Green Financing Instrument; activities related to the exploration, production, transportation, or consumption of fossil fuels; or activities related to nuclear energy.

PacifiCorp's long-term 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. Variable-rate tax-exempt bond obligations are generally redeemable at par value.

PacifiCorp currently has regulatory authority from the Oregon Public Utility Commission and the Idaho Public Utilities Commission to issue an additional $900 million 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 through September 2023.

The issuance of PacifiCorp's first mortgage bonds is limited by available property, earnings tests and other provisions of PacifiCorp's mortgage. Approximately $33 billion of PacifiCorp's eligible property (based on original cost) was subject to the lien of the mortgage as of December 31, 2022.

As of December 31, 2022, the annual principal maturities of long-term debt for 2023 and thereafter are as follows (in millions):

	Long-term Debt
2023	$ 449
2024	591
2025	302
2026	100
2027	—
Thereafter	8,300
Total	9,742
Unamortized discount and debt issuance costs	(76)
Total	$ 9,666

(9) Income Taxes

Income tax (benefit) expense consists of the following for the years ended December 31 (in millions):

	2022	2021	2020
Current:			
Federal	$ (216)	$ (150)	$ 19
State	(3)	7	30
Total	(219)	(143)	49
Deferred:			
Federal	90	26	(124)
State	71	40	1
Total	161	66	(123)
Investment tax credits	(4)	(2)	(1)
Total income tax (benefit) expense	$ (62)	$ (79)	$ (75)

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:

	2022	2021	2020
Federal statutory income tax rate	21 %	21 %	21 %
State income taxes, net of federal income tax benefit	3	3	3
Effects of ratemaking	(12)	(14)	(22)
Federal income tax credits	(22)	(20)	(13)
Valuation allowance	2	—	—
Other	1	—	—
Effective income tax rate	(7)%	(10)%	(11)%

Income 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. PTCs for the years ended December 31, 2022, 2021 and 2020 totaled $185 million, $164 million and $89 million, respectively.

Effects of ratemaking is primarily attributable to activity associated with excess deferred income taxes. Excess deferred income tax amortization, net of deferrals, was $102 million for 2022. Excess deferred income tax amortization, net of deferrals, was $112 million for 2021, including the use of $4 million to amortize certain regulatory balances in Wyoming and Idaho. Excess deferred income tax amortization, net of deferrals, was $132 million for 2020, including the use of $118 million to accelerate depreciation of certain retired equipment and to amortize certain regulatory balances in Idaho, Oregon and Utah.

The net deferred income tax liability consists of the following as of December 31 (in millions):

	2022	2021
Deferred income tax assets:		
Regulatory liabilities	$ 724	$ 682
Employee benefits	59	68
State carryforwards	73	73
Loss contingencies	107	63
Asset retirement obligations	79	73
Other	80	88
Total deferred income tax assets	1,122	1,047
Valuation allowances	(35)	(15)
Total deferred income tax assets, net	1,087	1,032
Deferred income tax liabilities:		
Property, plant and equipment	(3,612)	(3,468)
Regulatory assets	(462)	(332)
Other	(165)	(79)
Total deferred income tax liabilities	(4,239)	(3,879)
Net deferred income tax liability	$ (3,152)	$ (2,847)

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, 2022 (in millions):

	State
Net operating loss carryforwards	$ 1,159
Deferred income taxes on net operating loss carryforwards	$ 53
Expiration dates	2023 - indefinite
Tax credit carryforwards	$ 20
Expiration dates	2023 - 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 for Idaho through December 31, 2018, except for the impact of any federal audit adjustments. 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

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, collectively 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.

Pension Settlement

Pension settlement accounting was triggered in 2022 and 2021 as a result of the amount of lump sum distributions in the Retirement Plan exceeding the service and interest cost threshold. The 2021 pension settlement accounting included an interim July 31, 2021 remeasurement of the pension plan assets and projected benefit obligation. As a result of the settlement accounting, PacifiCorp recognized settlement losses of $6 million, net of regulatory deferrals during each of the years ended December 31, 2022 and 2021.

Net Periodic Benefit Cost

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 cost (credit) for the plans included the following components for the years ended December 31 (in millions):

	Pension			Other Postretirement		
	2022	2021	2020	2022	2021	2020
Service cost	$ —	$ —	$ —	$ 2	$ 2	$ 2
Interest cost	29	29	36	8	7	9
Expected return on plan assets	(42)	(51)	(56)	(11)	(9)	(14)
Settlement[(1)]	6	6	—	—	—	—
Net amortization	16	21	18	1	1	3
Net periodic benefit cost (credit)	$ 9	$ 5	$ (2)	$ —	$ 1	$ —

(1) Pension amounts represent settlement losses of $24 million and $15 million net of deferrals of $18 million and $9 million during the years ended December 31, 2022 and 2021.

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	
	2022	2021	2022	2021
Plan assets at fair value, beginning of year	$ 1,058	$ 1,064	$ 324	$ 327
Employer contributions[(1)]	4	5	—	1
Participant contributions	—	—	5	6
Actual (loss) return on plan assets	(172)	109	(42)	14
Settlement[(2)]	(67)	(52)	—	—
Benefits paid	(65)	(68)	(23)	(24)
Plan assets at fair value, end of year	$ 758	$ 1,058	$ 264	$ 324

(1) Pension amounts represent employer contributions to the SERP.

(2) Benefits paid in the form of lump sum distributions that gave rise to the settlement accounting described above.

The following table is a reconciliation of the benefit obligations for the years ended December 31 (in millions):

	Pension		Other Postretirement	
	2022	2021	2022	2021
Benefit obligation, beginning of year	$ 1,048	$ 1,202	$ 288	$ 307
Service cost	—	—	2	2
Interest cost	29	29	8	7
Participant contributions	—	—	5	6
Actuarial gain	(199)	(63)	(61)	(10)
Settlement[(1)]	(67)	(52)	—	—
Benefits paid	(65)	(68)	(23)	(24)
Benefit obligation, end of year	$ 746	$ 1,048	$ 219	$ 288
Accumulated benefit obligation, end of year	$ 746	$ 1,048		

(1) Benefits paid in the form of lump sum distributions that gave rise to the settlement accounting described above.

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	
	2022	2021	2022	2021
Plan assets at fair value, end of year	$ 758	$ 1,058	$ 264	$ 324
Less - Benefit obligation, end of year	746	1,048	219	288
Funded status	$ 12	$ 10	$ 45	$ 36
Amounts recognized on the Consolidated Balance Sheets:				
Other assets	$ 53	$ 63	$ 45	$ 36
Accrued employee expenses	(4)	(4)	—	—
Other long-term liabilities	(37)	(49)	—	—
Amounts recognized	$ 12	$ 10	$ 45	$ 36

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 $61 million and $69 million as of December 31, 2022 and 2021, respectively. These assets are not included in the plan assets in the above table, but are reflected in noncurrent other assets as of December 31, 2022 and 2021, respectively, on the Consolidated Balance Sheets. The projected and accumulated benefit obligations for the SERP were $42 million and $54 million at December 31, 2022 and 2021, respectively.

As of December 31, 2022, 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	
	2022	2021	2022	2021
Net loss (gain)	$ 273	$ 298	$ (36)	$ (28)
Regulatory deferrals[1]	29	11	1	2
Total	$ 302	$ 309	$ (35)	$ (26)

(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, 2022 and 2021 is as follows (in millions):

	Regulatory Asset	Accumulated Other Comprehensive Loss	Total
Pension			
Balance, December 31, 2020	$ 432	$ 25	$ 457
Net gain arising during the year	(120)	(1)	(121)
Net amortization	(20)	(1)	(21)
Settlement	(6)	—	(6)
Total	(146)	(2)	(148)
Balance, December 31, 2021	286	23	309
Net loss (gain) arising during the year	24	(9)	15
Net amortization	(14)	(2)	(16)
Settlement	(6)	—	(6)
Total	4	(11)	(7)
Balance, December 31, 2022	$ 290	$ 12	$ 302

	Regulatory Liability
Other Postretirement	
Balance, December 31, 2020	$ (10)
Net gain arising during the year	(15)
Net amortization	(1)
Total	(16)
Balance, December 31, 2021	(26)
Net gain arising during the year	(8)
Net amortization	(1)
Total	(9)
Balance, December 31, 2022	$ (35)

Plan Assumptions

Assumptions used to determine benefit obligations and net periodic benefit cost were as follows:

	Pension			Other Postretirement		
	2022	2021	2020	2022	2021	2020
Benefit obligations as of December 31:						
Discount rate	5.55 %	2.90 %	2.50 %	5.50 %	2.90 %	2.50 %
Rate of compensation increase	N/A	N/A	N/A	N/A	N/A	N/A
Interest crediting rates for cash balance plan - non-union						
2020	N/A	N/A	2.27 %	N/A	N/A	N/A
2021	N/A	0.82 %	0.82 %	N/A	N/A	N/A
2022	0.88 %	0.88 %	0.82 %	N/A	N/A	N/A
2023	4.73 %	0.88 %	2.00 %	N/A	N/A	N/A
2024	4.73 %	1.90 %	2.00 %	N/A	N/A	N/A
2025 and beyond	2.60 %	1.90 %	2.00 %	N/A	N/A	N/A
Interest crediting rates for cash balance plan - union						
2020	N/A	N/A	2.16 %	N/A	N/A	N/A
2021	N/A	1.42 %	1.42 %	N/A	N/A	N/A
2022	1.94 %	1.94 %	1.42 %	N/A	N/A	N/A
2023	3.55 %	1.94 %	2.40 %	N/A	N/A	N/A
2024	3.55 %	2.30 %	2.40 %	N/A	N/A	N/A
2025 and beyond	2.40 %	2.30 %	2.40 %	N/A	N/A	N/A
Net periodic benefit cost for the years ended December 31:						
Discount rate	2.90 %	2.50 %	3.25 %	2.90 %	2.50 %	3.20 %
Expected return on plan assets	4.70	6.00	6.50	3.44	2.90	4.92

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.

As a result of a plan amendment effective on January 1, 2017, the benefit obligation for the Retirement Plan is no longer affected by future increases in compensation. As a result of a labor settlement reached with UMWA in December 2014, the benefit obligation for the other postretirement plan is no longer affected by healthcare cost trends.

Contributions and Benefit Payments

Employer contributions to the pension and other postretirement benefit plans are expected to be $4 million and $— million, respectively, during 2023. 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 ("PPA of 2006"). PacifiCorp considers contributing additional amounts from time to time in order to achieve certain funding levels specified under the PPA 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 2023 through 2027 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments	
	Pension	Other Postretirement
2023	$ 76	$ 23
2024	73	22
2025	70	21
2026	67	20
2027	64	20
2028-2032	277	87

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.

In 2020, the assets of the PacifiCorp Master Retirement Trust were transferred into the BHE Master Retirement Trust.

The target allocations (percentage of plan assets) for PacifiCorp's pension and other postretirement benefit plan assets are as follows as of December 31, 2022:

	Pension(1)	Other Postretirement(1)
	%	%
Debt securities(2)	73	77
Equity securities(2)	22	23
Other	5	0

(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, 2022:				
Cash equivalents	$ —	$ 10	$ —	$ 10
Debt securities:				
U.S. government obligations	41	—	—	41
Corporate obligations	—	211	—	211
Municipal obligations	—	15	—	15
Agency, asset and mortgage-backed obligations	—	34	—	34
Equity securities:				
U.S. companies	69	—	—	69
Total assets in the fair value hierarchy	$ 110	$ 270	$ —	$ 380
Investment funds[2] measured at net asset value				346
Limited partnership interests[3] measured at net asset value				32
Investments at fair value				$ 758
As of December 31, 2021:				
Cash equivalents	$ —	$ 15	$ —	$ 15
Debt securities:				
U.S. government obligations	51	—	—	51
Corporate obligations	—	299	—	299
Municipal obligations	—	22	—	22
Agency, asset and mortgage-backed obligations	—	38	—	38
Equity securities:				
U.S. companies	61	—	—	61
Total assets in the fair value hierarchy	$ 112	$ 374	$ —	$ 486
Investment funds[2] measured at net asset value				538
Limited partnership interests[3] measured at net asset value				34
Investments at fair value				$ 1,058

(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 50% and 50%, respectively, for 2022 and 59% and 41%, respectively, for 2021, and are invested in U.S. and international securities of approximately 90% and 10%, respectively, for 2022 and 84% and 16%, respectively, for 2021.

(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, 2022:				
Cash and cash equivalents	$ 5	$ 5	$ —	$ 10
Debt securities:				
U.S. government obligations	6	—	—	6
Corporate obligations	—	49	—	49
Municipal obligations	—	13	—	13
Agency, asset and mortgage-backed obligations	—	47	—	47
Equity securities:				
U.S. companies	7	—	—	7
Total assets in the fair value hierarchy	$ 18	$ 114	$ —	132
Investment funds[2] measured at net asset value				132
Limited partnership interests[3] measured at net asset value				—
Investments at fair value				$ 264
As of December 31, 2021:				
Cash and cash equivalents	$ 4	$ 1	$ —	$ 5
Debt securities:				
U.S. government obligations	24	—	—	24
Corporate obligations	—	79	—	79
Municipal obligations	—	15	—	15
Agency, asset and mortgage-backed obligations	—	35	—	35
Equity securities:				
U.S. companies	4	—	—	4
Total assets in the fair value hierarchy	$ 32	$ 130	$ —	162
Investment funds[2] measured at net asset value				161
Limited partnership interests[3] measured at net asset value				1
Investments at fair value				$ 324

(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 41% and 59%, respectively, for 2022 and 39% and 61%, respectively, for 2021, and are invested in U.S. and international securities of approximately 91% and 9%, respectively, for 2022 and 90% and 10%, respectively, for 2021.

(3) Limited partnership interests include several funds that invest primarily in real estate, buyout, growth equity and venture capital.

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. 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 negotiations with the plan trustees.

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. This occurred as a result of Energy West Mining Company's withdrawal from the UMWA 1974 Pension 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):

		PPA of 2006 zone status or plan funded status percentage for plan years beginning July 1,					Contributions			
Plan name	**Employer Identification Number**	**2022**	**2021**	**2020**	**Funding improvement plan**	**Surcharge imposed under PPA of 2006**	**2022**	**2021**	**2020**	**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	$ 6	$ 6	$ 6	2022, 2021, 2020

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 that were due to expire in 2023 were extended to 2028 in December 2022.

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, 2022, 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 $44 million, $40 million and $41 million for the years ended December 31, 2022, 2021 and 2020, 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. Cost of removal regulatory liabilities totaled $1,332 million and $1,187 million as of December 31, 2022 and 2021, respectively.

The following table reconciles the beginning and ending balances of PacifiCorp's ARO liabilities for the years ended December 31 (in millions):

	2022	2021
Beginning balance	$ 304	$ 270
Change in estimated costs	20	40
Additions	3	—
Retirements	(6)	(15)
Accretion	10	9
Ending balance	$ 331	$ 304
Reflected as:		
Other current liabilities	$ 11	$ 5
Other long-term liabilities	320	299
	$ 331	$ 304

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.

(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, 2022:					
Not designated as hedging contracts[1]:					
Commodity assets	$ 279	$ 27	$ 9	$ 3	$ 318
Commodity liabilities	(22)	(7)	(14)	(5)	(48)
Total	257	20	(5)	(2)	270
Total derivatives	257	20	(5)	(2)	270
Cash collateral payable [2]	(73)	(5)	—	—	(78)
Total derivatives - net basis	$ 184	$ 15	$ (5)	$ (2)	$ 192
As of December 31, 2021:					
Not designated as hedging contracts[1]:					
Commodity assets	$ 81	$ 21	$ 2	$ —	$ 104
Commodity liabilities	(5)	(1)	(38)	(7)	(51)
Total	76	20	(36)	(7)	53
Total derivatives	76	20	(36)	(7)	53
Cash collateral receivable	—	—	5	—	5
Total derivatives - net basis	$ 76	$ 20	$ (31)	$ (7)	$ 58

(1) PacifiCorp's commodity derivatives are generally included in rates. As of December 31, 2022 a regulatory liability of $270 million was recorded related to the net derivative asset of $270 million. As of December 31, 2021 regulatory liability of $53 million was recorded related to the net derivative asset of $53 million.

(2) As December 31, 2022, PacifiCorp had an additional $12 million cash collateral payable that was not required to be netted against total derivatives.

The following table reconciles the beginning and ending balances of PacifiCorp's net regulatory (liabilities) assets and summarizes the pre-tax gains and losses on commodity derivative contracts recognized in net regulatory (liabilities) assets, as well as amounts reclassified to earnings for the years ended December 31 (in millions):

	2022	2021	2020
Beginning balance	$ (53)	$ 17	$ 62
Changes in fair value recognized in regulatory (liabilities) assets	(513)	(171)	(11)
Net (losses) gains reclassified to operating revenue	(13)	(23)	3
Net gains (losses) reclassified to cost of fuel and energy	309	124	(37)
Ending balance	$ (270)	$ (53)	$ 17

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	**2022**	**2021**
Electricity purchases, net	Megawatt hours	2	2
Natural gas purchases	Decatherms	127	106

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 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 PacifiCorp's creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2022, PacifiCorp'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.

The aggregate fair value of PacifiCorp's derivative contracts in liability positions with specific credit-risk-related contingent features totaled $48 million and $37 million as of December 31, 2022 and 2021, respectively, for which PacifiCorp had posted collateral of $— million and $5 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, 2022 and 2021, PacifiCorp would have been required to post $3 million and $23 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.

(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, 2022:					
Assets:					
Commodity derivatives	$ —	$ 318	$ —	$ (119)	$ 199
Money market mutual funds	649	—	—	—	649
Investment funds	23	—	—	—	23
	$ 672	$ 318	$ —	$ (119)	$ 871
Liabilities - Commodity derivatives	$ —	$ (48)	$ —	$ 41	$ (7)
As of December 31, 2021:					
Assets:					
Commodity derivatives	$ —	$ 104	$ —	$ (8)	$ 96
Money market mutual funds	181	—	—	—	181
Investment funds	27	—	—	—	27
	$ 208	$ 104	$ —	$ (8)	$ 304
Liabilities - Commodity derivatives	$ —	$ (51)	$ —	$ 13	$ (38)

(1) Represents netting under master netting arrangements and a net cash collateral payable of $78 million and a net cash collateral receivable of $5 million as of December 31, 2022 and 2021, respectively. As December 31, 2022, PacifiCorp had an additional $12 million cash collateral payable that was not required to be netted against total derivatives.

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):

	2022		2021	
	Carrying Value	**Fair Value**	**Carrying Value**	**Fair Value**
Long-term debt	$ 9,666	$ 9,045	$ 8,730	$ 10,374

(14) Commitments and Contingencies

Commitments

PacifiCorp has the following firm commitments that are not reflected on the Consolidated Balance Sheet. Certain commitments are with related parties. Refer to Note 21 for transactions associated with these related party contracts. Minimum payments as of December 31, 2022 are as follows (in millions):

	2023	2024	2025	2026	2027	2028 and Thereafter	Total
Contract type:							
Purchased electricity contracts - commercially operable	$ 547	$ 241	$ 199	$ 197	$ 197	$ 2,162	$ 3,543
Purchased electricity contracts - non-commercially operable	—	—	6	12	12	208	238
Fuel contracts	784	398	148	146	153	401	2,030
Construction commitments	535	210	14	1	—	—	760
Transmission	108	100	74	65	55	418	820
Easements	21	20	20	21	21	720	823
Maintenance, service and other contracts	101	54	55	53	53	197	513
Total commitments	$ 2,096	$ 1,023	$ 516	$ 495	$ 491	$ 4,106	$ 8,727

Purchased Electricity Contracts - Commercially Operable

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-powered or wind-powered generating facilities that are not included in the table above due to there being no minimum payments generally due to being dependent on wind and solar conditions. The PPAs generally range from 7 to 30 years in duration, with certain of the PPAs extending through 2054. Future payments associated with these PPAs are expected to be material. Certain of these PPAs qualify as leases as described in Note 2. 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 2022, 2021 and 2020 energy sources.

Purchased Electricity Contracts - Non-Commercially Operable

PacifiCorp has many long-term PPAs with facilities that have not yet achieved commercial operation, primarily related to wind-powered and solar-powered generated facilities and including with facilities that are not included in the table above due to there being no minimum payments generally due to being dependent on wind and solar conditions. The PPAs generally range from 7 to 30 years in duration with certain of the PPAs extending through 2054.

In September 2022, PacifiCorp entered into a purchased electricity contract for a 400 MW solar generating facility including a 200 MW battery storage unit. Minimum obligations associated with the battery storage unit are included in the table above. In January 2023, PacifiCorp entered into a PPA for a 525 MW solar generating facility with a corresponding agreement for a 150 MW battery storage unit for which the minimum obligations are being evaluated.

Future payments associated with these arrangements are expected to be material. However, to the extent these facilities do not achieve commercial obligation, 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, and distribution projects.

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 non-cancelable 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 is intended to resolve disputes surrounding PacifiCorp's efforts to relicense the Klamath Hydroelectric Project. The KHSA establishes a process for PacifiCorp, the states of Oregon and California ("States") and other stakeholders to assess whether dam removal can 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"), who would conduct dam removal; and (4) ability for PacifiCorp to operate the facilities for the benefit of customers until dam removal commences.

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 FERC approved the partial transfer of the Klamath license in a July 2020 order, subject to the condition that PacifiCorp remains co-licensee. Under the amended KHSA, PacifiCorp did not agree to remain co-licensee during the surrender and removal process given concerns about liability protections for PacifiCorp and its customers. In November 2020, PacifiCorp entered a memorandum of agreement (the "MOA") with the KRRC, the Karuk Tribe, the Yurok Tribe and the States to continue implementation of the KHSA. The agreement required the States, PacifiCorp and KRRC to file a new license transfer application to remove PacifiCorp from the license for the Lower Klamath Project and add the States and KRRC as co-licensees for the purposes of surrender. In addition, the MOA provides for additional contingency funding of $45 million, equally split between PacifiCorp and the States, and for PacifiCorp and the States to equally share in any additional cost overruns in the unlikely event that dam removal costs exceed the $450 million in funding to ensure dam removal is complete. The MOA also requires PacifiCorp to cover the costs associated with certain pre-existing environmental conditions. In June 2021, the FERC approved the transfer of the Lower Klamath Project dams from PacifiCorp to the KRRC and the States as co-licensees. In July 2021, the Oregon, Wyoming, Idaho and California state public utility commissions conditionally approved the required property transfer applications. In August 2021, PacifiCorp notified the Public Service Commission of Utah of the property transfer, however no formal approval is required in Utah. In August 2022, the FERC staff issued a final environmental impact statement for the project, concluding that dam removal is the preferred action. In November 2022, the FERC issued a license surrender order for the project, which was accepted by the KRRC and the States in December 2022, along with the transfer of the Lower Klamath Project dams. Although PacifiCorp no longer owns the Lower Klamath Project, PacifiCorp will continue to operate the facilities under an operation and maintenance agreement with the KRRC until each facility is ready for removal. Removal of the Copco No. 2 facility is anticipated to begin in 2023, and removal of the remaining three dams (J.C. Boyle, Copco No. 1, and Iron Gate) is anticipated to begin in 2024.

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 $282 million over the next 10 years.

Legal Matters

PacifiCorp is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. PacifiCorp does not believe that such normal and routine litigation will have a material impact on its consolidated financial results. PacifiCorp is also involved in other kinds of legal actions, some of which assert or may assert claims or seek to impose fines, penalties and other costs in substantial amounts and are described below.

Wildfires Overview

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. 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.

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 damages proximately caused by negligence, including real and personal property and natural resource damages; fire suppression costs; personal injury and loss of life damages; and interest.

2020 Wildfires

In September 2020, a severe weather event resulting in 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. Third party reports for these wildfires indicate over 2,000 structures destroyed, including residences; several structures damaged; multiple individuals injured; and several fatalities. Fire suppression costs estimated by various agencies total approximately $150 million.

Investigations into the cause and origin of each wildfire are complex and ongoing and being conducted by various entities, including the U.S. Forest Service, the California Public Utilities Commission, the Oregon Department of Forestry, the Oregon Department of Justice, PacifiCorp and various experts engaged by PacifiCorp.

As of the date of this filing, numerous lawsuits have been filed in Oregon and California, including a class action complaint in Oregon, on behalf of plaintiffs related to the 2020 Wildfires. The plaintiffs seek damages that include property damages, economic losses, punitive damages, exemplary damages, attorneys' fees and other damages. Additionally, several insurance carriers have filed subrogation complaints in Oregon and California with allegations similar to those made in the aforementioned lawsuits. The final determinations of liability, however, will only be made following the completion of comprehensive investigations and litigation processes.

PacifiCorp has accrued cumulative estimated probable losses associated with the 2020 Wildfires of $477 million, through December 31, 2022. The accrual includes PacifiCorp's estimate of losses for fire suppression costs, real and personal property damages, natural resource damages for certain areas and noneconomic damages such as personal injury damages and loss of life damages that are considered probable of being incurred and that it is reasonably able to estimate at this time. For certain aspects of the 2020 Wildfires for which loss is considered probable, information necessary to reasonably estimate the potential losses, such as those related to certain areas of natural resource damages, is not currently available.

It is reasonably possible PacifiCorp will incur additional losses beyond the amounts accrued; however, PacifiCorp is currently unable to estimate the range of possible additional losses that could be incurred due to the number of properties and parties involved and the variation in those types of properties and lack of available details. To the extent losses beyond the amounts accrued are incurred, additional insurance coverage is expected to be available to cover a portion of the losses.

The following table presents changes in PacifiCorp's liability for estimated losses associated with the 2020 Wildfires for the years ended December 31 (in millions):

	2022	2021	2020
Beginning balance	$ 252	$ 252	$ —
Accrued losses	225	—	252
Payments	(53)	—	—
Ending balance	$ 424	$ 252	$ 252

PacifiCorp's receivable for expected insurance recoveries associated with the probable losses was $246 million and $116 million, respectively, as of December 31, 2022 and 2021. During the years ended December 31, 2022, 2021, and 2020, PacifiCorp recognized probable losses net of expected insurance recoveries associated with the 2020 Wildfires of $64 million, $— million and $136 million, respectively.

2022 McKinney Fire

According to California Department of Forestry and Fire Protection, on July 29, 2022, at approximately 2:16 p.m. Pacific Time, a wildfire began in the Oak Knoll Ranger District of the Klamath National Forest in Siskiyou County, California (the "2022 McKinney Fire") located in PacifiCorp's service territory. Third party reports indicate that the 2022 McKinney Fire resulted in 11 structures damaged, 185 structures destroyed, 12 injuries and four fatalities and consumed 60,000 acres. The cause of the 2022 McKinney Fire is undetermined and remains under investigation by the U.S. Forest Service.

Due to the preliminary nature of the investigation PacifiCorp does not believe a loss is probable and therefore has not accrued any loss as of the date of this filing. While the loss is not probable, PacifiCorp estimates the potential loss, excluding losses for natural resource damages, to be $31 million, net of expected insurance recoveries. The loss estimate includes PacifiCorp's estimate of losses for fire suppression costs; real and personal property damages; and noneconomic damages such as personal injury damages and loss of life damages. PacifiCorp is unable to estimate the total potential loss, including losses for natural resource damages, because there are a number of unknown facts and legal considerations that may impact the amount of any potential liability, including the total scope and nature of claims that may be asserted against PacifiCorp. PacifiCorp has insurance available and estimates the potential insurance recoveries to be $103 million, to cover potential losses.

As of the date of this filing, multiple lawsuits have been filed in California on behalf of plaintiffs related to the 2022 McKinney Fire. The plaintiffs seek damages that include property damages, economic losses, punitive damages, exemplary damages, attorneys' fees and other damages but the amount of damages sought are not specified. The final determinations of liability, however, will only be made following the completion of comprehensive investigations and litigation processes.

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):

	2022	2021	2020
Customer Revenue:			
Retail:			
Residential	$ 2,013	$ 1,914	$ 1,910
Commercial	1,645	1,559	1,578
Industrial	1,163	1,125	1,185
Other retail	278	249	259
Total retail	5,099	4,847	4,932
Wholesale	260	157	107
Transmission	166	143	96
Other Customer Revenue	102	108	108
Total Customer Revenue	5,627	5,255	5,243
Other revenue	52	41	98
Total operating revenue	$ 5,679	$ 5,296	$ 5,341

(16) Preferred Stock

PacifiCorp has 3,500 thousand shares of Serial Preferred Stock authorized at the stated value of $100 per share. PacifiCorp had 24 thousand shares of Serial Preferred Stock issued and outstanding as of December 31, 2022 and 2021. The outstanding preferred stock series are non-redeemable and have annual dividend rates of 6.00% and 7.00%.

In the event of voluntary liquidation, all preferred stock is entitled to stated value or a specified preference amount per share plus accrued dividends. Upon involuntary liquidation, all preferred stock is entitled to stated value plus accrued dividends. Dividends on all preferred stock are cumulative. Holders also have 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.

PacifiCorp also has 16 million shares of No Par Serial Preferred Stock and 127 thousand shares of 5% Preferred Stock authorized, but no shares were issued or outstanding as of December 31, 2022 and 2021.

(17) Common Shareholder's Equity

Through PPW Holdings, 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, 2022, the most restrictive of these commitments prohibits PacifiCorp from making any distribution to PPW Holdings or BHE without prior state regulatory approval to the extent that it would reduce PacifiCorp's common equity below 44% of its total capitalization, excluding short-term debt and current maturities of long-term debt. As of December 31, 2022, PacifiCorp's actual common equity percentage, as calculated under this measure, was 54%, and PacifiCorp would have been permitted to dividend $3.5 billion under this commitment.

These commitments also restrict PacifiCorp from making any distributions to either PPW Holdings or BHE if PacifiCorp's senior unsecured debt rating is BBB- or lower by Standard & Poor's Rating Services or Fitch Ratings, or Baa3 or lower by Moody's Investor Service, as indicated by two of the three rating services. As of December 31, 2022, PacifiCorp met the minimum required senior unsecured debt ratings for making distributions.

PacifiCorp is also subject to a maximum debt-to-total capitalization percentage under various financing agreements as further discussed in Note 7.

In January 2023, PacifiCorp declared dividends of $300 million payable to PPW Holdings LLC in February 2023.

(18) Components of Accumulated Other Comprehensive Loss, Net

Accumulated other comprehensive loss, net consists of unrecognized amounts on retirement benefits, net of tax, of $9 million and $17 million as of December 31, 2022 and 2021, 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 $28 million and $45 million as of December 31, 2022 and 2021, 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):

	2022	2021	2020
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	$ 380	$ 395	$ 348
Income taxes (received) paid, net	$ (185)	$ (120)	$ 107
Supplemental disclosure of non-cash investing and financing activities:			
Accruals related to property, plant and equipment additions	$ 558	$ 254	$ 344

(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 $123 million, $70 million and $14 million during the years ended December 31, 2022, 2021 and 2020, respectively. Amounts charged to PacifiCorp in 2022 and 2021 were primarily reflected in construction work in progress on the Consolidated Balance Sheets as of December 31, 2022 and 2021. Payables associated with the charges were $16 million and $9 million as of December 31, 2022 and 2021, respectively. Amounts charged by PacifiCorp to BHE and its subsidiaries under these agreements totaled $23 million, $8 million and $5 million during the years ended December 31, 2022, 2021 and 2020, respectively. 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, transportation of natural gas and employee relocation services. These expenses totaled $8 million, $6 million and $6 million during the years ended December 31, 2022, 2021 and 2020, 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 $21 million, $19 million and $29 million during the years ended December 31, 2022, 2021 and 2020, respectively.

PacifiCorp has a long-term master materials supply contract with Marmon Utility, LLC, an indirect wholly owned subsidiary of a holding company in which Berkshire Hathaway holds a majority interest. Materials and supplies purchased under this contract were $8 million, $2 million and $3 million during the years ended December 31, 2022, 2021 and 2020, respectively.

PacifiCorp is party to a tax-sharing agreement and is part of the Berkshire Hathaway consolidated U.S. federal income tax return. Federal and state income taxes receivable from BHE were $84 million and $48 million as of December 31, 2022 and 2021, respectively. For the years ended December 31, 2022 and 2021, cash refunded from BHE for federal and state income taxes totaled $185 million and $120 million, respectively. For the year ended December 31, 2020, cash paid to BHE for federal and state income taxes totaled $107 million.

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, 2022, 2021 and 2020, coal purchases from PacifiCorp's equity investees totaled $119 million, $148 million and $145 million, respectively. Payables to PacifiCorp's equity investees were $10 million and $7 million as of December 31, 2022 and 2021, respectively.

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 2022 was $961 million, an increase of $67 million, or 7%, compared to 2021 primarily due to higher electric utility margin, a favorable income tax benefit, higher natural gas utility margin and higher AFUDC, partially offset by higher depreciation and amortization expense, higher operations and maintenance expense, unfavorable changes in the cash surrender value of corporate-owned life insurance policies, higher non-service benefit plan costs, higher interest expense and lower nonregulated utility margin. Electric utility margin increased due to higher wholesale utility margin from higher margins per unit and higher wholesale customer volumes of 12.2% and higher retail utility margin, largely from higher retail customer volumes. Retail customer volumes increased 4.3% due to higher customer usage, reflecting the favorable impact of weather and an increase in certain industrial customer usage. Energy generated increased 6% primarily due to higher wind-powered generation, partially offset by lower coal-fueled generation, and energy purchased increased 19%. The favorable income tax benefit was mainly due to higher PTCs recognized from higher wind- and solar-powered generation, partially offset by the timing of state income tax benefits. Depreciation and amortization expense increased primarily from the impacts of certain regulatory mechanisms and additional assets placed in-service.

MidAmerican Energy's net income for 2021 was $894 million, an increase of $68 million, or 8%, compared to 2020 primarily due to higher electric utility margin and a favorable income tax benefit, partially offset by higher depreciation and amortization expense, higher operations and maintenance expense and lower allowances for equity and borrowed funds. Electric utility margin increased primarily due to a higher retail utility margin, largely from higher customer volumes and price impacts from changes in sales mix, and higher wholesale utility margin from higher margins per unit and higher wholesale customer volumes of 42.7%. Electric retail customer volumes increased 5.8% primarily due to higher customer usage for certain industrial customers. Energy generated increased 26% primarily due to higher coal-fueled generation and higher wind-powered generation, and energy purchased decreased 35%. Operations and maintenance expense increased primarily due to higher costs associated with additional wind-powered generating facilities placed in-service as well as higher natural gas distribution costs, partially offset by 2020 costs associated with storm restoration activities. The increase in depreciation and amortization expense was primarily due to higher regulatory mechanisms and additional assets placed in-service. The favorable income tax benefit was from higher PTCs recognized due to new wind-powered generating facilities placed in-service in late 2020 and 2021, state income tax impacts and lower pretax income.

MidAmerican Funding -

MidAmerican Funding's net income for 2022 was $947 million, an increase of $64 million, or 7%, compared to 2021. MidAmerican Funding's net income for 2021 was $883 million, an increase of $65 million, or 8%, compared to 2020. The increases were primarily due to the changes in MidAmerican Energy's earnings discussed above.

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 profitability 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 managing 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):

	2022	2021	Change		2021	2020	Change	
Electric utility margin:								
Operating revenue	$ 2,988	$ 2,529	$ 459	18 %	$ 2,529	$ 2,139	$ 390	18 %
Cost of fuel and energy	679	539	140	26	539	339	200	59
Electric utility margin	2,309	1,990	319	16 %	1,990	1,800	190	11 %
Natural gas utility margin:								
Operating revenue	1,030	1,003	27	3 %	1,003	573	430	75 %
Natural gas purchased for resale	762	760	2	—	760	327	433	*
Natural gas utility margin	268	243	25	10 %	243	246	(3)	(1)%
Utility margin	$ 2,577	$ 2,233	$ 344	15 %	$ 2,233	$ 2,046	$ 187	9 %
Other operating revenue	7	15	(8)	(53)%	15	8	7	88 %
Other cost of sales	1	1	—	—	1	1	—	—
Operations and maintenance	828	775	53	7	775	754	21	3
Depreciation and amortization	1,168	914	254	28	914	716	198	28
Property and other taxes	149	142	7	5	142	135	7	5
Operating income	$ 438	$ 416	$ 22	5 %	$ 416	$ 448	$ (32)	(7)%

* Not meaningful.

Electric Utility Margin

A comparison of key operating results related to electric utility margin is as follows for the years ended December 31:

	2022	2021	Change		2021	2020	Change	
Utility margin (in millions):								
Operating revenue	$ 2,988	$ 2,529	$ 459	18 %	$ 2,529	$ 2,139	$ 390	18 %
Cost of fuel and energy	679	539	140	26	539	339	200	59
Utility margin	$ 2,309	$ 1,990	$ 319	16 %	$ 1,990	$ 1,800	$ 190	11 %
Sales (GWhs):								
Residential	7,006	6,718	288	4 %	6,718	6,687	31	— %
Commercial	4,017	3,841	176	5	3,841	3,707	134	4
Industrial	16,646	15,944	702	4	15,944	14,645	1,299	9
Other	1,621	1,571	50	3	1,571	1,484	87	6
Total retail	29,290	28,074	1,216	4	28,074	26,523	1,551	6
Wholesale	17,964	16,011	1,953	12	16,011	11,219	4,792	43
Total sales	47,254	44,085	3,169	7 %	44,085	37,742	6,343	17 %
Average number of retail customers (in thousands)	813	804	9	1 %	804	795	9	1 %
Average revenue per MWh:								
Retail	$ 79.23	$ 75.84	$ 3.39	4 %	$ 75.84	$ 72.57	$ 3.27	5 %
Wholesale	$ 31.07	$ 18.92	$ 12.15	64 %	$ 18.92	$ 11.08	$ 7.84	71 %
Heating degree days	6,449	5,704	745	13 %	5,704	5,932	(228)	(4)%
Cooling degree days	1,274	1,331	(57)	(4)%	1,331	1,172	159	14 %
Sources of energy (GWhs)[(1)]:								
Wind and other[(2)]	28,129	23,374	4,755	20 %	23,374	20,668	2,706	13 %
Coal	10,078	12,313	(2,235)	(18)	12,313	7,217	5,096	71
Nuclear	3,782	3,934	(152)	(4)	3,934	3,927	7	—
Natural gas	1,504	1,398	106	8	1,398	675	723	*
Total energy generated	43,493	41,019	2,474	6	41,019	32,487	8,532	26
Energy purchased	4,594	3,865	729	19	3,865	5,979	(2,114)	(35)
Total	48,087	44,884	3,203	7 %	44,884	38,466	6,418	17 %
Average cost of energy per MWh:								
Energy generated[(3)]	$ 7.42	$ 7.12	$ 0.30	4 %	$ 7.12	$ 4.74	$ 2.38	50 %
Energy purchased	$ 77.59	$ 64.04	$ 13.55	21 %	$ 64.04	$ 30.94	$ 33.10	*

* Not meaningful.

(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:

	2022	2021	Change		2021	2020	Change	
Utility margin (in millions):								
Operating revenue	$ 1,030	$ 1,003	$ 27	3 %	$ 1,003	$ 573	$ 430	75 %
Natural gas purchased for resale	762	760	2	—	760	327	433	*
Utility margin	$ 268	$ 243	$ 25	10 %	$ 243	$ 246	$ (3)	(1)%
Throughput (000's Dths):								
Residential	56,100	48,984	7,116	15 %	48,984	51,023	(2,039)	(4)%
Commercial	26,298	23,240	3,058	13	23,240	23,336	(96)	—
Industrial	6,039	5,287	752	14	5,287	5,275	12	—
Other	75	68	7	10	68	74	(6)	(8)
Total retail sales	88,512	77,579	10,933	14	77,579	79,708	(2,129)	(3)
Wholesale sales	30,996	34,337	(3,341)	(10)	34,337	34,691	(354)	(1)
Total sales	119,508	111,916	7,592	7	111,916	114,399	(2,483)	(2)
Natural gas transportation service	102,827	112,631	(9,804)	(9)	112,631	110,263	2,368	2
Total throughput	222,335	224,547	(2,212)	(1)%	224,547	224,662	(115)	— %
Average number of retail customers (in thousands)	789	781	8	1 %	781	774	7	1 %
Average revenue per retail Dth sold	$ 9.19	$ 10.59	$ (1.40)	(13)%	$ 10.59	$ 5.91	$ 4.68	79 %
Heating degree days	6,810	6,000	810	14 %	6,000	6,253	(253)	(4)%
Average cost of natural gas per retail Dth sold	$ 6.66	$ 7.95	$ (1.29)	(16)%	$ 7.95	$ 3.29	$ 4.66	*
Combined retail and wholesale average cost of natural gas per Dth sold	$ 6.38	$ 6.79	$ (0.41)	(6)%	$ 6.79	$ 2.86	$ 3.93	*

* Not meaningful.

Year Ended December 31, 2022 Compared to Year Ended December 31, 2021

MidAmerican Energy -

Electric utility margin increased $319 million, or 16%, for 2022 compared to 2021 primarily due to:

- a $250 million increase in wholesale utility margin due to higher margins per unit of $237 million, reflecting higher market prices and lower energy costs, and higher volumes of 12.2%;
- a $66 million increase in retail utility margin primarily due to $62 million from higher customer usage, including $7 million from the favorable impact of weather; and $9 million, net of energy costs, from higher recoveries through bill riders (offset in operations and maintenance expense and income tax benefit); partially offset by $6 million in 2021 from liquidated damages related to a wind-powered generation project. Retail customer volumes increased 4.3%; and
- a $3 million increase in Multi-Value Projects ("MVP") transmission revenue.

Natural gas utility margin increased $25 million, or 10%, for 2022 compared to 2021 primarily due to:

- an $18 million increase in customer usage, including $9 million from the favorable impact of weather;
- a $5 million increase from higher refunds related to amortization of excess accumulated deferred income taxes arising from in 2017 Tax Reform (offset in income tax benefit); and
- a $3 million increase in natural gas transportation margin, reflecting higher prices.

Operations and maintenance increased $53 million, or 7%, for 2022 compared to 2021 primarily due to higher other power generation costs of $21 million from additional wind turbines and easements, higher electric distribution costs of $17 million reflecting greater tree-trimming efforts, higher steam generation costs of $13 million and higher transmission costs from MISO of $6 million, partially offset by lower gas distribution costs of $6 million.

Depreciation and amortization increased $254 million, or 28%, for 2022 compared to 2021 primarily due to $181 million from higher Iowa revenue sharing accruals, $40 million related to new and repowered wind-powered generating facilities and other plant placed in-service and $31 million from a regulatory mechanism that provides customers the retail energy benefits of certain wind-powered generation projects.

Property and other taxes increased $7 million, or 5%, for 2022 compared to 2021 primarily due to higher wind turbine property taxes.

Interest expense increased $11 million, or 4%, for 2022 compared to 2021 primarily due to a higher average long-term debt balance and higher variable interest rates.

Allowance for borrowed and equity funds increased $14 million, or 27%, for 2022 compared to 2021 primarily due to higher construction work-in-progress balances related to wind- and solar-powered generation projects.

Other, net decreased $53 million, or 100%, for 2022 compared to 2021 primarily due to lower cash surrender values of corporate-owned life insurance policies of $37 million, higher non-service costs of postretirement employee benefit plans of $17 million and lower other investment values, partially offset by higher interest income.

Income tax benefit increased $95 million, or 14%, for 2022 compared to 2021, and the effective tax rate was (403)% for 2022 and (308)% for 2021. The change in the effective tax rate was substantially due to an increase of $136 million in PTCs, partially offset by state income tax impacts.

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. PTC's totaled $710 million, $574 million and $510 million in 2022, 2021 and 2020, respectively.

MidAmerican Funding -

Income tax benefit for MidAmerican Funding increased $96 million, or 14%, for 2022 compared to 2021, and the effective tax rate was (454)% for 2022 and (335)% for 2021. The change in effective tax rates was due principally to the factors discussed for MidAmerican Energy.

Year Ended December 31, 2021 Compared to Year Ended December 31, 2020

MidAmerican Energy -

Electric utility margin decreased $190 million, or 11%, for 2021 compared to 2020 primarily due to:

- a $99 million increase in retail utility margin primarily due to $50 million from higher usage for certain industrial customers; $13 million from the favorable impact of weather; $19 million due to price impacts from changes in sales mix; $10 million, net of energy costs, from higher recoveries through bill riders (offset in operations and maintenance expense and income tax benefit) and $6 million from liquidated damages related to a wind-powered generation project. Retail customer volumes increased 5.8%; and
- a $93 million increase in wholesale utility margin due to higher margins per unit of $52 million, reflecting higher market prices, net of higher energy costs, and higher volumes of 42.7%; partially offset by
- a $2 million decrease in Multi-Value Projects ("MVP") transmission revenue.

Natural gas utility margin decreased $3 million, or 1%, for 2021 compared to 2020 primarily due to:

- a $6 million decrease from higher refunds related to amortization of excess accumulated deferred income taxes arising from 2017 Tax Reform (offset in income tax benefit);
- a $3 million decrease due to the unfavorable impact of weather, partially offset by price impacts from changes in sales mix; partially offset by
- a $4 million increase in natural gas energy efficiency program revenue (offset in operations and maintenance expense); and
- a $2 million increase in natural gas transportation margin, reflecting higher volumes.

Operations and maintenance increased $21 million, or 3%, for 2021 compared to 2020 primarily due higher other generation operations and maintenance expenses of $7 million due to additional wind turbines and easements, higher energy efficiency program expense of $7 million (offset in operating revenue), higher natural gas distribution costs of $6 million and higher transmission operations costs from MISO of $3 million, partially offset by lower electric distribution costs of $11 million due to storm restoration costs in 2020.

Depreciation and amortization increased $198 million, or 28%, for 2021 compared to 2020 primarily due to $114 million from higher Iowa revenue sharing accruals, $25 million from a regulatory mechanism that provides customers the retail energy benefits of certain wind-powered generation projects and $59 million related to new and repowered wind-powered generating facilities and other plant placed in-service.

Property and other taxes increased $7 million, or 5%, for 2021 compared to 2020 primarily due to higher wind turbine property taxes.

Interest expense decreased $2 million, or 1%, for 2021 compared to 2020 primarily due to a decrease in a regulatory carrying charge and lower variable interest rates, partially offset by a higher average long-term debt balance.

Allowance for borrowed and equity funds decreased $8 million, or 13%, for 2021 compared to 2020 primarily due to lower construction work-in-progress balances related to wind-powered generation projects.

Other, net increased $1 million, or 2%, for 2021 compared to 2020 primarily due to higher cash surrender values of corporate-owned life insurance policies and lower non-service costs of postretirement employee benefit plans, partially offset by a gain from the contribution of land to a joint venture in 2020.

Income tax benefit increased $105 million, or 18%, for 2021 compared to 2020, and the effective tax rate was (308)% for 2021 and (223)% for 2020. The change in the effective tax rate was substantially due to an increase of $64 million in PTCs, state income tax impacts and lower pretax income in 2021.

MidAmerican Funding -

Income tax benefit for MidAmerican Funding increased $106 million, or 18%, for 2021 compared to 2020, and the effective tax rate was (335)% for 2021 and (235)% for 2020. The change in effective tax rates was due principally to the factors discussed for MidAmerican Energy.

Liquidity and Capital Resources

As of December 31, 2022, MidAmerican Energy's and MidAmerican Funding's total net liquidity were as follows (in millions):

MidAmerican Energy:		
Cash and cash equivalents	$	258
Credit facilities, maturing 2023 and 2025		1,505
Less:		
Tax-exempt bond support		(370)
Net credit facilities		1,135
MidAmerican Energy total net liquidity	$	1,393
MidAmerican Funding:		
MidAmerican Energy total net liquidity	$	1,393
Cash and cash equivalents		3
MHC, Inc. credit facility, maturing 2023		4
MidAmerican Funding total net liquidity	$	1,400

Operating Activities

MidAmerican Energy's net cash flows from operating activities were $2,174 million, $1,617 million and $1,543 million for 2022, 2021 and 2020, respectively. MidAmerican Funding's net cash flows from operating activities were $2,161 million, $1,605 million and $1,536 million for 2022, 2021 and 2020, respectively. Cash flows from operating activities increased for 2022 compared to 2021 primarily due to higher utility margins for MidAmerican Energy's regulated electric and natural gas businesses, higher income tax receipts and lower payments to vendors. Higher utility margins are partially attributable to timing of the recovery of higher natural gas costs caused by the February 2021 polar vortex weather event. Cash flows from operating activities increased for 2021 compared to 2020 primarily due to higher income tax receipts, lower payments for the settlement of AROs and lower interest payments.

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 $(1,867) million, $(1,911) million and $(1,826) million for 2022, 2021 and 2020, respectively. MidAmerican Funding's net cash flows from investing activities were $(1,868) million, $(1,912) million and $(1,825) million for 2022, 2021 and 2020, 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 investment proceeds relates primarily to company-owned life insurance policies.

Financing Activities

MidAmerican Energy's net cash flows from financing activities were $(278) million, $488 million and $(2) million for 2022, 2021 and 2020, respectively. MidAmerican Funding's net cash flows from financing activities were $(262) million, $501 million and $4 million for 2022, 2021 and 2020, respectively. In 2022 MidAmerican Energy paid $275 million in dividends to its parent company, MHC, Inc. In July 2021, MidAmerican Energy issued $500 million of its 2.70% First Mortgage Bonds due August 2052. In 2022, MidAmerican Funding made a $69 million distribution to its sole member, BHE. MidAmerican Funding paid $189 million in 2022 and received $12 million and $5 million in 2021 and 2020, respectively, 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, 2024, commercial paper and bank notes aggregating $1.5 billion. MidAmerican Energy has a $1.5 billion unsecured credit facility expiring in June 2025. 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 with the SEC to issue up to $3.25 billion of long-term debt securities and preferred stock through June 13, 2024. MidAmerican Energy has authorization from the FERC to issue, through June 30, 2023, long-term debt securities up to an aggregate of $2.0 billion and preferred stock up to an aggregate of $500 million. MidAmerican Energy has authorization from the ICC through May 25, 2025, to issue long-term debt securities up to an aggregate of $2.2 billion and preferred stock up to an aggregate of $500 million; through October 15, 2024, to issue $750 million of long-term debt securities for the purpose of refinancing $250 million of its 3.70% Senior notes due September 2023 and $500 million of its 2.40% Senior notes due October 2024; and through January 1, 2025, to issue $105 million of long-term debt securities for the purpose of refinancing three of its variable-rate tax-exempt bond series, including $57 million due in May 2023, $35 million due in October 2024 and $13 million due in January 2025.

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, 2022, MidAmerican Energy estimated it would be able to issue up to $9.3 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; 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		
	2020	2021	2022	2023	2024	2025
Wind generation	$ 911	$ 964	$ 685	$ 1,353	$ 1,288	$ 895
Electric distribution	273	257	311	296	250	259
Electric transmission	160	199	145	186	159	211
Solar generation	16	132	119	10	48	74
Other	476	360	609	606	404	352
Total	$ 1,836	$ 1,912	$ 1,869	$ 2,451	$ 2,149	$ 1,791

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.
  - Construction and acquisition of wind-powered generating facilities totaled $72 million for 2022, $540 million for 2021 and $848 million for 2020. The timing and amount of forecast wind generation capital expenditures may be impacted by the outcome of MidAmerican Energy's Wind PRIME filing currently before the IUB. MidAmerican Energy placed in-service 294 MWs during 2021 and 729 MWs during 2020. All of these wind-powered generating facilities placed in-service in 2021 and 2020 qualify for 100% of PTCs available. PTCs from these projects are excluded from MidAmerican Energy's Iowa EAC until these generation assets are reflected in base rates.
  - Repowering of wind-powered generating facilities totaled $500 million for 2022, $354 million for 2021 and $37 million for 2020. Planned spending for repowering totals $20 million in 2023. MidAmerican Energy expects its repowered facilities to meet IRS guidelines for the re-establishment of PTCs for 10 years from the date the facilities are placed in-service.
- Electric distribution includes expenditures for new facilities to meet retail demand growth and for replacement of existing facilities to maintain system reliability.
- 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 of solar-powered generating facilities totaling 141 MWs of small- and utility-scale solar generation, all of which were placed in-service in 2022, with total spend of $119 million in 2022 and $132 million in 2021. MidAmerican Energy is pursuing additional opportunities for solar generation, including those in MidAmerican Energy's Wind PRIME filing currently before the IUB.
- Remaining expenditures primarily relate to 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 $5.6 billion on long-term debt, including $316 million due in 2023. Additionally, MidAmerican Funding has cash requirements relating to interest payments on its long-term debt of $109 million, including $17 million due in 2023.

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.

Quad Cities Generating Station Operating Status

Constellation Energy Generation, LLC ("Constellation Energy"), the operator of Quad Cities Generating Station Units 1 and 2 ("Quad Cities Station") of which MidAmerican Energy has a 25% ownership interest, receives financial support for continued operation of Quad Cities Station from the zero emission standard enacted by the Illinois legislature in December 2016. 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. The proceeds from the ZECs provide Constellation Energy additional revenue through 2027 as an incentive for continued operation of Quad Cities Station. MidAmerican Energy does not receive additional revenue from the subsidy.

The PJM Interconnection, L.L.C. ("PJM") capacity market includes a Minimum Offer Price Rule ("MOPR"). If a generation resource is subjected to a MOPR, its offer price in the market is adjusted to effectively remove the revenues it receives through a state government-provided financial support program like the Illinois zero emission standard, resulting in a higher offer that may not clear the capacity market. Prior to December 19, 2019, the PJM MOPR applied only to certain new gas-fueled resources.

On December 19, 2019, the FERC issued an order requiring the PJM to broadly apply the MOPR to all new and existing resources, including nuclear. This greatly expanded the breadth and scope of the PJM's MOPR, which became effective as of the PJM's capacity auction for the 2022-2023 planning year. While the FERC included some limited exemptions, no exemptions were available to state-supported nuclear resources, such as Quad Cities Station. The FERC denied rehearing of that order on April 16, 2020. A number of parties, including Constellation Energy, have filed petitions for review of the FERC's orders in this proceeding, which remain pending before the Court of Appeals for the Seventh Circuit. MidAmerican Energy cannot predict the outcome of this proceeding.

While this litigation is pending, the MOPR applied to Quad Cities Station in the capacity auction for the 2022-2023 planning year in May 2021, which prevented Quad Cities Station from clearing in that capacity auction.

At the direction of the PJM Board of Managers, the PJM and its stakeholders developed further MOPR reforms to ensure that the capacity market rules respect and accommodate state resource preferences such as the ZEC programs. The PJM filed related tariff revisions with the FERC on July 30, 2021, and, on September 29, 2021, the PJM's proposed MOPR reforms became effective by operation of law. Under the new tariff provisions, the MOPR applied in the capacity auction for the 2023-2024 delivery year but did not restrict the offers of Quad Cities Station, which cleared in the capacity auction. Requests for rehearing of the FERC's notice establishing the effective date for the PJM's proposed market reforms were filed in October 2021 and denied by operation of law on November 4, 2021. Several parties have filed petitions for review of the FERC's orders in this proceeding, which remain pending before the Court of Appeals for the Third Circuit.

Assuming the continued effectiveness of the Illinois zero emission standard, Constellation Energy no longer considers Quad Cities Station to be at heightened risk for early retirement. However, to the extent the Illinois zero emission standard does not operate as expected over its full term, Quad Cities Station would be at heightened risk for early retirement. The FERC provided no new mechanism for accommodating state-supported resources like Quad Cities Station other than the existing Fixed Resource Requirement ("FRR") mechanism under which an entire utility zone would be removed from PJM's capacity auction along with sufficient resources to support the load in such zone. Depending on the outcome of the proceedings related to the PJM MOPR, the continued effectiveness of the Illinois zero emission standard may be undermined unless the PJM adopts further changes to the MOPR or Illinois implements an FRR mechanism, under which Quad Cities Station would be removed from the PJM's capacity auction.

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, 2022, 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, 2022, MidAmerican Energy would have been required to post $128 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.

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 $550 million and total regulatory liabilities were $1,119 million as of December 31, 2022. 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, 2022, 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, 2022. Additionally, no indicators of impairment were identified as of December 31, 2022. 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, 2022, MidAmerican Energy recognized a net liability totaling $99 million for the funded status of its defined benefit pension and other postretirement benefit plans. As of December 31, 2022, amounts not yet recognized as a component of net periodic benefit cost that were included in regulatory assets totaled $47 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. 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, 2022.

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 2028 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, 2022 Benefit Obligations:				
Discount rate	$ (22)	$ 24	$ (9)	$ 10
Effect on 2022 Periodic Cost:				
Discount rate	1	(1)	—	—
Expected rate of return on plan assets	(3)	3	(1)	1

A variety of factors affect the funded status of the plans, including asset returns, discount rates, 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% as a result of 2017 Tax Reform, certain property-related basis differences, and other various differences. As of December 31, 2022, these amounts were recognized as a net regulatory liability of $72 million and will be included in regulated rates when the temporary differences reverse.

Revenue Recognition - Unbilled Revenue

Revenue from electric and natural gas customers is recognized as electricity or natural gas is delivered or services are provided. The determination of customer billings is based on a systematic reading of customer meters and applicable rates. 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. Unbilled revenue was $102 million as of December 31, 2022. 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 sales among customer classes. Unbilled revenue is reversed in the following month, and billed revenue is recorded based on the subsequent meter readings.

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, 2022 and 2021, MidAmerican Energy had short- and long-term variable-rate obligations totaling $370 million 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, 2022, 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, 2022 and 2021.

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, 2022, 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

MidAmerican Funding, LLC and Subsidiaries

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, 2022 and 2021, 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, 2022, 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, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022, 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 audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Regulatory Matters — Effects of Rate Regulation on the Financial Statements — Refer to Notes 2 and 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 it meets 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 their 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 future decisions by the Commissions, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of future decisions by the Commissions included the following, among others:

- We evaluated MidAmerican Energy's disclosures related to the effects of rate regulation, including the balances recorded and regulatory developments.
- We read relevant regulatory orders issued by the Commissions, regulatory statutes, interpretations, procedural memorandums, filings made by interveners, and other external information. We evaluated the external information and compared to management's recorded regulatory asset and liability balances for completeness.
- For regulatory matters in process, 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.
- We inquired of management about property, plant, and equipment that may be abandoned. We inquired of management to identify projects that are designed to replace assets that may be retired prior to the end of the useful life. We inspected minutes of the board of directors and regulatory orders and other filings with the Commissions to identify any evidence that may contradict management's assertion regarding probability of an abandonment.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
February 24, 2023

We have served as MidAmerican Energy's auditor since 1999.

MIDAMERICAN ENERGY COMPANY
BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2022	2021
ASSETS		
Current assets:		
Cash and cash equivalents	$ 258	$ 232
Trade receivables, net	536	526
Income tax receivable	42	79
Inventories	277	234
Prepayments	91	71
Other current assets	66	52
Total current assets	1,270	1,194
Property, plant and equipment, net	21,091	20,301
Regulatory assets	550	473
Investments and restricted investments	902	1,026
Other assets	165	263
Total assets	$ 23,978	$ 23,257

The accompanying notes are an integral part of these financial statements.

MIDAMERICAN ENERGY COMPANY
BALANCE SHEETS (continued)
(Amounts in millions)

	As of December 31,	
	2022	**2021**
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Accounts payable	$ 536	$ 531
Accrued interest	85	84
Accrued property, income and other taxes	170	158
Current portion of long-term debt	317	—
Other current liabilities	93	145
Total current liabilities	1,201	918
Long-term debt	7,412	7,721
Regulatory liabilities	1,119	1,080
Deferred income taxes	3,433	3,389
Asset retirement obligations	683	714
Other long-term liabilities	485	475
Total liabilities	14,333	14,297
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	9,084	8,399
Total shareholder's equity	9,645	8,960
Total liabilities and shareholder's equity	$ 23,978	$ 23,257

The accompanying notes are an integral part of these financial statements.

MIDAMERICAN ENERGY COMPANY
STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2022	**2021**	**2020**
Operating revenue:			
Regulated electric	$ 2,988	$ 2,529	$ 2,139
Regulated natural gas and other	1,037	1,018	581
Total operating revenue	4,025	3,547	2,720
Operating expenses:			
Cost of fuel and energy	679	539	339
Cost of natural gas purchased for resale and other	763	761	328
Operations and maintenance	828	775	754
Depreciation and amortization	1,168	914	716
Property and other taxes	149	142	135
Total operating expenses	3,587	3,131	2,272
Operating income	438	416	448
Other income (expense):			
Interest expense	(313)	(302)	(304)
Allowance for borrowed funds	15	13	15
Allowance for equity funds	51	39	45
Other, net	—	53	52
Total other income (expense)	(247)	(197)	(192)
Income before income tax benefit	191	219	256
Income tax benefit	(770)	(675)	(570)
Net income	$ 961	$ 894	$ 826

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, 2019	$ —	$ 561	$ 6,679	$ 7,240
Net income	—	—	826	826
Other equity transactions	—	—	(1)	(1)
Balance, December 31, 2020	—	561	7,504	8,065
Net income	—	—	894	894
Other equity transactions	—	—	1	1
Balance, December 31, 2021	—	561	8,399	8,960
Net income	—	—	961	961
Common stock dividends	—	—	(275)	(275)
Other equity transactions	—	—	(1)	(1)
Balance, December 31, 2022	$ —	$ 561	$ 9,084	$ 9,645

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,		
	2022	2021	2020
Cash flows from operating activities:			
Net income	$ 961	$ 894	$ 826
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	1,168	914	716
Amortization of utility plant to other operating expenses	35	34	34
Allowance for equity funds	(51)	(39)	(45)
Deferred income taxes and amortization of investment tax credits	33	153	208
Settlements of asset retirement obligations	(85)	(103)	(124)
Other, net	51	21	(18)
Changes in other operating assets and liabilities:			
Trade receivables and other assets	(11)	(293)	48
Inventories	(43)	44	(52)
Pension and other postretirement benefit plans, net	8	(4)	(19)
Accrued property, income and other taxes, net	40	(71)	(64)
Accounts payable and other liabilities	68	67	33
Net cash flows from operating activities	2,174	1,617	1,543
Cash flows from investing activities:			
Capital expenditures	(1,869)	(1,912)	(1,836)
Purchases of marketable securities	(499)	(213)	(281)
Proceeds from sales of marketable securities	492	207	269
Proceeds from sales of other investments	—	—	2
Other investment proceeds	2	1	9
Other, net	7	6	11
Net cash flows from investing activities	(1,867)	(1,911)	(1,826)
Cash flows from financing activities:			
Common stock dividends	(275)	—	—
Proceeds from long-term debt	—	492	—
Repayments of long-term debt	(2)	(1)	—
Other, net	(1)	(3)	(2)
Net cash flows from financing activities	(278)	488	(2)
Net change in cash and cash equivalents and restricted cash and cash equivalents	29	194	(285)
Cash and cash equivalents and restricted cash and cash equivalents at beginning of year	239	45	330
Cash and cash equivalents and restricted cash and cash equivalents at end of year	$ 268	$ 239	$ 45

The accompanying notes are an integral part of these financial statements.

MIDAMERICAN ENERGY COMPANY
NOTES TO 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 owns subsidiaries principally engaged in energy businesses. BHE is a consolidated 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, 2022, 2021 and 2020.

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.

Accounting for the Effects of Certain Types of Regulation

MidAmerican Energy's utility operations are subject to the regulation of the Iowa Utilities Board ("IUB"), 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, 2022 and 2021 as presented in 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,	
	2022	**2021**
Cash and cash equivalents	$ 258	$ 232
Restricted cash and cash equivalents in other current assets	10	7
Total cash and cash equivalents and restricted cash and cash equivalents	$ 268	$ 239

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 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 nuclear generation assets 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 change 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):

	2022	2021	2020
Beginning balance	$ 12	$ 12	$ 5
Charged to operating costs and expenses, net	11	10	12
Write-offs, net	(9)	(10)	(5)
Ending balance	$ 14	$ 12	$ 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 $175 million and $135 million as of December 31, 2022 and 2021, respectively, coal stocks, totaling $68 million and $63 million as of December 31, 2022 and 2021, respectively, and natural gas in storage, totaling $27 million and $30 million as of December 31, 2022 and 2021, 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 $22 million and $27 million higher as of December 31, 2022 and 2021, 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, 2022 and 2021, unbilled revenue was $102 million and $85 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, 2022 and 2021, was $156 million and $230 million, respectively.

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 on the Consolidated Statements of Operations.

(3) Property, Plant and Equipment, Net

Property, plant and equipment, net consists of the following as of December 31 (in millions):

	Depreciable Life	2022	2021
Utility plant:			
Generation	20-62 years	$ 18,582	$ 17,397
Transmission	55-80 years	2,662	2,474
Electric distribution	15-80 years	4,931	4,661
Natural gas distribution	30-75 years	2,144	2,039
Utility plant in-service		28,319	26,571
Accumulated depreciation and amortization		(8,024)	(7,376)
Utility plant in-service, net		20,295	19,195
Nonregulated property, net of accumulated depreciation and amortization	20-50 years	6	6
		20,301	19,201
Construction work-in-progress		790	1,100
Property, plant and equipment, net		$ 21,091	$ 20,301

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:

	2022	2021	2020
Electric	3.2 %	3.3 %	3.2 %
Natural gas	2.9 %	2.8 %	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. For the years ended December 31, 2022, 2021 and 2020, $296 million, $115 million, and $— 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, 2022 (dollars in millions):

	Company Share	Plant in Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
Louisa Unit No. 1	88 %	$ 976	$ 511	$ 4
Quad Cities Unit Nos. 1 & 2[(1)]	25	730	482	11
Walter Scott, Jr. Unit No. 3	79	964	624	13
Walter Scott, Jr. Unit No. 4[(2)]	60	171	127	7
George Neal Unit No. 4	41	321	184	6
Ottumwa Unit No. 1[(2)]	52	569	280	19
George Neal Unit No. 3	72	535	312	20
Transmission facilities	Various	267	101	2
Total		$ 4,533	$ 2,621	$ 82

(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 $733 million and $150 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	2022	2021
Asset retirement obligations[(1)]	9 years	$ 469	$ 393
Employee benefit plans[(2)]	15 years	47	42
Other	Various	34	38
Total		$ 550	$ 473

(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.

MidAmerican Energy had regulatory assets not earning a return on investment of $548 million and $470 million as of December 31, 2022 and 2021, 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	2022	2021
Cost of removal[(1)]	29 years	$ 392	$ 394
Iowa electric revenue sharing[(2)]	1 year	312	115
Asset retirement obligations[(3)]	31 years	247	341
Deferred income taxes[(4)]	Various	72	83
Pre-funded AFUDC on transmission MVPs[(5)]	57 years	34	34
Unrealized gain on regulated derivative contracts	1 year	31	26
Employee benefit plans[(6)]	N/A	—	55
Other	Various	31	32
Total		$ 1,119	$ 1,080

(1) 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.

(2) Represents current-year accruals under a regulatory arrangement in Iowa in which equity returns exceeding specified thresholds reduce utility plant upon final determination.

(3) Amount represents the excess of nuclear decommission trust assets over the related ARO. Refer to Note 11 for a discussion of AROs.

(4) 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.

(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) 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.

Natural Gas Purchased for Resale

In February 2021, severe cold weather over the central U.S. caused disruptions in natural gas supply from the southern part of the U.S. These disruptions, combined with increased demand, resulted in historically high prices for natural gas purchased for resale to MidAmerican Energy's retail customers and caused an approximate $245 million increase in natural gas costs above those normally expected. These increased costs are reflected in cost of natural gas purchased for resale and other on the Statement of Operations and their recovery through the Purchased Gas Adjustment Clause is reflected in regulated natural gas and other revenue.

To mitigate the impact to MidAmerican Energy's customers, the IUB ordered the recovery of these higher costs to be applied to customer bills over the period April 2021 through April 2022 based on a customer's monthly natural gas usage. The unbilled portion of these costs as of December 31, 2021, is reflected in trade receivables, net on the Balance Sheet.

(6) Investments and Restricted Investments

Investments and restricted investments consists of the following amounts as of December 31 (in millions):

	2022	2021
Nuclear decommissioning trust	$ 664	$ 768
Rabbi trusts	215	233
Other	23	25
Total	$ 902	$ 1,026

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, 2022 and 2021, the fair value of the trust's funds was invested as follows: 54% and 56%, respectively, in domestic common equity securities, 32% and 30%, respectively, in U.S. government securities, 11% and 12%, respectively, in domestic corporate debt securities and 3% and 2%, 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 Operation.

(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):

	2022	2021
Credit facilities	$ 1,505	$ 1,505
Less:		
Variable-rate tax-exempt bond support	(370)	(370)
Net credit facilities	$ 1,135	$ 1,135

As of December 31, 2022, MidAmerican Energy has a $1.5 billion unsecured credit facility expiring in June 2025 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 2023 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, 2022 and 2021. 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, 2022, 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, 2024.

As of December 31, 2022 and 2021, MidAmerican Energy had $34 million and $42 million, respectively, of fully available letters of credit issued under committed arrangements outside of its 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	2022	2021
First mortgage bonds:			
3.70%, due 2023	$ 250	$ 250	$ 250
3.50%, due 2024	500	500	501
3.10%, due 2027	375	374	373
3.65%, due 2029	850	859	860
4.80%, due 2043	350	347	346
4.40%, due 2044	400	395	395
4.25%, due 2046	450	446	446
3.95%, due 2047	475	471	470
3.65%, due 2048	700	689	689
4.25%, due 2049	900	875	874
3.15%, due 2050	600	592	592
2.70%, due 2052	500	492	492
Notes:			
6.75% Series, due 2031	400	397	397
5.75% Series, due 2035	300	298	298
5.80% Series, due 2036	350	348	348
Transmission upgrade obligations, 3.20% to 7.81%, due 2036 to 2042	48	27	22
Variable-rate tax-exempt bond obligation series: (weighted average interest rate-2022-3.83%, 2021-0.13%):			
Due 2023, issued in 1993	7	7	7
Due 2023, issued in 2008	57	57	57
Due 2024	35	35	35
Due 2025	13	13	13
Due 2036	33	33	33
Due 2038	45	45	45
Due 2046	30	30	29
Due 2047	150	149	149
Total long-term debt	$ 7,818	$ 7,729	$ 7,721

Reflected as:

	2022	2021
Current portion of long-term debt	$ 317	$ —
Long-term debt	7,412	7,721
Total long-term debt	$ 7,729	$ 7,721

The annual repayments of MidAmerican Energy's long-term debt for the years beginning January 1, 2023, and thereafter, excluding unamortized premiums, discounts and debt issuance costs, are as follows (in millions):

2023	$ 317
2024	538
2025	15
2026	3
2027	378
2028 and thereafter	6,567

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 $24 billion of MidAmerican Energy's eligible property, based on original cost, was subject to the lien of the mortgage as of December 31, 2022. 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, 2022 and 2021. 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, 2022, MidAmerican Energy was in compliance with all of its applicable long-term debt covenants.

In March 1999, MidAmerican Energy committed to the IUB 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 IUB 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 IUB 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, 2022, MidAmerican Energy's common equity ratio was 55% 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 $4.2 billion as of December 31, 2022, without falling below 42%.

(9) Income Taxes

MidAmerican Energy's income tax benefit consists of the following for the years ended December 31 (in millions):

	2022	2021	2020
Current:			
Federal	$ (769)	$ (736)	$ (684)
State	(34)	(92)	(94)
	(803)	(828)	(778)
Deferred:			
Federal	77	189	201
State	(43)	(35)	8
	34	154	209
Investment tax credits	(1)	(1)	(1)
Total	$ (770)	$ (675)	$ (570)

A reconciliation of the federal statutory income tax rate to MidAmerican Energy's effective income tax rate applicable to income before income tax benefit is as follows for the years ended December 31:

	2022	2021	2020
Federal statutory income tax rate	21 %	21 %	21 %
Income tax credits	(372)	(262)	(199)
State income tax, net of federal income tax benefit	(32)	(46)	(27)
Effects of ratemaking	(23)	(20)	(17)
Other, net	3	(1)	(1)
Effective income tax rate	(403)%	(308)%	(223)%

Income 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. PTCs recognized for the years ended December 31, 2022, 2021 and 2020 totaled $710 million, $574 million and $510 million, respectively.

MidAmerican Energy's net deferred income tax liability consists of the following as of December 31 (in millions):

	2022	2021
Deferred income tax assets:		
Regulatory liabilities	$ 194	$ 240
Asset retirement obligations	191	220
Revenue sharing	87	33
State carryforwards	61	55
Employee benefits	37	26
Other	24	(3)
Total deferred income tax assets	594	571
Valuation allowances	(2)	(1)
Total deferred income tax assets, net	592	570
Deferred income tax liabilities:		
Depreciable property	(3,895)	(3,843)
Regulatory assets	(128)	(112)
Other	(2)	(4)
Total deferred income tax liabilities	(4,025)	(3,959)
Net deferred income tax liability	$ (3,433)	$ (3,389)

As of December 31, 2022, MidAmerican Energy's state tax carryforwards, principally related to $921 million of net operating losses, expire at various intervals between 2023 and 2041.

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 for other states through December 31, 2018, except for the impact of any federal audit adjustments. 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.

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):

	2022	2021
Beginning balance	$ 13	$ 8
Additions based on tax positions related to the current year	15	16
Reductions based on tax positions related to the current year	(12)	(11)
Ending balance	$ 16	$ 13

As of December 31, 2022, MidAmerican Energy had unrecognized tax benefits totaling $39 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. For the years ended December 31, 2022 and 2021, the defined benefit pension plan recorded a settlement loss of $4 million and a settlement gain of $5 million, respectively, for previously unrecognized losses and gains as a result of excess lump sum distributions over the defined threshold. In 2022, the defined benefit pension plan recorded a curtailment gain of $10 million as a result of certain plan amendments.

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 2022, 2021 and 2020, MidAmerican Energy's share of the pension net periodic benefit (credit) cost was $(2) million, $(20) million and $(13) million, respectively. MidAmerican Energy's share of the other postretirement net periodic benefit (credit) cost in 2022, 2021 and 2020 totaled $(2) million, $1 million and $(5) million, respectively.

Net periodic benefit cost (credit) 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		
	2022	2021	2020	2022	2021	2020
Service cost	$ 15	$ 20	$ 8	$ 8	$ 9	$ 4
Interest cost	23	22	25	8	8	7
Expected return on plan assets	(27)	(37)	(40)	(14)	(10)	(14)
Curtailment	(10)	—	—	—	—	—
Settlement	4	(5)	—	—	—	—
Net amortization	1	1	1	(2)	(4)	(5)
Net periodic benefit cost (credit)	$ 6	$ 1	$ (6)	$ —	$ 3	$ (8)

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	
	2022	2021	2022	2021
Plan assets at fair value, beginning of year	$ 704	$ 718	$ 308	$ 278
Employer contributions	7	8	3	10
Participant contributions	—	—	1	1
Actual return on plan assets	(130)	58	(58)	34
Settlement	(57)	(46)	—	—
Benefits paid	(34)	(34)	(14)	(15)
Plan assets at fair value, end of year	$ 490	$ 704	$ 240	$ 308

The following table is a reconciliation of the benefit obligations for the years ended December 31 (in millions):

	Pension		Other Postretirement	
	2022	2021	2022	2021
Benefit obligation, beginning of year	$ 781	$ 845	$ 285	$ 304
Service cost	15	20	8	9
Interest cost	23	22	8	8
Participant contributions	—	—	1	1
Actuarial (gain) loss	(129)	(25)	(64)	(18)
Amendment	(3)	—	19	1
Curtailment	(10)	—	—	—
Settlement	(57)	(46)	—	—
Acquisition	—	(1)	—	(5)
Benefits paid	(34)	(34)	(14)	(15)
Benefit obligation, end of year	$ 586	$ 781	$ 243	$ 285
Accumulated benefit obligation, end of year	$ 551	$ 721		

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	
	2022	2021	2022	2021
Plan assets at fair value, end of year	$ 490	$ 704	$ 240	$ 308
Less - Benefit obligation, end of year	586	781	243	285
Funded status	$ (96)	$ (77)	$ (3)	$ 23
Amounts recognized on the Balance Sheets:				
Other assets	$ —	$ 34	$ —	$ 23
Other current liabilities	(8)	(7)	—	—
Other long-term liabilities	(88)	(104)	(3)	—
Amounts recognized	$ (96)	$ (77)	$ (3)	$ 23

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 $134 million and $143 million as of December 31, 2022 and 2021, 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 accumulated benefit obligation and projected benefit obligation for the SERP was $85 million and $85 million for 2022 and $111 million and $111 million for 2021, 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	
	2022	2021	2022	2021
Net loss (gain)	$ (4)	$ (25)	$ 11	$ 2
Prior service cost (credit)	(3)	—	19	(3)
Total	$ (7)	$ (25)	$ 30	$ (1)

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, 2022 and 2021 is as follows (in millions):

	Regulatory Asset	Regulatory Liability	Receivables (Payables) with Affiliates	Total
Pension				
Balance, December 31, 2020	$ 21	$ (20)	$ 17	$ 18
Net loss (gain) arising during the year	2	(40)	(9)	(47)
Settlement	—	5	—	5
Net amortization	(1)	—	—	(1)
Total	1	(35)	(9)	(43)
Balance, December 31, 2021	22	(55)	8	(25)
Net loss (gain) arising during the year	(7)	58	(25)	26
Net prior service cost (credit) arising during the year	—	—	(3)	(3)
Settlement	—	(4)	—	(4)
Net amortization	(1)	—	—	(1)
Total	(8)	54	(28)	18
Balance, December 31, 2022	$ 14	$ (1)	$ (20)	$ (7)

	Regulatory Asset	Receivables (Payables) with Affiliates	Total
Other Postretirement			
Balance, December 31, 2020	$ 45	$ (9)	$ 36
Net loss (gain) arising during the year	(29)	(13)	(42)
Net prior service cost (credit) arising during the year	1	—	1
Net amortization	3	1	4
Total	(25)	(12)	(37)
Balance, December 31, 2021	20	(21)	(1)
Net loss (gain) arising during the year	10	(1)	9
Net prior service cost (credit) arising during the year	—	19	19
Net amortization	3	—	3
Total	13	18	31
Balance, December 31, 2022	$ 33	$ (3)	$ 30

Plan Assumptions

Assumptions used to determine benefit obligations and net periodic benefit cost were as follows:

	Pension			Other Postretirement		
	2022	**2021**	**2020**	**2022**	**2021**	**2020**
Benefit obligations as of December 31:						
Discount rate	5.70 %	3.05 %	2.75 %	5.60 %	2.95 %	2.65 %
Rate of compensation increase	3.00 %	2.75 %	2.75 %	N/A	N/A	N/A
Interest crediting rates for cash balance plan						
2020	N/A	N/A	2.27 %	N/A	N/A	N/A
2021	N/A	1.19 %	0.99 %	N/A	N/A	N/A
2022	3.74 %	1.19 %	0.99 %	N/A	N/A	N/A
2023	3.74 %	1.19 %	0.99 %	N/A	N/A	N/A
2024	3.74 %	1.19 %	0.99 %	N/A	N/A	N/A
2025 and beyond	3.74 %	1.19 %	0.99 %	N/A	N/A	N/A
Net periodic benefit cost for the years ended December 31:						
Discount rate	3.05 %	2.75 %	3.40 %	2.95 %	2.65 %	3.20 %
Expected return on plan assets(1)	4.30 %	5.60 %	6.25 %	5.30 %	4.00 %	6.00 %
Rate of compensation increase	2.75 %	2.75 %	2.75 %	N/A	N/A	N/A
Interest crediting rates for cash balance plan	3.74 %	1.19 %	2.27 %	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 4.21% for 2022, 2.39% for 2021 and 4.62% for 2020.

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.

	2022	**2021**
Assumed healthcare cost trend rates as of December 31:		
Healthcare cost trend rate assumed for next year	6.50 %	5.90 %
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	2028	2025

Contributions and Benefit Payments

Employer contributions to the pension and other postretirement benefit plans are expected to be $7 million and $2 million, respectively, during 2022. 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 2023 through 2027 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments	
	Pension	**Other Postretirement**
2023	$ 59	$ 21
2024	54	22
2025	53	23
2026	53	23
2027	51	23
2028-2032	231	105

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, 2022:

	Pension	**Other Postretirement**
	%	%
Debt securities(1)	40-70	20-40
Equity securities(1)	35-60	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, 2022:				
Cash equivalents	$ —	$ 15	$ —	$ 15
Debt securities:				
U.S. government obligations	22	—	—	22
Corporate obligations	—	135	—	135
Municipal obligations	—	10	—	10
Agency, asset and mortgage-backed obligations	—	13	—	13
Equity securities:				
U.S. companies	71	—	—	71
International companies	1	—	—	1
Total assets in the fair value hierarchy	$ 94	$ 173	$ —	267
Investment funds[2] measured at net asset value				223
Total assets measured at fair value				$ 490
As of December 31, 2021:				
Cash equivalents	$ —	$ 27	$ —	$ 27
Debt securities:				
U.S. government obligations	33	—	—	33
Corporate obligations	—	242	—	242
Municipal obligations	—	18	—	18
Agency, asset and mortgage-backed obligations	—	17	—	17
Equity securities:				
U.S. companies	35	—	—	35
Total assets in the fair value hierarchy	$ 68	$ 304	$ —	372
Investment funds[2] measured at net asset value				332
Total assets measured at fair value				$ 704

(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 55% and 45%, respectively, for 2022 and 56% and 44%, respectively, for 2021. Additionally, these funds are invested in U.S. and international securities of approximately 97% and 3%, respectively, for 2022 and 90% and 10%, respectively, for 2021.

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, 2022:				
Cash equivalents	$ 10	$ —	$ —	$ 10
Debt securities:				
U.S. government obligations	2	—	—	2
Corporate obligations	—	3	—	3
Municipal obligations	—	22	—	22
Agency, asset and mortgage-backed obligations	—	2	—	2
Equity securities:				
Investment funds[2]	201	—	—	201
Total assets measured at fair value	$ 213	$ 27	$ —	$ 240
As of December 31, 2021:				
Cash equivalents	$ 8	$ —	$ —	$ 8
Debt securities:				
U.S. government obligations	3	—	—	3
Corporate obligations	—	6	—	6
Municipal obligations	—	28	—	28
Agency, asset and mortgage-backed obligations	—	3	—	3
Equity securities:				
Investment funds[2]	260	—	—	260
Total assets measured at fair value	$ 271	$ 37	$ —	$ 308

(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 82% and 18%, respectively, for 2022 and 2021. Additionally, these funds are invested in U.S. and international securities of approximately 82% and 18%, respectively, for 2022 and for 2021.

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 $33 million, $27 million, and $26 million for the years ended December 31, 2022, 2021 and 2020, 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 $392 million and $394 million as of December 31, 2022 and 2021, respectively.

The following table presents MidAmerican Energy's ARO liabilities by asset type as of December 31 (in millions):

	2022	2021
Quad Cities Station	$ 417	$ 427
Fossil-fueled generating facilities	76	161
Wind-powered generating facilities	210	197
Solar-powered generating facilities and other	4	2
Total asset retirement obligations	$ 707	$ 787
Quad Cities Station nuclear decommissioning trust funds[(1)]	$ 664	$ 768

(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):

	2022	2021
Beginning balance	$ 787	$ 818
Change in estimated costs	(27)	35
Additions	2	6
Retirements	(85)	(103)
Accretion	30	31
Ending balance	$ 707	$ 787
Reflected as:		
Other current liabilities	$ 24	$ 73
Asset retirement obligations	683	714
	$ 707	$ 787

Retirements in 2022 and 2021 relate to settlements of MidAmerican Energy's coal combustion residuals ARO liabilities.

(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, 2022:					
Assets:					
Commodity derivatives	$ 1	$ 37	$ 6	$ (10)	$ 34
Money market mutual funds	225	—	—	—	225
Debt securities:					
U.S. government obligations	215	—	—	—	215
International government obligations	—	1	—	—	1
Corporate obligations	—	70	—	—	70
Municipal obligations	—	3	—	—	3
Agency, asset and mortgage-backed obligations	—	1	—	—	1
Equity securities:					
U.S. companies	360	—	—	—	360
International companies	8	—	—	—	8
Investment funds	16	—	—	—	16
	$ 825	$ 112	$ 6	$ (10)	$ 933
Liabilities - commodity derivatives	$ —	$ (12)	$ (1)	$ 10	$ (3)
As of December 31, 2021:					
Assets:					
Commodity derivatives	$ —	$ 32	$ 3	$ (7)	$ 28
Money market mutual funds	228	—	—	—	228
Debt securities:					
U.S. government obligations	232	—	—	—	232
International government obligations	—	2	—	—	2
Corporate obligations	—	90	—	—	90
Municipal obligations	—	3	—	—	3
Agency, asset and mortgage-backed obligations	—	2	—	—	2
Equity securities:					
U.S. companies	428	—	—	—	428
International companies	10	—	—	—	10
Investment funds	18	—	—	—	18
	$ 916	$ 129	$ 3	$ (7)	$ 1,041
Liabilities - commodity derivatives	$ —	$ (6)	$ (8)	$ 12	$ (2)

(1) Represents netting under master netting arrangements and a net cash collateral receivable of $— million and $5 million as of December 31, 2022 and 2021, 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):

	2022	2021	2020
Beginning balance	$ (5)	$ 2	$ 1
Changes in fair value recognized in net regulatory assets	37	(2)	2
Settlements	(27)	(5)	(1)
Ending balance	$ 5	$ (5)	$ 2

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):

	2022		2021	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 7,729	$ 6,964	$ 7,721	$ 9,037

(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, 2022, are as follows (in millions):

	2023	2024	2025	2026	2027	2028 and Thereafter	Total
Contract type:							
Coal and natural gas for generation	$ 139	$ 81	$ 60	$ 29	$ 30	$ —	$ 339
Electric capacity and transmission	33	32	33	33	17	7	155
Natural gas contracts for gas operations	172	78	70	60	47	33	460
Construction commitments	699	60	24	4	—	—	787
Easements	42	43	44	44	45	1,536	1,754
Maintenance, services and other	165	129	98	102	99	163	756
	$ 1,250	$ 423	$ 329	$ 272	$ 238	$ 1,739	$ 4,251

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 2027.

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 2027.

Construction Commitments

MidAmerican Energy's firm construction commitments reflected in the table above consist primarily of contracts for the repowering and construction of wind- and solar-powered generating facilities and the settlement of AROs.

Easements

MidAmerican Energy has non-cancelable easements with minimum payment commitments ranging through 2061 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 2030.

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. Plaintiffs occasionally seek punitive or exemplary damages. MidAmerican Energy does not believe that such normal and routine litigation will have a material impact on its financial results.

Transmission Rates

MidAmerican Energy's wholesale transmission rates are set annually using FERC-approved formula rates subject to true-up for actual cost of service. In November 2013 and February 2015, a coalition of intervenors filed successive complaints with the FERC requesting that the base return on equity ("ROE") used to determine rates in effect prior to September 2016 no longer be found just and reasonable and sought to reduce the base ROE. In August 2022, the U.S. Court of Appeals for the District of Columbia Circuit issued an opinion vacating all orders related to the complaints and remanding them back to the FERC. MidAmerican Energy cannot predict the ultimate outcome of these matters or the amount of refunds, if any, and accordingly, has reversed its previously accrued liability for potential refunds of amounts collected under the higher ROE during the periods covered by the complaints.

(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, 2022			
	Electric	**Natural Gas**	**Other**	**Total**
Customer Revenue:				
Retail:				
Residential	$ 765	$ 555	$ —	$ 1,320
Commercial	354	216	—	570
Industrial	1,047	38	—	1,085
Natural gas transportation services	—	44	—	44
Other retail	154	2	—	156
Total retail	2,320	855	—	3,175
Wholesale	495	173	—	668
Multi-value transmission projects	61	—	—	61
Other Customer Revenue	—	—	7	7
Total Customer Revenue	2,876	1,028	7	3,911
Other revenue	112	2	—	114
Total operating revenue	$ 2,988	$ 1,030	$ 7	$ 4,025

	For the Year Ended December 31, 2021			
	Electric	**Natural Gas**	**Other**	**Total**
Customer Revenue:				
Retail:				
Residential	$ 718	$ 564	$ —	$ 1,282
Commercial	327	223	—	550
Industrial	934	30	—	964
Natural gas transportation services	—	39	—	39
Other retail	149	3	—	152
Total retail	2,128	859	—	2,987
Wholesale	312	142	—	454
Multi-value transmission projects	58	—	—	58
Other Customer Revenue	—	—	15	15
Total Customer Revenue	2,498	1,001	15	3,514
Other revenue	31	2	—	33
Total operating revenue	$ 2,529	$ 1,003	$ 15	$ 3,547

	For the Year Ended December 31, 2020			
	Electric	Natural Gas	Other	Total
Customer Revenue:				
Retail:				
Residential	$ 685	$ 342	$ —	$ 1,027
Commercial	304	111	—	415
Industrial	804	14	—	818
Natural gas transportation services	—	36	—	36
Other retail	131	2	—	133
Total retail	1,924	505	—	2,429
Wholesale	133	66	—	199
Multi-value transmission projects	60	—	—	60
Other Customer Revenue	—	—	8	8
Total Customer Revenue	2,117	571	8	2,696
Other revenue	22	2	—	24
Total operating revenue	$ 2,139	$ 573	$ 8	$ 2,720

(15) Shareholder's Equity

In 2022, MidAmerican Energy paid $275 million in cash dividends to its parent company, MHC. In January 2023, MidAmerican Energy paid $100 million 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):

	2022	2021	2020
Non-service cost components of postretirement employee benefit plans	$ 9	$ 26	$ 24
Corporate-owned life insurance (loss) income	(16)	21	16
Gains on disposition of assets	—	—	6
Interest income and other, net	7	6	6
Total	$ —	$ 53	$ 52

(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):

	2022	2021	2020
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	$ 292	$ 279	$ 286
Income taxes received, net	$ 840	$ 746	$ 709
Supplemental disclosure of non-cash investing transactions:			
Accruals related to property, plant and equipment additions	$ 168	$ 257	$ 227

(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 $78 million, $66 million and $47 million for 2022, 2021 and 2020, respectively.

MidAmerican Energy reimbursed BHE in the amount of $79 million, $72 million and $15 million in 2022, 2021 and 2020, respectively, for its share of corporate expenses and other costs. Amounts charged to MidAmerican Energy in 2022 and 2021 were primarily reflected in construction work-in-progress on the Balance Sheets as of December 31, 2022 and 2021.

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 $141 million, $132 million and $129 million in 2022, 2021 and 2020, respectively. Additionally, in 2020, MidAmerican Energy paid $7 million to BHE Renewables, LLC, a wholly owned subsidiary of BHE, for the purchase of wind turbine components.

MidAmerican Energy had accounts receivable from affiliates of $9 million and $10 million as of December 31, 2022 and 2021, respectively, that are included in other current assets on the Balance Sheets. MidAmerican Energy also had accounts payable to affiliates of $22 million and $17 million as of December 31, 2022 and 2021, respectively, that are included in accounts payable on the Balance Sheets.

MidAmerican Energy is party to a tax-sharing agreement and is part of the Berkshire Hathaway consolidated U.S. federal income tax return. For current federal and state income taxes, MidAmerican Energy had a receivable from BHE of $42 million and $79 million as of December 31, 2022 and 2021, respectively. MidAmerican Energy received net cash payments for federal and state income taxes from BHE totaling $840 million, $746 million and $709 million for the years ended December 31, 2022, 2021 and 2020, 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 $79 million and $124 million as of December 31, 2022 and 2021, respectively, and are included in other assets on the Balance Sheets. Similar amounts payable to affiliates totaled $40 million and $63 million as of December 31, 2022 and 2021, 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 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, interest income, interest expense and income tax expense are allocated to each segment based on certain factors, which primarily relate to the nature of the cost. Refer to Note 9 for a discussion of items affecting income tax (benefit) expense for the regulated electric and natural gas operating segments.

The following tables provide information on a reportable segment basis (in millions):

	Years Ended December 31,		
	2022	2021	2020
Operating revenue:			
Regulated electric	$ 2,988	$ 2,529	$ 2,139
Regulated natural gas	1,030	1,003	573
Other	7	15	8
Total operating revenue	$ 4,025	$ 3,547	$ 2,720
Depreciation and amortization:			
Regulated electric	$ 1,112	$ 861	$ 667
Regulated natural gas	56	53	49
Total depreciation and amortization	$ 1,168	$ 914	$ 716
Operating income:			
Regulated electric	$ 372	$ 358	$ 384
Regulated natural gas	66	58	64
Total operating income	$ 438	$ 416	$ 448
Interest expense:			
Regulated electric	$ 290	$ 279	$ 281
Regulated natural gas	23	23	23
Total interest expense	$ 313	$ 302	$ 304

	Years Ended December 31,		
	2022	2021	2020
Income tax (benefit) expense:			
Regulated electric	$ (779)	$ (677)	$ (584)
Regulated natural gas	9	3	14
Other	—	(1)	—
Total income tax (benefit) expense	$ (770)	$ (675)	$ (570)
Net income:			
Regulated electric	$ 931	$ 844	$ 780
Regulated natural gas	30	50	45
Other	—	—	1
Net income	$ 961	$ 894	$ 826
Capital expenditures:			
Regulated electric	$ 1,742	$ 1,806	$ 1,704
Regulated natural gas	127	106	132
Total capital expenditures	$ 1,869	$ 1,912	$ 1,836

	As of December 31,		
	2022	2021	2020
Total assets:			
Regulated electric	$ 22,092	$ 21,385	$ 19,892
Regulated natural gas	1,885	1,871	1,544
Other	1	1	1
Total assets	$ 23,978	$ 23,257	$ 21,437

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, 2022 and 2021, 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, 2022, 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, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022, 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 audit 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 audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Regulatory Matters — Effects of Rate Regulation on the Financial Statements — Refer to Notes 2 and 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 it meets 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 their 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 future decisions by the Commissions, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of future decisions by the Commissions included the following, among others:

- We evaluated MidAmerican Funding's disclosures related to the effects of rate regulation, including the balances recorded and regulatory developments.
- We read relevant regulatory orders issued by the Commissions, regulatory statutes, interpretations, procedural memorandums, filings made by interveners, and other external information. We evaluated the external information and compared to management's recorded regulatory asset and liability balances for completeness.
- For regulatory matters in process, 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.
- We inquired of management about property, plant, and equipment that may be abandoned. We inquired of management to identify projects that are designed to replace assets that may be retired prior to the end of the useful life. We inspected minutes of the board of directors and regulatory orders and other filings with the Commissions to identify any evidence that may contradict management's assertion regarding probability of an abandonment.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
February 24, 2023

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,	
	2022	**2021**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 261	$ 233
Trade receivables, net	536	526
Income tax receivable	43	80
Inventories	277	234
Prepayments	91	71
Other current assets	66	52
Total current assets	1,274	1,196
Property, plant and equipment, net	21,092	20,302
Goodwill	1,270	1,270
Regulatory assets	550	473
Investments and restricted investments	904	1,028
Other assets	164	262
Total assets	$ 25,254	$ 24,531

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,	
	2022	**2021**
LIABILITIES AND MEMBER'S EQUITY		
Current liabilities:		
Accounts payable	$ 536	$ 531
Accrued interest	90	89
Accrued property, income and other taxes	170	158
Note payable to affiliate	—	189
Current portion of long-term debt	317	—
Other current liabilities	93	146
Total current liabilities	1,206	1,113
Long-term debt	7,652	7,961
Regulatory liabilities	1,119	1,080
Deferred income taxes	3,431	3,387
Asset retirement obligations	683	714
Other long-term liabilities	484	475
Total liabilities	14,575	14,730
Commitments and contingencies (Note 13)		
Member's equity:		
Paid-in capital	1,679	1,679
Retained earnings	9,000	8,122
Total member's equity	10,679	9,801
Total liabilities and member's equity	$ 25,254	$ 24,531

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,		
	2022	**2021**	**2020**
Operating revenue:			
Regulated electric	$ 2,988	$ 2,529	$ 2,139
Regulated natural gas and other	1,037	1,018	589
Total operating revenue	4,025	3,547	2,728
Operating expenses:			
Cost of fuel and energy	679	539	339
Cost of natural gas purchased for resale and other	763	761	329
Operations and maintenance	828	775	755
Depreciation and amortization	1,168	914	716
Property and other taxes	149	142	135
Total operating expenses	3,587	3,131	2,274
Operating income	438	416	454
Other income (expense):			
Interest expense	(333)	(319)	(322)
Allowance for borrowed funds	15	13	15
Allowance for equity funds	51	39	45
Other, net	—	54	52
Total other income (expense)	(267)	(213)	(210)
Income before income tax benefit	171	203	244
Income tax benefit	(776)	(680)	(574)
Net income	$ 947	$ 883	$ 818

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, 2019	$ 1,679	$ 6,422	$ 8,101
Net income	—	818	818
Balance, December 31, 2020	1,679	7,240	8,919
Net income	—	883	883
Other equity transactions	—	(1)	(1)
Balance, December 31, 2021	1,679	8,122	9,801
Net income	—	947	947
Distribution to member	—	(69)	(69)
Balance, December 31, 2022	$ 1,679	$ 9,000	$ 10,679

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,		
	2022	**2021**	**2020**
Cash flows from operating activities:			
Net income	$ 947	$ 883	$ 818
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	1,168	914	716
Amortization of utility plant to other operating expenses	35	34	34
Allowance for equity funds	(51)	(39)	(45)
Deferred income taxes and amortization of investment tax credits	33	153	211
Settlements of asset retirement obligations	(85)	(103)	(124)
Other, net	52	21	(17)
Changes in other operating assets and liabilities:			
Trade receivables and other assets	(11)	(293)	48
Inventories	(43)	44	(52)
Pension and other postretirement benefit plans, net	8	(4)	(19)
Accrued property, income and other taxes, net	40	(71)	(66)
Accounts payable and other liabilities	68	66	32
Net cash flows from operating activities	2,161	1,605	1,536
Cash flows from investing activities:			
Capital expenditures	(1,869)	(1,912)	(1,836)
Purchases of marketable securities	(499)	(213)	(281)
Proceeds from sales of marketable securities	492	207	269
Proceeds from sales of other investments	—	—	3
Other investment proceeds	2	1	9
Other, net	6	5	11
Net cash flows from investing activities	(1,868)	(1,912)	(1,825)
Cash flows from financing activities:			
Distribution to member	(69)	—	—
Proceeds from long-term debt	—	492	—
Repayments of long-term debt	(2)	(1)	—
Net change in note payable to affiliate	(189)	12	5
Other, net	(2)	(2)	(1)
Net cash flows from financing activities	(262)	501	4
Net change in cash and cash equivalents and restricted cash and cash equivalents	31	194	(285)
Cash and cash equivalents and restricted cash and cash equivalents at beginning of year	240	46	331
Cash and cash equivalents and restricted cash and cash equivalents at end of year	$ 271	$ 240	$ 46

The accompanying notes are an integral part of these consolidated financial statements.

MIDAMERICAN FUNDING, LLC AND SUBSIDIARIES
NOTES TO 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 owns subsidiaries principally engaged in energy businesses. BHE is a consolidated 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, 2022, 2021 and 2020.

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, 2022 and 2021 as presented in 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,	
	2022	2021
Cash and cash equivalents	$ 261	$ 233
Restricted cash and cash equivalents in other current assets	10	7
Total cash and cash equivalents and restricted cash and cash equivalents	$ 271	$ 240

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, 2022. 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 2022, 2021 and 2020, 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 $1 million and $1 million as of December 31, 2022 and 2021, 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, 2022 and 2021.

(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 2023 and has a variable interest rate based on the Secured Overnight Financing Rate, plus a spread. As of December 31, 2022 and 2021, there were no borrowings outstanding under this credit facility. As of December 31, 2022, 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, 2022 and 2021.

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 $5.4 billion as of December 31, 2022.

As of December 31, 2022, 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

MidAmerican Funding's income tax benefit consists of the following for the years ended December 31 (in millions):

	2022	2021	2020
Current:			
Federal	$ (773)	$ (739)	$ (689)
State	(36)	(94)	(96)
	(809)	(833)	(785)
Deferred:			
Federal	77	189	204
State	(43)	(35)	8
	34	154	212
Investment tax credits	(1)	(1)	(1)
Total	$ (776)	$ (680)	$ (574)

A reconciliation of the federal statutory income tax rate to MidAmerican Funding's effective income tax rate applicable to income before income tax benefit is as follows for the years ended December 31:

	2022	2021	2020
Federal statutory income tax rate	21 %	21 %	21 %
Income tax credits	(416)	(283)	(209)
State income tax, net of federal income tax benefit	(36)	(50)	(29)
Effects of ratemaking	(26)	(21)	(17)
Other, net	3	(2)	(1)
Effective income tax rate	(454)%	(335)%	(235)%

Income 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. PTCs recognized for the years ended December 31, 2022, 2021 and 2020 totaled $710 million, $574 million and $510 million, respectively.

MidAmerican Funding's net deferred income tax liability consists of the following as of December 31 (in millions):

	2022	2021
Deferred income tax assets:		
Regulatory liabilities	$ 194	$ 240
Asset retirement obligations	192	220
Revenue sharing	87	33
State carryforwards	61	55
Employee benefits	37	26
Other	24	(3)
Total deferred income tax assets	595	571
Valuation allowances	(2)	(1)
Total deferred income tax assets, net	593	570
Deferred income tax liabilities:		
Depreciable property	(3,895)	(3,843)
Regulatory assets	(128)	(112)
Other	(1)	(2)
Total deferred income tax liabilities	(4,024)	(3,957)
Net deferred income tax liability	$ (3,431)	$ (3,387)

As of December 31, 2022, MidAmerican Funding's state tax carryforwards, principally related to $921 million of net operating losses, expire at various intervals between 2023 and 2041.

The U.S. Internal Revenue Service has closed or effectively settled its examination 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 for other states through December 31, 2018, except for the impact of any federal audit adjustments. 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.

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):

	2022	2021
Beginning balance	$ 13	$ 8
Additions based on tax positions related to the current year	15	16
Reductions based on tax positions related to the current year	(12)	(11)
Ending balance	$ 16	$ 13

As of December 31, 2022, MidAmerican Funding had unrecognized tax benefits totaling $39 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):

	2022	2021	2020
Pension costs	$ 8	$ 21	$ 7
Other postretirement costs	1	2	(3)

(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):

	2022		2021	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 7,969	$ 7,219	$ 7,961	$ 9,350

(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. Plaintiffs occasionally seek punitive or exemplary damages. 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. Additionally, MidAmerican Funding had $— million, $— million and $8 million of other revenue from contracts with customers for the year ended December 31, 2022, 2021 and 2020, respectively.

(15) Member's Equity

In 2022, MidAmerican Funding paid a $69 million cash distribution to its parent company, BHE. In January 2023, MidAmerican Funding paid a $100 million cash distribution 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):

	2022	2021	2020
Non-service cost components of postretirement employee benefit plans	$ 9	$ 26	$ 24
Corporate-owned life insurance (loss) income	(16)	21	16
Gains on disposition of assets	—	—	6
Interest income and other, net	7	7	6
Total	$ —	$ 54	$ 52

(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):

	2022	2021	2020
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	$ 309	$ 296	$ 302
Income taxes received, net	$ 845	$ 751	$ 715
Supplemental disclosure of non-cash investing and financing transactions:			
Accruals related to property, plant and equipment additions	$ 168	$ 257	$ 227

(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 $77 million, $65 million and $46 million for 2022, 2021 and 2020, respectively.

MidAmerican Funding reimbursed BHE in the amount of $79 million, $72 million and $15 million in 2022, 2021 and 2020, respectively, for its share of corporate expenses and other costs. Amounts charged to MidAmerican Funding in 2022 and 2021 were primarily reflected in construction work-in-progress on the Consolidated Balance Sheets as of December 31, 2022 and 2021.

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 $141 million, $132 million and $129 million in 2022, 2021 and 2020, respectively. Additionally, in 2020, MidAmerican Energy paid $7 million to BHE Renewables, LLC, a wholly owned subsidiary of BHE, for the purchase of wind turbine components.

MHC has a $300 million revolving credit arrangement carrying interest at SOFR, plus a spread to borrow from BHE. Outstanding balances are unsecured and due on demand. The outstanding balance was $— million as of December 31, 2022, and $189 million at an interest rate of 0.353% as of December 31, 2021, and is reflected as note payable to affiliate on the Consolidated Balance Sheet. During 2022, MHC received $275 million in the form of a dividend from MidAmerican Energy that was used to pay off the note payable to BHE.

BHE has a $100 million revolving credit arrangement, carrying interest at SOFR, plus a spread to borrow from MHC. Outstanding balances are unsecured and due on demand. There were no borrowings outstanding throughout 2022 and 2021.

MidAmerican Funding had accounts receivable from affiliates of $10 million and $11 million as of December 31, 2022 and 2021, respectively, that are included in other current assets on the Consolidated Balance Sheets. MidAmerican Funding also had accounts payable to affiliates of $22 million and $17 million as of December 31, 2022 and 2021, respectively, that are included in accounts payable on the Consolidated Balance Sheets.

MidAmerican Funding is party to a tax-sharing agreement and is part of the Berkshire Hathaway consolidated U.S. federal income tax return. For current federal and state income taxes, MidAmerican Funding had a receivable from BHE of $43 million and $80 million as of December 31, 2022 and 2021, respectively. MidAmerican Funding received net cash payments for federal and state income taxes from BHE totaling $845 million, $751 million and $715 million for the years ended December 31, 2022, 2021 and 2020, 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 $79 million and $124 million as of December 31, 2022 and 2021, respectively, and are included in other assets on the Consolidated Balance Sheets. Similar amounts payable to affiliates totaled $40 million and $63 million as of December 31, 2022 and 2021, 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 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, interest income, interest expense and income tax expense are allocated to each segment based on certain factors, which primarily relate to the nature of the cost. "Other" in the tables below consists of the nonregulated subsidiaries of MidAmerican Funding not engaged in the energy business and parent company interest expense. Refer to Note 9 for a discussion of items affecting income tax (benefit) expense for the regulated electric and natural gas operating segments.

The following tables provide information on a reportable segment basis (in millions):

	Years Ended December 31,		
	2022	**2021**	**2020**
Operating revenue:			
Regulated electric	$ 2,988	$ 2,529	$ 2,139
Regulated natural gas	1,030	1,003	573
Other	7	15	16
Total operating revenue	$ 4,025	$ 3,547	$ 2,728
Depreciation and amortization:			
Regulated electric	$ 1,112	$ 861	$ 667
Regulated natural gas	56	53	49
Total depreciation and amortization	$ 1,168	$ 914	$ 716

	Years Ended December 31,		
	2022	2021	2020
Operating income:			
Regulated electric	$ 372	$ 358	$ 384
Regulated natural gas	66	58	64
Other	—	—	6
Total operating income	$ 438	$ 416	$ 454
Interest expense:			
Regulated electric	$ 290	$ 279	$ 281
Regulated natural gas	23	23	23
Other	20	17	18
Total interest expense	$ 333	$ 319	$ 322
Income tax (benefit) expense:			
Regulated electric	$ (779)	$ (677)	$ (584)
Regulated natural gas	9	3	14
Other	(6)	(6)	(4)
Total income tax (benefit) expense	$ (776)	$ (680)	$ (574)
Net income:			
Regulated electric	$ 931	$ 844	$ 780
Regulated natural gas	30	50	45
Other	(14)	(11)	(7)
Net income	$ 947	$ 883	$ 818
Capital expenditures:			
Regulated electric	$ 1,742	$ 1,806	$ 1,704
Regulated natural gas	127	106	132
Total capital expenditures	$ 1,869	$ 1,912	$ 1,836

	As of December 31,		
	2022	2021	2020
Total assets:			
Regulated electric	$ 23,283	$ 22,576	$ 21,083
Regulated natural gas	1,963	1,950	1,623
Other	8	5	5
Total assets	$ 25,254	$ 24,531	$ 22,711

Goodwill by reportable segment as of December 31, 2022 and 2021, was as follows (in millions):

Regulated electric	$ 1,191
Regulated natural gas	79
Total	$ 1,270

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, 2022 was $298 million, a decrease of $5 million, or 2%, compared to 2021, primarily due to lower cash surrender value of corporate-owned life insurance policies and higher pension expense, higher interest expense, primarily due to higher long-term debt, higher depreciation and amortization, mainly due to higher plant placed in-service, higher property and other taxes, mainly due to a decrease in the amount of abatements available, higher operations and maintenance expenses, mainly due to higher earnings sharing and higher plant operations and maintenance expenses, partially offset by higher interest and dividend income, primarily from carrying charges on regulatory balances, higher capitalized interest and allowance for funds used during construction from higher construction work-in-progress and higher utility margin. Utility margin increased primarily due to higher regulatory-related revenue deferrals and higher retail customer volumes, partially offset by unfavorable price impacts from changes in sales mix, lower transmission and wholesale revenue and lower other retail revenue. Retail customer volumes, including distribution only service customers, increased 1.9% primarily due to an increase in the average number of customers and favorable changes in customer usage, offset by the unfavorable impact of weather. Energy generated decreased 4% for 2022 compared to 2021 primarily due to lower natural gas-fueled generation. Wholesale electricity sales volumes increased 65% and purchased electricity volumes increased 14%.

Net income for the year ended December 31, 2021 was $303 million, an increase of $8 million, or 3%, compared to 2020, primarily due to lower operations and maintenance expenses, primarily due to lower net regulatory instructed deferrals and amortizations, lower earnings sharing and lower plant operations and maintenance expenses, lower income tax expense primarily due to the recognition of amortization of excess deferred income taxes following regulatory approval effective January 2021, $10 million of higher interest and dividend income, mainly from carrying charges on regulatory balances, lower interest expense and higher other, net. These increases are offset by lower utility margin, primarily due to lower retail rates from the 2020 regulatory rate review with new rates effective January 2021, lower revenue recognized due to a favorable regulatory decision in 2020 and an adjustment to regulatory-related revenue deferrals, partially offset by an increase in the average number of customers and higher transmission revenue, and higher depreciation and amortization, mainly due to regulatory amortizations approved in the 2020 regulatory rate review effective January 2021 and higher plant placed in-service. Retail customer volumes, including distribution only service customers, increased 3.5% primarily due to an increase in the average number of customers and favorable changes in customer usage patterns, offset by the unfavorable impact of weather. Energy generated increased 1% for 2021 compared to 2020 primarily due to higher natural gas-fueled generation. Wholesale electricity sales volumes decreased 5% and purchased electricity volumes increased 10%.

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 profitability 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 running 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):

	2022	2021	Change		2021	2020	Change	
Utility margin:								
Operating revenue	$ 2,630	$ 2,139	$ 491	23 %	$ 2,139	$ 1,998	$ 141	7 %
Cost of fuel and energy	1,427	939	488	52	939	816	123	15
Utility margin	1,203	1,200	3	—	1,200	1,182	18	2
Operations and maintenance	303	301	2	1	301	299	2	1
Depreciation and amortization	417	406	11	3	406	361	45	12
Property and other taxes	53	48	5	10	48	47	1	2
Operating income	$ 430	$ 445	$ (15)	(3)%	$ 445	$ 475	$ (30)	(6)%

Utility Margin

A comparison of key operating results related to utility margin is as follows for the years ended December 31:

	2022	2021	Change		2021	2020	Change	
Utility margin (in millions):								
Operating revenue	$ 2,630	$ 2,139	$ 491	23 %	$ 2,139	$ 1,998	$ 141	7 %
Cost of fuel and energy	1,427	939	488	52	939	816	123	15
Utility margin	$ 1,203	$ 1,200	$ 3	— %	$ 1,200	$ 1,182	$ 18	2 %
Sales (GWhs):								
Residential	10,299	10,415	(116)	(1)%	10,415	10,477	(62)	(1)%
Commercial	4,904	4,838	66	1	4,838	4,591	247	5
Industrial	5,630	5,270	360	7	5,270	4,881	389	8
Other	191	198	(7)	(4)	198	195	3	2
Total fully bundled[(1)]	21,024	20,721	303	1	20,721	20,144	577	3
Distribution only service	2,786	2,646	140	5	2,646	2,425	221	9
Total retail	23,810	23,367	443	2	23,367	22,569	798	4
Wholesale	586	356	230	65	356	374	(18)	(5)
Total GWhs sold	24,396	23,723	673	3 %	23,723	22,943	780	3 %
Average number of retail customers (in thousands)	1,001	985	16	2 %	985	968	17	2 %
Average revenue per MWh:								
Retail - fully bundled[(1)]	$120.21	$ 98.62	$ 21.59	22 %	$ 98.62	$ 94.83	$ 3.79	4 %
Wholesale	$ 61.83	$ 60.69	$ 1.14	2 %	$ 60.69	$ 42.83	$ 17.86	42 %
Heating degree days	1,904	1,613	291	18 %	1,613	1,753	(140)	(8)%
Cooling degree days	4,016	4,109	(93)	(2)%	4,109	4,236	(127)	(3)%
Sources of energy (GWhs)[(2)(3)]:								
Natural gas	13,068	13,655	(587)	(4)%	13,655	13,545	110	1 %
Renewables	69	65	4	6	65	66	(1)	(2)
Total energy generated	13,137	13,720	(583)	(4)	13,720	13,611	109	1
Energy purchased	8,830	7,778	1,052	14	7,778	7,044	734	10
Total	21,967	21,498	469	2 %	21,498	20,655	843	4 %
Average cost of energy per MWh[(4)]:								
Energy generated	$ 49.82	$ 24.41	$ 25.42	104 %	$ 24.41	$ 16.58	$ 7.83	47 %
Energy purchased	$ 87.49	$ 77.64	$ 9.85	13 %	$ 77.64	$ 83.74	$ (6.10)	(7)%

(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 1,113, 1,389 and 1,614 GWhs of natural gas generated energy that is purchased at cost by related parties for the years ended December 31, 2022, 2021 and 2020, 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, 2022 Compared to Year Ended December 31, 2021

Utility margin increased $3 million for 2022 compared to 2021 primarily due to:

- $11 million of higher regulatory-related revenue deferrals and
- $4 million of higher electric retail utility margin due to higher retail customer volumes, offset by unfavorable price impacts from changes in sales mix. Retail customer volumes, including distribution only service customers, increased 1.9% primarily due to an increase in the average number of customers and favorable changes in customer usage, offset by the unfavorable impact of weather.

The increase in utility margin was partially offset by:

- $6 million of lower energy efficiency program rates (offset in operations and maintenance expense);
- $3 million of lower transmission and wholesale revenue; and
- $3 million due to lower other retail revenue.

Operations and maintenance increased $2 million, or 1%, for 2022 compared to 2021 primarily due to higher earnings sharing and higher plant operations and maintenance expenses, partially offset by lower energy efficiency program costs (offset in operating revenue).

Depreciation and amortization increased $11 million, or 3%, for 2022 compared to 2021 primarily due to higher plant placed in-service.

Property and other taxes increased $5 million, or 10%, for 2022 compared to 2021 primarily due to a decrease in the amount of abatements available.

Interest expense increased $12 million, or 8%, for 2022 compared to 2021 primarily due to higher long-term debt.

Capitalized interest increased $5 million for 2022 compared to 2021 primarily due to higher construction work-in-progress.

Allowance for equity funds increased $4 million, or 57%, for 2022 compared to 2021 primarily due to higher construction work-in-progress.

Interest and dividend income increased $27 million for 2022 compared to 2021 primarily due to higher interest income, mainly from carrying charges on regulatory balances.

Other, net decreased $15 million, or 83%, for 2022 compared to 2021 primarily due to lower cash surrender value of corporate-owned life insurance policies and higher pension expense.

Year Ended December 31, 2021 Compared to Year Ended December 31, 2020

Utility margin increased $18 million for 2021 compared to 2020 due to:

- the $120 million one-time bill credit returned to customers in 2020 as a result of the Nevada Power regulatory rate review stipulation ("$120 million bill credit") (offset in operations and maintenance expense and income tax expense) and
- $5 million of higher transmission revenue.

The increase in utility margin was partially offset by:

- $66 million of lower retail electric utility margin primarily due to lower retail rates due to the 2020 regulatory rate review with new rates effective January 2021, offset by higher retail customer volumes. Retail customer volumes, including distribution only service customers, increased 3.5% primarily due to an increase in the average number of customers and favorable changes in customer usage patterns, offset by the unfavorable impact of weather;
- $21 million of lower revenue recognized due to a favorable regulatory decision in 2020;
- $10 million due to lower energy efficiency program rates (offset in operations and maintenance expense);
- $6 million due to an adjustment to regulatory-related revenue deferrals; and
- $4 million due to a regulatory amortization of an impact fee that ended December 2020.

Operations and maintenance increased $2 million, or 1%, for 2021 compared to 2020 primarily due to regulatory liability amortization in 2020 to satisfy a portion of the $120 million bill credit of $94 million (offset in operating revenue), partially offset by lower net regulatory instructed deferrals and amortizations of $46 million, mainly relating to deferrals in 2020 of the non-labor cost savings from the Navajo generating station retirement which was approved for amortization in the 2020 regulatory rate review with new rates effective January 2021, and timing of the regulatory impacts for the ON Line lease cost reallocation, lower earnings sharing, lower energy efficiency program costs (offset in operating revenue) and lower plant operations and maintenance expenses.

Depreciation and amortization increased $45 million, or 12%, for 2021 compared to 2020 primarily due to regulatory amortizations approved in the 2020 regulatory rate review effective January 2021 and higher plant placed in-service.

Interest expense decreased $9 million, or 6% for 2021 compared to 2020 primarily due to lower carrying charges on regulatory balances of $6 million and lower interest expense on long-term debt.

Interest and dividend income increased $10 million for 2021 compared to 2020 primarily due to higher interest income, mainly from carrying charges on regulatory balances.

Other, net increased $9 million for 2021 compared to 2020 primarily due to lower pension expense of $6 million and higher cash surrender value of corporate-owned life insurance policies.

Income tax expense decreased $10 million, or 21%, for 2021 compared to 2020. The effective tax rate was 11% in 2021 and 14% in 2020 and decreased primarily due to the recognition of amortization of excess deferred income taxes following regulatory approval effective January 2021, partially offset by the one-time recognition in 2020 of amortization of excess deferred income taxes to satisfy a portion of the $120 million bill credit (offset in operating revenue).

Liquidity and Capital Resources

As of December 31, 2022, Nevada Power's total net liquidity was $443 million as follows (in millions):

Cash and cash equivalents	$	43
Credit facilities[(1)]		400
Total net liquidity	$	443
Credit facilities:		
Maturity dates		2025

(1) 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.

Operating Activities

Net cash flows from operating activities for the years ended December 31, 2022 and 2021 were $355 million and $505 million, respectively. The change was primarily due to higher payments related to fuel and energy costs and the timing of payments for operating costs, partially offset by higher collections from customers and lower payments for income taxes.

Net cash flows from operating activities for the years ended December 31, 2021 and 2020 were $505 million and $467 million, respectively. The change was primarily due to higher collections from customers, timing of payments for operating costs, increased collections of customer advances and lower inventory purchases, partially offset by the timing of payments for fuel and energy costs and higher payments for income taxes.

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, 2022 and 2021 were $(862) million and $(447) million, respectively. The change was primarily due to increased capital expenditures and the issuance of an affiliate note receivable. Refer to "Future Uses of Cash" for further discussion of capital expenditures.

Net cash flows from investing activities for the years ended December 31, 2021 and 2020 were $(447) million and $(429) 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, 2022 and 2021 were $522 million and $(49) million, respectively. The change was primarily due to higher proceeds from the issuance of long-term debt, lower dividends paid to NV Energy, Inc. and higher contributions from NV Energy, Inc., partially offset by higher repayments of short-term debt.

Net cash flows from financing activities for the years ended December 31, 2021 and 2020 were $(49) million and $(27) million, respectively. The change was primarily due to lower proceeds from the issuance of long-term debt and higher dividends paid to NV Energy, Inc., partially offset by lower repayments of long-term debt and higher net proceeds from short-term debt.

Ability to Issue Debt

Nevada Power currently has an effective shelf registration statement with the SEC to issue up to $2.6 billion of general and refunding mortgage securities through November 1, 2025. Additionally, Nevada Power's ability to issue debt is primarily impacted by its financing authority from the PUCN. As of December 31, 2022, 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 $400 million secured credit facility) does not exceed $3.8 billion and to issue common and preferred stock so long as the total amounts outstanding do not exceed $4.1 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, 2022. In addition, certain financing agreements contain covenants which are currently suspended as Nevada Power's senior secured debt is rated investment grade. However, if Nevada Power's senior secured 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.

Ability to Issue 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, 2022, $9.8 billion of Nevada Power's assets were pledged. Nevada Power had the capacity to issue $3.3 billion of additional general and refunding mortgage securities as of December 31, 2022, 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.

Long-Term Debt

In October 2022, Nevada Power issued $400 million of 5.90% General and Refunding Mortgage bonds, Series GG, due 2053. The net proceeds were used to repay amounts outstanding under its existing revolving credit facility, to fund capital expenditures and for general corporate purposes.

In January 2022, Nevada Power entered into a $300 million secured delayed draw term loan facility maturing in January 2024. Amounts borrowed under the facility bear interest at variable rates based on the Secured Overnight Financing Rate or a base rate, at Nevada Power's option, plus a pricing margin. In January 2022, Nevada Power borrowed $200 million under the facility at an initial interest rate of 0.55%. In May 2022, Nevada Power drew the remaining $100 million available under the facility at an initial interest rate of 1.24%. Nevada Power used the proceeds to repay amounts outstanding under its existing secured credit facility and for general corporate purposes.

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		
	2020	**2021**	**2022**	**2023**	**2024**	**2025**
Electric distribution	$ 232	$ 184	$ 236	$ 276	$ 276	$ 275
Electric transmission	35	57	110	100	333	427
Solar generation	—	8	85	144	2	1
Electric battery storage	—	—	8	271	—	—
Other	188	200	323	512	342	150
Total	$ 455	$ 449	$ 762	$ 1,303	$ 953	$ 853

Nevada Power received PUCN approval through its recent IRP filings for an increase in solar generation and electric transmission and has included estimates from its IRP filings in its forecast capital expenditures for 2023 through 2025. These estimates are likely to change as a result of the RFP process. Nevada Power's historical and forecast capital expenditures include the following:

- Electric distribution includes both growth projects and operating expenditures consisting of routine expenditures for distribution needed to serve existing and expected demand.
- Electric transmission includes both growth projects and operating expenditures. Growth projects primarily relate to the Nevada Utilities' Greenlink Nevada transmission expansion program. In this project, the company has received approval from the PUCN to build a 350-mile, 525-kV transmission line, known as Greenlink West, connecting the Ft. Churchill substation to the Northwest substation to the Harry Allen substation; a 235-mile, 525-kV transmission line, known as Greenlink North, connecting the new Ft. Churchill substation to the Robinson Summit substation; a 46-mile, 345-kV transmission line from the new Ft. Churchill substation to the Mira Loma substations; and a 38-mile, 345-kV transmission line from the new Ft. Churchill substation to the Robinson Summit substations. Operating expenditures consist of routine expenditures for transmission and other infrastructure needed to serve existing and expected demand.

- Solar generation includes a growth project consisting of a 150-MW solar photovoltaic facility with an additional 100 MWs of co-located battery storage that will be developed in Clark County, Nevada. Commercial operation is expected by the end of 2023.
- Electric battery storage includes two growth projects consisting of a 100-MW battery energy storage system co-located with a 150-MW solar photovoltaic facility that will be developed in Clark County, Nevada. Commercial operation is expected by the end of 2023. The second project is a 220-MW grid-tied battery energy storage system that will be developed on the site of the retired Reid Gardner generating station in Clark County, Nevada. Commercial operation is expected by the end of 2023.
- Other includes both growth projects and operating expenditures consisting of turbine upgrades at several generating facilities, routine expenditures for generation, other operating projects and other infrastructure needed to serve existing and expected demand.

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 $2.4 billion on long-term debt, including $152 million due in 2023.

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 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, 2022, 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, 2022, Nevada Power would have been required to post $51 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.

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 $1.3 billion and total regulatory liabilities were $1.1 billion as of December 31, 2022. 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, 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% as a result of 2017 Tax Reform, certain property related basis differences and other various differences on to its customers. As of December 31, 2022, these amounts were recognized as a net regulatory liability of $560 million and will be included in regulated rates when the temporary differences reverse.

Revenue Recognition - Unbilled Revenue

Revenue is recognized as electricity is delivered or services are provided. The determination of customer billings is based on a systematic reading of meters. At the end of each month, energy provided to customers since their last billing is estimated, and the corresponding unbilled revenue is recorded. Unbilled revenue was $143 million as of December 31, 2022. 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. Estimates are reversed in the following month when actual revenue is recorded.

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, 2022:			
Total commodity derivative contracts	$ (52)	$ (23)	$ (81)
As of December 31, 2021:			
Total commodity derivative contracts	$ (113)	$ (93)	$ (133)

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, 2022 and 2021, a net regulatory asset of $52 million and $113 million, respectively, was recorded related to the net derivative liability of $52 million and $113 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, 2022 and 2021, Nevada Power had short- and long-term variable-rate obligations totaling $300 million and $180 million, respectively, that expose Nevada Power 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 Nevada Power's annual interest expense. The carrying value of the variable-rate obligations approximates fair value as of December 31, 2022 and 2021.

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, 2022, 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

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, 2022 and 2021, 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, 2022, 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, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022, 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 audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Regulatory Matters — Effects of Rate Regulation on the Financial Statements — Refer to Notes 2 and 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 it meets 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 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) a refund to customers. Given that management's accounting judgments are based on assumptions about the outcome of future decisions by the Commissions, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of future decisions by the Commissions included the following, among others:

- We evaluated Nevada Power's disclosures related to the effects of rate regulation, including the balances recorded and regulatory developments.
- We read relevant regulatory orders issued by the Commissions, regulatory statutes, interpretations, procedural memorandums, filings made by interveners, and other external information. We evaluated the external information and compared to management's recorded regulatory asset and liability balances for completeness.
- For regulatory matters in process, 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.
- We inquired of management about property, plant, and equipment that may be abandoned. We inquired of management to identify projects that are designed to replace assets that may be retired prior to the end of the useful life. We inspected minutes of the board of directors and regulatory orders and other filings with the Commissions to identify any evidence that may contradict management's assertion regarding probability of an abandonment.

/s/ Deloitte & Touche LLP

Las Vegas, Nevada
February 24, 2023

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, 2022	2021
ASSETS		
Current assets:		
Cash and cash equivalents	$ 43	$ 33
Trade receivables, net	388	227
Note receivable from affiliate	100	—
Inventories	93	64
Regulatory assets	666	291
Other current assets	89	86
Total current assets	1,379	701
Property, plant and equipment, net	7,406	6,891
Regulatory assets	628	728
Other assets	388	432
Total assets	$ 9,801	$ 8,752
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Accounts payable	$ 422	$ 242
Accrued interest	40	32
Accrued property, income and other taxes	32	29
Short-term debt	—	180
Regulatory liabilities	45	49
Customer deposits	51	44
Derivative contracts	51	55
Other current liabilities	49	62
Total current liabilities	690	693
Long-term debt	3,195	2,499
Finance lease obligations	295	310
Regulatory liabilities	1,093	1,100
Deferred income taxes	875	782
Other long-term liabilities	299	338
Total liabilities	6,447	5,722
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	2,333	2,308
Retained earnings	1,022	724
Accumulated other comprehensive loss, net	(1)	(2)
Total shareholder's equity	3,354	3,030
Total liabilities and shareholder's equity	$ 9,801	$ 8,752

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,		
	2022	**2021**	**2020**
Operating revenue	$ 2,630	$ 2,139	$ 1,998
Operating expenses:			
Cost of fuel and energy	1,427	939	816
Operations and maintenance	303	301	299
Depreciation and amortization	417	406	361
Property and other taxes	53	48	47
Total operating expenses	2,200	1,694	1,523
Operating income	430	445	475
Other income (expense):			
Interest expense	(165)	(153)	(162)
Capitalized interest	8	3	3
Allowance for equity funds	11	7	7
Interest and dividend income	47	20	10
Other, net	3	18	9
Total other income (expense)	(96)	(105)	(133)
Income before income tax expense	334	340	342
Income tax expense	36	37	47
Net income	$ 298	$ 303	$ 295

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, 2019	1,000	$ —	$ 2,308	$ 493	$ (4)	$ 2,797
Net income	—	—	—	295	—	295
Dividends declared	—	—	—	(155)	—	(155)
Other equity transactions	—	—	—	1	1	2
Balance, December 31, 2020	1,000	—	2,308	634	(3)	2,939
Net income	—	—	—	303	—	303
Dividends declared	—	—	—	(213)	—	(213)
Other equity transactions	—	—	—	—	1	1
Balance, December 31, 2021	1,000	—	2,308	724	(2)	3,030
Net income	—	—	—	298	—	298
Contributions	—	—	25	—	—	25
Other equity transactions	—	—	—	—	1	1
Balance, December 31, 2022	1,000	$ —	$ 2,333	$ 1,022	$ (1)	$ 3,354

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,		
	2022	**2021**	**2020**
Cash flows from operating activities:			
Net income	$ 298	$ 303	$ 295
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	417	406	361
Allowance for equity funds	(11)	(7)	(7)
Deferred energy	(541)	(245)	(44)
Amortization of deferred energy	160	11	(41)
Other changes in regulatory assets and liabilities	(15)	(19)	(42)
Deferred income taxes and amortization of investment tax credits	49	—	(10)
Other, net	8	—	2
Changes in other operating assets and liabilities:			
Trade receivables and other assets	(178)	6	45
Inventories	(29)	5	(7)
Accrued property, income and other taxes	21	(18)	5
Accounts payable and other liabilities	176	63	(90)
Net cash flows from operating activities	355	505	467
Cash flows from investing activities:			
Capital expenditures	(762)	(449)	(455)
Proceeds from sale of assets	—	—	26
Issuance of affiliate note receivable	(100)	—	—
Other, net	—	2	—
Net cash flows from investing activities	(862)	(447)	(429)
Cash flows from financing activities:			
Proceeds from long-term debt	694	—	718
Repayments of long-term debt	—	—	(575)
Net (repayments of) proceeds from short-term debt	(180)	180	—
Dividends paid	—	(213)	(155)
Contributions from parent	25	—	—
Other, net	(17)	(16)	(15)
Net cash flows from financing activities	522	(49)	(27)
Net change in cash and cash equivalents and restricted cash and cash equivalents	15	9	11
Cash and cash equivalents and restricted cash and cash equivalents at beginning of period	45	36	25
Cash and cash equivalents and restricted cash and cash equivalents at end of period	$ 60	$ 45	$ 36

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 owns subsidiaries principally engaged in energy businesses. BHE is a consolidated 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, 2022, 2021 and 2020.

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 PUCN for a certain renewable energy contract. A reconciliation of cash and cash equivalents and restricted cash and cash equivalents as of December 31, 2022 and December 31, 2021, as presented in 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,	
	2022	**2021**
Cash and cash equivalents	$ 43	$ 33
Restricted cash and cash equivalents included in other current assets	17	12
Total cash and cash equivalents and restricted cash and cash equivalents	$ 60	$ 45

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):

	2022	**2021**	**2020**
Beginning balance	$ 18	$ 19	$ 15
Charged to operating costs and expenses, net	14	13	13
Write-offs, net	(12)	(14)	(9)
Ending balance	$ 20	$ 18	$ 19

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 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 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 $93 million and $64 million as of December 31, 2022 and 2021. 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 Public Utilities Commission of Nevada ("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 non-current 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 asset or liability.

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 2022 and 2021 was 6.55% and 7.14%, 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. Leases will be 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, 2022 and 2021, trade receivables, net on the Consolidated Balance Sheets relate substantially to Customer Revenue, including unbilled revenue of $143 million and $107 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 $4 million and $6 million as of December 31, 2022 and 2021, 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 separate return 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 on the Consolidated Statements of Operations.

Segment Information

Nevada Power currently has one segment, which includes its regulated electric utility operations.

(3) Property, Plant and Equipment, Net

Property, plant and equipment, net consists of the following as of December 31 (in millions):

	Depreciable Life	2022	2021
Utility plant:			
Generation	30 - 55 years	$ 3,977	$ 3,793
Transmission	45 - 70 years	1,562	1,503
Distribution	20 - 65 years	4,134	3,920
General and intangible plant	5 - 65 years	871	836
Utility plant		10,544	10,052
Accumulated depreciation and amortization		(3,624)	(3,406)
Utility plant, net		6,920	6,646
Nonregulated, net of accumulated depreciation and amortization	45 years	1	1
		6,921	6,647
Construction work-in-progress		485	244
Property, plant and equipment, net		$ 7,406	$ 6,891

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, 2022, 2021 and 2020 was 3.1%, 3.2%, 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 2017.

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, 2022 (dollars in millions):

	Nevada Power's Share	Utility Plant	Accumulated Depreciation	Construction Work-in-Progress
Navajo Generating Station[(1)]	11 %	$ 1	$ 4	$ —
ON Line Transmission Line	19	121	26	1
Other transmission facilities	Various	56	27	—
Total		$ 178	$ 57	$ 1

(1) Represents Nevada Power's proportionate share of capitalized asset retirement costs to retire the Navajo Generating Station, which was shut down in November 2019.

(5) Leases

The following table summarizes Nevada Power's leases recorded on the Consolidated Balance Sheet as of December 31 (in millions):

	2022	2021
Right-of-use assets:		
Operating leases	$ 9	$ 10
Finance leases	303	326
Total right-of-use assets	$ 312	$ 336
Lease liabilities:		
Operating leases	$ 11	$ 13
Finance leases	313	336
Total lease liabilities	$ 324	$ 349

The following table summarizes Nevada Power's lease costs for the years ended December 31 (in millions):

	2022	2021	2020
Variable	$ 369	$ 449	$ 434
Operating	2	2	3
Finance:			
Amortization	14	13	12
Interest	27	28	29
Total lease costs	$ 412	$ 492	$ 478
Weighted-average remaining lease term (years):			
Operating leases	4.8	5.7	6.5
Finance leases	29.1	28.7	28.7
Weighted-average discount rate:			
Operating leases	4.5 %	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):

	2022	2021	2020
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	(28)	(29)	(34)
Financing cash flows from finance leases	(17)	(16)	(15)
Right-of-use assets obtained in exchange for lease liabilities:			
Operating leases	$ —	$ —	$ 1
Finance leases	3	1	9

Nevada Power has the following remaining lease commitments as of December 31, 2022 (in millions):

	Operating	Finance	Total
2023	$ 2	$ 44	$ 46
2024	3	44	47
2025	3	43	46
2026	3	44	47
2027	2	42	44
Thereafter	—	414	414
Total undiscounted lease payments	13	631	644
Less - amounts representing interest	(2)	(318)	(320)
Lease liabilities	$ 11	$ 313	$ 324

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, previously split 95% for Nevada Power and 5% for Sierra Pacific. In December 2019, the PUCN ordered the Nevada Utilities to complete the necessary procedures to change the ownership split to 75% for Nevada Power and 25% for Sierra Pacific, effective January 1, 2020. In August 2020, the FERC approved the amended agreement between the Nevada Utilities and Great Basin Transmission, LLC that reallocated the PUCN-approved ownership percentage change from Nevada Power to Sierra Pacific. The term of the lease is 41 years with the agreement ending December 31, 2054. Total ON Line finance lease obligations of $276 million and $286 million were included on the Consolidated Balance Sheets as of December 31, 2022 and 2021, 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	2022	2021
Deferred energy costs	1 year	654	273
Decommissioning costs	3 years	116	169
Merger costs from 1999 merger	22 years	105	110
Unrealized loss on regulated derivative contracts	1 year	75	117
Asset retirement obligations	5 years	69	73
Deferred operating costs	13 years	67	93
Other	Various	208	184
Total regulatory assets		$ 1,294	$ 1,019
Reflected as:			
Current assets		$ 666	$ 291
Noncurrent assets		628	728
Total regulatory assets		$ 1,294	$ 1,019

Nevada Power had regulatory assets not earning a return on investment of $320 million and $371 million as of December 31, 2022 and 2021, respectively. The regulatory assets not earning a return on investment primarily consist of merger costs from the 1999 merger, AROs, deferred operating costs, a portion of the employee benefit plans, losses on reacquired debt and deferred energy costs.

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	**2022**	**2021**
Deferred income taxes(1)	Various	$ 560	$ 603
Cost of removal(2)	31 years	358	348
Earning sharing mechanism	4 years	114	73
Other	Various	106	125
Total regulatory liabilities		$ 1,138	$ 1,149
Reflected as:			
Current liabilities		$ 45	$ 49
Noncurrent liabilities		1,093	1,100
Total regulatory liabilities		$ 1,138	$ 1,149

(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 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 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.

(7) Short-term Debt and Credit Facilities

The following table summarizes Nevada Power's availability under its credit facilities as of December 31 (in millions):

	2022	2021
Credit facilities	$ 400	$ 400
Short-term debt	—	(180)
Net credit facilities	$ 400	$ 220

Nevada Power has a $400 million secured credit facility expiring in June 2025 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, 2022 and 2021, Nevada Power had borrowings of $— million and $180 million, respectively, outstanding under the credit facility. As of December 31, 2022 and 2021, the weighted average interest rate on borrowings outstanding was —% and 0.86%, 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, 2022 and 2021, Nevada Power had $— million and $15 million, respectively, of a fully available letter of credit issued under committed arrangements in support of certain transactions required by a third party and has provisions that automatically extend the annual expiration date for an additional year unless the issuing bank elects not to renew the letter of credit prior to the expiration date.

(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	2022	2021
General and refunding mortgage securities:			
3.700% Series CC, due 2029	$ 500	$ 497	$ 497
2.400% Series DD, due 2030	425	422	422
6.650% Series N, due 2036	367	360	359
6.750% Series R, due 2037	349	346	346
5.375% Series X, due 2040	250	248	248
5.450% Series Y, due 2041	250	239	239
3.125% Series EE, due 2050	300	298	297
5.900% Series GG, due 2053	400	394	—
Tax-exempt refunding revenue bond obligations:			
Fixed-rate series:			
1.875% Pollution Control Bonds Series 2017A, due 2032(1)	40	39	39
1.650% Pollution Control Bonds Series 2017, due 2036(1)	40	39	39
1.650% Pollution Control Bonds Series 2017B, due 2039(1)	13	13	13
Variable-rate 4.821% Term Loan, due 2024(2)	300	300	—
Total long-term debt	$ 3,234	$ 3,195	$ 2,499
Reflected as:			
Total long-term debt		$ 3,195	$ 2,499

(1) Subject to mandatory purchase by Nevada Power in March 2023 at which date the interest rate may be adjusted.

(2) Amounts borrowed under the facility bear interest at variable rates based on SOFR or a base rate, at Nevada Power's option, plus a pricing margin.

Annual Payment on Long-Term Debt

The annual repayments of long-term debt for the years beginning January 1, 2023 and thereafter, are as follows (in millions):

2024	$ 300
2028 and thereafter	2,934
Total	3,234
Unamortized premium, discount and debt issuance cost	(39)
Total	$ 3,195

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, 2022, approximately $9.8 billion (based on original cost) of Nevada Power's property was subject to the liens of the mortgages.

(9) Income Taxes

Income tax expense consists of the following for the years ended December 31 (in millions):

	2022	2021	2020
Current – Federal	$ (13)	$ 37	$ 57
Deferred – Federal	49	—	(10)
Total income tax expense	$ 36	$ 37	$ 47

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:

	2022	2021	2020
Federal statutory income tax rate	21 %	21 %	21 %
Effects of ratemaking	(11)	(11)	(8)
Other	1	1	1
Effective income tax rate	11 %	11 %	14 %

The net deferred income tax liability consists of the following as of December 31 (in millions):

	2022	2021
Deferred income tax assets:		
Regulatory liabilities	$ 186	$ 195
Operating and finance leases	68	73
Customer advances	27	25
Unamortized contract value	20	25
Other	9	8
Total deferred income tax assets	310	326
Deferred income tax liabilities:		
Property related items	(821)	(800)
Regulatory assets	(273)	(204)
Operating and finance leases	(65)	(70)
Other	(26)	(34)
Total deferred income tax liabilities	(1,185)	(1,108)
Net deferred income tax liability	$ (875)	$ (782)

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, 2013. 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, 2022, 2021 and 2020. Nevada Power contributed $1 million to the Non-Qualified Pension Plans for the years ended December 31, 2022, 2021 and 2020. Nevada Power did not make any contributions to the Other Postretirement Plans for the years ended December 31, 2022, 2021 and 2020. 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):

	2022	2021
Qualified Pension Plan -		
Other non-current assets	$ 27	$ 42
Non-Qualified Pension Plans:		
Other current liabilities	(1)	(1)
Other long-term liabilities	(6)	(8)
Other Postretirement Plans -		
Other non-current assets	7	8

(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 $358 million and $348 million as of December 31, 2022 and 2021, respectively.

The following table presents Nevada Power's ARO liabilities by asset type as of December 31 (in millions):

	2022	2021
Waste water remediation	$ 31	$ 37
Evaporative ponds and dry ash landfills	14	13
Solar-powered generating facilities	3	3
Other	11	15
Total asset retirement obligations	$ 59	$ 68

The following table reconciles the beginning and ending balances of Nevada Power's ARO liabilities for the years ended December 31 (in millions):

	2022	2021
Beginning balance	$ 68	$ 72
Change in estimated costs	5	—
Retirements	(16)	(6)
Accretion	2	2
Ending balance	$ 59	$ 68
Reflected as:		
Other current liabilities	$ 16	$ 19
Other long-term liabilities	43	49
	$ 59	$ 68

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, and as such, 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.

(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, 2022:				
Not designated as hedging contracts [1]:				
Commodity assets	$ 23	$ —	$ —	$ 23
Commodity liabilities	—	(51)	(24)	(75)
Total derivative - net basis	$ 23	$ (51)	$ (24)	$ (52)
As of December 31, 2021:				
Not designated as hedging contracts[1]:				
Commodity assets	$ 4	$ —	$ —	$ 4
Commodity liabilities	—	(55)	(62)	(117)
Total derivative - net basis	$ 4	$ (55)	$ (62)	$ (113)

(1) Nevada Power's commodity derivatives not designated as hedging contracts are included in regulated rates. As of December 31, 2022 and 2021, a regulatory asset of $52 million and $113 million, respectively, was recorded related to the net derivative liability of $52 million and $113 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	2022	2021
Electricity purchases	Megawatt hours	2	1
Natural gas purchases	Decatherms	109	119

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, 2022, Nevada Power'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.

The aggregate fair value of Nevada Power's derivative contracts in liability positions with specific credit-risk-related contingent features totaled \$5 million and \$6 million as of December 31, 2022 and 2021, 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, 2022:				
Assets:				
Commodity derivatives	$ —	$ —	$ 23	$ 23
Money market mutual funds	34	—	—	34
Investment funds	3	—	—	3
	$ 37	$ —	$ 23	$ 60
Liabilities - commodity derivatives	$ —	$ —	$ (75)	$ (75)
As of December 31, 2021:				
Assets:				
Commodity derivatives	$ —	$ —	$ 4	$ 4
Money market mutual funds	34	—	—	34
Investment funds	3	—	—	3
	$ 37	$ —	$ 4	$ 41
Liabilities - commodity derivatives	$ —	$ —	$ (117)	$ (117)

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, 2022, 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.

Nevada Power's investments in money market mutual funds and equity securities 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.

The following table reconciles the beginning and ending balances of Nevada Power'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):

	2022	2021	2020
Beginning balance	$ (113)	$ 15	$ (8)
Changes in fair value recognized in regulatory assets or liabilities	(68)	(90)	(17)
Settlements	129	(38)	40
Ending balance	$ (52)	$ (113)	$ 15

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):

	2022		2021	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 3,195	$ 3,114	$ 2,499	$ 3,067

(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, 2022 are as follows (in millions):

	2023	2024	2025	2026	2027	2028 and Thereafter	Total
<u>Contract type:</u>							
Fuel, capacity and transmission contract commitments	$ 1,149	$ 485	$ 357	$ 360	$ 349	$ 2,871	$ 5,571
Fuel and capacity contract commitments (not commercially operable)	60	181	211	211	211	4,148	5,022
Construction commitments	525	77	20	21	10	—	653
Easements	5	3	2	2	2	50	64
Maintenance, service and other contracts	30	24	24	19	11	38	146
Total commitments	$ 1,769	$ 770	$ 614	$ 613	$ 583	$ 7,107	$11,456

Fuel and Capacity Contract Commitments

Purchased Power

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 2023 to 2067. Purchased power includes estimated payments for contracts which meet the definition of a lease and payments are based on the amount of energy expected to be generated. See Note 5 for further discussion of Nevada Power's lease commitments.

Natural Gas

Nevada Power's gas transportation contracts expire from 2027 to 2039 and the gas supply contracts expires from 2023 to 2024.

Fuel and Capacity Contract Commitments - Not 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.

Construction Commitments

Nevada Power's construction commitments included in the table above relate to firm commitments and include costs associated with a planned 150-MW solar photovoltaic facility with an additional 100 MWs of co-located battery storage that will be developed in Clark County, Nevada, a planned 220-MW grid-tied battery energy storage system that will be developed on the site of the retired Reid Gardner generating station in Clark County, Nevada and certain other generating plant projects.

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, 2022, 2021 and 2020.

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 2023 to 2031.

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.

Senate Bill 123

In June 2013, the Nevada State Legislature passed Senate Bill 123 ("SB 123"), which included the retirement of coal plants and replacing the capacity with renewable facilities and other generating facilities. In May 2014, Nevada Power filed its Emissions Reduction and Capacity Replacement Plan ("ERCR Plan") in compliance with SB 123. In July 2015, Nevada Power filed an amendment to its ERCR Plan with the PUCN which was approved in September 2015. In June 2015, the Nevada State Legislature passed Assembly Bill No. 498, which modified the capacity replacement components of SB 123.

In compliance with SB 123, Nevada Power retired 255 MWs of coal-fueled generation in 2019 in addition to the 557 MWs of coal-fueled generation retired in 2017. Consistent with the ERCR Plan, between 2014 and 2016, Nevada Power acquired 536 MWs of natural gas generating resources, executed long-term power purchase agreements for 200 MWs of nameplate renewable energy capacity and constructed a 15-MW solar photovoltaic facility. Nevada Power has the option to acquire 35 MWs of nameplate renewable energy capacity in the future under the ERCR Plan, subject to PUCN approval.

Legal Matters

Nevada Power is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. Nevada Power does not believe that such normal and routine litigation will have a material impact on its consolidated financial results. Nevada Power is also involved in other kinds of legal actions, some of which assert or may assert claims or seek to impose fines, penalties and other costs in substantial amounts.

(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):

	2022	2021	2020
Customer Revenue:			
Retail:			
Residential	$ 1,440	$ 1,207	$ 1,145
Commercial	525	414	384
Industrial	528	386	345
Other	14	14	12
Total fully bundled	2,507	2,021	1,886
Distribution-only service	20	22	24
Total retail	2,527	2,043	1,910
Wholesale, transmission and other	82	74	62
Total Customer Revenue	2,609	2,117	1,972
Other revenue	21	22	26
Total operating revenue	$ 2,630	$ 2,139	$ 1,998

(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):

	2022	2021	2020
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	$ 121	$ 115	$ 115
Income taxes (refunded) paid	$ (29)	$ 63	$ 50
Supplemental disclosure of non-cash investing and financing transactions:			
Accruals related to property, plant and equipment additions	$ 98	$ 53	$ 32

(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 $46 million, $30 million and $6 million for the years ended December 31, 2022, 2021 and 2020, respectively. Amounts charged to Nevada Power in 2022 and 2021 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 $49 million, $52 million, $52 million for the years ended December 31, 2022, 2021 and 2020, respectively. As of December 31, 2022 and 2021, Nevada Power's Consolidated Balance Sheets included amounts due to Kern River Gas Transmission Company of $3 million and $4 million, respectively.

Nevada Power provided electricity and other services to PacifiCorp, an indirect subsidiary of BHE, of $4 million, $3 million and $3 million for the years ended December 31, 2022, 2021 and 2020, respectively. There were no receivables associated with these services as of December 31, 2022 and 2021. PacifiCorp provided electricity and the sale of renewable energy credits to Nevada Power of $— million, $— million and $1 million for the years ended December 31, 2022, 2021, and 2020, respectively. There were no payables associated with these transactions as of December 31, 2022 and 2021.

Nevada Power provided electricity to Sierra Pacific of $362 million, $179 million and $106 million for the years ended December 31, 2022, 2021 and 2020, respectively. Receivables associated with these transactions were $41 million and $13 million as of December 31, 2022 and 2021, respectively. Nevada Power purchased electricity from Sierra Pacific of $86 million, $43 million and $34 million for the years ended December 31, 2022, 2021 and 2020, respectively. Payables associated with these transactions were $5 million and $— million as of December 31, 2022 and 2021, 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 $3 million, $1 million and $— million for each of the years ending December 31, 2022, 2021 and 2020, respectively. NV Energy provided services to Nevada Power of $9 million for the years ending December 31, 2022, 2021 and 2020. Nevada Power provided services to Sierra Pacific of $25 million, $25 million and $26 million for the years ended December 31, 2022, 2021 and 2020, respectively. Sierra Pacific provided services to Nevada Power of $16 million, $15 million and $15 million for the years ended December 31, 2022, 2021 and 2020, respectively. As of December 31, 2022 and 2021, Nevada Power's Consolidated Balance Sheets included amounts due to NV Energy of $51 million and $33 million, respectively. There were no receivables due from NV Energy as of December 31, 2022 and 2021. In November 2022, Nevada Power entered into a $100 million unsecured note with NV Energy receivable upon demand and $100 million was outstanding as of December 31, 2022. As of December 31, 2022 and 2021, Nevada Power's Consolidated Balance Sheets included receivables due from Sierra Pacific of $33 million and $2 million, respectively. There were no payables due to Sierra Pacific as of December 31, 2022 and 2021.

Nevada Power is party to a tax-sharing agreement with NV Energy and NV Energy is part of the Berkshire Hathaway consolidated U.S. federal income tax return. As of December 31, 2022 and 2021 federal income taxes receivable from NV Energy were $12 million and $27 million, respectively. Nevada Power received cash refunds of $29 million for federal income taxes for the year ended December 31, 2022 and made cash payments of $63 million and $50 million for federal income taxes for the years ended December 31, 2021 and 2020, respectively.

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 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, 2022 was $118 million, a decrease of $6 million, or 5%, compared to 2021, primarily due to higher operations and maintenance expenses, mainly due to higher plant operations and maintenance expenses, lower other, net, mainly due to higher pension expense and lower cash surrender value of corporate-owned life insurance policies, higher depreciation and amortization, primarily due to higher plant in-service, higher interest expense mainly due to higher long-term debt, partially offset by higher electric utility margin and higher interest and dividend income, mainly from carrying charges on regulatory balances. Electric utility margin increased primarily due to higher transmission and wholesale revenue, higher customer volumes and higher regulatory-related revenue deferrals, partially offset by unfavorable price impacts from changes in sales mix. Electric retail customer volumes, including distribution only service customers, increased 2.8% primarily due to an increase in the average number of customers, offset by the unfavorable impact of weather and unfavorable changes in customer usage. Energy generated decreased 13% for 2022 compared to 2021 primarily due to lower natural gas- and coal-fueled generation. Wholesale electricity sales volumes increased 13% and purchased electricity volumes decreased 5%.

Net income for the year ended December 31, 2021 was $124 million, an increase of $13 million, or 12%, compared to 2020, primarily due to higher interest and dividend income, mainly from carrying charges on regulatory balances, higher electric utility margin, mainly from price impacts from changes in sales mix and an increase in the average number of customer, primarily from the residential customer class, partially offset by lower revenue recognized due to a favorable regulatory decision and an adjustment to regulatory-related revenue deferrals, higher other, net, mainly due to lower pension expense and higher cash surrender value of corporate-owned life insurance policies, higher allowance for equity funds, mainly due to higher construction work-in-progress, higher natural gas utility margin, mainly due to higher commercial usage, and lower interest expense, mainly due to lower carrying charges on regulatory balances, partially offset by higher income tax expense primarily due to higher pretax income, higher depreciation and amortization, mainly from regulatory amortizations and higher plant in-service, and higher operations and maintenance expenses, mainly due to higher plant operations and maintenance expenses and higher legal expenses, offset by lower earnings sharing. Electric retail customer volumes, including distribution only service customers, increased 2.9% primarily due to an increase in the average number of customers, favorable changes in customer usage patterns and the favorable impact of weather. Energy generated decreased 2% for 2021 compared to 2020 primarily due to lower natural gas-fueled generation, partially offset by higher coal-fueled generation. Wholesale electricity sales volumes increased 20% 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, 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 explains profitability 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 running 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):

	2022	2021	Change		2021	2020	Change	
Electric utility margin:								
Operating revenue	$ 1,025	$ 848	$ 177	21 %	$ 848	$ 738	$ 110	15 %
Cost of fuel and energy	555	407	148	36	407	301	106	35
Electric utility margin	470	441	29	7 %	441	437	4	1 %
Natural gas utility margin:								
Operating revenue	168	117	51	44 %	117	116	1	1 %
Natural gas purchased for resale	111	61	50	82	61	62	(1)	(2)
Natural gas utility margin	57	56	1	2 %	56	54	2	4 %
Utility margin	527	497	30	6 %	497	491	6	1 %
Operations and maintenance	189	163	26	16 %	163	162	1	1 %
Depreciation and amortization	149	143	6	4	143	141	2	1
Property and other taxes	24	24	—	—	24	23	1	4
Operating income	$ 165	$ 167	$ (2)	(1)%	$ 167	$ 165	$ 2	1 %

Electric Utility Margin

A comparison of key operating results related to electric utility margin is as follows for the years ended December 31:

	2022	2021	Change		2021	2020	Change	
Utility margin (in millions):								
Operating revenue	$ 1,025	$ 848	$ 177	21 %	$ 848	$ 738	$ 110	15 %
Cost of fuel and energy	555	407	148	36	407	301	106	35
Utility margin	$ 470	$ 441	$ 29	7 %	$ 441	$ 437	$ 4	1 %
Sales (GWhs):								
Residential	2,747	2,769	(22)	(1)%	2,769	2,672	97	4 %
Commercial	3,124	3,056	68	2	3,056	2,977	79	3
Industrial	2,867	3,716	(849)	(23)	3,716	3,544	172	5
Other	13	15	(2)	(13)	15	15	—	—
Total fully bundled[1]	8,751	9,556	(805)	(8)	9,556	9,208	348	4
Distribution only service	2,757	1,639	1,118	68	1,639	1,670	(31)	(2)
Total retail	11,508	11,195	313	3	11,195	10,878	317	3
Wholesale	741	656	85	13	656	548	108	20
Total GWhs sold	12,249	11,851	398	3 %	11,851	11,426	425	4 %
Average number of retail customers (in thousands)	371	365	6	2 %	365	359	6	2 %
Average revenue per MWh:								
Retail - fully bundled[1]	$106.57	$ 81.77	$ 24.80	30 %	$ 81.77	$ 73.89	$ 7.88	11 %
Wholesale	$ 75.48	$ 58.14	$ 17.34	30 %	$ 58.14	$ 52.52	$ 5.62	11 %
Heating degree days	4,631	4,494	137	3 %	4,494	4,477	17	— %
Cooling degree days	1,353	1,366	(13)	(1)%	1,366	1,176	190	16 %
Sources of energy (GWhs)[2][3]:								
Natural gas	4,075	4,712	(637)	(14)%	4,712	5,219	(507)	(10)%
Coal	1,077	1,220	(143)	(12)	1,220	855	365	43
Renewables[4]	26	31	(5)	(16)	31	37	(6)	(16)
Total energy generated	5,178	5,963	(785)	(13)	5,963	6,111	(148)	(2)
Energy purchased	4,691	4,960	(269)	(5)	4,960	4,753	207	4
Total	9,869	10,923	(1,054)	(10)%	10,923	10,864	59	1 %
Average cost of energy per MWh[5]:								
Energy generated	$ 46.05	$ 28.84	$ 17.21	60 %	$ 28.84	$ 20.12	$ 8.72	43 %
Energy purchased	$ 67.49	$ 47.39	$ 20.10	42 %	$ 47.39	$ 37.46	$ 9.93	27 %

(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 -, 2 and 10 GWhs of coal and -, 6 and 31 GWhs of natural gas generated energy that is purchased at cost by related parties for the years ended December 31, 2022, 2021 and 2020, respectively.

(3) GWh amounts are net of energy used by the related generating facilities.

(4) Includes the Fort Churchill Solar Array which was under lease by Sierra Pacific until it was acquired in December 2021.

(5) 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:

	2022	2021	Change		2021	2020	Change	
Utility margin (in millions):								
Operating revenue	$ 168	$ 117	$ 51	44 %	$ 117	$ 116	$ 1	1 %
Natural gas purchased for resale	111	61	50	82	61	62	(1)	(2)
Utility margin	$ 57	$ 56	$ 1	2 %	$ 56	$ 54	$ 2	4 %
Sold (000's Dths):								
Residential	11,269	10,662	607	6 %	10,662	10,452	210	2 %
Commercial	5,897	5,524	373	7	5,524	5,148	376	7
Industrial	2,211	1,981	230	12	1,981	1,826	155	8
Total retail	19,377	18,167	1,210	7 %	18,167	17,426	741	4 %
Average number of retail customers (in thousands)	180	177	3	2 %	177	174	3	2 %
Average revenue per retail Dth sold	$ 8.67	$ 6.44	$ 2.23	35 %	$ 6.44	$ 6.66	$ (0.22)	(3)%
Heating degree days	4,631	4,494	137	3 %	4,494	4,477	17	— %
Average cost of natural gas per retail Dth sold	$ 5.73	$ 3.36	$ 2.37	71 %	$ 3.36	$ 3.56	$ (0.20)	(6)%

Year Ended December 31, 2022 Compared to Year Ended December 31, 2021

Electric utility margin increased $29 million, or 7%, for 2022 compared to 2021 primarily due to:

- $15 million of higher ON Line temporary rider (offset in operations and maintenance expense) for the recovery of deferred costs for ON Line due to the regulatory-directed reallocation of costs between Nevada Power and Sierra Pacific;
- $9 million of higher transmission and wholesale revenue;
- $4 million of higher regulatory-related revenue deferrals; and
- $1 million of higher electric retail utility margin due to higher customer volumes, offset by unfavorable price impacts from changes in sales mix. Retail customer volumes, including distribution only service customers, increased 2.8% primarily due to an increase in the average number of customers, offset by the unfavorable impact of weather and unfavorable changes in customer usage.

The increase in electric utility margin was offset by:

- $2 million in lower energy efficiency program rates (offset in operations and maintenance expense).

Operations and maintenance increased $26 million, or 16%, for 2022 compared to 2021 primarily due to higher regulatory-approved cost recovery for the ON Line reallocation of $15 million (offset in operating revenue) and higher plant operations and maintenance expenses, partially offset by lower energy efficiency program costs (offset in operating revenue).

Depreciation and amortization increased $6 million, or 4%, for 2022 compared to 2021 primarily due to higher plant in-service.

Interest expense increased $4 million, or 7%, for 2022 compared to 2021 primarily due to higher interest rates and debt.

Interest and dividend income increased $9 million for 2022 compared to 2021 primarily due to higher interest income, mainly from carrying charges on regulatory balances.

Other, net decreased $9 million, or 82%, for 2022 compared to 2021 primarily due to higher pension expense and lower cash surrender value of corporate-owned life insurance policies.

Year Ended December 31, 2021 Compared to Year Ended December 31, 2020

Electric utility margin increased $4 million, or 1%, for 2021 compared to 2020 primarily due to:

- $10 million of higher electric retail utility margin primarily due to higher retail customer volumes. Retail customer volumes, including distribution only service customers, increased 2.9% primarily due to an increase in the average number of customers, favorable changes in customer usage patterns and the favorable impact of weather, and
- $3 million of higher transmission and wholesale revenue.

The increase in electric utility margin was offset by:

- $3 million in lower revenue recognized due to a favorable regulatory decision in 2020;
- $3 million due to an adjustment to regulatory-related revenue deferrals; and
- $2 million due to lower energy efficiency program rates (offset in operations and maintenance expense).

Natural gas utility margin increased $2 million, or 4%, for 2021 compared to 2020 primarily due to favorable changes in customer usage patterns.

Operations and maintenance increased $1 million, or 1%, for 2021 compared to 2020 primarily due to higher plant operations and maintenance expenses and higher legal expenses, offset by lower earnings sharing and lower energy efficiency program costs (offset in operating revenue).

Depreciation and amortization increased $2 million, or 1%, for 2021 compared to 2020 primarily due to regulatory amortizations and higher plant in-service.

Interest expense decreased $2 million, or 4%, for 2021 compared to 2020 primarily due to lower carrying charges on regulatory balances.

Allowance for equity funds increased $3 million, or 75%, for 2021 compared to 2020 primarily due to higher construction work-in-progress.

Interest and dividend income increased $5 million for 2021 compared to 2020 primarily due to higher interest income, mainly from carrying charges on regulatory balances.

Other, net increased $4 million, or 57%, for 2021 compared to 2020 primarily due to lower pension expense and higher cash surrender value of corporate-owned life insurance policies.

Income tax expense increased $3 million, or 20%, for 2021 compared to 2020 primarily due to higher pretax income. The effective tax rate was 13% in 2021 and 12% in 2020.

Liquidity and Capital Resources

As of December 31, 2022, Sierra Pacific's total net liquidity was $299 million as follows (in millions):

Cash and cash equivalents	$	49
Credit facilities[(1)]		250
Total net liquidity	$	299
Credit facilities:		
Maturity dates		2025

(1) 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.

Operating Activities

Net cash flows from operating activities for the years ended December 31, 2022 and 2021 were $109 million and $183 million, respectively. The change was primarily due to higher payments related to fuel and energy costs and the timing of payments for operating costs, partially offset by higher collections from customers.

Net cash flows from operating activities for the years ended December 31, 2021 and 2020 were $183 million and $190 million, respectively. The change was primarily due to the timing of payments for fuel and energy costs, partially offset by higher collections from customers, the timing of payments for operating costs, lower inventory purchases and increased collections of customer advances.

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, 2022 and 2021 were $(351) million and $(300) 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, 2021 and 2020 were $(300) million and $(246) 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, 2022 and 2021 were $282 million and $107 million, respectively. The change was primarily due to higher contributions from NV Energy, Inc. and greater proceeds from the issuance of long-term debt, partially offset by higher long-term debt reacquired, higher repayments of short-term debt and higher dividends paid to NV Energy, Inc.

Net cash flows from financing activities for the years ended December 31, 2021 and 2020 were $107 million and $50 million, respectively. The change was primarily due to higher proceeds from short-term debt and lower dividends paid to NV Energy, Inc., partially offset by lower proceeds from the issuance of long-term debt.

Ability to Issue Debt

Sierra Pacific's ability to issue debt is primarily impacted by its financing authority from the PUCN. As of December 31, 2022, 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 $250 million secured credit facility) does not exceed $1.9 billion and to issue common and preferred stock so long as the total amounts outstanding do not exceed $2.2 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, 2022. In addition, certain financing agreements contain covenants which are currently suspended as Sierra Pacific's senior secured debt is rated investment grade. However, if Sierra Pacific's senior secured 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.

Ability to Issue 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, 2022, $4.9 billion of Sierra Pacific's assets were pledged. Sierra Pacific had the capacity to issue $2.0 billion of additional general and refunding mortgage securities as of December 31, 2022 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.

Long-Term Debt

In June 2022, Sierra Pacific purchased $60 million of its variable-rate tax-exempt Gas & Water Facilities Refunding Revenue Bonds, Series 2016B, due 2036, as required by the bond indenture. Sierra Pacific is holding these bonds and can re-offer them at a future date.

In May 2022, Sierra Pacific issued $250 million of 4.71% General and Refunding Mortgage bonds, Series W, due 2052. The net proceeds were used to repay the outstanding $200 million unsecured loan with NV Energy, Inc., repay amounts outstanding under its existing revolving credit facility and for general corporate purposes.

In April 2022, Sierra Pacific entered into a $200 million unsecured loan with NV Energy payable upon demand. The net proceeds were used to purchase certain tax-exempt refunding revenue bond obligations that were subject to mandatory purchase by Sierra Pacific in April 2022. The loan has an underlying variable interest rate based on 30-day U.S. dollar deposits offered on the London Interbank Offered Rate market plus a spread of 0.75%.

In April 2022, Sierra Pacific purchased the following series of bonds that were held by the public: $30 million of its variable-rate tax-exempt Water Facilities Refunding Revenue Bonds, Series 2016C, due 2036; $25 million of its variable-rate tax-exempt Water Facilities Refunding Revenue Bonds, Series 2016D, due 2036; $25 million of its variable-rate tax-exempt Water Facilities Refunding Revenue Bonds, Series 2016E, due 2036; $75 million of its variable-rate tax-exempt Water Facilities Refunding Revenue Bonds, Series 2016F, due 2036; $20 million of its variable-rate tax-exempt Water Facilities Refunding Revenue Bonds, Series 2016G, due 2036; and $30 million of its variable-rate tax-exempt Pollution Control Refunding Revenue Bonds, Series 2016B, due 2029. Sierra Pacific purchased these bonds as required by the bond indentures. Sierra Pacific is holding these bonds and can re-offer them at a future date.

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		
	2020	2021	2022	2023	2024	2025
Electric distribution	$ 128	$ 96	$ 113	$ 125	$ 112	$ 269
Electric transmission	60	77	75	45	247	188
Solar generation	—	17	36	—	—	—
Electric battery storage	—	18	—	—	270	196
Other	58	92	127	141	147	116
Total	$ 246	$ 300	$ 351	$ 311	$ 776	$ 769

Sierra Pacific received PUCN approval through its recent IRP filings for an increase in solar generation and electric transmission and has included estimates from its latest IRP filing in its forecast capital expenditures for 2022 through 2024. These estimates are likely to change as a result of the RFP process. Sierra Pacific's historical and forecast capital expenditures include the following:

- Electric distribution includes both growth projects and operating expenditures consisting of routine expenditures for distribution needed to serve existing and expected demand.
- Electric transmission includes both growth projects and operating expenditures. Growth projects primarily relate to the Nevada Utilities' Greenlink Nevada transmission expansion program. In this project, the company has received approval from the PUCN to build a 350-mile, 525-kV transmission line, known as Greenlink West, connecting the Ft. Churchill substation to the Northwest substation to the Harry Allen substation; a 235-mile, 525-kV transmission line, known as Greenlink North, connecting the new Ft. Churchill substation to the Robinson Summit substation; a 46-mile, 345-kV transmission line from the new Ft. Churchill substation to the Mira Loma substations; and a 38-mile, 345-kV transmission line from the new Ft. Churchill substation to the Robinson Summit substations. Operating expenditures consist of routine expenditures for transmission and other infrastructure needed to serve existing and expected demand.
- Solar generation includes solar photovoltaic panels procured for future growth projects.
- Electric battery storage includes a growth projects consisting of a 200-MW battery energy storage system that will be developed on the site of the Valmy generating station in Humboldt County, Nevada. Commercial operation is expected by the end of 2025.
- Other includes both growth projects and operating expenditures consisting of turbine upgrades at the Tracy generating facility, routine expenditures for generation, other operating projects and other infrastructure needed to serve existing and expected demand.

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 $647 million on long-term debt, including $48 million due in 2023.

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 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, 2022, 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, 2022, Sierra Pacific would not have been required to post 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 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.

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 $611 million and total regulatory liabilities were $455 million as of December 31, 2022. 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, 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 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% as a result of 2017 Tax Reform, certain property-related basis differences and other various differences on to its customers. As of December 31, 2022, these amounts were recognized as a net regulatory liability of $223 million and will be included in regulated rates when the temporary differences reverse.

Revenue Recognition - Unbilled Revenue

Revenue is recognized as electricity or natural gas is delivered or services are provided. The determination of customer billings is based on a systematic reading of meters. At the end of each month, energy provided to customers since their last billing is estimated, and the corresponding unbilled revenue is recorded. Unbilled revenue was $94 million as of December 31, 2022. 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. Estimates are reversed in the following month when actual revenue is recorded.

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, 2022:			
Total commodity derivative contracts	$ (13)	$ (3)	$ (23)
As of December 31, 2021:			
Total commodity derivative contracts	$ (33)	$ (26)	$ (40)

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, 2022 and 2021, a net regulatory asset of $13 million and $33 million, respectively, was recorded related to the net derivative liability of $13 million and $33 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, 2022 and 2021, Sierra Pacific had short-term variable-rate obligations totaling $— million and $159 million, respectively, that expose Sierra Pacific 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 Sierra Pacific's annual interest expense. The carrying value of the variable-rate obligations approximates fair value as of December 31, 2022 and 2021.

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, 2022, 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

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, 2022 and 2021, 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, 2022, 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, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022, 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 audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Regulatory Matters — Effects of Rate Regulation on the Financial Statements — Refer to Notes 2 and 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 it meets 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 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) a refund to customers. Given that management's accounting judgments are based on assumptions about the outcome of future decisions by the Commissions, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of future decisions by the Commissions included the following, among others:

- We evaluated Sierra Pacific's disclosures related to the effects of rate regulation, including the balances recorded and regulatory developments.
- We read relevant regulatory orders issued by the Commissions, regulatory statutes, interpretations, procedural memorandums, filings made by interveners, and other external information. We evaluated the external information and compared to management's recorded regulatory asset and liability balances for completeness.
- For regulatory matters in process, 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.
- We inquired of management about property, plant, and equipment that may be abandoned. We inquired of management to identify projects that are designed to replace assets that may be retired prior to the end of the useful life. We inspected minutes of the board of directors and regulatory orders and other filings with the Commissions to identify any evidence that may contradict management's assertion regarding probability of an abandonment.

/s/ Deloitte & Touche LLP

Las Vegas, Nevada
February 24, 2023

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,	
	2022	2021
ASSETS		
Current assets:		
Cash and cash equivalents	$ 49	$ 10
Trade receivables, net	175	128
Inventories	79	65
Regulatory assets	357	177
Other current assets	50	35
Total current assets	710	415
Property, plant and equipment, net	3,587	3,340
Regulatory assets	254	263
Other assets	181	205
Total assets	$ 4,732	$ 4,223
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Accounts payable	$ 224	$ 147
Note payable to affiliate	70	—
Short-term debt	—	159
Current portion of long-term debt	250	—
Other current liabilities	108	108
Total current liabilities	652	414
Long-term debt	898	1,164
Finance lease obligations	100	106
Regulatory liabilities	436	444
Deferred income taxes	445	402
Other long-term liabilities	153	158
Total liabilities	2,684	2,688
Commitments and contingencies (Note 14)		
Shareholder's equity:		
Common stock - $3.75 stated value, 20,000,000 shares authorized and 1,000 issued and outstanding	—	—
Additional paid-in capital	1,576	1,111
Retained earnings	473	425
Accumulated other comprehensive loss, net	(1)	(1)
Total shareholder's equity	2,048	1,535
Total liabilities and shareholder's equity	$ 4,732	$ 4,223

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,		
	2022	**2021**	**2020**
Operating revenue:			
Regulated electric	$ 1,025	$ 848	$ 738
Regulated natural gas	168	117	116
Total operating revenue	1,193	965	854
Operating expenses:			
Cost of fuel and energy	555	407	301
Cost of natural gas purchased for resale	111	61	62
Operations and maintenance	189	163	162
Depreciation and amortization	149	143	141
Property and other taxes	24	24	23
Total operating expenses	1,028	798	689
Operating income	165	167	165
Other income (expense):			
Interest expense	(58)	(54)	(56)
Allowance for borrowed funds	3	2	2
Allowance for equity funds	7	7	4
Interest and dividend income	18	9	4
Other, net	2	11	7
Total other income (expense)	(28)	(25)	(39)
Income before income tax expense	137	142	126
Income tax expense	19	18	15
Net income	$ 118	$ 124	$ 111

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, 2019	1,000	$ —	$ 1,111	$ 210	$ (1)	$ 1,320
Net income	—	—	—	111	—	111
Dividends declared	—	—	—	(20)	—	(20)
Balance, December 31, 2020	1,000	—	1,111	301	(1)	1,411
Net income	—	—	—	124	—	124
Balance, December 31, 2021	1,000	—	1,111	425	(1)	1,535
Net income	—	—	—	118	—	118
Dividends declared	—	—	—	(70)	—	(70)
Contributions	—	—	465	—	—	465
Balance, December 31, 2022	1,000	$ —	$ 1,576	$ 473	$ (1)	$ 2,048

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,		
	2022	2021	2020
Cash flows from operating activities:			
Net income	$ 118	$ 124	$ 111
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	149	143	141
Allowance for equity funds	(7)	(7)	(4)
Deferred energy	(267)	(116)	(17)
Amortization of deferred energy	97	29	(14)
Other changes in regulatory assets and liabilities	(1)	(39)	(33)
Deferred income taxes and amortization of investment tax credits	31	13	12
Other, net	3	(1)	(2)
Changes in other operating assets and liabilities:			
Trade receivables and other assets	(52)	(27)	(81)
Inventories	(14)	12	(19)
Accrued property, income and other taxes	(13)	9	9
Accounts payable and other liabilities	65	43	87
Net cash flows from operating activities	109	183	190
Cash flows from investing activities:			
Capital expenditures	(351)	(300)	(246)
Net cash flows from investing activities	(351)	(300)	(246)
Cash flows from financing activities:			
Proceeds from long-term debt	248	—	30
Long-term debt reacquired	(265)	—	—
Net (repayments of) proceeds from short-term debt	(159)	114	45
Net proceeds from affiliate note payable	70	—	—
Dividends paid	(70)	—	(20)
Contributions from parent	465	—	—
Other, net	(7)	(7)	(5)
Net cash flows from financing activities	282	107	50
Net change in cash and cash equivalents and restricted cash and cash equivalents	40	(10)	(6)
Cash and cash equivalents and restricted cash and cash equivalents at beginning of period	16	26	32
Cash and cash equivalents and restricted cash and cash equivalents at end of period	$ 56	$ 16	$ 26

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 owns subsidiaries principally engaged in energy businesses. BHE is a consolidated 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, 2022, 2021 and 2020.

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 PUCN for a certain renewable energy contract. A reconciliation of cash and cash equivalents and restricted cash and cash equivalents as of December 31, 2022 and December 31, 2021, as presented in 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,	
	2022	2021
Cash and cash equivalents	$ 49	$ 10
Restricted cash and cash equivalents included in other current assets	7	6
Total cash and cash equivalents and restricted cash and cash equivalents	$ 56	$ 16

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):

	2022	2021	2020
Beginning balance	$ 1	$ 2	$ 2
Charged to operating costs and expenses, net	2	2	2
Write-offs, net	(1)	(3)	(2)
Ending balance	$ 2	$ 1	$ 2

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 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 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 $69 million and $62 million as of December 31, 2022 and 2021, respectively, and fuel, which includes coal stock, stored natural gas and fuel oil, totaling $10 million and $3 million as of December 31, 2022 and 2021, 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 Public Utilities Commission of Nevada ("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 non-current 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 asset or liability.

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 2022 and 2021 was 5.52% and 6.75%, respectively, for electric, 5.09% and 5.75%, respectively, for natural gas and 5.23% and 6.65%, 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 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, 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. Leases will be 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, 2022 and 2021, trade receivables, net on the Consolidated Balance Sheets relate substantially to Customer Revenue, including unbilled revenue of $94 million and $78 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 separate return 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 on the Consolidated Statements of Operations.

(3) Property, Plant and Equipment, Net

Property, plant and equipment, net consists of the following as of December 31 (in millions):

	Depreciable Life	2022	2021
Utility plant:			
Electric generation	25 - 60 years	$ 1,298	$ 1,163
Electric transmission	50 - 100 years	993	940
Electric distribution	20 - 100 years	1,983	1,846
Electric general and intangible plant	5 - 70 years	219	204
Natural gas distribution	35 - 70 years	455	438
Natural gas general and intangible plant	5 - 70 years	15	14
Common general	5 - 70 years	380	370
Utility plant		5,343	4,975
Accumulated depreciation and amortization		(1,992)	(1,854)
Utility plant, net		3,351	3,121
Construction work-in-progress		236	219
Property, plant and equipment, net		$ 3,587	$ 3,340

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, 2022, 2021 and 2020 was 3.0%, 3.1% and 3.2%, 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.

Construction work-in-progress is primarily related to the construction of regulated assets.

(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, 2022 (dollars in millions):

	Sierra Pacific's Share	Utility Plant	Accumulated Depreciation	Construction Work-in-Progress
Valmy Generating Station	50 %	$ 399	$ 327	$ 2
ON Line Transmission Line	6	40	8	—
Valmy Transmission	50	4	2	1
Total		$ 443	$ 337	$ 3

(5) Leases

The following table summarizes Sierra Pacific's leases recorded on the Consolidated Balance Sheet as of December 31 (in millions):

	2022	2021
Right-of-use assets:		
Operating leases	$ 16	$ 15
Finance leases	105	111
Total right-of-use assets	$ 121	$ 126
Lease liabilities:		
Operating leases	$ 15	$ 15
Finance leases	108	115
Total lease liabilities	$ 123	$ 130

The following table summarizes Sierra Pacific's lease costs for the years ended December 31 (in millions):

	2022	2021	2020
Variable	$ 103	$ 86	$ 78
Operating	1	1	2
Finance:			
Amortization	5	5	4
Interest	8	9	9
Total lease costs	$ 117	$ 101	$ 93
Weighted-average remaining lease term (years):			
Operating leases	26.0	27.4	27.2
Finance leases	28.2	28.4	27.8
Weighted-average discount rate:			
Operating leases	5.0 %	5.0 %	5.0 %
Finance leases	8.4 %	8.2 %	8.1 %

The following table summarizes Sierra Pacific's supplemental cash flow information relating to leases for the years ended December 31 (in millions):

	2022	2021	2020
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows from operating leases	$ (1)	$ (1)	$ (2)
Operating cash flows from finance leases	(9)	(9)	(6)
Financing cash flows from finance leases	(7)	(7)	(5)
Right-of-use assets obtained in exchange for lease liabilities:			
Operating leases	$ 1	$ —	$ —
Finance leases	1	1	89

Sierra Pacific has the following remaining lease commitments as of December 31, 2022 (in millions):

	Operating	Finance	Total
2023	$ 1	$ 16	$ 17
2024	1	15	16
2025	1	16	17
2026	1	15	16
2027	1	13	14
Thereafter	23	137	160
Total undiscounted lease payments	28	212	240
Less - amounts representing interest	(13)	(104)	(117)
Lease liabilities	$ 15	$ 108	$ 123

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, previously split 95% for Nevada Power and 5% for Sierra Pacific. In December 2019, the PUCN ordered the Nevada Utilities to complete the necessary procedures to change the ownership split to 75% for Nevada Power and 25% for Sierra Pacific, effective January 1, 2020. In August 2020, the FERC approved the amended agreement between the Nevada Utilities and Great Basin Transmission, LLC that reallocated the PUCN-approved ownership percentage change from Nevada Power to 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 $107 million and $110 million were included on the Consolidated Balance Sheets as of December 31, 2022 and 2021, 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	2022	2021
Deferred energy costs	1 year	$ 277	$ 107
Natural disaster protection plan	1 year	69	62
Merger costs from 1999 merger	24 years	63	66
Employee benefit plans(1)	8 years	57	46
Deferred operating costs	7 years	35	31
Unrealized loss on regulated derivative contracts	1 year	21	35
Other	Various	89	93
Total regulatory assets		$ 611	$ 440
Reflected as:			
Current assets		$ 357	$ 177
Noncurrent assets		254	263
Total regulatory assets		$ 611	$ 440

(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 $143 million and $158 million as of December 31, 2022 and 2021, 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, losses on reacquired debt, AROs and legacy meters.

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	2022	2021
Deferred income taxes[1]	Various	$ 223	$ 234
Cost of removal[2]	35 years	200	201
Other	Various	32	28
Total regulatory liabilities		$ 455	$ 463
Reflected as:			
Current liabilities		$ 19	$ 19
Noncurrent liabilities		436	444
Total regulatory liabilities		$ 455	$ 463

(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 and other various 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 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 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 June 2022, Sierra Pacific filed a regulatory rate review with the PUCN that requested an annual revenue increase of $88 million, or 9.7%. In addition, a filing was made to revise depreciation rates based on a study, the results of which are reflected in the proposed revenue requirement. In August 2022, Sierra Pacific filed an updated certification filing that requested an annual revenue increase of $77 million, or 8.5%. Parties to the review filed testimony and evidence in August and September 2022. Hearings in the cost of capital, revenue requirement, and rate design phases were held in September, October, and November 2022, respectively. In December 2022, the PUCN issued an order approving an increase in base rates of $58 million, effective January 1, 2023, reflecting a reduction in Sierra Pacific's requested rate of return, updated depreciation and amortization rates for its electric operations and updated time of use periods to reflect the changes in system costs due to the increased solar generation on the system.

(7) Short-term Debt and Credit Facilities

The following table summarizes Sierra Pacific's availability under its credit facilities as of December 31 (in millions):

	2022	2021
Credit facilities	$ 250	$ 250
Short-term debt	—	(159)
Net credit facilities	$ 250	$ 91

Sierra Pacific has a $250 million secured credit facility expiring in June 2025 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, 2022 and 2021, Sierra Pacific had borrowings of $— million and $159 million, respectively, outstanding under the credit facility. As of December 31, 2022 and 2021, the weighted average interest rate on borrowings outstanding was —% and 0.86%, respectively. 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.

(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	2022	2021
General and refunding mortgage securities:			
3.375% Series T, due 2023	$ 250	$ 249	$ 249
2.600% Series U, due 2026	400	397	397
6.750% Series P, due 2037	252	254	253
4.710% Series W, due 2052	250	248	—
Tax-exempt refunding revenue bond obligations:			
Fixed-rate series:			
1.850% Pollution Control Series 2016B, due 2029	—	—	30
3.000% Gas and Water Series 2016B, due 2036	—	—	60
0.625% Water Facilities Series 2016C, due 2036	—	—	30
2.050% Water Facilities Series 2016D, due 2036	—	—	25
2.050% Water Facilities Series 2016E, due 2036	—	—	25
2.050% Water Facilities Series 2016F, due 2036	—	—	75
1.850% Water Facilities Series 2016G, due 2036	—	—	20
Total long-term debt	$ 1,152	$ 1,148	$ 1,164
Reflected as:			
Current portion of long-term debt		$ 250	$ —
Long-term debt		898	1,164
Total long-term debt		$ 1,148	$ 1,164

Annual Payment on Long-Term Debt

The annual repayments of long-term debt for the years beginning January 1, 2023 and thereafter, are as follows (in millions):

2023	$ 250
2026	400
2028 and thereafter	502
Total	1,152
Unamortized premium, discount and debt issuance cost	(4)
Total	$ 1,148

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, 2022, approximately $4.9 billion (based on original cost) of Sierra Pacific's property was subject to the liens of the mortgages.

(9) Income Taxes

Income tax expense consists of the following for the years ended December 31 (in millions):

	2022	2021	2020
Current – Federal	$ (12)	$ 5	$ 3
Deferred – Federal	31	13	12
Total income tax expense	$ 19	$ 18	$ 15

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:

	2022	2021	2020
Federal statutory income tax rate	21 %	21 %	21 %
Effects of ratemaking	(7)	(8)	(9)
Effective income tax rate	14 %	13 %	12 %

The net deferred income tax liability consists of the following as of December 31 (in millions):

	2022	2021
Deferred income tax assets:		
Regulatory liabilities	$ 63	$ 64
Operating and finance leases	26	27
Customer advances	17	14
Unamortized contract value	6	8
Other	6	6
Total deferred income tax assets	118	119
Deferred income tax liabilities:		
Property related items	(387)	(379)
Regulatory assets	(135)	(94)
Operating and finance leases	(25)	(27)
Other	(16)	(21)
Total deferred income tax liabilities	(563)	(521)
Net deferred income tax liability	$ (445)	$ (402)

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, 2013. 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, 2022, 2021 and 2020. Sierra Pacific contributed $1 million to the Non-Qualified Pension Plans for the years ended December 31, 2022, 2021 and 2020. Sierra Pacific contributed $5 million and $1 million to the Other Post Retirement Plans for the years ended December 31, 2022 and 2021, respectively. Sierra Pacific did not make any contributions to the Other Post Retirement Plans for the year ended December 31, 2020. 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):

	2022	2021
Qualified Pension Plan -		
Other non-current assets	$ 43	$ 62
Non-Qualified Pension Plans:		
Other current liabilities	(1)	(1)
Other long-term liabilities	(5)	(7)
Other Postretirement Plans -		
Other long-term liabilities	(2)	(10)

(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 $200 million and $201 million as of December 31, 2022 and 2021, respectively.

The following table presents Sierra Pacific's ARO liabilities by asset type as of December 31 (in millions):

	2022	2021
Asbestos	$ 5	$ 5
Evaporative ponds and dry ash landfills	3	3
Other	3	3
Total asset retirement obligations	$ 11	$ 11

Sierra Pacific's ARO liabilities beginning and ending balances totaled $11 million for the years ended December 31, 2022 and 2021. These balances are reflected as other long-term liabilities on the Consolidated Balance Sheets.

Certain of Sierra Pacific's decommissioning and reclamation obligations relate to jointly-owned facilities, and as such, 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.

(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 Current Assets	Other Current Liabilities	Other Long-term Liabilities	Total
As of December 31, 2022:				
Not designated as hedging contracts [1]:				
Commodity assets	$ 8	$ —	$ —	$ 8
Commodity liabilities	—	(14)	(7)	(21)
Total derivative - net basis	$ 8	$ (14)	$ (7)	$ (13)
As of December 31, 2021:				
Not designated as hedging contracts[1]:				
Commodity assets	$ 2	$ —	$ —	$ 2
Commodity liabilities	—	(16)	(19)	(35)
Total derivative - net basis	$ 2	$ (16)	$ (19)	$ (33)

(1) Sierra Pacific's commodity derivatives not designated as hedging contracts are included in regulated rates. As of December 31, 2022 and 2021, a regulatory asset of $13 million and $33 million, respectively, was recorded related to the net derivative liability of $13 million and $33 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	2022	2021
Electricity purchases	Megawatt hours	1	1
Natural gas purchases	Decatherms	52	53

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, 2022, Sierra Pacific'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.

The aggregate fair value of Sierra Pacific's derivative contracts in liability positions with specific credit-risk-related contingent features totaled $— million as of December 31, 2022 and 2021, 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, 2022:				
Assets:				
Commodity derivatives	$ —	$ —	$ 8	$ 8
Money market mutual funds	49	—	—	49
Investment funds	1	—	—	1
	$ 50	$ —	$ 8	$ 58
Liabilities - commodity derivatives	$ —	$ —	$ (21)	$ (21)
As of December 31, 2021:				
Assets:				
Commodity derivatives	$ —	$ —	$ 2	$ 2
Money market mutual funds	10	—	—	10
Investment funds	1	—	—	1
	$ 11	$ —	$ 2	$ 13
Liabilities - commodity derivatives	$ —	$ —	$ (35)	$ (35)

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, 2022, 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.

Sierra Pacific's investments in money market mutual funds and equity securities 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.

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):

	2022	2021	2020
Beginning balance	$ (33)	$ 7	$ (1)
Changes in fair value recognized in regulatory assets or liabilities	(21)	(25)	(2)
Settlements	41	(15)	10
Ending balance	$ (13)	$ (33)	$ 7

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):

	2022		2021	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 1,148	$ 1,111	$ 1,164	$ 1,316

(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, 2022 are as follows (in millions):

	2023	2024	2025	2026	2027	2028 and Thereafter	Total
Contract type:							
Fuel, capacity and transmission contract commitments	$ 413	$ 244	$ 184	$ 134	$ 127	$ 1,447	$ 2,549
Fuel and capacity contract commitments (not commercially operable)	8	11	12	12	11	236	290
Construction commitments	500	741	86	268	—	—	1,595
Easements	2	2	2	2	2	33	43
Maintenance, service and other contracts	7	5	5	3	—	5	25
Total commitments	$ 930	$ 1,003	$ 289	$ 419	$ 140	$ 1,721	$ 4,502

Fuel and Capacity Contract Commitments

Purchased Power

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 2025 to 2047. Purchased power includes estimated payments for contracts which meet the definition of a lease and payments are based on the amount of energy expected to be generated. See Note 5 for further discussion of Sierra Pacific's lease commitments.

Coal and Natural Gas

Sierra Pacific has a long-term contract for the transport of coal that expires in 2024. Additionally, gas transportation contracts expire from 2023 to 2046 and the gas supply contracts expire from 2023 to 2024.

Fuel and Capacity Contract Commitments - Not 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.

Construction Commitments

Sierra Pacific's construction commitments included in the table above relate to firm commitments and include costs associated with two solar photovoltaic facility projects and solar photovoltaic panels for future projects. The first project is a 250-MW solar photovoltaic facility with an additional 200 MWs of co-located battery storage that will be developed in Humboldt County, Nevada. The second project is a 350-MW solar photovoltaic facility with an additional 280 MWs of co-located battery storage that will be developed in Humboldt County, Nevada. Commercial operation has been delayed for both projects to an undetermined date. Both facilities will be jointly owned and operated by Nevada Power and Sierra Pacific.

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, 2022, 2021 and 2020.

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 2046.

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.

Legal Matters

Sierra Pacific is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. Sierra Pacific does not believe that such normal and routine litigation will have a material impact on its financial results. Sierra Pacific is also involved in other kinds of legal actions, some of which assert or may assert claims or seek to impose fines, penalties and other costs in substantial amounts.

(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):

	2022			2021			2020		
	Electric	Natural Gas	Total	Electric	Natural Gas	Total	Electric	Natural Gas	Total
Customer Revenue:									
Retail:									
Residential	$ 365	$ 105	$ 470	$ 307	$ 76	$ 383	$ 273	$ 76	$ 349
Commercial	333	45	378	267	29	296	233	29	262
Industrial	229	16	245	202	10	212	170	9	179
Other	6	1	7	5	—	5	5	—	5
Total fully bundled	933	167	1,100	781	115	896	681	114	795
Distribution only service	5	—	5	3	—	3	4	—	4
Total retail	938	167	1,105	784	115	899	685	114	799
Wholesale, transmission and other	86	—	86	62	—	62	50	—	50
Total Customer Revenue	1,024	167	1,191	846	115	961	735	114	849
Other revenue	1	1	2	2	2	4	3	2	5
Total operating revenue	$ 1,025	$ 168	$ 1,193	$ 848	$ 117	$ 965	$ 738	$ 116	$ 854

(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):

	2022	2021	2020
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	$ 45	$ 41	$ 42
Income taxes (refunded) paid	$ (1)	$ (3)	$ 2
Supplemental disclosure of non-cash investing and financing transactions:			
Accruals related to property, plant and equipment additions	$ 57	$ 27	$ 17

(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 $23 million, $14 million and $4 million for the years ended December 31, 2022, 2021 and 2020. Amounts charged to Sierra Pacific in 2022 and 2021 primarily relate to information technology projects billed at a consolidated level and passed through to affiliates.

Sierra Pacific provided electricity to Nevada Power of $86 million, $43 million and $34 million for the years ended December 31, 2022, 2021 and 2020, respectively. Receivables associated with these transactions were $5 million and $— million as of December 31, 2022 and 2021, respectively. Sierra Pacific purchased electricity from Nevada Power of $362 million, $179 million and $106 million for the years ended December 31, 2022, 2021 and 2020, respectively. Payables associated with these transactions were $41 million and $13 million as of December 31, 2022 and 2021, 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 $5 million for the years ending December 31, 2022, 2021 and 2020, respectively. Sierra Pacific provided services to Nevada Power of $16 million, $15 million, and $15 million for the years ended December 31, 2022, 2021 and 2020, respectively. Nevada Power provided services to Sierra Pacific of $25 million, $25 million, and $26 million for the years ended December 31, 2022, 2021 and 2020, respectively. Sierra Pacific provided services to NV Energy of $1 million, $— million, and $— million for the years ended December 31, 2022, 2021 and 2020, respectively. As of December 31, 2022 and 2021, Sierra Pacific's Consolidated Balance Sheets included amounts due to NV Energy of $47 million and $19 million, respectively. There were no receivables due from NV Energy as of December 31, 2022 and 2021. In November 2022, Sierra Pacific entered into a $100 million unsecured note with NV Energy payable upon demand and $70 million was outstanding as of December 31, 2022. As of December 31, 2022 and 2021, Sierra Pacific's Consolidated Balance Sheets included payables due to Nevada Power of $33 million and $2 million, respectively. There were no receivables due from Nevada Power as of December 31, 2022 and 2021.

Sierra Pacific is party to a tax-sharing agreement with NV Energy and NV Energy is part of the Berkshire Hathaway consolidated U.S. federal income tax return. As of December 31, 2022 and 2021 federal income taxes receivable from NV Energy were $11 million and $— million, respectively. Sierra Pacific received cash refunds of $1 million and $3 million for federal income taxes for the years ended December 31, 2022 and 2021, respectively, and made cash payments of $2 million for federal income taxes for the year ended December 31, 2020.

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 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):

	Years Ended December 31,		
	2022	2021	2020
Operating revenue:			
Regulated electric	$ 1,025	$ 848	$ 738
Regulated natural gas	168	117	116
Total operating revenue	$ 1,193	$ 965	$ 854
Operating income:			
Regulated electric	$ 146	$ 148	$ 147
Regulated natural gas	19	19	18
Total operating income	165	167	165
Interest expense	(58)	(54)	(56)
Allowance for borrowed funds	3	2	2
Allowance for equity funds	7	7	4
Interest and dividend income	18	9	4
Other, net	2	11	7
Income before income tax expense	$ 137	$ 142	$ 126

	As of December 31,		
	2022	2021	2020
Assets			
Regulated electric	$ 4,224	$ 3,829	$ 3,540
Regulated natural gas	441	365	342
Regulated common assets(1)	67	29	37
Total assets	$ 4,732	$ 4,223	$ 3,919

(1) 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, 2022 was $426 million, an increase of $164 million, or 63%, compared to 2021, primarily due to higher margin from EGTS' regulated gas transmission and storage operations of $128 million, a benefit from the settlement of regulated tax matters in the Iroquois rate case and a decrease due to the settlement of depreciation rates in EGTS' general rate case, partially offset by an increase in income tax expense primarily due to higher pre-tax income.

Net income attributable to Eastern Energy Gas for the year ended December 31, 2021 was $262 million, an increase of $153 million, or 140%, compared to 2020, primarily due to a 2020 charge associated with the abandonment of a significant portion of a project in connection with the Atlantic Coast Pipeline project ("Supply Header Project") and a 2020 charge for cash flow hedges of debt-related items that were probable of not occurring as a result of the GT&S Transaction. These increases were partially offset by an increase in net income attributable to DEI's 50% noncontrolling interest in Cove Point and the November 2020 disposition of Questar Pipeline Group of $75 million, both of which were a result of the GT&S Transaction, and an increase in income tax expense primarily due to higher pre-tax income.

Year Ended December 31, 2022 Compared to Year Ended December 31, 2021

Operating revenue increased $136 million, or 7%, for 2022 compared to 2021, primarily due to an increase in regulated gas transmission and storage services revenues due to the settlement of EGTS' general rate case of $101 million, an increase in Cove Point LNG variable revenue of $69 million and an increase in variable revenue related to park and loan activity of $24 million, partially offset by a decrease in regulated gas sales for operational and system balancing purposes primarily due to decreased volumes of $49 million and decreased LNG service as a result of increased scheduled maintenance days of $13 million.

(Excess) cost of gas was a credit of $30 million for 2022 compared to an expense of $12 million for 2021. The change is primarily due to a decrease in volumes sold of $62 million, partially offset by an unfavorable change to operational and system balancing volumes of $20 million.

Operations and maintenance increased $15 million, or 3%, for 2022 compared to 2021, primarily due to a 2021 benefit from the finalization of entries for the disallowance of capitalized AFUDC of $11 million and higher corporate charges of $11 million, partially offset by lower long-term incentive plan expenses of $8 million.

Depreciation and amortization decreased $7 million, or 2%, for 2022 compared to 2021, primarily due to the settlement of depreciation rates in EGTS' general rate case of $23 million, partially offset by higher plant placed in-service of $16 million.

Property and other taxes decreased $10 million, or 7%, for 2022 compared to 2021, primarily due to lower than estimated 2021 tax assessments.

Interest expense decreased $4 million, or 3%, for 2022 compared to 2021, primarily due to the repayment of $500 million of long-term debt in the second quarter of 2021.

Interest and dividend income increased $7 million for 2022 compared to 2021, primarily due to interest income from BHE GT&S' intercompany revolving credit agreement with Eastern Energy Gas.

Other, net was an expense of $1 million for 2022 compared to a credit of $1 million for 2021. The change is primarily due to losses on marketable securities.

Income tax expense (benefit) increased $50 million, or 43%, for 2022 compared to 2021 and the effective tax rate was 18% for 2022 and 16% for 2021. The effective tax rate increased primarily due to the revaluation of deferred taxes from changes in various state income tax rates.

Equity income increased $59 million for 2022 compared 2021, primarily due to a benefit from the settlement of regulated tax matters in the Iroquois rate case of $45 million and higher operating revenues at Iroquois due to favorable fixed negotiated rate agreements and hedges of $15 million.

Net income attributable to noncontrolling interests increased $33 million for 2022 compared to 2021, primarily due to an increase in Cove Point LNG variable revenue, partially offset by decreased LNG service as a result of increased scheduled maintenance days.

Year Ended December 31, 2021 Compared to Year Ended December 31, 2020

Operating revenue decreased $220 million, or 11%, for 2021 compared to 2020, primarily due to the November 2020 disposition of Questar Pipeline Group of $197 million and a decrease in services performed for Atlantic Coast Pipeline of $43 million, which is offset in operations and maintenance expense, partially offset by an increase in regulated gas revenues for operational and system balancing purposes primarily due to increased prices of $15 million.

Cost of gas decreased $12 million, or 50%, for 2021 compared to 2020, primarily due to a favorable change in natural gas prices of $55 million and the November 2020 disposition of Questar Pipeline Group of $3 million, partially offset by an increase in prices of natural gas sold of $49 million.

Operations and maintenance decreased $627 million, or 55%, for 2021 compared to 2020, primarily due to a 2020 charge associated with the abandonment of the Supply Header Project of $463 million, a decrease in services performed for Atlantic Coast Pipeline of $45 million, the November 2020 disposition of Questar Pipeline Group of $43 million, a 2020 charge for disallowance of capitalized AFUDC due to the resolution of EGTS' 2015 FERC audit of $43 million, the 2020 write-off of certain items in connection with the GT&S Transaction of $17 million and a 2021 benefit from the finalization of entries for the disallowance of capitalized AFUDC of $11 million.

Depreciation and amortization decreased $38 million, or 10%, for 2021 compared to 2020, primarily due the November 2020 disposition of Questar Pipeline Group.

Property and other taxes increased $9 million, or 6%, for 2021 compared to 2020, primarily due to higher tax assessments.

Interest expense decreased $188 million, or 55%, for 2021 compared to 2020, primarily due to a charge in 2020 for cash flow hedges of $141 million of debt-related items that were probable of not occurring as a result of the GT&S Transaction, the November 2020 disposition of Questar Pipeline Group of $16 million and lower interest expense of $17 million from the repayment of $700 million of long-term debt in the fourth quarter of 2020 and $5 million from the repayment of $500 million of long-term debt in the second quarter of 2021.

Allowance for borrowed funds decreased $4 million, or 67%, for 2021 compared to 2020, primarily due to the 2020 abandonment of the Supply Header Project.

Allowance for equity funds decreased $6 million, or 46%, for 2021 compared to 2020, primarily due to the 2020 abandonment of the Supply Header Project.

Interest and dividend income decreased $67 million for 2021 compared to 2020, primarily due to interest income from the East Ohio Gas Company of $33 million and DEI of $32 million recognized in 2020.

Other, net decreased $41 million, or 98%, for 2021 compared to 2020, primarily due to non-service cost credits recognized in 2020 related to certain Eastern Energy Gas benefit plans that were retained by DEI as a result of the GT&S Transaction.

Income tax expense (benefit) was an expense of $117 million for 2021 compared to a benefit of $24 million for 2020. The effective tax rate was 16% in 2021 and (12)% in 2020. The effective tax rate increased primarily due to the change in the noncontrolling interest of Cove Point as a result of the GT&S Transaction, lower pre-tax income driven by charges associated with the Supply Header Project in 2020 and the finalization of the effects from the change in tax status of certain Eastern Energy Gas subsidiaries in 2020.

Net income attributable to noncontrolling interests increased $226 million for 2021 compared to 2020, primarily due to DEI's 50% noncontrolling interest in Cove Point effective with the GT&S Transaction.

Liquidity and Capital Resources

As of December 31, 2022, Eastern Energy Gas' total net liquidity was as follows (in millions):

Cash and cash equivalents	$	65
Intercompany revolving credit agreement[(1)]		400
Total net liquidity	$	465
Intercompany credit agreement:		
Maturity date		2023

(1) 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.

Operating Activities

Net cash flows from operating activities for the years ended December 31, 2022 and 2021 were $1.3 billion and $1.1 billion, respectively. The change was primarily due to the impacts from the proposed rate increase in effect April 1, 2022 for the EGTS general rate case, timing of income tax payments and other changes in working capital, partially offset by lower collections from customers.

Net cash flows from operating activities for the years ended December 31, 2021 and 2020 were $1.1 billion and $1.3 billion, respectively. The change was primarily due to lower collections from affiliates, the November 2020 disposition of Questar Pipeline Group and the timing of payments of operating costs, partially offset by the settlement of interest rate swaps in 2020 and higher income tax receipts.

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

Investing Activities

Net cash flows from investing activities for the years ended December 31, 2022 and 2021 were $(778) million and $(486) million, respectively. The change was primarily due to higher loans to affiliates of $381 million and lower repayments of loans by affiliates of $266 million, partially offset by equity method distribution of $150 million in 2022, equity method contributions of $154 million in 2021 and a decrease in capital expenditures of $55 million.

Net cash flows from investing activities for the years ended December 31, 2021 and 2020 were $(486) million and $3.1 billion, respectively. The change was primarily due to lower repayments of loans by affiliates of $3.1 billion, loans to affiliates of $183 million and higher funding of equity method investments of $152 million.

Financing Activities

Net cash flows from financing activities for the year ended December 31, 2022 were $(515) million and consisted of distributions to noncontrolling interests from Cove Point.

Net cash flows from financing activities for the year ended December 31, 2021 were $(615) million. Sources of cash totaled $346 million and consisted of proceeds from equity contributions, that included a contribution from its indirect parent, BHE, to Eastern Energy Gas to assist in the repayment of $500 million of debt. Uses of cash totaled $961 million and consisted mainly of repayments of long-term debt of $500 million, distributions to noncontrolling interests from Cove Point of $450 million and repayment of notes to affiliates of $9 million.

Net cash flows from financing activities for the year ended December 31, 2020 were $(4.3) billion. Sources of cash totaled $1.2 billion and consisted of proceeds from equity contributions, that included a contribution from its indirect parent BHE to Eastern Energy Gas to repay its $700 million of debt. Uses of cash totaled $5.5 billion and consisted mainly of distributions of $4.5 billion, repayments of long-term debt of $700 million and net repayments of affiliated current borrowings of $251 million as required by the GT&S Transaction.

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		
	2020	2021	2022	2023	2024	2025
Natural gas transmission and storage	$ 112	$ 16	$ 43	$ 15	$ 46	$ 147
Other	262	426	344	336	285	245
Total	$ 374	$ 442	$ 387	$ 351	$ 331	$ 392

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, 2022, Eastern Energy Gas' investments that are accounted for under the equity method had short- and long-term debt of $307 million and an unused revolving credit facility of $10 million. As of December 31, 2022, Eastern Energy Gas' pro-rata share of such short- and long-term debt was $154 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, 2022 (in millions):

	Payments Due by Periods				
	2023	2024-2025	2026-2027	2028 and thereafter	Total
Interest payments on long-term debt(1)	$ 136	$ 205	$ 164	$ 1,012	$ 1,517
Natural gas supply and transmission(1)	49	98	98	—	245
Total cash requirements	$ 185	$ 303	$ 262	$ 1,012	$ 1,762

(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 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.

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 $48 million and total regulatory liabilities were $722 million as of December 31, 2022. 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, 2022 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, 2022. Additionally, no indicators of impairment were identified as of December 31, 2022. 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. 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% as a result of 2017 Tax Reform, certain property-related basis differences and other various differences on to their customers. As of December 31, 2022, these amounts were recognized as a net regulatory liability of $406 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 commodity prices, 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.

Commodity Price Risk

Eastern Energy Gas is exposed to the impact of market fluctuations in commodity prices. Eastern Energy Gas is principally exposed to natural gas market fluctuations primarily through fuel retained and used during the operation of the pipeline system as well as lost and unaccounted for gas. Eastern Energy Gas is exposed to the risk of fuel retention, meaning customers have a fixed fuel retention percentage assessed on transmission and storage quantities, and the pipeline bears the risk of under-recovery and benefits from any over-recovery of volumes. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, facility availability, customer usage, storage and transmission constraints. Eastern Energy Gas does not engage in proprietary trading activities. 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 quantities or sell future supply quantities generally at fixed prices. Eastern Energy Gas does not hedge all of its commodity price risk, thereby exposing the unhedged portion to changes in market prices. As of February 2023, all of Eastern Energy Gas' regulated operations recover their cost of gas through fuel trackers and are no longer subject to significant commodity price risk.

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.

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, 2022 and 2021, 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, 2022 and 2021.

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, 2022, Eastern Energy Gas' credit exposure totaled $90 million. Of this amount, investment grade counterparties, including those internally rated, represented 98%, with three investment grade counterparties representing 57%.

Item 8. Financial Statements and Supplementary Data

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, 2022 and 2021, 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, 2022, 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, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022, 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 audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Regulatory Matters — 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. Management has determined its rate regulated subsidiaries 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 economics 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 future regulatory orders on the financial statements. Management judgments include assessing the likelihood of (1) recovery in future rates of incurred costs and (2) a refund to customers. Given that management's accounting judgments are based on assumptions about the outcome of future decisions by the FERC, auditing these judgments required specialized knowledge of the accounting for rate regulation and the rate setting process due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of future decisions by the FERC included the following, among others:

- We evaluated the Eastern Energy Gas disclosures related to the effects of rate regulation, including the balances recorded and regulatory developments.
- We read relevant regulatory orders issued by the FERC, regulatory statutes, interpretations, procedural memorandums, filings made by interveners, and other external information. We evaluated the external information and compared to management's recorded regulatory asset and liability balances for completeness.
- For regulatory matters in process, 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 24, 2023

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,	
	2022	**2021**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 65	$ 22
Restricted cash and cash equivalents	30	17
Trade receivables, net	202	183
Receivables from affiliates	30	47
Notes receivable from affiliates	536	7
Inventories	127	122
Prepayments	78	76
Natural gas imbalances	193	100
Other current assets	42	47
Total current assets	1,303	621
Property, plant and equipment, net	10,202	10,200
Goodwill	1,286	1,286
Investments	278	412
Other assets	95	129
Total assets	$ 13,164	$ 12,648

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,	
	2022	2021
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 86	$ 79
Accounts payable to affiliates	10	38
Accrued interest	19	19
Accrued property, income and other taxes	77	89
Accrued employee expenses	14	13
Regulatory liabilities	126	40
Asset retirement obligations	25	33
Current portion of long-term debt	649	—
Other current liabilities	107	54
Total current liabilities	1,113	365
Long-term debt	3,243	3,906
Regulatory liabilities	596	645
Other long-term liabilities	324	238
Total liabilities	5,276	5,154
Commitments and contingencies (Note 14)		
Equity:		
Member's equity:		
Membership interests	3,983	3,501
Accumulated other comprehensive loss, net	(42)	(43)
Total member's equity	3,941	3,458
Noncontrolling interests	3,947	4,036
Total equity	7,888	7,494
Total liabilities and equity	$ 13,164	$ 12,648

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,		
	2022	**2021**	**2020**
Operating revenue	$ 2,006	$ 1,870	$ 2,090
Operating expenses:			
(Excess) cost of gas	(30)	12	24
Operations and maintenance	530	515	1,142
Depreciation and amortization	321	328	366
Property and other taxes	139	149	140
Total operating expenses	960	1,004	1,672
Operating income	1,046	866	418
Other income (expense):			
Interest expense	(147)	(151)	(339)
Allowance for borrowed funds	2	2	6
Allowance for equity funds	6	7	13
Interest and dividend income	7	—	67
Other, net	(1)	1	42
Total other income (expense)	(133)	(141)	(211)
Income before income tax expense (benefit) and equity income	913	725	207
Income tax expense (benefit)	167	117	(24)
Equity income	103	44	42
Net income	849	652	273
Net income attributable to noncontrolling interests	423	390	164
Net income attributable to Eastern Energy Gas	$ 426	$ 262	$ 109

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,		
	2022	2021	2020
Net income	$ 849	$ 652	$ 273
Other comprehensive income, net of tax:			
Unrecognized amounts on retirement benefits, net of tax of $—, $— and $40	5	6	94
Unrealized (losses) gains on cash flow hedges, net of tax of $—, $1 and $10	(1)	9	30
Total other comprehensive income, net of tax	4	15	124
Comprehensive income	853	667	397
Comprehensive income attributable to noncontrolling interests	426	395	154
Comprehensive income attributable to Eastern Energy Gas	$ 427	$ 272	$ 243

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, 2019	$ 9,031	$ (187)	$ 1,385	$ 10,229
Net income	109	—	164	273
Other comprehensive income (loss)	—	134	(10)	124
Distributions	(4,282)	—	(216)	(4,498)
Contributions	1,223	—	—	1,223
Distribution of Questar Pipeline Group	(699)	—	—	(699)
Distribution of 50% interest in Cove Point	(2,765)	—	2,765	—
Acquisition of Eastern Energy Gas by BHE	343	—	—	343
Other equity transactions	(3)	—	3	—
Balance, December 31, 2020	2,957	(53)	4,091	6,995
Net income	262	—	390	652
Other comprehensive income	—	10	5	15
Distributions	(137)	—	(450)	(587)
Contributions	419	—	—	419
Balance, December 31, 2021	3,501	(43)	4,036	7,494
Net income	426	—	423	849
Other comprehensive income	—	1	3	4
Distributions	(42)	—	(515)	(557)
Contributions	98	—	—	98
Balance, December 31, 2022	$ 3,983	$ (42)	$ 3,947	$ 7,888

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,		
	2022	2021	2020
Cash flows from operating activities:			
Net income	$ 849	$ 652	$ 273
Adjustments to reconcile net income to net cash flows from operating activities:			
Losses (gains) on other items, net	5	(3)	531
Depreciation and amortization	321	328	366
Allowance for equity funds	(6)	(7)	(13)
Equity (income) loss, net of distributions	(58)	—	35
Changes in regulatory assets and liabilities	56	(20)	(37)
Deferred income taxes	126	186	(5)
Other, net	8	(19)	23
Changes in other operating assets and liabilities:			
Trade receivables and other assets	(77)	7	346
Derivative collateral, net	(1)	10	(140)
Pension and other postretirement benefit plans	—	—	(88)
Accrued property, income and other taxes	27	(30)	23
Accounts payable and other liabilities	99	(12)	(40)
Net cash flows from operating activities	1,349	1,092	1,274
Cash flows from investing activities:			
Capital expenditures	(387)	(442)	(374)
Loans to affiliates	(564)	(183)	—
Repayment of loans by affiliates	39	305	3,422
Equity method investments	150	(154)	(2)
Other, net	(16)	(12)	18
Net cash flows from investing activities	(778)	(486)	3,064
Cash flows from financing activities:			
Repayments of long-term debt	—	(500)	(700)
Net (repayments of) proceeds from short-term debt	—	—	(62)
Repayment of affiliated current borrowings, net	—	(9)	(251)
Proceeds from equity contributions	—	346	1,223
Distributions to parent	—	—	(4,323)
Distributions to noncontrolling interests	(515)	(450)	(216)
Other, net	—	(2)	—
Net cash flows from financing activities	(515)	(615)	(4,329)
Net change in cash and cash equivalents and restricted cash and cash equivalents	56	(9)	9
Cash and cash equivalents and restricted cash and cash equivalents at beginning of period	39	48	39
Cash and cash equivalents and restricted cash and cash equivalents at end of period	$ 95	$ 39	$ 48

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 pipeline 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 owns 100% of the general partner interest and 25% of the limited partnership interest in Cove Point. In addition, Eastern Energy Gas owns a 50% noncontrolling interest in Iroquois Gas Transmission System, L.P. ("Iroquois"), a 416-mile FERC-regulated interstate natural gas transmission pipeline. On November 1, 2020, Berkshire Hathaway Energy Company ("BHE") completed its acquisition of substantially all of the natural gas transmission and storage business of Dominion Energy, Inc. ("DEI") (the "GT&S Transaction"). As a result of the GT&S Transaction, Eastern Energy Gas became an indirect wholly owned subsidiary of BHE. BHE is a holding company based in Des Moines, Iowa that owns subsidiaries principally engaged in the energy industry. BHE is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway"). See Note 3 for more information regarding the GT&S Transaction.

(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, 2022 and 2021, as presented in 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,	
	2022	**2021**
Cash and cash equivalents	$ 65	$ 22
Restricted cash and cash equivalents	30	17
Total cash and cash equivalents and restricted cash and cash equivalents	$ 95	$ 39

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 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 evaluates the financial condition of the individual customer and the nature of any disputed amount.

The changes in the balance of the allowance for credit losses, which is included in trades receivables, net on the Consolidated Balance Sheets, is summarized as follows for the years ended December 31, (in millions):

	2022	**2021**	**2020**
Beginning balance	$ 6	$ 5	$ 2
Charged to operating costs and expenses, net	—	1	4
Write-offs, net	(3)	—	(1)
Ending balance	$ 3	$ 6	$ 5

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 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. 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 to determine the appropriate group lives, net salvage and group depreciation rates. These studies are reviewed and rates are ultimately approved by the FERC. See Note 6 for the prospective impacts related to changes in depreciation rates. 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 natural gas pipeline 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. The impacts of regulation are considered when evaluating the carrying value of regulated assets. See Note 6 for more information.

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, 2022. 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 2022, 2021 and 2020, 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.

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, 2022 and 2021, trade receivables, net on the Consolidated Balance Sheets relate substantially to Customer Revenue, including unbilled revenue of $18 million and $36 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. See Note 6 for discussion surrounding the Eastern Gas Transmission and Storage, Inc. ("EGTS") provision for rate refund. 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 $10 million and $19 million as of December 31, 2022 and 2021, respectively, and $80 million and $18 million of contract liabilities as of December 31, 2022 and 2021, respectively, due to Eastern Energy Gas' 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

Prior to the GT&S Transaction, DEI included Eastern Energy Gas in its consolidated U.S. federal income tax return. Subsequent to the GT&S Transaction, 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 segment, which includes its natural gas pipeline, storage and LNG operations.

(3) Business Acquisitions and Dispositions

Acquisition of Eastern Energy Gas by BHE

In July 2020, DEI entered into an agreement to sell substantially all of its natural gas transmission and storage operations, including Eastern Energy Gas and a 25% limited partnership interest in Cove Point, to BHE. Approval of the transaction under the Hart-Scott-Rodino Act was not obtained within 75 days and DEI and BHE mutually agreed to a dual-phase closing consisting of two separate disposal groups identified as the GT&S Transaction and the proposed sale of Dominion Energy Questar Pipeline, LLC and related entities ("the Questar Pipeline Group") by DEI to BHE pursuant to a purchase and sale agreement entered into on October 5, 2020 ("Q-Pipe Transaction"). In July 2021, Dominion Energy Questar Corporation ("Dominion Questar") and DEI delivered a written notice to BHE stating that BHE and Dominion Questar mutually elected to terminate the Q-Pipe Transaction. Prior to the completion of the GT&S Transaction, Eastern Energy Gas finalized a restructuring whereby Eastern Energy Gas distributed the Questar Pipeline Group and a 50% noncontrolling interest in Cove Point to DEI. This restructuring was accounted for by Eastern Energy Gas as a reorganization of entities under common control and the disposition was reflected as an equity transaction. The disposition was not reported as a discontinued operation as the disposal did not represent a strategic shift in the way management had intended to run the business.

In November 2020, the GT&S Transaction was completed and Eastern Energy Gas, with the exception of the Questar Pipeline Group as discussed above, became an indirect wholly-owned subsidiary of BHE. DEI retained a 50% noncontrolling interest in Cove Point as well as the assets and obligations of the pension and other postretirement employee benefit plans associated with the operations sold and relating to services provided before closing. The GT&S Transaction was treated as a deemed asset sale for federal and state income tax purposes and all deferred taxes at Eastern Energy Gas were reset to reflect financial and tax basis differences as of November 1, 2020. See Notes 9 and 16 for more information on the GT&S Transaction.

Eastern Energy Gas recorded a distribution of net assets of $699 million, including goodwill of $185 million and $41 million of cash, for the distribution of the Questar Pipeline Group to DEI and recorded an approximately $2.8 billion increase in noncontrolling interests for DEI's retained 50% noncontrolling interest in Cove Point. Additionally, in accordance with the terms of the GT&S Transaction, DEI retained certain assets and liabilities associated with Eastern Energy Gas and settled all affiliated balances. As a result, Eastern Energy Gas recorded a contribution for the reset of deferred taxes of $1.3 billion, net of distributions of $895 million related to the pension and other postretirement employee benefit plans retained by DEI and $107 million related to the settlement of affiliated balances.

(4) Property, Plant and Equipment, Net

Property, plant and equipment, net consists of the following as of December 31 (in millions):

	Depreciable Life	2022	2021
Utility Plant:			
Interstate natural gas pipeline and storage assets	21 - 52 years	$ 8,922	$ 8,675
Intangible plant	5 - 18 years	113	110
Utility plant in-service		9,035	8,785
Accumulated depreciation and amortization		(3,039)	(2,901)
Utility plant in-service, net		5,996	5,884
Nonutility Plant:			
LNG facility	40 years	4,522	4,475
Intangible plant	14 years	25	25
Nonutility plant		4,547	4,500
Accumulated depreciation and amortization		(542)	(423)
Nonutility plant, net		4,005	4,077
		10,001	9,961
Construction work- in-progress		201	239
Property, plant and equipment, net		$ 10,202	$ 10,200

Construction work-in-progress includes $181 million and $209 million as of December 31, 2022 and 2021, respectively, related to the construction of utility plant.

(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, 2022 (dollars in millions):

	Eastern Energy Gas' Share	Facility in Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
Ellisburg Pool	39 %	$ 32	$ 11	$ —
Ellisburg Station	50	26	8	3
Harrison	50	53	18	—
Leidy	50	143	47	1
Oakford	50	202	70	4
Tioga	56	69	30	2
Total		$ 456	$ 154	$ 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	2022	2021
Employee benefit plans[1]	11 years	$ 32	$ 62
Other	Various	16	12
Total regulatory assets		$ 48	$ 74
Reflected as:			
Other current assets		$ 8	$ 6
Other assets		40	68
Total regulatory assets		$ 48	$ 74

(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.

Eastern Energy Gas had regulatory assets not earning a return on investment of $44 million and $8 million as of December 31, 2022 and 2021, 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	2022	2021
Income taxes refundable through future rates[1]	Various	$ 406	$ 468
Other postretirement benefit costs[2]	Various	123	116
Provision for rate refunds[3]		90	—
Cost of removal[4]	53 years	82	73
Other	Various	21	28
Total regulatory liabilities		$ 722	$ 685
Reflected as:			
Current liabilities		$ 126	$ 40
Noncurrent liabilities		596	645
Total regulatory liabilities		$ 722	$ 685

(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) Reflects amounts expected to be refunded to customers in late February 2023 in connection with the EGTS rate case. See below for more information.

(4) 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.

Regulatory Matters

Eastern Gas Transmission and Storage, Inc.

In September 2021, EGTS filed a general rate case for its FERC-jurisdictional services, with proposed rates to be effective November 1, 2021. EGTS' previous general rate case was settled in 1998. EGTS proposed an annual cost-of-service of approximately $1.1 billion, and requested increases in various rates, including general system storage rates by 85% and general system transmission rates by 60%. In October 2021, the FERC issued an order that accepted the November 1, 2021 effective date for certain changes in rates, while suspending the other changes for five months following the proposed effective date, until April 1, 2022, subject to refund. In September 2022, a settlement agreement was filed with the FERC, resolving EGTS' general rate case for its FERC-jurisdictional services and providing for increased service rates and decreased depreciation rates. Under the terms of the settlement agreement, EGTS' rates result in an increase to annual firm transmission and storage revenues of approximately $160 million and a decrease in annual depreciation expense of approximately $30 million, compared to the rates in effect prior to April 1, 2022. As of December 31, 2022, EGTS' provision for rate refund for April 2022 through December 2022 totaled $90 million and was included in current regulatory liabilities on the Consolidated Balance Sheet. In November 2022, the FERC approved the settlement agreement.

In July 2017, the FERC audit staff communicated to EGTS that it had substantially completed an audit of EGTS' compliance with the accounting and reporting requirements of the FERC's Uniform System of Accounts and provided a description of matters and preliminary recommendations. In November 2017, the FERC audit staff issued its audit report. In December 2017, EGTS provided its response to the audit report. EGTS requested FERC review of the contested findings and submitted its plan for compliance with the uncontested portions of the report. EGTS reached resolution of certain matters with the FERC in the fourth quarter of 2018. EGTS recognized a charge for a disallowance of plant, originally established beginning in 2012, for the resolution of one matter with the FERC. In December 2020, the FERC issued a final ruling on the remaining matter, which resulted in a $43 million ($31 million after-tax) estimated charge for disallowance of capitalized AFUDC, recorded within operations and maintenance expense in the Consolidated Statement of Operations. As a condition of the December 2020 ruling, EGTS filed its proposed accounting entries and supporting documentation with the FERC during the second quarter of 2021. During the finalization of these entries, EGTS refined the estimated charge for disallowance of capitalized AFUDC, which resulted in a reduction to the estimated charge of $11 million ($8 million after-tax) that was recorded in operations and maintenance expense in the Consolidated Statement of Operations in the second quarter of 2021. In September 2021, the FERC approved EGTS' accounting entries and supporting documentation.

In December 2014, EGTS entered into a precedent agreement with Atlantic Coast Pipeline, LLC ("Atlantic Cost Pipeline") for the project previously intended for EGTS to provide approximately 1,500,000 decatherms ("Dth") of firm transmission service to various customers in connection with the Atlantic Coast Pipeline project ("Supply Header Project"). As a result of the cancellation of the Atlantic Coast Pipeline project, in the second quarter of 2020 Eastern Energy Gas recorded a charge of $482 million ($359 million after-tax) in operations and maintenance expense in its Consolidated Statement of Operations associated with the probable abandonment of a significant portion of the project as well as the establishment of a $75 million ARO. In the third quarter of 2020, Eastern Energy Gas recorded an additional charge of $10 million ($7 million after-tax) associated with the probable abandonment of a significant portion of the project and a $29 million ($20 million after-tax) benefit from a revision to the previously established ARO, both of which were recorded in operations and maintenance expense in Eastern Energy Gas' Consolidated Statement of Operations. As EGTS evaluates its future use, approximately $40 million remains within property, plant and equipment for a potential modified project.

Cove Point

In January 2020, pursuant to the terms of a previous settlement, Cove Point filed a general rate case for its FERC-jurisdictional services, with proposed rates to be effective March 1, 2020. Cove Point proposed an annual cost-of-service of $182 million. In February 2020, FERC approved suspending the changes in rates for five months following the proposed effective date, until August 1, 2020, subject to refund. In November 2020, Cove Point reached an agreement in principle with the active participants in the general rate case proceeding. Under the terms of the agreement in principle, Cove Point's rates effective August 1, 2020 resulted in an increase to annual revenues of $4 million and a decrease in annual depreciation expense of $1 million, compared to the rates in effect prior to August 1, 2020. The interim settlement rates were implemented November 1, 2020, and Cove Point's provision for rate refunds for August 2020 through October 2020 totaled $7 million. The agreement in principle was reflected in a stipulation and agreement filed with the FERC in January 2021. In March 2021, the FERC approved the stipulation and agreement and the rate refunds to customers were processed in late April 2021.

(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):

	2022	2021
Investments:		
Investment funds	$ 14	$ 13
Equity method investments:		
Iroquois	264	399
Total investments	278	412
Restricted cash and cash equivalents:		
Customer deposits	30	17
Total restricted cash and cash equivalents	30	17
Total investments and restricted cash and cash equivalents	$ 308	$ 429
Reflected as:		
Current assets	$ 30	$ 17
Noncurrent assets	278	412
Total investments and restricted cash and cash equivalents	$ 308	$ 429

Equity Method Investments

Eastern Energy Gas, through subsidiaries, owns 50% of Iroquois, which owns and operates an interstate natural gas pipeline located in the states of New York and Connecticut. Prior to the GT&S Transaction, Eastern Energy Gas, through the Questar Pipeline Group, owned 50% of White River Hub, which owns and operates a natural gas pipeline in northwest Colorado.

As of both December 31, 2022 and 2021, 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 made contributions of $154 million in 2021. Eastern Energy Gas received distributions from its investments of $195 million, $44 million and $77 million for the years ended December 31, 2022, 2021 and 2020, respectively. In the third quarter of 2022, in connection with the settlement of regulated tax matters in the Iroquois rate case, Eastern Energy Gas released a long-term regulatory liability and recognized a $45 million benefit that was recorded in equity income in its Consolidated Statements of Operations.

(8) Long-term Debt

On June 30, 2021, as part of an intercompany transaction with its wholly owned subsidiary EGTS, Eastern Energy Gas exchanged a total of $1.6 billion of its issued and outstanding third party notes, making EGTS the primary obligor of the exchanged notes. The intercompany debt exchange was a common control transaction accounted for as a debt modification with no gain or loss recognized on the Consolidated Financial Statements.

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	2022	2021
Eastern Energy Gas:			
2.875% Senior Notes, due 2023	$ 250	$ 250	$ 250
3.55% Senior Notes, due 2023	400	399	399
2.50% Senior Notes, due 2024	600	598	597
3.60% Senior Notes, due 2024	339	338	338
3.32% Senior Notes, due 2026 (€250)(1)	268	267	283
3.00% Senior Notes, due 2029	174	173	173
3.80% Senior Notes, due 2031	150	150	150
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
EGTS:			
3.60% Senior Notes, due 2024	111	110	110
3.00% Senior Notes, due 2029	426	422	422
4.80% Senior Notes, due 2043	346	342	341
4.60% Senior Notes, due 2044	444	437	437
3.90% Senior Notes, due 2049	273	271	271
Total long-term debt	$ 3,918	$ 3,892	$ 3,906
Reflected as:			
Current portion of long-term debt		$ 649	$ —
Long-term debt		3,243	3,906
Total long-term debt		$ 3,892	$ 3,906

(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 both December 31, 2022 and 2021 that averaged 3.32%.

Annual Payment on Long-Term Debt

The annual repayments of long-term debt for the years beginning January 1, 2023 and thereafter, are as follows (in millions):

2023	$ 650
2024	1,050
2025	—
2026	268
2027	—
2028 and thereafter	1,950
Total	3,918
Unamortized premium, discount and debt issuance cost	(26)
Total	$ 3,892

(9) Income Taxes

Income tax expense (benefit) consists of the following for the years ended December 31 (in millions):

	2022	2021	2020
Current:			
Federal	$ 12	$ (47)	$ (20)
State	29	(21)	1
	41	(68)	(19)
Deferred:			
Federal	88	129	23
State	38	56	(28)
	126	185	(5)
Total	$ 167	$ 117	$ (24)

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:

	2022	2021	2020
Federal statutory income tax rate	21 %	21 %	21 %
State income tax, net of federal income tax benefit	6	3	(13)
Equity interest	2	1	4
Effects of ratemaking	(1)	1	(2)
Change in tax status	—	—	(9)
AFUDC-equity	—	—	(1)
Noncontrolling interest	(10)	(11)	(16)
Write-off of regulatory assets	—	—	3
Other, net	—	1	1
Effective income tax rate	18 %	16 %	(12)%

For the year ended December 31, 2022, Eastern Energy Gas' reconciliation of the federal statutory income tax rate to the effective income tax rate is driven primarily by the absence of tax on noncontrolling interest.

The net deferred income tax liability consists of the following as of December 31 (in millions):

	2022	2021
Deferred income tax assets:		
Federal and state carryforwards	$ 23	$ 7
Employee benefits	22	33
Intangibles	112	150
Derivatives and hedges	16	16
Other	7	9
Total deferred income tax assets	180	215
Deferred income tax liabilities:		
Property related items	(214)	(129)
Partnership investments	(51)	(49)
Debt exchange	(53)	(60)
Deferred state income taxes	(4)	(16)
Other	(12)	(16)
Total deferred income tax liabilities	(334)	(270)
Net deferred income tax liability[1]	$ (154)	$ (55)

(1) Net deferred income tax liability, as of both December 31, 2022 and 2021, is presented in other assets and other long-term liabilities in the Consolidated Balance Sheet.

As of December 31, 2022, Eastern Energy Gas' state tax carryforwards, entirely related to $23 million of net operating losses, expire at various intervals between 2036 and indefinite.

Through October 31, 2020, Eastern Energy Gas was included in DEI's consolidated federal income tax return and, where applicable, combined state income tax returns. As a result of the GT&S Transaction, DEI retained the rights and obligations of Eastern Energy Gas' federal and state income tax returns through October 31, 2020. 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

As discussed in Note 3, in November 2020, the GT&S Transaction was completed and the assets and obligations of the pension and other postretirement employee benefit plans associated with the operations sold and relating to services provided before closing were retained by DEI. As a result, just prior to completing the sale, net benefit plan assets of $895 million were distributed through an equity transaction with DEI.

Subsequent to the GT&S Transaction

Subsequent to the GT&S Transaction, 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 $14 million, $18 million and $3 million of contributions to the MidAmerican Energy Company Retirement Plan for the years ended December 31, 2022, 2021 and 2020, respectively. Eastern Energy Gas made $2 million, $10 million and $2 million of contributions to the MidAmerican Energy Company Welfare Benefit Plan for the years ended December 31, 2022, 2021 and 2020, 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.

Eastern Energy Gas participates in the BHE GT&S, LLC ("BHE GT&S") defined contribution employee savings plan subsequent to the GT&S Transaction. Eastern Energy Gas' matching contributions are based on each participant's level of contribution. Contributions cannot exceed the maximum allowable for tax purposes. Eastern Energy Gas' contributions to the 401(k) plan were $6 million, $5 million and $1 million for the years ended December 31, 2022, 2021 and 2020, respectively.

Prior to the GT&S Transaction

Defined Benefit Plans

Prior to the GT&S Transaction, certain Eastern Energy Gas employees not represented by collective bargaining units were covered by the Dominion Energy Pension Plan, a defined benefit pension plan sponsored by DEI that provides benefits to multiple DEI subsidiaries. As participating employers, Eastern Energy Gas was subject to DEI's funding policy, which was to contribute annually an amount that is in accordance with the Employee Retirement Income Security Act of 1974. Eastern Energy Gas' net periodic pension credit related to this plan was $14 million for the year ended December 31, 2020. Net periodic pension credit is reflected in other operations and maintenance expense in the Consolidated Statement of Operations. The funded status of various DEI subsidiary groups and employee compensation are the basis for determining the share of total pension costs for participating DEI subsidiaries.

Prior to the GT&S Transaction, certain retiree healthcare and life insurance benefits for Eastern Energy Gas employees not represented by collective bargaining units were covered by the Dominion Energy Retiree Health and Welfare Plan, a plan sponsored by DEI that provides certain retiree healthcare and life insurance benefits to multiple DEI subsidiaries. Eastern Energy Gas' net periodic benefit credit related to this plan was $5 million for the year ended December 31, 2020. Net periodic benefit credit is reflected in other operations and maintenance expense in the Consolidated Statement of Operations. Employee headcount is the basis for determining the share of total other postretirement benefit costs for participating DEI subsidiaries.

Pension benefits for Eastern Energy Gas employees represented by collective bargaining units were covered by a separate pension plan that provides benefits to employees of both EGTS and Hope Gas, Inc. ("Hope"). Employee compensation was the basis for allocating pension costs and obligations between EGTS and Hope. Retiree healthcare and life insurance benefits for Eastern Energy Gas employees represented by collective bargaining units were covered by a separate other postretirement benefit plan that provides benefits to both EGTS and Hope. Employee headcount was the basis for allocating other postretirement benefit costs and obligations between EGTS and Hope.

Pension Remeasurement

In the third quarter of 2020, Eastern Energy Gas remeasured a pension plan due to a curtailment resulting from the agreement for DEI to retain the assets and obligations of the pension benefit plan associated with the GT&S Transaction. The remeasurement resulted in an increase in the pension benefit obligation of $3 million and a decrease in the fair value of the pension plan assets of $7 million for Eastern Energy Gas. The impact of the remeasurement on net periodic pension benefit credit was recognized prospectively from the remeasurement date and was not material. The discount rate used for the remeasurement was 3.16%. All other assumptions used for the remeasurement were consistent with the measurement as of December 31, 2019.

Net Periodic Benefit Credit

Net periodic benefit credit for the plans included the following components for the year ended December 31, 2020 (in millions):

	Pension	Other Postretirement
Service cost	$ 5	$ 1
Interest cost	8	4
Expected return on plan assets	(47)	(16)
Net amortization	5	(3)
Net periodic benefit credit	$ (29)	$ (14)

Significant assumptions used to determine periodic credits for the year ended December 31, 2020:

	Pension	Other Postretirement
Discount rate	3.16% - 3.63%	3.44 %
Expected long-term rate of return on plan assets	8.60 %	8.50 %
Weighted average rate of increase for compensation	4.73 %	N/A
Healthcare cost trend rate		6.50 %
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)		5.00 %
Year that the rate reached the ultimate trend rate		2026

Defined Contribution Plans

Eastern Energy Gas participated in the DEI defined contribution employee savings plans prior to the GT&S Transaction. Eastern Energy Gas' matching contributions were based on each participant's level of contribution. Contributions could not exceed the maximum allowable for tax purposes. Eastern Energy Gas' contributions to the 401(k) plan were $3 million for the year ended December 31, 2020.

(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. Cost of removal regulatory liabilities totaled $82 million and $73 million as of December 31, 2022 and 2021, respectively. Eastern Energy Gas will continue to monitor operational and strategic developments to identify if sufficient information exists to reasonably estimate a retirement date for these assets.

The following table reconciles the beginning and ending balances of Eastern Energy Gas' ARO liabilities for the years ended December 31 (in millions):

	2022	2021
Beginning balance	$ 55	$ 71
Additions	4	—
Retirements	(12)	(17)
Accretion	1	1
Ending balance	$ 48	$ 55
Reflected as:		
Current liabilities	$ 25	$ 33
Other long-term liabilities	23	22
Total ARO liability	$ 48	$ 55

(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 as well as lost and unaccounted for gas, to interest rate risk on its outstanding variable-rate short- and long-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 net notional amounts 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	2022	2021
Foreign currency	Euro €	250	250
Natural gas	Dth	3	2

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.

Upon the Cove Point LNG export/liquefaction facility commencing commercial operations, 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 38% and 40% of Eastern Energy Gas' operating revenues for the years ended December 31, 2022 and 2021, respectively, with Eastern Energy Gas' largest customer representing approximately 20% of such amounts.

For the year ended December 31, 2022, EGTS provided service to 266 customers with approximately 95% of its storage and transmission revenue being provided through firm services. The 10 largest customers provided approximately 38% of the total storage and transmission revenue and the thirty largest provided approximately 71% of the 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, 2022				
Assets:				
Commodity derivative	$ —	$ 1	$ —	$ 1
Money market mutual funds	42	—	—	42
Equity securities:				
Investment funds	14	—	—	14
	$ 56	$ 1	$ —	$ 57
Liabilities:				
Foreign currency exchange rate derivatives	$ —	$ (20)	$ —	$ (20)
	$ —	$ (20)	$ —	$ (20)
As of December 31, 2021				
Assets:				
Foreign currency exchange rate derivatives	$ —	$ 3	$ —	$ 3
Equity securities:				
Investment funds	13	—	—	13
	$ 13	$ 3	$ —	$ 16
Liabilities:				
Foreign currency exchange rate derivatives	$ —	$ (3)	$ —	$ (3)
	$ —	$ (3)	$ —	$ (3)

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 carrying value of Eastern Energy Gas' 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 Eastern Energy Gas' long-term debt as of December 31 (in millions):

	2022		2021	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 3,892	$ 3,510	$ 3,906	$ 4,266

(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.

Carbon Regulations

In August 2016, the EPA issued a draft rule proposing to reaffirm that a source's obligation to obtain a prevention of significant deterioration or Title V permit for greenhouse gases ("GHG") is triggered only if such permitting requirements are first triggered by non-GHG, or conventional, pollutants that are regulated by the New Source Review program, and to set a significant emissions rate at 75,000 tons per year of carbon dioxide equivalent emissions under which a source would not be required to apply best available control technology for its GHG emissions. Until the EPA ultimately takes final action on this rulemaking, Eastern Energy Gas cannot predict the impact to its results of operations, financial condition and/or cash flows.

Legal Matters

Eastern Energy Gas is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. 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, 2022, Eastern Energy Gas had purchased $19 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):

	2022	2021	2020
Customer Revenue:			
Regulated:			
Gas transmission and storage	$ 1,179	$ 1,044	$ 1,242
Wholesale	8	57	43
Other	1	(2)	4
Total regulated	1,188	1,099	1,289
Nonregulated	821	767	798
Total Customer Revenue	2,009	1,866	2,087
Other revenue[1]	(3)	4	3
Total operating revenue	$ 2,006	$ 1,870	$ 2,090

(1) Other revenue consists primarily of revenue recognized in accordance with Accounting Standards Codification 815, "Derivative and Hedging" and includes unrealized gains and losses for derivatives not designated as hedges related to natural gas sales contracts.

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, 2022 (in millions):

	Performance obligations expected to be satisfied		
	Less than 12 months	More than 12 months	Total
Eastern Energy Gas	$ 1,694	$ 15,598	$ 17,292

(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, 2019	$ (106)	$ (81)	$ —	$ (187)
Other comprehensive income	94	30	10	134
Balance, December 31, 2020	(12)	(51)	10	(53)
Other comprehensive income (loss)	6	9	(5)	10
Balance, December 31, 2021	(6)	(42)	5	(43)
Other comprehensive income (loss)	5	(1)	(3)	1
Balance, December 31, 2022	$ (1)	$ (43)	$ 2	$ (42)

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
2022		
Deferred (gains) and losses on derivatives-hedging activities:		
Interest rate contracts	$ 3	Interest expense
Foreign currency contracts	1	Other, net
Total	4	
Tax	(1)	Income tax expense (benefit)
Total, net of tax	$ 3	
2021		
Deferred (gains) and losses on derivatives-hedging activities:		
Interest rate contracts	$ 6	Interest expense
Foreign currency contracts	21	Other, net
Total	27	
Tax	(7)	Income tax expense (benefit)
Total, net of tax	$ 20	
2020		
Deferred (gains) and losses on derivatives-hedging activities:		
Interest rate contracts	$ 157	Interest expense
Foreign currency contracts	(25)	Other, net
Total	132	
Tax	(34)	Income tax expense (benefit)
Total, net of tax	$ 98	
Unrecognized pension costs:		
Actuarial losses	$ 6	Other, net
Total	6	
Tax	(2)	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, 2022 (in millions):

	AOCI After-Tax	Amounts Expected to be Reclassified to Earnings During the Next 12 Months After-Tax	Maximum Term
Interest rate	$ (37)	$ (3)	264 months
Foreign currency	(6)	(4)	42 months
Total	$ (43)	$ (7)	

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.

In July 2020, Eastern Energy Gas recorded a loss of $141 million ($105 million after-tax) in interest expense in the Consolidated Statement of Operations, for cash flow hedges of debt-related items that are probable of not occurring as a result of the GT&S Transaction. The derivatives related to these hedges were settled in October 2020 for a cash payment of $165 million.

(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 1) the power to direct the activities that most significantly impact the entity's economic performance and 2) the obligation to absorb losses or receive benefits from the entity that could potentially be significant to the VIE.

In November 2019, DEI contributed to Eastern Energy Gas a 75% controlling limited partner interest in Cove Point. In December 2019, DEI sold its retained 25% noncontrolling limited partner interest in Cove Point. As discussed in Note 3, as part of the GT&S Transaction, Eastern Energy Gas finalized a restructuring which included the disposition of a 50% noncontrolling interest in Cove Point to DEI, which resulted in Eastern Energy Gas owning 100% of the general partner interest and 25% of the limited partnership interest in Cove Point. Eastern Energy Gas concluded that Cove Point is a VIE due to the limited partners 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 $12 million for each of the years ended December 31, 2022, 2021 and 2020. Eastern Energy Gas' Consolidated Balance Sheets included amounts due to Carolina Gas Services of $1 million and $7 million as of December 31, 2022 and 2021, respectively. Eastern Energy Gas determined that neither it nor any of its consolidated entities is the primary beneficiary of Carolina Gas Services as neither it nor any of its consolidated entities has both 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 them. Carolina Gas Services provides marketing and operational services. Neither Eastern Energy Gas nor any of its consolidated entities has any obligation to absorb more than its allocated share of Carolina Gas Services costs.

Prior to the GT&S Transaction, Eastern Energy Gas purchased shared services from Dominion Energy Questar Pipeline Services, Inc. ("DEQPS"), an affiliated VIE, of $23 million for the year ended December 31, 2020. Eastern Energy Gas determined that neither it nor any of its consolidated entities was the primary beneficiary of DEQPS, as neither it nor any of its consolidated entities has both the power to direct the activities that most significantly impact their economic performance as well as the obligation to absorb losses and benefits which could be significant to them. DEQPS 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 DEQPS costs.

Prior to the GT&S Transaction, Eastern Energy Gas purchased shared services from Dominion Energy Services, Inc. ("DES"), an affiliated VIE, of $90 million for the year ended December 31, 2020. Eastern Energy Gas determined that neither it nor any of its consolidated entities was the primary beneficiary of DES as neither it nor any of its consolidated entities had both the power to direct the activities that most significantly impact their economic performance as well as the obligation to absorb losses and benefits which could be significant to them. DES provided accounting, legal, finance and certain administrative and technical services. Neither Eastern Energy Gas nor any of its consolidated entities had any obligation to absorb more than its allocated share of DES costs.

Included in noncontrolling interests in the Consolidated Financial Statements are DEI's 50% interest in Cove Point (effective November 2020) 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):

	2022	2021	2020
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	$ 143	$ 144	$ 317
Income taxes paid (received), net	$ 2	$ (60)	$ 31
Supplemental disclosure of non-cash investing and financing transactions:			
Accruals related to property, plant and equipment additions	$ 29	$ 42	$ 30
Equity distributions(1)	$ (42)	$ (137)	$ —
Equity contributions(1)	$ 98	$ 73	$ —
Distribution of Questar Pipeline Group	$ —	$ —	$ (699)
Distribution of 50% interest in Cove Point	$ —	$ —	$ (2,765)
Acquisition of Eastern Energy Gas by BHE	$ —	$ —	$ 343

(1) Amounts primarily represent the forgiveness of affiliated receivables/payables.

(19) Related Party Transactions

Transactions Prior to the GT&S Transaction

Prior to the GT&S Transaction, Eastern Energy Gas engaged in related party transactions primarily with other DEI subsidiaries (affiliates). Eastern Energy Gas' receivable and payable balances with affiliates were settled based on contractual terms or on a monthly basis, depending on the nature of the underlying transactions. Through October 31, 2020, Eastern Energy Gas was included in DEI's consolidated federal income tax return and, where applicable, combined state income tax returns. All affiliate payables or receivables were settled with DEI prior to the closing date of the GT&S Transaction.

Eastern Energy Gas transacted with affiliates for certain quantities of natural gas and other commodities at market prices in the ordinary course of business. Additionally, Eastern Energy Gas provided transmission and storage services to affiliates. Eastern Energy Gas also entered into certain other contracts with affiliates, and related parties, including construction services, which were presented separately from contracts involving commodities or services. Eastern Energy Gas participated in certain DEI benefit plans as described in Note 10.

DES, Carolina Gas Services, DEQPS and other affiliates provided accounting, legal, finance and certain administrative and technical services to Eastern Energy Gas. Eastern Energy Gas provided certain services to related parties, including technical services.

The financial statements for the year ended December 31, 2020 include costs for certain general, administrative and corporate expenses assigned by DES, Carolina Gas Services and DEQPS to Eastern Energy Gas on the basis of direct and allocated methods in accordance with Eastern Energy Gas' services agreements with DES, Carolina Gas Services and DEQPS. Where costs incurred cannot be determined by specific identification, the costs were allocated based on the proportional level of effort devoted by DES, Carolina Gas Services and DEQPS resources that is attributable to the entity, determined by reference to number of employees, salaries and wages and other similar measures for the relevant DES service. Management believes the assumptions and methodologies underlying the allocation of general corporate overhead expenses are reasonable.

Subsequent to the GT&S Transaction, and with the exception of Cove Point, Eastern Energy Gas' transactions with other DEI subsidiaries are no longer related party transactions.

Presented below are Eastern Energy Gas' significant transactions with DES, Carolina Gas Services, DEQPS and other affiliated and related parties for the year ended December 31 (in millions):

		2020
Sales of natural gas and transmission and storage services	$	207
Purchases of natural gas and transmission and storage services		10
Services provided by related parties(1)		129
Services provided to related parties(2)		83

(1) Includes capitalized expenditures of $14 million.

(2) Includes amounts attributable to Atlantic Coast Pipeline, a related party VIE prior to the GT&S Transaction. See below for more information.

EGTS provided services to Atlantic Coast Pipeline, which totaled $46 million for the year ended December 31, 2020, included in operating revenue in the Consolidated Statement of Operations.

Interest income related to the affiliated notes receivable under the DEI money pool was $3 million for the year ended December 31, 2020.

Eastern Energy Gas' affiliated notes receivable from DEI totaled $1.8 billion as of December 31, 2019. In August 2020, DEI repaid the remaining principal balance outstanding. Interest income on the promissory notes was $32 million for the year ended December 31, 2020.

As of December 31, 2019, Eastern Energy Gas' affiliated notes receivable from the East Ohio Gas Company totaled $1.7 billion. In June 2020, the East Ohio Gas Company repaid the remaining principal balance outstanding. Interest income on these promissory notes was $33 million for the year ended December 31, 2020.

Interest charges related to Eastern Energy Gas' total borrowings under an intercompany revolving credit agreement with DEI were $3 million for the year ended December 31, 2020.

Interest charges related to CPMLP Holdings Company LLC's total borrowings from DES were $3 million for the year ended December 31, 2020.

For the year ended December 31, 2020, Eastern Energy Gas distributed $4.3 billion to DEI.

Transactions Subsequent to the GT&S Transaction

Eastern Energy Gas is party to a tax-sharing agreement and is part of the Berkshire Hathaway consolidated U.S. federal income tax return. For current federal and state income taxes, Eastern Energy Gas had a receivable from BHE of $16 million and $8 million as of December 31, 2022 and 2021, respectively. Eastern Energy Gas received net cash receipts for federal and state income taxes from BHE totaling $47 million and $76 million for the years ended December 31, 2021 and 2020, respectively.

Other assets included amounts due from an affiliate of $3 million as of December 31, 2021.

As of December 31, 2022 and 2021, Eastern Energy Gas had $1 million and $5 million, respectively, of natural gas imbalances payable to affiliates, presented in other current liabilities on the Consolidated Balance Sheets.

Presented below are Eastern Energy Gas' significant transactions with affiliated and related parties for the years ended December 31 (in millions):

	2022	2021	2020
Sales of natural gas and transmission and storage services	$ 27	$ 32	$ 4
Purchases of natural gas and transmission and storage services	4	5	—
Services provided by related parties(1)	83	51	4
Services provided to related parties	38	32	7

(1) Includes capitalized expenditures.

Eastern Energy Gas participates in certain MidAmerican Energy benefit plans as described in Note 10. As of December 31, 2022 and 2021, 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 $51 million and $95 million, respectively.

Borrowings with BHE GT&S

Eastern Energy Gas has a $400 million intercompany revolving credit agreement from its parent, BHE GT&S, expiring in November 2023. 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 ("SOFR") plus a fixed spread. There were no amounts outstanding under the credit agreement as of both December 31, 2022 and 2021.

BHE GT&S has an intercompany revolving credit agreement from Eastern Energy Gas expiring in November 2023. In March 2021, BHE GT&S increased its credit facility limit from $200 million to $400 million and to $650 million in November 2022. The credit agreement has a variable interest rate based on SOFR plus a fixed spread. As of December 31, 2022 and 2021, $536 million and $7 million, respectively, was outstanding under the credit agreement. Interest income related to this borrowing totaled $7 million for the year ended December 31, 2022.

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, 2022 was $261 million, an increase of $105 million, or 67%, compared to 2021, primarily due to higher margin from regulated gas transmission and storage operations of $128 million and a decrease due to the settlement of depreciation rates in EGTS' general rate case, partially offset by an increase in income tax expense primarily due to higher pre-tax income.

Net income for the year ended December 31, 2021 was $156 million compared to a net loss of $181 million for 2020, primarily due to a 2020 charge associated with the abandonment of a significant portion of a project in connection with the Atlantic Coast Pipeline project ("Supply Header Project") and a 2020 charge for disallowance of capitalized AFUDC due to the resolution of EGTS' 2015 FERC audit, partially offset by a decrease of $50 million due to non-service cost credits recognized in 2020 related to certain Eastern Energy Gas over-funded benefit plans that were retained DEI as a result of the GT&S Transaction and an increase in income tax expense primarily due to higher pre-tax income.

Year Ended December 31, 2022 Compared to Year Ended December 31, 2021

Operating revenue increased $82 million, or 9%, for 2022 compared to 2021, primarily due to an increase in regulated gas transmission and storage services revenues due to the settlement of EGTS' general rate case of $101 million and an increase in variable revenue related to park and loan activity of $24 million, partially offset by a decrease in regulated gas sales for operational and system balancing purposes primarily due to decreased volumes of $49 million.

(Excess) cost of gas was a credit of $33 million for 2022 compared to an expense of $13 million for 2021. The change is primarily due to a decrease in volumes sold of $62 million, partially offset by unfavorable change to operational and system balancing volumes of $20 million.

Operations and maintenance decreased $12 million, or 3%, for 2022 compared to 2021, primarily due to a decrease in post-retirement benefit related costs.

Depreciation and amortization decreased $14 million, or 8%, for 2022 compared to 2021, primarily due to the settlement of depreciation rates in EGTS' general rate case of $23 million, partially offset by higher plant placed in-service of $9 million.

Property and other taxes decreased $8 million, or 13%, for 2022 compared to 2021, primarily due to lower than estimated 2021 tax assessments.

Disallowance and abandonment of utility plant was a credit of $11 million for 2021. The change is due to a 2021 benefit from the finalization of entries for the disallowance of capitalized AFUDC.

Interest expense decreased $9 million, or 12%, for 2022 compared to 2021, primarily due to lower expense of $44 million related to the elimination of long-term indebtedness to Eastern Energy Gas following the Debt Exchange Transaction in June 2021. These decreases were partially offset by $32 million of interest expense incurred under the senior notes issued in connection with that transaction, which bear lower interest rates than the original long-term indebtedness to Eastern Energy Gas.

Other, net was an expense of $2 million for 2022 compared to a credit of $2 million in 2021. The change is primarily due to losses on marketable securities.

Income tax expense (benefit) increased $48 million, or 79%, for 2022 compared to 2021 and the effective tax rate was 29% in 2022 and 28% in 2021. The effective tax rate increased primarily due to the revaluation of deferred taxes from changes in various state income tax rates.

Year Ended December 31, 2021 Compared to Year Ended December 31, 2020

Operating revenue decreased $25 million, or 3%, for 2021 compared to 2020, primarily due to $43 million of lower fees earned for services performed for Atlantic Coast Pipeline, partially offset by an increase in regulated natural gas sales of $15 million for operational and system balancing purposes primarily due to higher natural gas prices.

Cost of gas decreased $8 million, or 38%, for 2021 compared to 2020, primarily due to favorable valuations of system gas of $55 million, partially offset by an increase in prices of natural gas sold of $49 million.

Operations and maintenance decreased $16 million, or 4%, for 2021 compared to 2020, primarily due to lower expenses incurred in connection with services performed for Atlantic Coast Pipeline in connection with the cancelled Atlantic Coast Pipeline project of $45 million, partially offset by a $27 million increase in salaries, wages and benefits and general administrative expenses.

Depreciation and amortization increased $3 million, or 2%, for 2021 compared to 2020, primarily due to higher plant placed in-service during 2021.

Property and other taxes increased $9 million, or 17%, for 2021 compared to 2020, primarily due to higher property tax assessments.

Disallowance and abandonment of utility plant was a credit of $11 million for 2021 compared to an expense of $525 million for 2020. The change is primarily due to a 2020 charge associated with the abandonment of the Supply Header Project of $463 million, a 2020 charge for disallowance of capitalized AFUDC due to the resolution of EGTS' 2015 FERC audit of $43 million, the 2020 write-off of certain items in connection with the GT&S Transaction of $18 million and a 2021 benefit from the finalization of entries for the disallowance of capitalized AFUDC of $11 million.

Interest expense decreased $11 million, or 12%, for 2021 compared to 2020, primarily due to lower expense of $44 million related to the elimination of long-term indebtedness to Eastern Energy Gas following the Debt Exchange Transaction in June 2021. These decreases were partially offset by $32 million of interest expense incurred under the senior notes issued in connection with that transaction, which bear lower interest rates than the original long-term indebtedness to Eastern Energy Gas.

Allowance for equity funds decreased $6 million, or 50%, for 2021 compared to 2020, primarily due to lower capital expenditures related to the Supply Header Project as a result of the abandonment of the project.

Other, net decreased $60 million, or 97%, for the year ended December 31, 2021 compared to 2020, primarily due to non-service cost credits recognized in 2020 related to the overfunded status of certain DEI benefit plans in which EGTS' employees participated prior to the GT&S Transaction.

Income tax expense (benefit) was an expense of $61 million for 2021 compared to a benefit of $67 million for 2020. The effective tax rate was 28% in 2021 and 27% in 2020.

Liquidity and Capital Resources

As of December 31, 2022, EGTS' total net liquidity was as follows (in millions):

Cash and cash equivalents	$	16
Intercompany revolving credit agreement[(1)]		400
Less:		
Notes payable to affiliates		36
Net intercompany revolving credit agreement		364
Total net liquidity	$	380
Intercompany credit agreement:		
Maturity date		2023

(1) Refer to Note 19 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for further discussion regarding EGTS' intercompany revolving credit agreement.

Operating Activities

Net cash flows from operating activities for the years ended December 31, 2022 and 2021 were $552 million and $367 million, respectively. The change was primarily due to the impacts from the proposed rate increase in effect April 1, 2022 for the EGTS general rate case, timing of income tax payments, higher collections of receivables from affiliates and other working capital adjustments.

Net cash flows from operating activities for each of the years ended December 31, 2021 and 2020 were $367 million. Higher collections of non-trade receivables and lower payments on outstanding accounts payable balances were offset by lower collections from affiliates and other changes in working capital amounts.

The timing of EGTS' 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, 2022 and 2021 were $(286) million and $(357) million, respectively. The change was primarily due to a decrease in capital expenditures of $83 million and lower loans to affiliates of $6 million, partially offset by lower repayments of loans by affiliates of $8 million.

Net cash flows from investing activities for the years ended December 31, 2021 and 2020 were $(357) million and $(265) million, respectively. The change was primarily due to increases in capital expenditures of $95 million related to increased pipeline integrity work.

Financing Activities

Net cash flows from financing activities for the year ended December 31, 2022 were $(247) million and consisted of dividends paid to Eastern Energy Gas of $215 million and net repayment of notes payable to Eastern Energy Gas of $32 million.

Net cash flows from financing activities for the year ended December 31, 2021 were $(7) million, primarily reflecting dividends paid of $18 million and the net repayment of notes payable to Eastern Energy Gas of $13 million, partially offset by a $20 million equity contribution from Eastern Energy Gas.

Net cash flows from financing activities for the year ended December 31, 2020 were $(91) million, reflecting dividends paid of $125 million, partially offset by the issuance of notes payable from Eastern Energy Gas of $34 million.

Short-term Debt

As of December 31, 2022, EGTS had $36 million of an outstanding note payable to an affiliate at a weighted average interest rate of 1.43%. As of December 31, 2021, EGTS had $68 million of an outstanding note payable to an affiliate at a weighted average interest rate of 0.51%. For further discussion, refer to Note 19 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

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		
	2020	2021	2022	2023	2024	2025
Natural gas transmission and storage	$ 110	$ 10	$ 35	$ 9	$ 40	$ 107
Other	153	348	240	191	173	173
Total	$ 263	$ 358	$ 275	$ 200	$ 213	$ 280

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, 2022 (in millions):

	Payments Due by Periods				
	2023	2024-2025	2026-2027	2028 and thereafter	Total
Interest payments on long-term debt(1)	$ 64	$ 125	$ 121	$ 873	$ 1,183
Natural gas supply and transmission(1)	49	98	98	—	245
Total cash requirements	$ 113	$ 223	$ 219	$ 873	$ 1,428

(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 6), long-term debt (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 10) and AROs (refer to Note 12). 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 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.

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 $39 million and total regulatory liabilities were $627 million as of December 31, 2022. Refer to EGTS' Note 7 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 10 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% as a result of 2017 Tax Reform, certain property-related basis differences and other various differences on to their customers. As of December 31, 2022, these amounts were recognized as a net regulatory liability of $382 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 commodity prices, 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.

Commodity Price Risk

EGTS is exposed to the impact of market fluctuations in commodity prices. EGTS is principally exposed to natural gas market fluctuations primarily through fuel retained and used during the operation of the pipeline system as well as lost and unaccounted for gas. EGTS is exposed to the risk of fuel retention, meaning customers have a fixed fuel retention percentage assessed on transmission and storage quantities, and the pipeline bears the risk of under-recovery and benefits from any over-recovery of volumes. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, facility availability, customer usage, storage and transmission constraints. EGTS does not engage in proprietary trading activities. 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 quantities or sell future supply quantities generally at fixed prices. EGTS does not hedge all of its commodity price risk, thereby exposing the unhedged portion to changes in market prices. As of February 2023, EGTS recovers its cost of gas through a fuel tracker and is no longer subject to significant commodity price risk.

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 9 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, 2022 and 2021, EGTS had short- and long-term variable-rate obligations totaling $36 million and $68 million, respectively, that expose EGTS 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 EGTS' annual interest expense. The carrying value of the variable-rate obligations approximates fair value as of December 31, 2022 and 2021.

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, 2022, EGTS credit exposure totaled $90 million. Of this amount, investment grade counterparties, including those internally rated, represented 98%, with three investment grade counterparties representing 57%.

Item 8. Financial Statements and Supplementary Data

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, 2022 and 2021, 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, 2022, 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, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022, 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 audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Regulatory Matters — Effects of Rate Regulation on the Financial Statements — Refer to Notes 2 and 7 to the Financial Statements

Critical Audit Matter Description

EGTS prepares its Consolidated Financial Statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Management has determined EGTS meets 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. 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. Furthermore, revenue provided by EGTS' interstate natural gas transmission operations is based primarily on rates approved by the Federal Energy Regulatory Commission ("FERC").

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. 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 related regulatory assets and liabilities will be recognized in net income, returned to customers, or re-established as accumulated comprehensive income (loss). Accounting for the economics of rate regulation has a pervasive effect on the financial statements.

We identified the effects of rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about affected account balances and disclosures and the high degree of subjectivity involved in assessing the impact of future regulatory orders on the financial statements. Management judgments include assessing the likelihood of (1) recovery in future rates of incurred costs and (2) a refund to customers. Given that management's accounting judgments are based on assumptions about the outcome of future decisions by the FERC, auditing these judgments required specialized knowledge of the 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 assessment of whether recovery of regulatory assets through future rates or a regulatory liability due to customers is probable included the following, among others:

- We evaluated EGTS' disclosures related to the effects of rate regulation, including the balances recorded and regulatory developments.
- We read relevant regulatory orders issued by the FERC, as well as relevant regulatory statutes, interpretations, procedural memorandums, filings made by interveners, and other external information. We evaluated the external information and compared to management's recorded regulatory assets and liability balances for completeness and to assess whether this external information was properly considered by management in concluding upon the financial statement impacts of rate regulation.
- For regulatory matters in process, 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 refunds due to customers based on precedents of the FERC's treatment of similar costs under similar circumstances.

/s/ Deloitte & Touche LLP

Richmond, Virginia
February 24, 2023

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,	
	2022	**2021**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 16	$ 11
Restricted cash and cash equivalents	29	15
Trade receivables, net	113	98
Receivables from affiliates	13	9
Inventories	50	48
Income taxes receivable	21	19
Prepayments	36	35
Natural gas imbalances	193	94
Other current assets	9	10
Total current assets	480	339
Property, plant and equipment, net	4,504	4,440
Notes receivable from affiliates	—	3
Other assets	190	319
Total assets	$ 5,174	$ 5,101

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,	
	2022	**2021**
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Accounts payable	$ 46	$ 54
Accounts payable to affiliates	5	13
Accrued property, income and other taxes	71	71
Accrued employee expenses	13	12
Notes payable to affiliates	36	68
Regulatory liabilities	109	25
Customer and security deposits	29	15
Asset retirement obligations	25	33
Other current liabilities	39	37
Total current liabilities	373	328
Long-term debt	1,582	1,581
Regulatory liabilities	518	507
Other long-term liabilities	101	145
Total liabilities	2,574	2,561
Commitments and contingencies (Note 15)		
Shareholder's equity:		
Common stock - 75,000 shares authorized, $10,000 par value, 60,101 issued and outstanding	609	609
Additional paid-in capital	1,275	1,241
Retained earnings	746	721
Accumulated other comprehensive loss, net	(30)	(31)
Total shareholder's equity	2,600	2,540
Total liabilities and shareholder's equity	$ 5,174	$ 5,101

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,		
	2022	**2021**	**2020**
Operating revenue	$ 973	$ 891	$ 916
Operating expenses:			
(Excess) cost of gas	(33)	13	21
Operations and maintenance	364	376	392
Depreciation and amortization	152	166	163
Property and other taxes	54	62	53
Disallowance and abandonment of utility plant	—	(11)	525
Total operating expenses	537	606	1,154
Operating income (loss)	436	285	(238)
Other income (expense):			
Interest expense	(69)	(78)	(89)
Allowance for borrowed funds	1	2	5
Allowance for equity funds	4	6	12
Other, net	(2)	2	62
Total other income (expense)	(66)	(68)	(10)
Income (loss) before income tax expense (benefit)	370	217	(248)
Income tax expense (benefit)	109	61	(67)
Net income (loss)	$ 261	$ 156	$ (181)

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 (LOSS)
(Amounts in millions)

	Years Ended December 31,		
	2022	2021	2020
Net income (loss)	$ 261	$ 156	$ (181)
Other comprehensive income (loss), net of tax:			
Unrealized gains (losses) on cash flow hedges, net of tax of $1, $(12) and $—	1	(31)	—
Unrecognized amounts on retirement benefits, net of tax of $—, $— and $30	—	—	77
Total other comprehensive income (loss), net of tax	1	(31)	77
Comprehensive income (loss)	$ 262	$ 125	$ (104)

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, 2019	60,101	$ 609	$ 889	$ 947	$ (77)	$ 2,368
Net loss	—	—	—	(181)	—	(181)
Other comprehensive income	—	—	—	—	77	77
Dividends declared	—	—	—	(125)	—	(125)
Acquisition of EGTS by BHE	—	—	40	—	—	40
Balance, December 31, 2020	60,101	609	929	641	—	2,179
Net income	—	—	—	156	—	156
Other comprehensive loss	—	—	—	—	(31)	(31)
Dividends declared		—	—	(76)	—	(76)
Contributions	—	—	312	—	—	312
Balance, December 31, 2021	60,101	609	1,241	721	(31)	2,540
Net income	—	—	—	261	—	261
Other comprehensive income	—	—	—	—	1	1
Dividends declared	—	—	—	(236)	—	(236)
Contributions	—	—	34	—	—	34
Balance, December 31, 2022	60,101	$ 609	$ 1,275	$ 746	$ (30)	$ 2,600

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,		
	2022	**2021**	**2020**
Cash flows from operating activities:			
Net income (loss)	$ 261	$ 156	$ (181)
Adjustments to reconcile net income (loss) to net cash flows from operating activities:			
Losses (gains) on other items, net	1	(8)	517
Depreciation and amortization	152	166	163
Allowance for equity funds	(4)	(6)	(12)
Changes in regulatory assets and liabilities	61	—	24
Deferred income taxes	92	93	(121)
Other, net	6	(7)	26
Changes in other operating assets and liabilities:			
Trade receivables and other assets	(48)	48	49
Receivables from affiliates	(4)	(46)	4
Pension and other postretirement benefit plans	—	(17)	(85)
Accrued property, income and other taxes	18	(23)	10
Accounts payable and other liabilities	25	—	5
Accounts payable to affiliates	(8)	11	(32)
Net cash flows from operating activities	552	367	367
Cash flows from investing activities:			
Capital expenditures	(275)	(358)	(263)
Loans to affiliates	(8)	(14)	—
Repayment of loans by affiliates	11	19	—
Other, net	(14)	(4)	(2)
Net cash flows from investing activities	(286)	(357)	(265)
Cash flows from financing activities:			
(Repayment) issuance of notes payable, net	(32)	(13)	34
Proceeds from equity contributions	—	20	—
Dividends paid	(215)	(18)	(125)
Other, net	—	4	—
Net cash flows from financing activities	(247)	(7)	(91)
Net change in cash and cash equivalents and restricted cash and cash equivalents	19	3	11
Cash and cash equivalents and restricted cash and cash equivalents at beginning of period	26	23	12
Cash and cash equivalents and restricted cash and cash equivalents at end of period	$ 45	$ 26	$ 23

The accompanying notes are an integral part of these 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 pipeline and underground storage. EGTS' operations include transmission pipelines 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"). On November 1, 2020, Berkshire Hathaway Energy Company ("BHE") completed its acquisition of substantially all of the natural gas transmission and storage business of Dominion Energy, Inc. ("DEI") (the "GT&S Transaction"). As a result of the GT&S Transaction, EGTS became an indirect wholly-owned subsidiary of BHE. BHE is a holding company based in Des Moines, Iowa that owns subsidiaries principally engaged in the energy industry. BHE is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway"). See Note 3 for more information regarding the GT&S Transaction.

(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, 2022 and 2021, as presented in 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,	
	2022	2021
Cash and cash equivalents	$ 16	$ 11
Restricted cash and cash equivalents	29	15
Total cash and cash equivalents and restricted cash and cash equivalents	$ 45	$ 26

Allowance for Credit Losses

Trade receivables are primarily short-term in nature 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 evaluates the financial condition of the individual customer and the nature of any disputed amount.

The changes in the balance of the allowance for credit losses, which is included in trades receivables, net on the Consolidated Balance Sheets, is summarized as follows for the years ended December 31, (in millions):

	2022	2021	2020
Beginning balance	$ 3	$ 2	$ 1
Charged to operating costs and expenses, net	—	1	1
Write-offs, net	(3)	—	—
Ending balance	$ —	$ 3	$ 2

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. See Note 7 for the prospective impacts related to changes in depreciation rates. 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 natural gas pipeline 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. See Note 7 for more information.

Leases

EGTS has non-cancelable operating leases primarily for office space, office equipment and land and finance leases consisting primarily of natural gas pipeline facilities and vehicles. 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. Leases will be 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 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

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. As of December 31, 2022 and 2021, trade receivables, net on the Consolidated Balance Sheets relate substantially to Customer Revenue, including unbilled revenue of $9 million and $28 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. See Note 7 for discussion surrounding EGTS' provision for rate refund. 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 $10 million and $19 million as of December 31, 2022 and 2021, respectively, and $9 million and $3 million of contract liabilities as of December 31, 2022 and 2021, 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

Prior to the GT&S Transaction, DEI included EGTS in its consolidated U.S. federal income tax return. Subsequent to the GT&S Transaction, 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 segment, which includes its natural gas pipeline and storage operations.

(3) Business Acquisitions and Dispositions

Acquisition of EGTS *by BHE*

In July 2020, DEI entered into an agreement to sell substantially all of its natural gas transmission and storage operations, including EGTS, to BHE. In November 2020, the GT&S Transaction was completed and EGTS became an indirect wholly-owned subsidiary of BHE. DEI retained the assets and obligations of the pension and other postretirement employee benefit plans associated with the operations sold and relating to services provided before closing. The GT&S Transaction was treated as a deemed asset sale for federal and state income tax purposes and all deferred taxes at EGTS were reset to reflect financial and tax basis differences as of November 1, 2020. See Notes 10 and 11 for more information on the GT&S Transaction.

In accordance with the terms of the GT&S Transaction, DEI retained certain assets and liabilities associated with EGTS and settled all affiliated balances. As a result, EGTS recorded a contribution for the reset of deferred taxes of $1.0 billion and $34 million for retained tax liabilities payable to EGTS by DEI, net of distributions of $904 million related to the pension and other postretirement employee benefit plans retained by DEI and $107 million of other pension related amounts. In addition, EGTS decided to forgo recovery of $18 million of certain property, plant and equipment as a result of the GT&S Transaction, included in disallowance and abandonment of utility plant on the Consolidated Statement of Operations.

(4) Property, Plant and Equipment, Net

Property, plant and equipment, net consists of the following as of December 31 (in millions):

	Depreciable Life	2022	2021
Interstate natural gas pipeline and storage assets	28 - 50 years	$ 6,724	$ 6,517
Intangible plant	12 - 20 years	79	74
Plant in-service		6,803	6,591
Accumulated depreciation and amortization		(2,440)	(2,339)
		4,363	4,252
Construction work-in-progress		141	188
Property, plant and equipment, net		$ 4,504	$ 4,440

(5) 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, 2022 (dollars in millions):

	EGTS' Share	Facility in Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
Ellisburg Pool	39 %	$ 32	$ 11	$ —
Ellisburg Station	50	26	8	3
Harrison	50	53	18	—
Leidy	50	143	47	1
Oakford	50	202	70	4
Total		$ 456	$ 154	$ 8

(6) Leases

The following table summarizes EGTS' leases recorded on the Consolidated Balance Sheets as of December 31 (in millions):

	2022	2021
Right-of-use assets:		
Operating leases	$ 19	$ 20
Total right-of-use assets	$ 19	$ 20
Lease liabilities:		
Operating leases	$ 18	$ 18
Total lease liabilities	$ 18	$ 18

The following table summarizes EGTS' lease costs for the years ended December 31 (in millions):

	2022	2021	2020
Operating	$ 2	$ 3	$ 6
Short-term	—	—	3
Total lease costs	$ 2	$ 3	$ 9
Weighted-average remaining lease term (years):			
Operating leases	13.7	14.7	11.7
Finance leases	0.0	0.0	4.6
Weighted-average discount rate:			
Operating leases	4.3 %	4.3 %	4.4 %
Finance leases	— %	— %	2.6 %

The following table summarizes EGTS' supplemental cash flow information relating to leases for the years ended December 31 (in millions):

	2022	2021	2020
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows from operating leases	$ 2	$ 3	$ 9
Operating cash flows from finance leases	—	1	—
Right-of-use assets obtained in exchange for lease liabilities:			
Finance leases	$ —	$ —	$ 1

EGTS has the following remaining operating lease commitments as of December 31, 2022 (in millions):

2023	$ 2
2024	2
2025	2
2026	2
2027	2
Thereafter	14
Total undiscounted lease payments	24
Less - amounts representing interest	(6)
Lease liabilities	$ 18

(7) 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	2022	2021
Employee benefit plans[1]	11 years	$ 31	$ 58
Other	Various	8	6
Total regulatory assets		$ 39	$ 64
Reflected as:			
Current assets		$ 5	$ 2
Noncurrent assets		34	62
Total regulatory assets		$ 39	$ 64

(1) Represents costs expected to be recovered through future rates generally over the expected remaining service period of plan participants.

EGTS had regulatory assets not earning a return on investment of $39 million and $64 million as of December 31, 2022 and 2021, 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	2022		2021	
Income taxes refundable through future rates[1]	Various	$	382	$	391
Other postretirement benefit costs[2]	Various		123		116
Provision for rate refunds[3]			90		—
Cost of removal[4]	53 years		24		16
Other	Various		8		9
Total regulatory liabilities		$	627	$	532
Reflected as:					
Current liabilities		$	109	$	25
Noncurrent liabilities			518		507
Total regulatory liabilities		$	627	$	532

(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) Reflects amounts expected to be refunded to customers in late February 2023 in connection with the EGTS rate case. See below for more information.

(4) 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 12 for more information.

Regulatory Matters

In September 2021, EGTS filed a general rate case for its FERC-jurisdictional services, with proposed rates to be effective November 1, 2021. EGTS' previous general rate case was settled in 1998. EGTS proposed an annual cost-of-service of approximately $1.1 billion, and requested increases in various rates, including general system storage rates by 85% and general system transmission rates by 60%. In October 2021, the FERC issued an order that accepted the November 1, 2021 effective date for certain changes in rates, while suspending the other changes for five months following the proposed effective date, until April 1, 2022, subject to refund. In September 2022, a settlement agreement was filed with the FERC, resolving EGTS' general rate case for its FERC-jurisdictional services and providing for increased service rates and decreased depreciation rates. Under the terms of the settlement agreement, EGTS' rates result in an increase to annual firm transmission and storage revenues of approximately $160 million and a decrease in annual depreciation expense of approximately $30 million, compared to the rates in effect prior to April 1, 2022. As of December 31, 2022, EGTS' provision for rate refund for April 2022 through December 2022 totaled $90 million and was included in current regulatory liabilities on the Consolidated Balance Sheet. In November 2022, the FERC approved the settlement agreement.

In July 2017, the FERC audit staff communicated to EGTS that it had substantially completed an audit of EGTS' compliance with the accounting and reporting requirements of the FERC's Uniform System of Accounts and provided a description of matters and preliminary recommendations. In November 2017, the FERC audit staff issued its audit report. In December 2017, EGTS provided its response to the audit report. EGTS requested FERC review of the contested findings and submitted its plan for compliance with the uncontested portions of the report. EGTS reached resolution of certain matters with the FERC in the fourth quarter of 2018. EGTS recognized a charge for a disallowance of plant, originally established beginning in 2012, for the resolution of one matter with the FERC. In December 2020, the FERC issued a final ruling on the remaining matter, which resulted in a $43 million ($31 million after-tax) estimated charge for disallowance of capitalized AFUDC, recorded in disallowance and abandonment of utility plant on the Consolidated Statement of Operations. As a condition of the December 2020 ruling, EGTS filed its proposed accounting entries and supporting documentation with the FERC during the second quarter of 2021. During the finalization of these entries, EGTS refined the estimated charge for disallowance of capitalized AFUDC, which resulted in a reduction to the estimated charge of $11 million ($8 million after-tax) that was recorded in disallowance and abandonment of utility plant on the Consolidated Statement of Operations in the second quarter of 2021. In September 2021, the FERC approved EGTS' accounting entries and supporting documentation.

In December 2014, EGTS entered into a precedent agreement with Atlantic Coast Pipeline, LLC ("Atlantic Cost Pipeline") for the project previously intended for EGTS to provide approximately 1,500,000 decatherms ("Dth") of firm transmission service to various customers in connection with the Atlantic Coast Pipeline project ("Supply Header Project"). As a result of the cancellation of the Atlantic Coast Pipeline project, in the second quarter of 2020 EGTS recorded a charge of $482 million ($359 million after-tax) in disallowance and abandonment of utility plant on the Consolidated Statement of Operations associated with the probable abandonment of a significant portion of the project as well as the establishment of a $75 million ARO. In the third quarter of 2020, EGTS recorded an additional charge of $10 million ($7 million after-tax) associated with the probable abandonment of a significant portion of the project and a $29 million ($20 million after-tax) benefit from a revision to the previously established ARO, both of which were recorded in disallowance and abandonment of utility plant on the Consolidated Statement of Operations. As EGTS evaluates its future use, approximately $40 million remains within property, plant and equipment for a potential modified project.

(8) Investments and Restricted Cash and Cash Equivalents

Investments and restricted cash and cash equivalents consists of the following as of December 31 (in millions):

	2022	2021
Investments:		
Investment funds	$ 14	$ 13
Restricted cash and cash equivalents:		
Customer deposits	29	15
Total restricted cash and cash equivalents	29	15
Total investments and restricted cash and cash equivalents	$ 43	$ 28
Reflected as:		
Current assets	$ 29	$ 15
Noncurrent assets	14	13
Total investments and restricted cash and cash equivalents	$ 43	$ 28

(9) Long-term Debt

On June 30, 2021, Eastern Energy Gas exchanged a total of $1.6 billion of its issued and outstanding third-party notes for new notes, making EGTS the primary obligor of the new notes. The terms of the new notes are substantially similar to the terms of the original Eastern Energy Gas notes. The debt exchange was a common control transaction accounted for as a debt modification. As such, no gain or loss was recognized on the Consolidated Statements of Operations and approximately $17 million of unamortized discounts and debt issuance costs and $32 million of deferred losses on previously settled interest rate swaps remaining in AOCI were contributed to EGTS by Eastern Energy Gas in connection with the transaction. In addition, new fees of $2 million paid directly to note holders in connection with the exchange were deferred as additional debt issuance costs that will be amortized over the lives of the respective notes. As a result of the transaction, EGTS' $1.9 billion of long-term indebtedness to Eastern Energy Gas was cancelled in full and the remaining balance was satisfied through a capital contribution.

EGTS' long-term debt consists of the following, including unamortized discounts and debt issuance costs, as of December 31 (dollars in millions):

	Par Value	2022	2021
3.60% Senior Notes, due 2024	$ 111	$ 110	$ 110
3.00% Senior Notes, due 2029	426	422	422
4.80% Senior Notes, due 2043	346	342	341
4.60% Senior Notes, due 2044	444	437	437
3.90% Senior Notes, due 2049	273	271	271
Total long-term debt	$ 1,600	$ 1,582	$ 1,581

Annual Payment on Long-Term Debt

The annual repayments of long-term debt for the years beginning January 1, 2023 and thereafter, are as follows (in millions):

2023	$ —
2024	111
2025	—
2026	—
2027	—
2028 and thereafter	1,489
Total	1,600
Unamortized discounts and debt issuance costs	(18)
Total	$ 1,582

AOCI

The following table presents selected information related to losses on interest rate cash flow hedges included in AOCI in EGTS' Consolidated Balance Sheet as of December 31, 2022 (in millions):

	AOCI After-Tax	Amounts Expected to be Reclassified to Earnings During the Next 12 Months After-Tax	Maximum Term
Interest rate	$ (30)	$ (2)	264 months

EGTS reclassified $2 million and $1 million from AOCI to interest expense for the years ended December 31, 2022 and 2021, respectively.

(10) Income Taxes

Income tax expense (benefit) consists of the following for the years ended December 31 (in millions):

	2022	2021	2020
Current:			
Federal	$ 5	$ (22)	$ 48
State	12	(10)	6
	17	(32)	54
Deferred:			
Federal	64	67	(93)
State	28	26	(28)
	92	93	(121)
Total	$ 109	$ 61	$ (67)

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:

	2022	2021	2020
Federal statutory income tax rate	21 %	21 %	21 %
State income tax, net of federal income tax benefit	9	8	7
Effects of ratemaking	—	—	2
AFUDC-equity	—	—	1
Write-off of regulatory assets	—	—	(3)
Other, net	(1)	(1)	(1)
Effective income tax rate	29 %	28 %	27 %

The net deferred income tax asset consists of the following as of December 31 (in millions):

	2022	2021
Deferred income tax assets:		
Federal and state carryforwards	$ 6	$ —
Employee benefits	22	31
Intangibles and goodwill	265	298
Derivatives and hedges	11	12
Other	4	4
Total deferred income tax assets	308	345
Deferred income tax liabilities:		
Property related items	(146)	(77)
Debt exchange	(53)	(60)
Employee benefits	(4)	(9)
Total deferred income tax liabilities	(203)	(146)
Net deferred income tax asset[1]	$ 105	$ 199

(1) Net deferred income tax asset, as of both December 31, 2022 and 2021, is presented in other assets in the Consolidated Balance Sheet.

As of December 31, 2022, EGTS' state tax carryforwards, entirely related to $6 million of net operating losses, expire at various intervals between 2036 and indefinite.

Through October 31, 2020, EGTS was included in DEI's consolidated federal income tax return and, where applicable, combined state income tax returns. As a result of the GT&S Transaction, DEI retained the rights and obligations of EGTS' federal and state income tax returns through October 31, 2020. 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.

(11) Employee Benefit Plans

As discussed in Note 3, in November 2020, the GT&S Transaction was completed and the assets and obligations of the pension and other postretirement employee benefit plans associated with the operations sold and relating to services provided before closing were retained by DEI. As a result, just prior to completing the sale, net benefit plan assets of $904 million were distributed through an equity transaction with DEI.

Subsequent to the GT&S Transaction

Defined Benefit Plans

Subsequent to the GT&S Transaction, EGTS is a participant in benefit plans sponsored by 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 $12 million, $16 million and $2 million of contributions to the MidAmerican Energy Company Retirement Plan for the years ended December 31, 2022, 2021 and 2020, respectively. EGTS made $2 million, $9 million and $2 million of contributions to the MidAmerican Energy Company Welfare Benefit Plan for the years ended December 31, 2022, 2021 and 2020, 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 BHE GT&S defined contribution employee savings plan subsequent to the GT&S Transaction. EGTS' matching contributions are based on each participant's level of contribution. Contributions cannot exceed the maximum allowable for tax purposes. EGTS' contributions to the 401(k) plan were $5 million and $4 million and $1 million for the years ended December 31, 2022, 2021 and 2020, respectively

Prior to the GT&S Transaction

Defined Benefit Plans

Prior to the GT&S Transaction, certain EGTS employees not represented by collective bargaining units were covered by the Dominion Energy Pension Plan, a defined benefit pension plan sponsored by DEI that provides benefits to multiple DEI subsidiaries. As participating employers, EGTS was subject to DEI's funding policy, which was to contribute annually an amount that is in accordance with the Employee Retirement Income Security Act of 1974. EGTS' net periodic pension credit related to this plan was $17 million for the year ended December 31, 2020, reflected in operations and maintenance expense in the Consolidated Statement of Operations. The funded status of various DEI subsidiary groups and employee compensation are the basis for determining the share of total pension costs for participating DEI subsidiaries.

Prior to the GT&S Transaction, certain retiree healthcare and life insurance benefits for EGTS employees not represented by collective bargaining units were covered by the Dominion Energy Retiree Health and Welfare Plan, a plan sponsored by DEI that provides certain retiree healthcare and life insurance benefits to multiple DEI subsidiaries. EGTS' net periodic benefit credit related to this plan was $5 million for the year ended December 31, 2020, reflected in operations and maintenance expense in the Consolidated Statement of Operations. Employee headcount is the basis for determining the share of total other postretirement benefit costs for participating DEI subsidiaries.

Pension benefits for EGTS employees represented by collective bargaining units were covered by a separate pension plan that provides benefits to employees of both EGTS and Hope Gas, Inc. ("Hope"). Employee compensation was the basis for allocating pension costs and obligations between EGTS and Hope. Retiree healthcare and life insurance benefits, for EGTS employees represented by a collective bargaining unit, were covered by a separate other postretirement benefit plan that provides benefits to both EGTS and Hope. Employee headcount was the basis for allocating other postretirement benefit costs and obligations between EGTS and Hope.

Pension Remeasurement

In the third quarter of 2020, EGTS remeasured a pension plan due to a curtailment resulting from the agreement for DEI to retain the assets and obligations of the pension benefit plan associated with the GT&S Transaction. The remeasurement resulted in an increase in the pension benefit obligation of $3 million and a decrease in the fair value of the pension plan assets of $7 million for EGTS. The impact of the remeasurement on net periodic pension benefit credit was recognized prospectively from the remeasurement date and was not material. The discount rate used for the remeasurement was 3.16%. All other assumptions used for the remeasurement were consistent with the measurement as of December 31, 2019.

Net Periodic Benefit Credit

Net periodic benefit credit for the plans included the following components for the year ended December 31, 2020 (in millions):

	Pension	Other Postretirement
Service cost	$ 5	$ 1
Interest cost	8	4
Expected return on plan assets	(47)	(16)
Net amortization	3	(3)
Net periodic benefit credit	$ (31)	$ (14)

Significant assumptions used to determine periodic credits for the year ended December 31, 2020:

	Pension	Other Postretirement
Discount rate	3.16% - 3.63%	3.44 %
Expected long-term rate of return on plan assets	8.60 %	8.50 %
Weighted average rate of increase for compensation	4.73 %	N/A
Healthcare cost trend rate		6.50 %
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)		5.00 %
Year that the rate reached the ultimate trend rate		2026

Defined Contribution Plans

EGTS participated in the DEI defined contribution employee savings plans prior to the GT&S Transaction. EGTS' matching contributions were based on each participant's level of contribution. Contributions could not exceed the maximum allowable for tax purposes. EGTS' contributions to the 401(k) plan were $2 million for the year ended December 31, 2020.

(12) 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. Cost of removal regulatory liabilities totaled $24 million and $16 million as of December 31, 2022 and 2021, respectively. EGTS will continue to monitor operational and strategic developments to identify if sufficient information exists to reasonably estimate a retirement date for these assets.

The following table reconciles the beginning and ending balances of EGTS' ARO liabilities for the years ended December 31 (in millions):

	2022	2021
Beginning balance	$ 55	$ 71
Additions	4	—
Retirements	(12)	(17)
Accretion	1	1
Ending balance	$ 48	$ 55
Reflected as:		
Current liabilities	$ 25	$ 33
Other long-term liabilities	23	22
Total ARO liability	$ 48	$ 55

(13) 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 as well as lost and unaccounted for gas. 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 14 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 14 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, 2022, the ten largest customers provided 38% 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.

(14) 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, 2022				
Assets:				
Commodity derivatives	$ —	$ 1	$ —	$ 1
Money market mutual funds	8	—	—	8
Equity securities:				
Investment funds	14	—	—	14
	$ 22	$ 1	$ —	$ 23
As of December 31, 2021				
Assets:				
Equity securities:				
Investment funds	$ 13	$ —	$ —	$ 13
	$ 13	$ —	$ —	$ 13

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):

	2022		2021	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 1,582	$ 1,337	$ 1,581	$ 1,812

(15) 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.

Carbon Regulations

In August 2016, the EPA issued a draft rule proposing to reaffirm that a source's obligation to obtain a prevention of significant deterioration or Title V permit for greenhouse gases ("GHG") is triggered only if such permitting requirements are first triggered by non-GHG, or conventional, pollutants that are regulated by the New Source Review program, and to set a significant emissions rate at 75,000 tons per year of carbon dioxide equivalent emissions under which a source would not be required to apply best available control technology for its GHG emissions. Until the EPA ultimately takes final action on this rulemaking, EGTS cannot predict the impact to its results of operations, financial condition and/or cash flows.

Legal Matters

EGTS is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. 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, 2022, EGTS had purchased $16 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.

(16) 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):

	2022	2021	2020
Customer Revenue:			
Regulated:			
Gas transmission	$ 644	$ 574	$ 583
Gas storage	248	188	191
Wholesale	8	57	41
Total regulated	900	819	815
Management services and other revenues	79	73	100
Total Customer Revenue	979	892	915
Other revenue(1)	(6)	(1)	1
Total operating revenue	$ 973	$ 891	$ 916

(1) Other revenue consists primarily of revenue recognized in accordance with Accounting Standards Codification 815, "Derivative and Hedging" and includes unrealized gains and losses for derivatives not designated as hedges related to natural gas sales contracts.

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, 2022 (in millions):

	Performance obligations expected to be satisfied		
	Less than 12 months	More than 12 months	Total
EGTS	$ 766	$ 3,431	$ 4,197

(17) Variable Interest Entities

The primary beneficiary of a variable interest entity ("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: (1) the power to direct the activities that most significantly impact the entity's economic performance and (2) the obligation to absorb losses or receive benefits from the entity that could potentially be significant to the VIE.

EGTS had been engaged to oversee the construction of, and to subsequently operate and maintain, the projects undertaken by Atlantic Coast Pipeline based on the overall direction and oversight of Atlantic Coast Pipeline's members. Prior to the GT&S Transaction, an affiliate of EGTS held a membership interest in Atlantic Coast Pipeline; therefore, EGTS was considered to have a variable interest in Atlantic Coast Pipeline. Prior to the cancellation of the project in 2020, the members of Atlantic Coast Pipeline held the power to direct the construction, operations and maintenance activities of the entity. EGTS concluded it was not the primary beneficiary of Atlantic Coast Pipeline as it did not have the power to direct the activities of Atlantic Coast Pipeline that most significantly impacted its economic performance. EGTS had no obligation to absorb any losses of the VIE.

Prior to the GT&S Transaction, EGTS purchased shared services from Dominion Energy Services, Inc. ("DES"), an affiliated VIE, of $53 million for the year ended December 31, 2020. EGTS determined that neither it nor any of its consolidated entities was the primary beneficiary of DES as neither it nor any of its consolidated entities had both the power to direct the activities that most significantly impact their economic performance as well as the obligation to absorb losses and benefits which could be significant to them. DES provided accounting, legal, finance and certain administrative and technical services. Neither EGTS nor any of its consolidated entities had any obligation to absorb more than its allocated share of DES costs.

(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):

	2022	2021	2020
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	$ 67	$ 71	$ 82
Income taxes paid (received), net	$ 2	$ (12)	$ 58
Supplemental disclosure of non-cash investing and financing transactions:			
Accruals related to property, plant and equipment additions	$ 15	$ 29	$ 25
Equity dividends(1)	$ (21)	$ (58)	$ —
Equity contributions(2)	$ 34	$ 292	$ —
Acquisition of EGTS by BHE	$ —	$ —	$ 40

(1) Equity dividends represents the forgiveness of affiliated receivables.

(2) Equity contributions for the year ended December 31, 2021 primarily reflect the impacts from the intercompany debt exchange with Eastern Energy Gas. See Note 9 for more information regarding the intercompany debt exchange with Eastern Energy Gas.

(19) Related Party Transactions

Transactions Prior to the GT&S Transaction

Prior to the GT&S Transaction, EGTS engaged in related party transactions primarily with other DEI subsidiaries (affiliates). EGTS' receivable and payable balances with affiliates were settled based on contractual terms or on a monthly basis, depending on the nature of the underlying transactions. Through October 31, 2020, EGTS was included in DEI's consolidated federal income tax return and, where applicable, combined state income tax returns. All affiliate payables or receivables were settled with DEI prior to the closing date of the GT&S Transaction.

EGTS transacted with affiliates for certain quantities of natural gas and other commodities at market prices in the ordinary course of business. Additionally, EGTS provided transmission and storage services to affiliates. EGTS also entered into certain other contracts with affiliates, and related parties, including construction services, which were presented separately from contracts involving commodities or services. EGTS participated in certain DEI benefit plans as described in Note 11.

DES and other affiliates provided accounting, legal, finance and certain administrative and technical services to EGTS. EGTS provided certain services to related parties, including technical services.

The financial statements for the year ended 2020 includes costs for certain general, administrative and corporate expenses assigned by DES to EGTS on the basis of direct and allocated methods in accordance with EGTS' services agreements with DES. Where costs incurred cannot be determined by specific identification, the costs were allocated based on the proportional level of effort devoted by DES resources that is attributable to the entity, determined by reference to number of employees, salaries and wages and other similar measures for the relevant DES service. Management believes the assumptions and methodologies underlying the allocation of general corporate overhead expenses are reasonable.

Subsequent to the GT&S Transaction EGTS' transactions with other DEI subsidiaries are no longer related party transactions.

Presented below are EGTS' significant transactions with DES and other affiliated and related parties for the year ended December 31 (in millions):

		2020
Sales of natural gas and transmission and storage services	$	71
Purchases of natural gas and transmission and storage services		7
Services provided by related parties[(1)]		67
Services provided to related parties[(2)]		86

(1) Includes capitalized expenditures of $14 million.

(2) Includes amounts attributable to Atlantic Coast Pipeline, a related party VIE prior to the GT&S Transaction. See below for more information.

EGTS provided services to Atlantic Coast Pipeline, which totaled $46 million for the year ended December 31, 2020, included in operating revenue in the Consolidated Statement of Operations.

Transactions Subsequent to the GT&S Transaction

EGTS is party to a tax-sharing agreement and is part of the Berkshire Hathaway Inc. consolidated U.S. federal income tax return. For current federal and state income taxes, EGTS had a receivable from BHE of $21 million and $11 million as of December 31, 2022 and 2021, respectively. EGTS received net cash receipts for federal and state income taxes from BHE totaling $10 million for the year ended December 31, 2021, and paid net cash payments for federal and state income taxes to BHE totaling $7 million for the year ended December 31, 2020.

Trade receivables, net as of both December 31, 2022 and 2021 included $2 million of accrued unbilled revenue. This revenue is based on estimated amounts of services provided but not yet billed to an affiliate.

As of December 31, 2022 and 2021, EGTS had $10 million and $8 million, respectively, 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 11. As of December 31, 2022 and 2021, EGTS' amount due to MidAmerican Energy associated with these plans and reflected in other long-term liabilities on the Consolidated Balance Sheets was $47 million and $85 million, respectively.

Presented below are EGTS' significant transactions with related parties for the years ended December 31 (in millions):

		2022		2021		2020
Sales of natural gas and transmission and storage services	$	26	$	28	$	4
Purchases of natural gas and transmission and storage services		4		5		—
Services provided by related parties		46		26		2
Services provided to related parties		62		57		10

Borrowings With Eastern Energy Gas

EGTS has a $400 million intercompany revolving credit agreement from its parent, Eastern Energy Gas, expiring in November 2023. 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. Net outstanding borrowings totaled $36 million with a weighted-average interest rate of 1.43% as of December 31, 2022 and $68 million with a weighted-average interest rate of 0.51% as of December 31, 2021. Interest expense related to these borrowings totaled $1 million for the year ended December 31, 2020.

In March 2021, Eastern Energy Gas entered into a $400 million intercompany revolving credit agreement from EGTS that currently expires in March 2024. The credit agreement, which is for general corporate purposes, has a variable interest rate based on SOFR plus a fixed spread. Net outstanding borrowings totaled $2,071 as of December 31, 2021. Interest income related to this borrowing totaled $2,071 for the year ended December 31, 2021.

EGTS had also borrowed from Eastern Energy Gas pursuant to a series of long-term notes with fixed interest rates ranging from 3.6% to 5.0%, due 2024 to 2047. EGTS incurred interest charges related to these borrowings of $44 million and $88 million for the years ended December 31, 2021 and 2020, respectively. Refer to Note 9 for more information.

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, 2022 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 and Eastern Energy Gas Holdings, LLC, 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, 2022, 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, 2022.

This first Annual Report on Form 10-K for Eastern Gas Transmission and Storage, Inc. does not include a report of management's assessment regarding internal control over financial reporting due to a transition period established by U.S. Securities and Exchange Commission rules applicable to new registrants. Management will be required to provide an assessment of the effectiveness of Eastern Gas Transmission and Storage, Inc.'s internal control over financial reporting as of December 31, 2023.

Berkshire Hathaway Energy Company February 24, 2023	PacifiCorp February 24, 2023	MidAmerican Funding, LLC February 24, 2023
MidAmerican Energy Company February 24, 2023	Nevada Power Company February 24, 2023	Sierra Pacific Power Company February 24, 2023
Eastern Energy Gas Holdings, LLC February 24, 2023	Eastern Gas Transmission and Storage, Inc. February 24, 2023	

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

BERKSHIRE HATHAWAY ENERGY, 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.

PACIFICORP

PacifiCorp is an indirect subsidiary of BHE, and its directors consist of executive management from both BHE and PacifiCorp. Each director was elected based on individual responsibilities, experience in the energy industry and functional expertise. There are no family relationships among the executive officers, nor any arrangements or understandings between any executive officer and any other person pursuant to which the executive officer was appointed. Set forth below is certain information, as of January 31, 2023, with respect to the current directors and executive officers of PacifiCorp:

SCOTT W. THON, 59, Chair of the Board of Directors and Chief Executive Officer since April 2022. Mr. Thon has been President of Operations for Berkshire Hathaway Energy since April 2022. Mr. Thon previously served as President and Chief Executive Officer of BHE Canada since 2014 and the Chief Executive Officer of its largest Canadian subsidiary, AltaLink, since 2002. Mr. Thon has led the investment and construction of significant energy infrastructure developments in Alberta, Canada and globally.

STEFAN A. BIRD, 56, Director since 2015. President and Chief Executive Officer of Pacific Power since 2015. Mr. Bird was Senior Vice President, Commercial and Trading, of PacifiCorp from 2007 to 2014. Mr. Bird joined BHE in 1998 and has significant operational, public policy and leadership experience in the energy industry, including expertise in energy supply management, resource acquisition and federal and state regulatory matters.

GARY W. HOOGEVEEN, 54, Director since November 2018, President since June 2018 and Chief Executive Officer since November 2018 of Rocky Mountain Power. Prior to his current positions, Mr. Hoogeveen served as Senior Vice President and Chief Commercial Officer of Rocky Mountain Power since November 2014 and President and CEO of Kern River Gas Transmission Company from 2010 to 2014. He joined Kern River after serving as Vice President of Customer Service and Business Development for Northern Natural Gas Company. Prior to joining Northern Natural Gas Company, Mr. Hoogeveen held various management positions at Berkshire Hathaway Energy, joining BHE in 2000. He has significant operational, public policy and leadership experience in both the electricity and natural gas industries, including customer, regulatory and government relations.

NIKKI L. KOBLIHA, 50, Director since 2017. Vice President and Chief Financial Officer since 2015 and Treasurer since 2017. Ms. Kobliha joined PacifiCorp in 1997 and has significant financial, accounting and leadership experience in the energy industry, including expertise in financial reporting to the SEC and FERC.

CALVIN D. HAACK, 54, Director since May 2020. Mr. Haack has been Senior Vice President and Chief Financial Officer of BHE since March 2020 and was Vice President and Treasurer of BHE from 2010 to 2020. Mr. Haack joined BHE in 1997 and has significant financial experience, including expertise in mergers and acquisitions, accounting, treasury and tax functions. Mr. Haack is also a manager of MidAmerican Funding, LLC and Eastern Energy Gas Holdings, LLC.

NATALIE L. HOCKEN, 53, Director since 2007. Ms. Hocken has been Senior Vice President and General Counsel of BHE since 2015 and Corporate Secretary since 2017. Ms. Hocken was Senior Vice President, Transmission and System Operations of PacifiCorp from 2012 to 2015 and Vice President and General Counsel of Pacific Power from 2007 to 2012. Ms. Hocken joined PacifiCorp in 2002 and has significant experience in the utility industry, including expertise in transmission, legal matters and federal and state regulatory matters. Ms. Hocken is also a manager of MidAmerican Funding, LLC and Eastern Energy Gas Holdings, LLC.

Board's Role in the Risk Oversight Process

PacifiCorp's Board of Directors is comprised of a combination of BHE senior executives and PacifiCorp senior management who have direct and indirect responsibility for the management and oversight of risk. PacifiCorp's Board of Directors has not established a separate risk management and oversight committee.

Audit Committee and Audit Committee Financial Expert

During the year ended December 31, 2022, and as of the date of this Annual Report on Form 10-K, PacifiCorp's Board of Directors did not have an audit committee. PacifiCorp is not required to have an audit committee as its common stock is indirectly and wholly owned by BHE. However, the audit committee of BHE acts as the audit committee for PacifiCorp.

Code of Ethics

PacifiCorp has adopted a code of ethics that applies to its principal executive officer, its principal financial and accounting officer, or persons acting in such capacities, and certain other covered officers. The code of ethics is incorporated by reference in the exhibits to this Annual Report on Form 10-K.

Item 11. Executive Compensation

BERKSHIRE HATHAWAY ENERGY, 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.

PACIFICORP

Compensation Discussion and Analysis

Compensation Philosophy and Overall Objectives

On April 13, 2022, Mr. William J. Fehrman resigned as PacifiCorp's Chair of the Board of Directors ("Chair") and Chief Executive Officer ("CEO") and Mr. Scott W. Thon was elected as PacifiCorp's Chair and CEO. Neither Mr. Fehrman nor Mr. Thon received any direct compensation from PacifiCorp in 2022. PacifiCorp reimbursed its indirect parent company, BHE, for the cost of Mr. Fehrman's and Mr. Thon's time spent on matters supporting PacifiCorp, including compensation paid to them by BHE, pursuant to an intercompany administrative services agreement among BHE and its subsidiaries.

PacifiCorp believes that the compensation paid to each of its Chief Financial Officer, or CFO, and its other most highly compensated executive officers, to whom PacifiCorp refers collectively as its Named Executive Officers, or NEOs, should be closely aligned with PacifiCorp's overall performance, and each NEO's contribution to that performance, on both a short- and long-term basis, and that such compensation should be sufficient to attract and retain highly qualified leaders who can create significant value for the organization. PacifiCorp's compensation programs are designed to provide its NEOs meaningful incentives for superior corporate and individual performance. Performance is evaluated on a subjective basis within the context of both financial and non-financial objectives, among which are customer service, employee commitment, environmental respect, regulatory integrity, operational excellence and financial strength, which PacifiCorp believes contribute to its long-term success.

How Compensation is Determined

PacifiCorp's compensation committee consists solely of the Chair and CEO. The Chair and CEO is responsible for the establishment and oversight of PacifiCorp's compensation policy and for approving compensation decisions for its NEOs, such as approving base pay increases, incentive and performance awards, off-cycle pay changes, and participation in other employee benefit plans and programs.

PacifiCorp's criteria for assessing executive performance and determining compensation in any year is inherently subjective and is not based upon specific formulas or weighting of factors. PacifiCorp does not specifically use other companies as benchmarks when establishing its NEOs' compensation.

Discussion and Analysis of Specific Compensation Elements

Base Salary

PacifiCorp determines base salaries for all of its NEOs, other than the Chair and CEO, by reviewing its overall performance, and each NEO's performance, the value each NEO brings to PacifiCorp and general labor market conditions. Base salary is intended to compensate NEOs for services rendered during the fiscal year and to provide sufficient cash income for retention and recruitment purposes. While base salary provides a base level of compensation intended to be competitive with the external market, the annual base salary adjustment for each NEO, other than the Chair and CEO, is determined on a subjective basis after consideration of these factors and is not based on target percentiles or other formal criteria. All merit increases are approved by the Chair and CEO and take effect in the last payroll period of the year. An increase or decrease in base salary may also result from a promotion or other significant change in an NEO's responsibilities during the year. For 2022, base salaries for all NEOs, other than the Chair and CEO, increased on average by 2.27% effective December 26, 2021, reflecting merit increases.

Short-Term Incentive Compensation

The objective of short-term incentive compensation is to reward the achievement of significant annual corporate and business unit goals while also providing NEOs with competitive total cash compensation.

<u>Annual Incentive Plan</u>

Under PacifiCorp's Annual Incentive Plan, or AIP, all NEOs, other than the Chair and CEO, are eligible to earn an annual discretionary cash incentive award, which is determined on a subjective basis at the Chair and CEO's sole discretion and is not based on a specific formula or cap. The Chair and CEO considers a variety of factors in determining each NEO's annual incentive award including the NEO's performance, PacifiCorp's overall performance and each NEO's contribution to that overall performance. The Chair and CEO evaluates performance using financial and non-financial objectives, including customer service, employee commitment, environmental respect, regulatory integrity, operational excellence and financial strength, as well as the NEO's response to issues and opportunities that arise during the year. No factor was individually material to the Chair and CEO's determination regarding the amounts paid to each NEO under the AIP for 2022. Approved awards are paid prior to year-end.

<u>*Performance Awards*</u>

In addition to the annual awards under the AIP, PacifiCorp may grant cash performance awards periodically during the year to one or more NEOs, other than the Chair and CEO, to reward the accomplishment of significant non-recurring tasks or projects. These awards are discretionary and are approved by the Chair and CEO. In 2022, a cash performance award was granted to Ms. Kobliha in recognition of her outstanding efforts.

Long-Term Incentive Compensation

The objective of long-term incentive compensation is to retain NEOs, reward their exceptional performance and motivate them to create long-term, sustainable value. PacifiCorp's current long-term incentive compensation program is cash-based. PacifiCorp does not utilize stock options or other forms of equity-based awards.

Long-Term Incentive Partnership Plan

The PacifiCorp Long-Term Incentive Partnership Plan, or LTIP, is designed to retain key employees and to align PacifiCorp's interests and the interests of the participating employees. All of PacifiCorp's NEOs, other than the Chair and CEO, participate in the LTIP. The LTIP provides for annual discretionary awards based upon significant accomplishments by the individual participants and the achievement of the financial and non-financial objectives previously described. The goals are developed with the objective of being attainable with a sustained, focused and concerted effort and are determined and communicated by January of each plan year. The BHE Chair and PacifiCorp's Presidents approve eligibility to participate in the LTIP and the amount of the incentive award. Awards are finalized in the first quarter of the following year. PacifiCorp's Presidents may participate in the LTIP but only the BHE Chair shall make determinations regarding their participation and the value of their incentive award. These cash-based awards are subject to mandatory deferral and equal annual vesting over a four-year period starting in the performance year. Participants allocate the value of their deferral accounts among various investment alternatives. Gains or losses may be incurred based on investment performance. Participating NEOs may elect to defer all or a part of the award or receive payment in cash after the four-year mandatory deferral and vesting period. Vested balances (including any investment gains or losses thereon) of terminating participants are paid at the time of termination.

Deferred Compensation Plan

PacifiCorp's Executive Voluntary Deferred Compensation Plan, or DCP, provides a means for all NEOs, other than the Chair and CEO, to make voluntary deferrals of up to 50% of base salary and 100% of short-term incentive compensation awards. PacifiCorp includes the DCP as part of the participating NEO's overall compensation in order to provide a comprehensive, competitive package. The deferrals and any investment returns grow on a tax-deferred basis. Amounts deferred under the DCP receive a rate of return based on the returns of any combination of various investment alternatives offered under the DCP and selected by the participant. The plan allows participants to choose from three forms of distribution. The plan permits PacifiCorp to make discretionary contributions on behalf of participants.

Potential Payments Upon Termination

PacifiCorp's NEOs are generally not entitled to severance or enhanced benefits upon termination of employment or change in control. None of PacifiCorp's NEOs have an employment agreement; therefore, payments upon termination are determined by the applicable plan documents and our general employment policies and practices as discussed below.

Compensation Committee Report

Mr. Thon, PacifiCorp's current Chair and CEO and sole member of PacifiCorp's compensation committee, has reviewed the Compensation Discussion and Analysis and, based on his review, has recommended to the Board of Directors that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K.

Scott W. Thon

Summary Compensation Table

The following table sets forth information regarding compensation earned by each of PacifiCorp's NEOs during the years indicated:

Name and Principal Position	Year	Salary	Bonus (1)	Change in Pension Value and Nonqualified Deferred Compensation Earnings(2)	All Other Compensation (3)	Total (4)
Scott W. Thon(6)(7)	2022	$ —	$ —	$ —	$ —	$ —
Chair of the Board of Directors	2021	—	—	—	—	—
and Chief Executive Officer	2020	—	—	—	—	—
William J. Fehrman(5)(6)	2022	—	—	—	—	—
Chair of the Board of Directors	2021	—	—	—	—	—
and Chief Executive Officer	2020	—	—	—	—	—
Stefan A. Bird	2022	510,000	1,134,275	—	41,525	1,685,800
President and Chief Executive	2021	473,011	1,142,660	—	33,010	1,648,681
Officer, Pacific Power	2020	375,000	1,327,839	17,723	33,479	1,754,041
Gary W. Hoogeveen	2022	510,000	881,112	—	41,979	1,433,091
President and Chief Executive	2021	473,011	1,066,924	—	33,010	1,572,945
Officer, Rocky Mountain Power	2020	361,080	1,109,713	—	32,690	1,503,483
Nikki L. Kobliha	2022	282,182	259,110	—	37,131	578,423
Vice President, Chief Financial	2021	262,260	396,880	—	32,651	691,791
Officer and Treasurer	2020	262,260	330,510	37,438	32,286	662,494

(1) Consists of annual cash incentive awards earned pursuant to the AIP for PacifiCorp's NEOs, performance awards, and the vesting of LTIP awards and associated vested earnings. The breakout for 2022 is as follows:

			LTIP		
	AIP	Performance Award	Vested Awards	Vested Earnings (Losses)	Total
Stefan A. Bird	$ 450,000	$ —	$ 661,250	$ 23,025	$ 684,275
Gary W. Hoogeveen	450,000	—	530,000	(98,888)	431,112
Nikki L. Kobliha	106,026	50,000	162,250	(59,166)	103,084

The ultimate payouts of LTIP awards are undeterminable as the amounts to be paid out may increase or decrease depending on investment performance. BHE's Chair and PacifiCorp's Presidents establish the award categories for determining LTIP awards based on net income target goals or other criteria. In 2022, the gross award was subjectively determined at the discretion of the BHE Chair and PacifiCorp's Presidents based on the overall achievement of PacifiCorp's financial and non-financial objectives including customer service, employee commitment and safety, environmental respect, regulatory integrity, operational excellence and financial strength.

(2) Amounts are based upon the aggregate change in the actuarial present value of all qualified and nonqualified defined benefit plans, which includes the Retirement Plan. For Mr. Bird and Ms. Kobliha, such change was negative ($(23,432) and $(69,705), respectively). Refer to the Pension Benefits table below for a discussion of the assumptions used in calculating these amounts. No participant in PacifiCorp's nonqualified deferred compensation plans earned "above market" or "preferential" earnings on amounts deferred.

(3) Amounts consist of PacifiCorp K Plus Employee Savings Plan, or 401(k) Plan, contributions PacifiCorp paid on behalf of the NEOs, except for Mr. Hoogeveen for whom PacifiCorp also includes an amount paid for a tax gross-up with respect to a personal benefit with a value less than $10,000.

(4) Any amounts voluntarily deferred by the NEO, if applicable, are included in the appropriate column in the Summary Compensation Table.

(5) In 2022, PacifiCorp reimbursed BHE $118,237 for the cost of Mr. Fehrman's time spent on matters supporting PacifiCorp pursuant to the intercompany administrative services agreement.

(6) On April 13, 2022, Mr. William J. Fehrman resigned as PacifiCorp's Chair of the Board of Directors and Chief Executive Officer and Mr. Scott W. Thon was elected as PacifiCorp's Chair of the Board of Directors and Chief Executive Officer.

(7) In 2022, PacifiCorp reimbursed BHE $145,283 for the cost of Mr. Thon's time spent on matters supporting PacifiCorp pursuant to the intercompany administrative services agreement.

Pension Benefits

The following table sets forth certain information regarding the defined benefit pension plan accounts held by each of PacifiCorp's NEOs as of December 31, 2022:

Name	Plan name	Number of years of credited service	Present value of accumulated benefits (1)
Scott W. Thon	n/a	n/a	n/a
William J. Fehrman	n/a	n/a	n/a
Stefan A. Bird	Retirement	10 years	$ 200,512
Gary W. Hoogeveen	n/a	n/a	n/a
Nikki L. Kobliha	Retirement	12 years	98,895

(1) Amounts are computed using assumptions, other than the expected retirement age, consistent with those used in preparing the related pension disclosures in the Notes to Consolidated Financial Statements of PacifiCorp in Item 8 of this Form 10-K and are as of December 31, 2022, which is the measurement date for the plans. The expected retirement age assumption has been determined in accordance with Instruction 2 to Item 402(h)(2) of Regulation S-K. For the Retirement Plan calculations of the present value of accumulated benefits, the following assumptions were used: 60% lump sum payment; 40% joint and 100% survivor annuity if participant is married and 40% single life annuity if participant is single. The present value assumptions used in calculating the present value of accumulated benefits for the Retirement Plan were as follows: a discount rate of 5.55%; an expected retirement age of 65; cash balance interest crediting assumption of 5.43% for 2023 and 2024, and 2.60% thereafter; postretirement mortality using the Pri-2012 gender specific tables; generational mortality improvements from 2012 forward based on MP-2021; and the applicable lump sum interest and mortality rates set forth in IRC 417(e)(3) for the upcoming fiscal year.

Historically, the majority of PacifiCorp's employees were entitled to participate in PacifiCorp's Retirement Plan, other than employees subject to collective bargaining agreements that do not provide for coverage under the Retirement Plan. Through May 31, 2007, participants earned benefits at retirement payable for life based on length of service through May 31, 2007 and average pay in the 60 consecutive months of highest pay out of the 120 months prior to May 31, 2007. Pay for this purpose included base salary and annual incentive plan payments up to 10% of base salary, but was limited to the amounts specified in Internal Revenue Code Section 401(a)(17). Benefits were based on 1.3% of final average pay plus 0.65% of final average pay in excess of covered compensation (as defined in Internal Revenue Code Section 401(1)(5)(E)) multiplied by years of service.

The Retirement Plan was amended effective June 1, 2007 to change from a traditional final average pay formula as described above to a cash balance formula for non-union participants. Benefits under the final average pay formula were frozen as of May 31, 2007, and no future benefits will accrue under that formula for non-union participants. Under the cash balance formula, benefits are based on pay credits to each participant's account of 6.5% (5.0% for employees hired after June 30, 2006 and before January 1, 2008) of eligible compensation. In addition, through August 1, 2009, there was a pay credit of 4% of eligible compensation in excess of the Social Security Wage Base. Interest is also credited to each participant's account. Employees who were age 40 or older as of May 31, 2007 received certain additional transition pay credits for five years from the effective date of the Retirement Plan restatement.

Participants in the Retirement Plan are entitled to receive full benefits upon retirement on or after age 65. Such participants are also entitled to receive reduced benefits upon early retirement after age 55 with at least five years of service or when age plus years of service equals 75.

The Retirement Plan was closed to non-union employees hired after December 31, 2007 (which includes Mr. Hoogeveen, Mr. Fehrman and Mr. Thon). In 2008, non-union employee participants in the Retirement Plan were offered the option to continue to receive pay credits in the Retirement Plan or receive equivalent fixed contributions to the 401(k) Plan with any such election becoming effective January 1, 2009. Ms. Kobliha elected the equivalent fixed 401(k) contribution option and, therefore, no longer receives pay credits in the Retirement Plan. In 2017, the Retirement Plan was frozen for the remainder of the non-union employees who had participated (which includes Mr. Bird) with pay credits equivalent to those received in the Retirement Plan allocated into the 401(k) Plan. Mr. Bird and Ms. Kobliha continue to receive interest credits in the Retirement Plan.

Nonqualified Deferred Compensation

The following table sets forth certain information regarding the nonqualified deferred compensation plan accounts held by each of PacifiCorp's NEOs as of December 31, 2022:

Name	Executive contributions in 2022[(1)(2)]	Registrant contributions in 2022	Aggregate earnings/(losses) in 2022	Aggregate withdrawals/ distributions	Aggregate balance as of 12/31/2022[(3)]
Scott W. Thon	$ —	$ —	$ —	$ —	$ —
William J. Fehrman	—	—	—	—	—
Stefan A. Bird	—	—	—	—	—
Gary W. Hoogeveen	330,330	—	(589,981)	—	3,607,102
Nikki L. Kobliha	333,707	—	(65,034)	—	805,545

(1) The executive contribution amount shown for Mr. Hoogeveen represents a deferral of $330,330 of his 2019 LTIP award which was deferred in 2022. $74,389 of the deferred 2019 LTIP award is included in the 2022 total compensation reported for him in the Summary Compensation Table and is not additional compensation. The remaining LTIP award was earned prior to 2022.

(2) The executive contribution amount shown for Ms. Kobliha represents a deferral of $140,093 of her 2022 compensation and a deferral of $193,614 of her 2019 LTIP award which was deferred in 2022. $12,895 of the deferred 2019 LTIP award is included in the 2022 total compensation reported for her in the Summary Compensation Table and is not additional compensation. The remaining LTIP award was earned prior to 2022.

(3) The aggregate balance as of December 31, 2022, shown for Mr. Hoogeveen and Ms. Kobliha includes $567,702 and $136,703, respectively, of compensation previously reported in the Summary Compensation Table.

Eligibility for PacifiCorp's DCP is restricted to select management and highly compensated employees. The plan provides tax benefits to eligible participants by allowing them to defer compensation on a pretax basis, thus reducing their current taxable income. Deferrals and any investment returns grow on a tax-deferred basis, thus participants pay no income tax until they receive distributions. The DCP permits participants to make a voluntary deferral of up to 50% of base salary and 100% of short-term incentive compensation awards. All deferrals are net of social security taxes. Amounts deferred under the DCP receive a rate of return based on the returns of any combination of various investment alternatives offered by the plan and selected by the participant. Gains or losses are calculated daily, and returns are posted to accounts based on participants' fund allocation elections. Participants can change their fund allocations as of the end of any day on which the market is open.

The DCP allows participants to maintain three accounts based upon when they want to receive payments: retirement account, in-service account and education account. Both the retirement and in-service accounts can be distributed as lump sums or in up to 10 annual installments, except in the case of the four DCP transition accounts that allow for a grandfathered payout based on the previous deferred compensation plan distribution elections of lump sum, 5, 10 or 15 annual installments. Effective December 31, 2006, no new money may be deferred into the DCP transition accounts. The education account is distributed in four annual installments. If a participant leaves employment prior to retirement (age 55), all amounts in the participant's account will be paid out in a lump sum as soon as administratively practicable. Participants are 100% vested in their deferrals and any investment gains or losses recorded in their accounts.

Participants in PacifiCorp's LTIP also have the option of deferring all or a part of those awards after the four-year mandatory deferral and vesting period. The provisions governing the deferral of LTIP awards are similar to those described for the DCP above.

Potential Payments Upon Termination

PacifiCorp's NEOs are not generally entitled to severance or enhanced benefits upon termination of employment or change in control. None of PacifiCorp's NEOs have an employment agreement; therefore, payments upon termination are determined by the applicable plan documents and our general employment policies and practices as discussed below.

The following table sets forth the estimated increase in the present value of benefits pursuant to the termination scenarios indicated for PacifiCorp's NEOs, other than Mr. Thon. Payments or benefits that are not enhanced in form or amount upon the occurrence of a particular termination scenario, which include 401(k) and nonqualified deferred compensation account balances and those portions of long-term incentive payments that would have otherwise been paid, are not included herein. All estimated payments reflected in the table below assume termination on December 31, 2022 and are payable as lump sums unless otherwise noted.

Termination Scenario	Incentive [1]	Pension [2]
Stefan A. Bird:		
Retirement, Voluntary and Involuntary With or Without Cause	$ —	$ 43,590
Death and Disability	944,233	43,950
Gary W. Hoogeveen:		
Retirement, Voluntary and Involuntary With or Without Cause	—	n/a
Death and Disability	838,153	n/a
Nikki L. Kobliha:		
Retirement, Voluntary and Involuntary With or Without Cause	—	—
Death and Disability	228,678	—

(1) Amounts represent the unvested portion of each NEO's LTIP account, which becomes 100% vested under certain circumstances.

(2) Pension values represent the excess of the present value of benefits payable under each termination scenario over the amount already reflected in the Pension Benefits table.

Chief Executive Officer Pay Ratio

PacifiCorp's CEO receives no direct compensation from PacifiCorp, and no amounts are reported for the CEO in the Summary Compensation Table. Accordingly, PacifiCorp has determined that the CEO pay ratio is not calculable.

Director Compensation

PacifiCorp's directors do not receive additional compensation for service as directors of PacifiCorp. Compensation information for Messrs. Thon, Fehrman, Bird, Hoogeveen, and Ms. Kobliha for their services as executive officers of PacifiCorp is described above.

Compensation Committee Interlocks and Insider Participation

Mr. Thon is PacifiCorp's Chair and CEO. None of PacifiCorp's executive officers serves as a member of the compensation committee of any company that has an executive officer serving as a member of PacifiCorp's Board of Directors. None of PacifiCorp's executive officers serves as a member of the board of directors of any company (other than BHE) that has an executive officer serving as a member of PacifiCorp's compensation committee. See also PacifiCorp's Item 13 in this Annual Report on Form 10-K.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

BERKSHIRE HATHAWAY ENERGY, 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.

PACIFICORP

Beneficial Ownership

PacifiCorp is a consolidated subsidiary of BHE. PacifiCorp's common stock is indirectly owned by BHE, 666 Grand Avenue, Des Moines, Iowa 50309-2580. BHE is a consolidated subsidiary of Berkshire Hathaway that, as of January 31, 2023, owns 92% of BHE's common stock. The balance of BHE's common stock is beneficially owned by family members and related or affiliated entities of the late Mr. Walter Scott, Jr., a former member of BHE's Board of Directors.

None of PacifiCorp's executive officers or directors owns shares of its preferred stock. The following table sets forth certain information regarding the beneficial ownership of BHE's common stock and the Class A and Class B shares of Berkshire Hathaway common stock held by each of PacifiCorp's directors, executive officers and all of its directors and executive officers as a group as of January 31, 2023:

	BHE		Berkshire Hathaway			
	Common Stock		Class A Common Stock		Class B Common Stock	
Beneficial Owner	Number of Shares Beneficially Owned(1)	Percentage of Class(1)	Number of Shares Beneficially Owned(1)	Percentage of Class(1)	Number of Shares Beneficially Owned(1)	Percentage of Class(1)
Scott W. Thon	—	—	—	—	1,042	*
Stefan A. Bird	—	—	—	—	—	—
Calvin D. Haack	—	—	—	—	—	—
Natalie L. Hocken	—	—	—	—	—	—
Nikki L. Kobliha	—	—	—	—	—	—
Gary W. Hoogeveen	—	—	—	—	521	*
All executive officers and directors as a group (6 persons)	—	—	—	—	1,563	*

* Indicates beneficial ownership of less than one percent of all outstanding shares.

(1) Includes shares of which the listed beneficial owner is deemed to have the right to acquire beneficial ownership under Rule 13d-3(d) under the Securities Exchange Act, including, among other things, shares which the listed beneficial owner has the right to acquire within 60 days.

Item 13. Certain Relationships and Related Transactions, and Director Independence

BERKSHIRE HATHAWAY ENERGY, 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.

PACIFICORP

Certain Relationships and Related Transactions

The Berkshire Hathaway Inc. Code of Business Conduct and Ethics and the BHE Code of Business Conduct, or the Codes, which apply to all of PacifiCorp's directors, officers and employees and those of its subsidiaries, generally govern the review, approval or ratification of any related-person transaction. A related-person transaction is one in which PacifiCorp or any of its subsidiaries participate and in which one or more of PacifiCorp's directors, executive officers, holders of more than five percent of its voting securities or any of such persons' immediate family members have a direct or indirect material interest.

Under the Codes, all of PacifiCorp's directors and executive officers (including those of its subsidiaries) must disclose to PacifiCorp's legal department any material transaction or relationship that reasonably could be expected to give rise to a conflict with its interests. No action may be taken with respect to such transaction or relationship until approved by the legal department. For PacifiCorp's chief executive officer and chief financial officer, prior approval for any such transaction or relationship must be given by Berkshire Hathaway's audit committee. In addition, prior legal department approval must be obtained before a director or executive officer can accept employment, offices or board positions in other for-profit businesses, or engage in his or her own business that raises a potential conflict or appearance of conflict with PacifiCorp's interests.

Under an intercompany administrative services agreement PacifiCorp has entered into with BHE and its other subsidiaries, the costs of certain administrative services provided by BHE to PacifiCorp or by PacifiCorp to BHE, or shared with BHE and other subsidiaries, are directly charged or allocated to the entity receiving such services. This agreement has been filed with the regulatory commissions in the states where PacifiCorp serves retail customers. PacifiCorp also provides an annual report of all transactions with its affiliates to its state regulatory commissions, who have the authority to refuse recovery in rates for payments PacifiCorp makes to its affiliates deemed to have the effect of subsidizing the separate business activities of BHE or its other subsidiaries.

Refer to Note 21 of the Notes to the Consolidated Financial Statements of PacifiCorp in Item 8 of this Form 10-K for additional information regarding related party transactions.

Director Independence

Because PacifiCorp's common stock is indirectly, wholly owned by BHE and its Board of Directors consists of BHE and PacifiCorp employees, PacifiCorp is not required to have independent directors or audit, nominating or compensation committees consisting of independent directors.

Based on the standards of the New York Stock Exchange LLC, on which the common stock of PacifiCorp's ultimate parent company, Berkshire Hathaway, is listed, PacifiCorp's Board of Directors has determined that none of its directors are considered independent because of their employment by BHE or PacifiCorp.

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
2022								
Audit fees(2)	$ 12.6	$ 1.7	$ 1.3	$ 1.2	$ 1.0	$ 0.9	$ 1.7	$ 1.3
Audit-related fees(3)	0.8	—	—	—	—	—	0.2	0.1
Tax fees(4)	—	—	—	—	—	—	—	—
Other	0.6	—	—	—	—	—	—	—
Total	$ 14.0	$ 1.7	$ 1.3	$ 1.2	$ 1.0	$ 0.9	$ 1.9	$ 1.4
2021								
Audit fees(2)	$ 11.3	$ 1.7	$ 1.3	$ 1.2	$ 0.9	$ 0.9	$ 1.2	$ —
Audit-related fees(3)	0.8	0.1	0.1	0.1	—	—	0.2	—
Tax fees(4)	0.1	—	—	—	—	—	—	—
Total	$ 12.2	$ 1.8	$ 1.4	$ 1.3	$ 0.9	$ 0.9	$ 1.4	$ —

(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, which became an SEC registrant on July 28, 2022.

(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.

The 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 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 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. Under the policy, requests to provide services that require specific approval by the audit committee will be submitted to the audit committee by both the Registrants' independent auditor and BHE's Chief Financial Officer. All requests for services to be provided by the independent auditor that do not require specific approval by the audit committee will be submitted to BHE's Chief Financial Officer and must include a detailed description of the services to be rendered. BHE's Chief Financial Officer will determine whether such services are included within the list of services that have received the general pre-approval of the audit committee. The audit committee will be informed on a timely basis of any such services rendered by the independent auditor.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) Financial Statements and Schedules

(1) Financial Statements

(2) Financial Statement Schedules

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.

(b) Exhibits

Item 16. Form 10-K Summary

None.

Schedule I

BERKSHIRE HATHAWAY ENERGY COMPANY
PARENT COMPANY ONLY
CONDENSED BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2022	**2021**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 32	$ 18
Accounts receivable	4	—
Accounts receivable - affiliate	263	117
Notes receivable - affiliate	10	189
Income tax receivable	28	23
Other current assets	12	13
Total current assets	349	360
Investments in subsidiaries	59,944	58,190
Other investments	205	237
Goodwill	1,221	1,221
Other assets	1,152	1,101
Total assets	$ 62,871	$ 61,109
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and other current liabilities	$ 429	$ 397
Notes payable - affiliate	287	353
Short-term debt	245	—
Current portion of BHE senior debt	900	—
Total current liabilities	1,861	750
BHE senior debt	13,096	13,003
BHE junior subordinated debentures	100	100
Notes payable - affiliate	477	2
Other long-term liabilities	505	560
Total liabilities	16,039	14,415
Equity:		
BHE shareholders' equity:		
Preferred stock - 100 shares authorized, $0.01 par value, 1 and 2 shares issued and outstanding	850	1,650
Common stock - 115 shares authorized, no par value, 76 shares issued and outstanding	—	—
Additional paid-in capital	6,298	6,374
Long-term income tax receivable	—	(744)
Retained earnings	41,833	40,754
Accumulated other comprehensive loss, net	(2,149)	(1,340)
Total BHE shareholders' equity	46,832	46,694
Noncontrolling interest	—	—
Total equity	46,832	46,694
Total liabilities and equity	$ 62,871	$ 61,109

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,		
	2022	**2021**	**2020**
Operating expenses:			
General and administration	$ 31	$ 83	$ 57
Depreciation and amortization	8	6	4
Total operating expenses	39	89	61
Operating loss	(39)	(89)	(61)
Other income (expense):			
Interest expense	(629)	(580)	(527)
Other, net	(45)	1,846	4,789
Total other income (expense)	(674)	1,266	4,262
(Loss) income before income tax (benefit) expense and equity income	(713)	1,177	4,201
Income tax (benefit) expense	(259)	194	1,089
Equity income	3,175	4,807	3,832
Net income	2,721	5,790	6,944
Net income attributable to noncontrolling interest	—	—	1
Net income attributable to BHE shareholders	2,721	5,790	6,943
Preferred dividends	46	121	26
Earnings on common shares	$ 2,675	$ 5,669	$ 6,917

The accompanying notes are an integral part of this financial statement schedule.

BERKSHIRE HATHAWAY ENERGY COMPANY
PARENT COMPANY ONLY
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME
(Amounts in millions)

	Years Ended December 31,		
	2022	**2021**	**2020**
Net income	$ 2,721	$ 5,790	$ 6,944
Other comprehensive (loss) income, net of tax	(809)	212	154
Comprehensive income	1,912	6,002	7,098
Comprehensive income attributable to noncontrolling interests	—	—	1
Comprehensive income attributable to BHE shareholders	$ 1,912	$ 6,002	$ 7,097

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,		
	2022	**2021**	**2020**
Cash flows from operating activities	$ 1,252	$ 1,819	$ 1,639
Cash flows from investing activities:			
Investments in subsidiaries	(1,085)	(1,206)	(6,422)
Purchases of marketable securities	(20)	(29)	(55)
Proceeds from sales of marketable securities	11	28	22
Purchases of other investments	—	—	(1,290)
Proceeds from other investments	—	1,290	—
Notes receivable from affiliate, net	390	200	(121)
Other, net	(44)	(20)	(20)
Net cash flows from investing activities	(748)	263	(7,886)
Cash flows from financing activities:			
Proceeds from issuance of preferred stock	—	—	3,750
Preferred stock redemptions	(800)	(2,100)	—
Preferred dividends	(50)	(132)	(7)
Common stock purchases	(870)	—	(126)
Proceeds from BHE senior debt	986	—	5,212
Repayments of BHE senior debt	—	(450)	(350)
Net proceeds from (repayments of) short-term debt	245	—	(1,590)
Other, net	(1)	(5)	(32)
Net cash flows from financing activities	(490)	(2,687)	6,857
Net change in cash and cash equivalents	14	(605)	610
Cash and cash equivalents at beginning of year	18	623	13
Cash and cash equivalents at end of year	$ 32	$ 18	$ 623

The accompanying notes are an integral part of this financial statement schedule.

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, 2022, 2021 and 2020 were $1.9 billion, $2.4 billion and $2.0 billion, respectively. In January and February 2023, BHE received cash dividends from its subsidiaries totaling $495 million.

Guarantees and commitments - BHE has issued guarantees and letters of credit in respect of subsidiaries, equity method investments and other related parties aggregating $1.6 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,	
	2022	**2021**
ASSETS		
Current assets:		
Receivables from affiliates	$ 1	$ 1
Investments in and advances to subsidiaries	10,959	10,070
Total assets	$ 10,960	$ 10,071
LIABILITIES AND MEMBER'S EQUITY		
Current liabilities:		
Interest accrued and other current liabilities	$ 5	$ 5
Payable to affiliate	36	25
Long-term debt	240	240
Total liabilities	281	270
Member's equity:		
Paid-in capital	1,679	1,679
Retained earnings	9,000	8,122
Total member's equity	10,679	9,801
Total liabilities and member's equity	$ 10,960	$ 10,071

The accompanying notes are an integral part of this financial statement schedule.

Schedule I

MIDAMERICAN FUNDING, LLC
PARENT COMPANY ONLY
CONDENSED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2022	**2021**	**2020**
Other income (expense):			
Interest expense	$ (17)	$ (16)	$ (16)
Loss before income taxes	(17)	(16)	(16)
Income tax benefit	(5)	(5)	(5)
Equity in undistributed earnings of subsidiaries	959	894	829
Net income	$ 947	$ 883	$ 818

The accompanying notes are an integral part of this financial statement schedule.

MIDAMERICAN FUNDING, LLC
PARENT COMPANY ONLY
CONDENSED STATEMENTS OF CASH FLOWS
(In millions)

	Years Ended December 31,		
	2022	**2021**	**2020**
Net cash flows from operating activities	$ (12)	$ (12)	$ (12)
Net cash flows from investing activities:			
Dividend from subsidiary	69	—	—
Net cash flows from investing activities	69	—	—
Net cash flows from financing activities:			
Distribution to member	(69)	—	—
Net change in amounts payable to subsidiary	12	12	12
Net cash flows from financing activities	(57)	12	12
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.

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, 2022, 2021 and 2020 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, 2022, 2021 and 2020.

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 $81 million, $12 million and $12 million in 2022, 2021 and 2020, respectively, on behalf of MidAmerican Funding.

Distribution to Parent - In 2022, MidAmerican Funding declared and paid, via MHC, a cash dividend of $69 million. In January 2023, MidAmerican Funding declared and paid, via MHC, a cash dividend of $100 million.

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	Second Amended and Restated Articles of Incorporation of MidAmerican Energy Holdings Company effective March 2, 2006 (incorporated by reference to Exhibit 3.1 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2005).
3.2	Articles of Amendment to the Second Amended and Restated Articles of Incorporation of MidAmerican Energy Holdings Company effective April 30, 2014 (incorporated by reference to Exhibit 3.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2014).
3.3	Third Amended and Restated Articles of Incorporation of Berkshire Hathaway Energy Company, effective as of October 22, 2020 (incorporated by reference to Exhibit 3.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated November 2, 2020).
3.4	Amended and Restated Bylaws of Berkshire Hathaway Energy Company (incorporated by reference to Exhibit 3.2 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2005).
4.1	Shareholders Agreement, dated as of March 14, 2000 (incorporated by reference to Exhibit 4.19 to the Berkshire Hathaway Energy Company Registration Statement No. 333-101699 dated December 6, 2002).
4.2	Amendment No. 1 to Shareholders Agreement, dated December 7, 2005 (incorporated by reference to Exhibit 4.17 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2005).
4.3	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).
4.4	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).
4.5	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).
4.6	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).
4.7	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 3.750% Senior Notes due 2023 and 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).
4.8	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 3.50% Senior Notes due 2025 and 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).
4.9	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).
4.10	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 2.80% Senior Notes due 2023, 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).

Exhibit No.	Description
4.11	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).
4.12	Fourteenth Supplemental Indenture, dated as of March 24, 2020, by and between Berkshire Hathaway Energy Company and The Bank of New York Mellon Trust Company, N.A., as trustee, relating to the 4.05% Senior Notes due 2025 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated March 25, 2020).
4.13	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).
4.14	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).
4.15	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).
4.16	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).
4.17	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).
4.18	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).
4.19	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).
4.20	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).
4.21	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).
4.22	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).
4.23	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).
4.24	Supplemental Trust Deed, dated May 5, 2005 among CE Electric UK Funding Company, Ambac Assurance UK Limited and The Law Debenture Trust Corporation plc (incorporated by reference to Exhibit 99.5 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).

Exhibit No.	Description
4.25	Second Supplemental Agreement to Insurance and Indemnity Agreement, dated May 5, 2005 by and between CE Electric UK Funding Company and Ambac Assurance UK Limited (incorporated by reference to Exhibit 99.6 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).
4.26	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).
4.27	Trust Deed, dated as of April 1, 2015, among Northern Powergrid (Yorkshire) plc and HSBC Corporate Trustee Company (UK) Limited, relating to the £150,000,000 in principal amount of the 2.50% Bonds due 2025 (incorporated by reference to Exhibit 4.3 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2015).
4.28	£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).
4.29	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).
4.30	£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).
4.31	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).
4.32	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).
4.33	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).
4.34	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).
4.35	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).
4.36	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).
4.37	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).
4.38	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).

Exhibit No.	Description
4.39	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).
4.40	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).
4.41	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).
4.42	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 (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 (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 (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 (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	Seventeenth Supplemental Indenture, dated May 22, 2013, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.105 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.49	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).
4.50	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).
4.51	Twentieth Supplemental Indenture, dated June 30, 2015, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada, relating to C$350,000,000 in principal amount of the 4.09% Series 2015-1 Medium-Term Notes due 2045 (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).
4.52	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
4.53	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).
4.54	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.
4.55	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).
4.56	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).
4.57	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).
4.58	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	$3,500,000,000 Third Amended and Restated Credit Agreement, dated as of June 30, 2022, among Berkshire Hathaway Energy Company, as Borrower, the Banks, Financial Institutions and Other Institutional Lenders, as Initial Lenders, MUFG Bank, Ltd. as Administrative Agent and the LC Issuing Banks (incorporated by reference to Exhibit 10.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2022).
10.2	Amended and Restated £200,000,000 Facility Agreement, dated as of December 22, 2021, among Northern Powergrid Holdings Company, as Guarantor, Northern Powergrid (Yorkshire) plc and Northern Powergrid (Northeast) Limited, as Borrowers, and Santander UK plc, Lloyds Bank plc and National Westminster Bank plc, as Original Lenders (incorporated by reference to Exhibit 10.2 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2021).
10.3	Amended and Restated Credit Agreement, dated as of January 24, 2020, among AltaLink Investments, L.P., as borrower, AltaLink Investment Management Ltd., as general partner, Royal Bank of Canada, as administrative agent, and Lenders (incorporated by reference to Exhibit 10.3 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2019).
10.4	Third Amending Agreement to the Amended and Restated Credit Agreement, dated as of December 15, 2021, among AltaLink Investments, L.P., as borrower, AltaLink Investment Management Ltd., as general partner, Royal Bank of Canada, as administrative agent, and Lenders (incorporated by reference to Exhibit 10.4 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2021).
10.5	Fourth Amended and Restated Credit Agreement, dated as of January 24, 2020, among AltaLink, L.P., as borrower, AltaLink Management Ltd., as general partner, The Bank of Nova Scotia, as administrative agent, and Lenders (incorporated by reference to Exhibit 10.5 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2019).
10.6	Second Amending Agreement to the Fourth Amended and Restated Credit Agreement, dated as of December 15, 2021, among AltaLink, L.P., as borrower, AltaLink Management Ltd., as general partner and The Bank of Nova Scotia, as administrative agent (Incorporated by reference to Exhibit 10.6 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2021).
10.7	Third Amending Agreement to the Fourth Amended and Restated Credit Agreement, dated as of December 15, 2022, among AltaLink, L.P., as borrower, AltaLink Management Ltd., as general partner and The Bank of Nova Scotia, as administrative agent.

Exhibit No.	Description
10.8	Fifth Amended and Restated Credit Agreement, dated as of January 24, 2020, among AltaLink, L.P., as borrower, AltaLink Management Ltd., as general partner, The Bank of Nova Scotia, as administrative agent, and Lenders (incorporated by reference to Exhibit 10.4 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2019).
10.9	Second Amending Agreement to the Fifth Amended and Restated Credit Agreement, dated as of December 15, 2021, among AltaLink, L.P., as borrower, AltaLink Management Ltd., as general partner, The Bank of Nova Scotia, as administrative agent and Lenders (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, 2021).
10.10	Third Amending Agreement to the Fifth Amended and Restated Credit Agreement, dated as of December 15, 2022, among AltaLink, L.P., as borrower, AltaLink Management Ltd., as general partner, The Bank of Nova Scotia, as administrative agent and Lenders.
10.11	Credit Agreement, dated as of April 27, 2020, among AltaLink Investments, L.P., as borrower, AltaLink Investment Management Ltd., as general partner, Royal Bank of Canada, as administrative agent, and Lenders (incorporated by reference to Exhibit 10.2 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2020).
10.12	Berkshire Hathaway Energy Company Executive Voluntary Deferred Compensation Plan restated effective as of January 1, 2007 (incorporated by reference to Exhibit 10.9 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2007).
10.13	Berkshire Hathaway Energy Company Long-Term Incentive Partnership Plan as Amended and Restated December 31, 2021 (incorporated by reference to Exhibit 10.11 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2021.
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.
24.1	Power of Attorney.
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

3.5	Third Restated Articles of Incorporation of PacifiCorp (incorporated by reference to Exhibit (3)a to the PacifiCorp Annual Report on Form 10-K for the year ended December 31, 1996).
3.6	Bylaws of PacifiCorp, as amended May 23, 2005 (incorporated by reference to Exhibit 3.2 to the PacifiCorp Annual Report on Form 10-K for the year ended March 31, 2005).
10.14*	Summary of Key Terms of Compensation Arrangements with PacifiCorp's Named Executive Officers and Directors.
10.15*	PacifiCorp Executive Voluntary Deferred Compensation Plan (incorporated by reference to Exhibit 10.3 to the PacifiCorp Annual Report on Form 10-K for the year ended December 31, 2007).
10.16*	Supplemental Executive Retirement Plan (incorporated by reference to Exhibit 10.7 to the PacifiCorp Annual Report on Form 10-K for the year ended March 31, 2005).
10.17*	Amendment No. 10 to PacifiCorp Supplemental Executive Retirement Plan dated June 2, 2006 (incorporated by reference to Exhibit 10.5 to the PacifiCorp Quarterly Report on Form 10-Q for the quarter ended June 30, 2006).
10.18*	Amendment No. 11 to PacifiCorp Supplemental Executive Retirement Plan dated June 2, 2006 (incorporated by reference to Exhibit 10.6 to the PacifiCorp Quarterly Report on Form 10-Q for the quarter ended June 30, 2006).

Exhibit No.	Description
10.19*	Amendment No. 1 to the PacifiCorp Executive Voluntary Deferred Compensation Plan dated October 28, 2008 (incorporated by reference to Exhibit 10.10 to the PacifiCorp Annual Report on Form 10-K for the year ended December 31, 2009).
10.20*	Amendment No. 2 to the PacifiCorp Executive Voluntary Deferred Compensation Plan dated October 16, 2012 (incorporated by reference to Exhibit 10.11 to the PacifiCorp Annual Report on Form 10-K for the year ended December 31, 2012).
10.21*	PacifiCorp Long Term Incentive Partnership Plan effective January 1, 2014 and Restated Effective December 1, 2019 (incorporated by reference to Exhibit 10.15 to the PacifiCorp Annual Report on Form 10-K for the year ended December 31, 2019).
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

4.59 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 33 Supplemental Indentures, each incorporated by reference, as follows:

Exhibit Number	PacifiCorp File Type	File Date
(4)(b)[(a)]	SE	November 2, 1989
(4)(a)[(a)]	8-K	January 9, 1990
(4)(a)[(a)]	8-K	September 11, 1991
(4)(a)[(a)]	8-K	January 7, 1992
(4)(a)[(a)]	10-Q	Quarter ended March 31, 1992
(4)(a)[(a)]	10-Q	Quarter ended September 30, 1992
(4)(a)[(a)]	8-K	April 1, 1993
(4)(a)[(a)]	10-Q	Quarter ended September 30, 1993
(4)a	10-Q	Quarter ended June 30, 1994
(4)b	10-K	Year ended December 31, 1994
(4)b	10-K	Year ended December 31, 1995
(4)b	10-K	Year ended December 31, 1996
(4)b	10-K	Year ended December 31, 1998
99(a)	8-K	November 21, 2001
4.1	10-Q	Quarter ended June 30, 2003
99	8-K	September 9, 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	May 12, 2011
4.1	8-K	January 6, 2012
4.1	8-K	June 6, 2013
4.1	8-K	March 13, 2014
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

10.22 $1,200,000,000 Third Amended and Restated Credit Agreement, dated as of June 30, 2022, among PacifiCorp, as Borrower, the Banks, Financial Institutions and Other Institutional Lenders, as Initial Lenders, JP Morgan Chase Bank, N.A. as Administrative Agent and the LC Issuing Banks (incorporated by reference to Exhibit 10.2 to the PacifiCorp Quarterly Report on Form 10-Q for the quarter ended June 30, 2022).

10.23 $800,000,000 Credit Agreement dated as of January 3, 2023, among PacifiCorp, as Borrower, the Banks, Financial Institutions and Other Institutional Lenders, as Initial Lenders, and PNC Bank, N.A. as Administrative Agent.

95 Mine Safety Disclosures Required by the Dodd-Frank Wall Street Reform and Consumer Protection Act.

Exhibit No.	Description
MIDAMERICAN ENERGY	
3.7	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).
3.8	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	
3.9	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).
3.10	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).
3.11	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	
4.60	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).
4.61	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).
4.62	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).
4.63	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).
4.64	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).

Exhibit No.	Description
4.65	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).
4.66	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).
4.67	Specimen of 3.70% First Mortgage Bonds due 2023 (incorporated by reference to Exhibit 4.3 to the MidAmerican Energy Company Current Report on Form 8-K dated September 19, 2013).
4.68	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).
4.69	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).
4.70	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).
4.71	Specimen of 3.50% First Mortgage Bonds due 2024 (incorporated by reference to Exhibit 4.4 to the MidAmerican Energy Company Current Report on Form 8-K dated April 3, 2014).
4.72	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).
4.73	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).
4.74	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).
4.75	Specimen of 3.50% First Mortgage Bonds due 2024 (incorporated by reference to Exhibit 4.3 to the MidAmerican Energy Company Current Report on Form 8-K dated October 15, 2015).
4.76	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).
4.77	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).
4.78	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).
4.79	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).
4.80	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).
4.81	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).
4.82	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).

Exhibit No.	Description
4.83	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).
4.84	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).
4.85	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).
4.86	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).
4.87	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).
4.88	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).
4.89	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).
4.90	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).
4.91	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).
4.92	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).
4.93	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).
4.94	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).
4.95	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).
10.24	$1,500,000,000 Third Amended and Restated Credit Agreement, dated as of June 30, 2022, among MidAmerican Energy Company, as Borrower, the Banks, Financial Institutions and Other Institutional Lenders, as Initial Lenders, Mizuho Bank, Ltd., as Administrative Agent and the LC Issuing Banks (incorporated by reference to Exhibit 10.3 to the MidAmerican Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2022).

BERKSHIRE HATHAWAY ENERGY AND MIDAMERICAN FUNDING

Exhibit No.	Description
4.96	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).

Exhibit No.	Description
NEVADA POWER	
3.12	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).
3.13	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).
4.97	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).
4.98	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).
10.25	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).
10.26	$300,000,000 Delayed Draw Term Loan Agreement, dated as of January 14, 2022, among Nevada Power Company, as Borrower, the Banks, Financial Institutions and Other Institutional Lenders, as Initial Lenders, U.S. Bank National Association, as Administrative Agent and U.S. Bank National Association and Sumitomo Mitsui Banking Corporation, as Joint Lead Arrangers and Joint Bookrunners (incorporated by reference to Exhibit 10.23 to the Nevada Power Company Annual Report on Form 10-K for the year ended December 31, 2021.
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.
BERKSHIRE HATHAWAY ENERGY AND NEVADA POWER	
4.99	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).
4.100	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).
4.101	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 Form 10-Q for the quarter ended March 31, 2006).
4.102	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).
4.103	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).
4.104	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).

Exhibit No.	Description
4.105	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).
4.106	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).
4.107	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).
4.108	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).
4.109	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).
10.27	$400,000,000 Fifth Amended and Restated Credit Agreement, dated as of June 30, 2022, among Nevada Power Company, as Borrower, the Banks, Financial Institutions and Other Institutional Lenders, as Initial Lenders, Wells Fargo Bank, National Association, as Administrative Agent and the LC Issuing Banks (incorporated by reference to Exhibit 10.4 to the Nevada Power Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2022).

SIERRA PACIFIC

3.14	Restated Articles of Incorporation of Sierra Pacific Power Company, dated October 25, 2006 (incorporated by reference to Exhibit 3.1 to the Sierra Pacific Power Company Quarterly Report on Form 10-Q for quarter ended September 30, 2006).
3.15	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).
4.110	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).
4.111	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).
4.112	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).
10.28	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).
10.29	$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).
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.

Exhibit No.	Description
32.12	Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

BERKSHIRE HATHAWAY ENERGY AND SIERRA PACIFIC

4.113	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).
4.114	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).
4.115	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 4.2 to the Sierra Pacific Power Company Current Report on Form 8-K dated June 3, 2022).
4.116	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).
4.117	Officer's Certificate establishing the terms of Sierra Pacific Power Company's 3.375% General and Refunding Mortgage Notes, Series T, due 2023 (incorporated by reference to Exhibit 4.1 to the Sierra Pacific Power Company Current Report on Form 8-K dated August 14, 2013).
4.118	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).
4.119	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).
4.120	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).
4.121	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).
10.30	$250,000,000 Fifth Amended and Restated Credit Agreement, dated as of June 30, 2022, among Sierra Pacific Power Company, as Borrower, the Banks, Financial Institutions and Other Institutional Lenders, as Initial Lenders, Wells Fargo Bank, National Association, as Administrative Agent and the LC Issuing Banks (incorporated by reference to Exhibit 10.6 to the Sierra Pacific Power Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2022).

EASTERN ENERGY GAS

3.16	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).
3.17	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).
3.18	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).
10.31	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).
10.32	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).
31.13	Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

Exhibit No.	Description
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.

BERKSHIRE HATHAWAY ENERGY AND EASTERN ENERGY GAS

4.122	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).
4.123	Second 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 3.55% Senior Notes due 2023 (incorporated by reference to Exhibit 4.3, Form S-4, File No. 333-195066 dated April 4, 2014).
4.124	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).
4.125	Fifth 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 3.60% Senior Notes due 2024 (incorporated by reference to Exhibit 4.3 to the Eastern Energy Gas Holdings, LLC Current Report on Form 8-K dated December 8, 2014).
4.126	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).
4.127	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 Form 10-Q for the quarter ended June 30, 2016).
4.128	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 Form 10-Q for the quarter ended June 30, 2016).
4.129	Tenth 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 2.875% Senior Notes due 2023 (incorporated by reference to Exhibit 4.1.c to the Eastern Energy Gas Holdings, LLC Form 10-Q for the quarter ended June 30, 2016).
4.130	Eleventh Supplemental Indenture, dated June 1, 2018, by and between Dominion Energy Gas Holdings, LLC and Deutsche Bank Trust Company Americas, Trustee, relating to the Floating Rate Senior Notes due 2021 (incorporated by reference to Exhibit 4.2 to the Eastern Energy Gas Holdings, LLC Current Report on Form 8-K dated June 19, 2018).
4.131	Twelfth Supplemental Indenture, dated November 1, 2019, by and between Dominion Energy Gas Holdings, LLC and Deutsche Bank Trust Company Americas, Trustee, relating to the 2.50% Senior Notes due 2024 (incorporated by reference to Exhibit 4.2 to the Eastern Energy Gas Holdings, LLC Current Report on Form 8-K dated November 21, 2019).
4.132	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).
4.133	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).
4.134	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).

Exhibit No.	Description
4.135	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).
10.33	$400,000,000 Inter-Company Credit Agreement, dated as of November 1, 2020, by and between BHE GT&S, LLC and Eastern Energy Gas Holdings, LLC (incorporated by reference to Exhibit 10.3 to the Eastern Energy Gas Holdings, LLC Quarterly Report on Form 10-Q for the quarter ended September 30, 2020).

EASTERN GAS TRANSMISSION AND STORAGE

3.19	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).
3.20	Bylaws of Dominion Energy Transmission, Inc. (incorporated by reference to Exhibit 3.2, Form S-4, File No. 333-266049 dated July 25, 2022).
10.34	$400,000,000 Inter-Company Credit Agreement, dated as of November 1, 2020, by and between Eastern Energy Gas Holdings, LLC and Eastern Gas Transmission and Storage, Inc. (incorporated by reference to Exhibit 10.1, Form S-4, File No. 333-266049 dated July 25, 2022).
10.35	$400,000,000 Inter-Company Credit Agreement, dated as of March 26, 2021, by and between Eastern Gas Transmission and Storage, Inc. and Eastern Energy Gas Holdings, LLC (incorporated by reference to Exhibit 10.2, Form S-4, File No. 333-266049 dated July 25, 2022).
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

4.136	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 Berkshire Hathaway Energy Company and Eastern Energy Gas Holdings, LLC combined Quarterly Report on Form 10-Q for the quarter ended June 30, 2021).
4.137	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 Berkshire Hathaway Energy Company and Eastern Energy Gas Holdings, LLC combined Quarterly Report on Form 10-Q for the quarter ended June 30, 2021).
4.138	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 Berkshire Hathaway Energy Company and Eastern Energy Gas Holdings, LLC combined Quarterly Report on Form 10-Q for the quarter ended June 30, 2021).
4.139	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 Berkshire Hathaway Energy Company and Eastern Energy Gas Holdings, LLC combined Quarterly Report on Form 10-Q for the quarter ended June 30, 2021).
4.140	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 Berkshire Hathaway Energy Company and Eastern Energy Gas Holdings, LLC combined Quarterly Report on Form 10-Q for the quarter ended June 30, 2021).
4.141	Fifth 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 3.600% Senior Notes due 2024 (incorporated by reference to Exhibit 4.11 to the Berkshire Hathaway Energy Company and Eastern Energy Gas Holdings, LLC combined Quarterly Report on Form 10-Q for the quarter ended June 30, 2021).

Exhibit No.	**Description**
ALL REGISTRANTS	
101	The following financial information from each respective Registrant's Annual Report on Form 10-K for the year ended December 31, 2022 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.

* Management contract or compensatory plan.

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 24th day of February 2023.

BERKSHIRE HATHAWAY ENERGY COMPANY

/s/ William J. Fehrman*

William J. Fehrman
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/ William J. Fehrman* William J. Fehrman	Director, President and Chief Executive Officer (principal executive officer)	February 24, 2023
/s/ Calvin D. Haack* Calvin D. Haack	Senior Vice President and Chief Financial Officer (principal financial and accounting officer)	February 24, 2023
/s/ Gregory E. Abel* Gregory E. Abel	Chair of the Board of Directors	February 24, 2023
/s/ Warren E. Buffett* Warren E. Buffett	Director	February 24, 2023
/s/ Marc D. Hamburg* Marc D. Hamburg	Director	February 24, 2023
*By: /s/ Natalie L. Hocken Natalie L. Hocken	Attorney-in-Fact	February 24, 2023

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 24th day of February 2023.

PACIFICORP

/s/ Nikki L. Kobliha

Nikki L. Kobliha
Director, 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/ Scott W. Thon Scott W. Thon	Chair of the Board of Directors and Chief Executive Officer (principal executive officer)	February 24, 2023
/s/ Nikki L. Kobliha Nikki L. Kobliha	Director, Vice President, Chief Financial Officer and Treasurer (principal financial and accounting officer)	February 24, 2023
/s/ Stefan A. Bird Stefan A. Bird	Director	February 24, 2023
/s/ Calvin D. Haack Calvin D. Haack	Director	February 24, 2023
/s/ Natalie L. Hocken Natalie L. Hocken	Director	February 24, 2023
/s/ Gary W. Hoogeveen Gary W. Hoogeveen	Director	February 24, 2023

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 24th day of February 2023.

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 24, 2023
/s/ Thomas B. Specketer Thomas B. Specketer	Director, Vice President and Chief Financial Officer (principal financial and accounting officer)	February 24, 2023

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 24th day of February 2023.

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 24, 2023
/s/ Thomas B. Specketer Thomas B. Specketer	Vice President and Controller (principal financial and accounting officer)	February 24, 2023
/s/ Daniel S. Fick Daniel S. Fick	Manager	February 24, 2023
/s/ Calvin D. Haack Calvin D. Haack	Manager	February 24, 2023
/s/ Natalie L. Hocken Natalie L. Hocken	Manager	February 24, 2023

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 24th day of February 2023.

NEVADA POWER COMPANY

/s/ Douglas A. Cannon

Douglas A. Cannon
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/ Douglas A. Cannon Douglas A. Cannon	Director, President and Chief Executive Officer (principal executive officer)	February 24, 2023
/s/ Michael J. Behrens Michael J. Behrens	Interim Chief Financial Officer (principal financial and accounting officer)	February 24, 2023
/s/ Brandon M. Barkhuff Brandon M. Barkhuff	Director	February 24, 2023
/s/ Jennifer L. Oswald Jennifer L. Oswald	Director	February 24, 2023
/s/ Anthony F. Sanchez, III Anthony F. Sanchez, III	Director	February 24, 2023

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 24th day of February 2023.

SIERRA PACIFIC POWER COMPANY

/s/ Douglas A. Cannon

Douglas A. Cannon
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/ Douglas A. Cannon Douglas A. Cannon	Director, President and Chief Executive Officer (principal executive officer)	February 24, 2023
/s/ Michael J. Behrens Michael J. Behrens	Interim Chief Financial Officer (principal financial and accounting officer)	February 24, 2023
/s/ Brandon M. Barkhuff Brandon M. Barkhuff	Director	February 24, 2023
/s/ Jennifer L. Oswald Jennifer L. Oswald	Director	February 24, 2023
/s/ Anthony F. Sanchez, III Anthony F. Sanchez, III	Director	February 24, 2023

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 24th day of February 2023.

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 24, 2023
/s/ Scott C. Miller Scott C. Miller	Vice President, Chief Financial Officer and Treasurer (principal financial and accounting officer)	February 24, 2023
/s/ Mark A. Hewett Mark A. Hewett	Manager	February 24, 2023
/s/ Calvin D. Haack Calvin D. Haack	Manager	February 24, 2023
/s/ Natalie L. Hocken Natalie L. Hocken	Manager	February 24, 2023

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 24th day of February 2023.

EASTERN GAS TRANSMISSION AND STORAGE, INC.

/s/ Paul E. Ruppert

Paul E. Ruppert
President and Chair of the Board of Directors
(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 Chair of the Board of Directors (principal executive officer)	February 24, 2023
/s/ Scott C. Miller Scott C. Miller	Vice President, Chief Financial Officer, Treasurer and Director (principal financial and accounting officer)	February 24, 2023
/s/ Anne E. Bomar Anne E. Bomar	Senior Vice President, General Counsel and Director	February 24, 2023

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
BHE Pipeline Group, LLC	Delaware
BHE GT&S, LLC	Delaware
Eastern Energy Gas Holdings, LLC	Virginia
Eastern Gas Transmission and Storage, Inc.	Delaware
BHE Canada Holdings Corporation	Canada
BHE U.S. Transmission, LLC	Delaware
BHE Renewables, LLC	Delaware
HomeServices of America, Inc.	Delaware

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-228511 on Form S-8 of our report dated February 24, 2023, relating to the financial statements and financial statement schedule of Berkshire Hathaway Energy Company appearing in this Annual Report on Form 10-K.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
February 24, 2023

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EXHIBIT 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-249044 on Form S-3 of our report dated February 24, 2023, relating to the financial statements of PacifiCorp appearing in this Annual Report on Form 10-K.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 24, 2023

EXHIBIT 23.3

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-257069 on Form S-3 of our report dated February 24, 2023, relating to the financial statements of MidAmerican Energy Company appearing in this Annual Report on Form 10-K.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
February 24, 2023

EXHIBIT 23.4

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-267865 on Form S-3 of our report dated February 24, 2023 relating to the financial statements of Nevada Power Company appearing in this Annual Report on Form 10-K.

/s/ Deloitte & Touche LLP

Las Vegas, Nevada
February 24, 2023

EXHIBIT 24.1

POWER OF ATTORNEY

The undersigned, a member of the Board of Directors or an officer of BERKSHIRE HATHAWAY ENERGY COMPANY, an Iowa corporation (the "Company"), hereby constitutes and appoints Natalie L. Hocken and Jeffery B. Erb and each of them, as his/her true and lawful attorney-in-fact and agent, with full power of substitution and resubstitution, for and in his/her stead, in any and all capacities, to sign on his/her behalf the Company's Annual Report on Form 10-K for the fiscal year ending December 31, 2022 and to execute any amendments thereto and to file the same, with all exhibits thereto, and all other documents in connection therewith, with the Securities and Exchange Commission and applicable stock exchanges, with the full power and authority to do and perform each and every act and thing necessary or advisable to all intents and purposes as he/she might or could do in person, hereby ratifying and confirming all that said attorney-in-fact and agent, or his/her substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Executed as of February 24, 2023

/s/ William J. Fehrman	/s/ Calvin D. Haack
WILLIAM J. FEHRMAN	CALVIN D. HAACK
/s/ Gregory E. Abel	/s/ Warren E. Buffett
GREGORY E. ABEL	WARREN E. BUFFETT
/s/ Marc D. Hamburg	
MARC D. HAMBURG	

EXHIBIT 31.1

CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002

I, William J. Fehrman, 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 24, 2023

/s/ William J. Fehrman
William J. Fehrman
President and Chief Executive Officer
(principal executive officer)

EXHIBIT 31.2

CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002

I, Calvin D. Haack, 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 24, 2023

/s/ Calvin D. Haack
Calvin D. Haack
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, Scott W. Thon, 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 24, 2023

/s/ Scott W. Thon

Scott W. Thon
Chair of the Board of Directors and Chief Executive Officer
(principal executive officer)

EXHIBIT 31.4

CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002

I, Nikki L. Kobliha, 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 24, 2023

/s/ Nikki L. Kobliha
Nikki L. Kobliha
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 24, 2023

/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, Thomas B. Specketer, 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 24, 2023

/s/ Thomas B. Specketer
Thomas B. Specketer
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 24, 2023

/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, Thomas B. Specketer, 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 24, 2023

/s/ Thomas B. Specketer
Thomas B. Specketer
Vice President and Controller
(principal financial officer)

EXHIBIT 31.9

CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002

I, Douglas A. Cannon, 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 24, 2023

/s/ Douglas A. Cannon
Douglas A. Cannon
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 24, 2023

/s/ Michael J. Behrens
Michael J. Behrens
Interim Chief Financial Officer
(principal financial officer)

EXHIBIT 31.11

**CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Douglas A. Cannon, 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 24, 2023

/s/ Douglas A. Cannon
Douglas A. Cannon
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 24, 2023

/s/ Michael J. Behrens
Michael J. Behrens
Interim 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 24, 2023

/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 24, 2023

/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 24, 2023

/s/ Paul E. Ruppert
Paul E. Ruppert
President and Chair of the Board of Directors
(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 24, 2023

/s/ Scott C. Miller
Scott C. Miller
Vice President, Chief Financial Officer, Treasurer and Director
(principal financial officer)

EXHIBIT 32.1

CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

I, William J. Fehrman, 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, 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 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 24, 2023

/s/ William J. Fehrman
William J. Fehrman
President and Chief Executive Officer
(principal executive officer)

EXHIBIT 32.2

**CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Calvin D. Haack, 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, 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 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 24, 2023

/s/ Calvin D. Haack
Calvin D. Haack
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, Scott W. Thon, Chair of the Board of Directors and 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, 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 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 24, 2023

/s/ Scott W. Thon
Scott W. Thon
Chair of the Board of Directors and Chief Executive Officer
(principal executive officer)

EXHIBIT 32.4

CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

I, Nikki L. Kobliha, Vice President, Chief Financial Officer and Treasurer 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, 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 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 24, 2023

/s/ Nikki L. Kobliha
Nikki L. Kobliha
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, 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 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 24, 2023

/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, Thomas B. Specketer, 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, 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 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 24, 2023

/s/ Thomas B. Specketer
Thomas B. Specketer
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, 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 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 24, 2023

/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, Thomas B. Specketer, 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, 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 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 24, 2023

/s/ Thomas B. Specketer
Thomas B. Specketer
Vice President and Controller
(principal financial officer)

EXHIBIT 32.9

CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

I, Douglas A. Cannon, 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, 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 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 24, 2023

/s/ Douglas A. Cannon
Douglas A. Cannon
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, Interim 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, 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 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 24, 2023

/s/ Michael J. Behrens
Michael J. Behrens
Interim Chief Financial Officer
(principal financial officer)

EXHIBIT 32.11

CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

I, Douglas A. Cannon, 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, 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 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 24, 2023

/s/ Douglas A. Cannon
Douglas A. Cannon
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, Interim 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, 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 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 24, 2023

/s/ Michael J. Behrens
Michael J. Behrens
Interim 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 24, 2023

/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 24, 2023

/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, President and Chair of the Board of Directors 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 24, 2023

/s/ Paul E. Ruppert
Paul E. Ruppert
President and Chair of the Board of Directors
(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 24, 2023

/s/ Scott C. Miller
Scott C. Miller
Vice President, Chief Financial Officer, Treasurer and Director
(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, 2022 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, 2022 are not included in the information below. There were no mining-related fatalities during the year ended December 31, 2022. 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, 2022.

	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	—	—	1
Bridger (underground)	—	—	—	—	—	—	1	2	2
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) Includes one labor-related complaint under Subpart E 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 MSHA during the reporting period.

APPENDIX B

PacifiCorp
State of California
ECAC/GHG Application
Statement of Present and Proposed Rates

Tariff Schedules	Present Rates	Proposed Rates	
Schedule D (Standard Residential)			
Basic Charge	$8.12	$8.12	/month
Energy Charge			
Baseline kWh	16.236	20.246	¢/kWh
Non-Baseline kWh	18.297	22.307	¢/kWh
Schedule DL-6 (Residential CARE)			
Basic Charge	$6.50	$6.50	/month
Energy Charge			
Baseline kWh	12.532	15.740	¢/kWh
Non-Baseline kWh	14.181	17.389	¢/kWh
Schedule A-25 Secondary			
Basic Charge			
1 Phase	$15.66	$15.66	/month
3 Phase	$21.49	$21.49	/month
Energy Charge	18.616	22.437	¢/kWh
Schedule A-25 Primary			
Basic Charge			
1 Phase	$15.66	$15.66	/month
3 Phase	$21.49	$21.49	/month
Energy Charge	18.431	22.214	¢/kWh
Schedule A-32 Secondary			
Basic Charge			
1 Phase	$14.39	$14.39	/month
3 Phase	$19.75	$19.75	/month
Distribution Demand Charge	$1.80	$1.80	/kW
Generation & Transmission Demand Charge	$4.40	$6.67	/kW
Energy Charge	13.682	16.530	¢/kWh
Reactive Power	60.00	60.00	¢/kVar
Schedule A-32 Primary			
Basic Charge			
1 Phase	$14.39	$14.39	/month
3 Phase	$19.75	$19.75	/month
Distribution Demand Charge	$1.26	$1.26	/kW
Generation & Transmission Demand Charge	$4.40	$6.67	/kW
Energy Charge	13.546	16.366	¢/kWh
Reactive Power	60.00	60.00	¢/kVar
High Voltage Charge	$60.00	$60.00	/month

Reflects present rates in effect at the time of the intial filing in this docket.

PacifiCorp
State of California
ECAC/GHG Application
Statement of Present and Proposed Rates

Tariff Schedules	Present Rates	Proposed Rates	
Schedule A-36 Secondary			
Basic Charge	$256.68	$256.68	/month
Distribution Demand Charge	$3.32	$3.32	/kW
Generation & Transmission Demand Charge	$8.41	$13.19	/kW
Energy Charge	10.635	13.659	¢/kWh
Reactive Power	60.00	60.00	¢/kVar
Schedule A-36 Primary			
Basic Charge	$256.68	$256.68	/month
Distribution Demand Charge	$2.32	$2.32	/kW
Generation & Transmission Demand Charge	$8.41	$13.19	/kW
Energy Charge	10.530	13.524	¢/kWh
Reactive Power	60.00	60.00	¢/kVar
High Voltage Charge	$60.00	$60.00	/month
Schedule AT-48 Secondary			
Basic Charge	$464.40	$464.40	/month
Distribution Demand Charge	$1.99	$1.99	/kW
Generation & Transmission Demand Charge (Summer)	$6.83	$11.41	/kW
Generation & Transmission Demand Charge (Winter)	$7.49	$12.07	/kW
Energy Charge	9.041	12.225	¢/kWh
Reactive Power	60.00	60.00	¢/kVar
Schedule AT-48 Primary/Transmission			
Basic Charge	$464.40	$464.40	/month
Distribution Demand Charge	$1.39	$1.39	/kW
Generation & Transmission Demand Charge (Summer)	$6.83	$11.41	/kW
Generation & Transmission Demand Charge (Winter)	$7.49	$12.07	/kW
Energy Charge	8.952	12.104	¢/kWh
Reactive Power	60.00	60.00	¢/kVar
High Voltage Charge	$60.00	$60.00	/month
Schedule PA-20			
Basic Charge - Annually (billed in November)			
1 Phase Any Size, 3 Phase <= 50kW	$81.75	$81.75	
3 Phase Load Size > 50 kW	$168.89	$168.89	
Distribution Demand Charge - Annually (billed in November)	$18.02	$18.02	/kW
Generation & Transmission Demand Charge	$5.64	$8.27	/kW
Energy Charge	12.179	15.081	¢/kWh
Reactive Power	60.00	60.00	¢/kVar

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PacifiCorp
State of California
ECAC/GHG Application
Statement of Present and Proposed Rates

Tariff Schedules				Present Rates	Proposed Rates	
Schedule OL-15						
	lumen		*kWh*			
Mercury Vapor	7,000		76	$21.53	$24.07	/Lamp
Mercury Vapor	21,000		172	$45.66	$51.41	/Lamp
Mercury Vapor	55,000		412	$104.26	$118.05	/Lamp
High Pressure Sodium	5,800		31	$16.51	$17.55	/Lamp
High Pressure Sodium	22,000		85	$31.19	$34.03	/Lamp
High Pressure Sodium	50,000		176	$56.60	$62.50	/Lamp
Schedule OL-42						
Basic Charge						
Single Phase				$10.07	$10.07	/month
Three Phase				$13.79	$13.79	/month
All kWh				21.071	24.727	¢/kWh
Schedule LS-51						
	lumen	*Watts*	*kWh*			
HPSV - Functional						
High Pressure Sodium	5,800	70	31	$12.55	$13.50	/Lamp
High Pressure Sodium	9,500	100	44	$15.32	$16.68	/Lamp
High Pressure Sodium	16,000	150	64	$21.14	$23.11	/Lamp
High Pressure Sodium	22,000	200	85	$27.18	$29.79	/Lamp
High Pressure Sodium	27,500	250	115	$35.86	$39.40	/Lamp
High Pressure Sodium	50,000	400	176	$53.80	$59.21	/Lamp
Decorative Series 1						
High Pressure Sodium	9,500	100	44	$38.20	$39.56	/Lamp
High Pressure Sodium	16,000	150	64	$41.49	$43.46	/Lamp
Decorative Series 2						
High Pressure Sodium	9,500	100	44	$31.78	$33.14	/Lamp
High Pressure Sodium	16,000	150	64	$35.02	$36.99	/Lamp
LED - Functional						
Light Emitting Diode	4,000	50	17	$11.38	$11.91	/Lamp
Light Emitting Diode	6,200	75	25	$15.66	$16.43	/Lamp
Light Emitting Diode	13,000	135	47	$29.60	$31.04	/Lamp
Light Emitting Diode	16,800	185	64	$43.42	$45.39	/Lamp

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PacifiCorp
State of California
ECAC/GHG Application
Statement of Present and Proposed Rates

Tariff Schedules				Present Rates	Proposed Rates	
Schedule LS-53						
	lumen	*Watts*	*kWh*			
High Pressure Sodium	5,800	70	31	$5.42	$6.65	/Lamp
High Pressure Sodium	9,500	100	44	$7.69	$9.45	/Lamp
High Pressure Sodium	16,000	150	64	$11.16	$13.70	/Lamp
High Pressure Sodium	22,000	200	85	$14.86	$18.24	/Lamp
High Pressure Sodium	27,500	250	115	$20.07	$24.66	/Lamp
High Pressure Sodium	50,000	400	176	$30.74	$37.74	/Lamp
Non-Listed Luminaire				17.464	21.442	¢/kWh
Schedule LS-58						
Class A	*lumen*		*kWh*			
Incandescent	2,500		73	$15.33	$18.10	/Lamp
Mercury Vapor	7,000		76	$15.97	$18.86	/Lamp
Mercury Vapor	21,000		172	$36.15	$42.67	/Lamp

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APPENDIX C

Appendix C
PacifiCorp
Summary of Earnings
Twelve Months Ended December 31, 2022

Line	Item	California
1	Operating Revenue	$111,438,373
2	Operating Expenses	$92,203,880
3	Operating Revenue for Return	$19,234,493
4	Total Rate Base	$343,774,805
5	Return on Rate Base	5.60%